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FPSC - COMMISSION CLERK

Docket 140001-EI
Comprehensive Exhibit List for Entry into Hearing Record
October 22, 2014

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF				
1		Exhibit List	Comprehensive Exhibit List	**Stipulated**
FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)				
2	G. J. Yupp	GJY-1	2013 Incentive Mechanism Results	**Stipulated**
3	G. J. Yupp	GJY-2	August 2013 through December 2013 Hedging Activity True-up Report	**Stipulated**
4	G. J. Yupp	GJY-3	FCR 2015 Risk Management Plan	**Stipulated**
5	G. J. Yupp	GJY-4	Hedging Activity Report	**Stipulated**
6	G. J. Yupp	GJY-5	Fuel Cost Recovery Forecast Assumptions	**Stipulated**
7	Terry J. Keith	TJK-1	Fuel Cost Recovery 2013 Final True Up Calculation	**Stipulated**
8	Terry J. Keith	TJK-2	Capacity Cost Recovery 2013 Final True Up Calculation	**Stipulated**
9	Terry J. Keith	TJK-3	FCR 2014 Actual/Estimated True Up Calculation	**Stipulated**
10	Terry J. Keith	TJK-4	CCR 2014 Actual/Estimated True Up Calculation	**Stipulated**
11	Terry J. Keith	TJK-5	FCR 2015 E-Schedules (with Gas Reserves Project) Jan through Dec 2015	**Stipulated**

12	Terry J. Keith	TJK-6	FCR 2015 E-Schedules (without Gas Reserves Project) Jan through Dec 2015	**Stipulated**
13	Terry J. Keith	TJK-7	CCR 2015 E-Schedules (with Gas Reserves Project) January through December 2015	**Stipulated**
14	Terry J. Keith	TJK-8	CCR 2015 E-Schedules (without Gas Reserves Project) January through December 2015	**Stipulated**
15	Terry J. Keith	TJK-9	2015 Revenue Requirement Calculation for West County Energy Center Unit 3	**Stipulated**
16	J. C. Bullock	JCB-1	Generating Performance Incentive Factor Performance Results for January 2013 through December 2013	**Stipulated**
17	J. C. Bullock	JCB-2	Generating Performance Incentive Factor Performance Targets for January 2015 through December 2015 (with Gas Reserves Project)	**Stipulated**
18	J. C. Bullock	JCB-3	Generating Performance Incentive Factor Performance Targets for January 2015 through December 2015 (without Gas Reserves Project)	**Stipulated**
DUKE ENERGY FLORIDA (DEF)(DIRECT)				
19	Thomas G. Foster	TGF-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2013)	**Stipulated**
20	Thomas G. Foster	TGF-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2013)	**Stipulated**
21	Thomas G. Foster	TGF-3T	Schedules A1 through A3, A6 and A12 for Dec 2013	**Stipulated**
22	Thomas G. Foster	TGF-4T	2013 Capital Structure and Cost Rates Applied to Capital Projects	**Stipulated**
23	Thomas G. Foster	TGF-2	Actual/Estimated true-up Schedules for period January – December 2014	**Stipulated**
24	Thomas G. Foster	TGF-3	Projection factors for January to December 2015	**Stipulated**

24A	James McClay	JM-1T	Hedging Details, January – December 2013	**Stipulated**
25	James McClay	JM-1P	2015 Risk Management Plan	**Stipulated**
26	James McClay	JM-2P	Hedging Report (January – July 2014)	**Stipulated**
27	Matthew J. Jones	MJJ-1T	GPIF Reward/Penalty Schedules for 2013	**Stipulated**
28	Matthew J. Jones	MJJ-1P	GPIF Targets/Ranges Schedules (for Jan – Dec. 2015)	**Stipulated**
FLORIDA PUBLIC UTILITIES COMPANY (FPUC) (DIRECT)				
29	Curtis D. Young	CDY-1	Final True Up Schedules (Schedules F-1 and M-1 for FPUC's Divisions)	**Stipulated**
30	Curtis D. Young	CDY-2	Estimated/Actual (Schedules El-A, El-B, and El-B1 for the Northwest Division and El-A, El-B, and El-B1 for the Northeast Division) (Revised)	**Stipulated**
31	Curtis D. Young P. Mark Cutshaw (Panel)	CDY-3	Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and E1, E1A, E2, E7, E8, and E10 for the Northeast Division, including revised pages 8, 14, and 22 that reflect the approval of new base rates per Docket 140025-EI	**Stipulated**
GULF POWER (GULF)(DIRECT)				
32	H. R. Ball	HRB-1	Coal Suppliers, Natural Gas Price Variance, Hedging Effectiveness	**Stipulated**
33	H. R. Ball	HRB-2	Purchase power agreement between Gulf Power and Bay County	**Stipulated**
34	H. R. Ball	HRB-3	Projected vs. Actual Fuel Cost of System Generation Comparison 2004 - 2015	**Stipulated**

35	H. R. Ball	HRB-4	Hedging Information Report August – December 2012 (sic) (2013)	**Stipulated**
36	H. R. Ball	HRB-5	Hedging Information Report January – July 2014	**Stipulated**
37	H. R. Ball	HRB-6	Risk Management Plan for Fuel Procurement for 2015	**Stipulated**
38	C. S. Boyett	RWD-1	Calculation of Final True-Up and A-Schedules January 2013 – December 2013	**Stipulated**
39	C. S. Boyett	CSB-1	Estimated True-Up January 2014 – December 2014	**Stipulated**
40	C. S. Boyett	CSB-2	Projection January 2015 – December 2015	**Stipulated**
41	M. A. Young	MAY-1	Gulf Power Company GPIF Results January 2013 – December 2013	**Stipulated**
42	M. A. Young	MAY-2	Gulf Power Company GPIF Targets and Ranges January 2015 – December 2015	**Stipulated**
TAMPA ELECTRIC COMPANY (TECO)(DIRECT)				
43	Penelope A. Rusk	PAR-1	For January 2013 - December 2013: Final True-up Capacity Cost Recovery; Final True-up Fuel Cost Recovery; Actual Fuel True-up compared to Original Estimates; Schedules A-1, A-2 and A-6 through A-9 and A-12; Calculation of Revenue Requirement Rate of Return; and Final True-Up Polk Unit 1 Ignition Oil Conversion	**Stipulated**
44	Penelope A. Rusk	PAR-2	For January 2014 – December 2014: Actual/Estimated True-Up Fuel Cost Recovery; Actual/Estimated True-Up Capacity Cost Recovery; and Actual/Estimated True-Up Polk Unit 1 Ignition Oil Conversion	**Stipulated**

45	Penelope A. Rusk	PAR-3	For January 2015 – December 2015: Projected Capacity Cost Recovery; Projected Fuel Cost Recovery; Levelized and Tiered Fuel Rate; and Capital Projects Approved for Fuel Clause Recovery	**Stipulated**
46	Brian S. Buckley	BSB-1	For January 2013 – December 2013: Final True-Up Generating Performance Incentive Factor and Actual Unit Performance Data	**Stipulated**
47	Brian S. Buckley	BSB-2	For January 2015 – December 2015: Generating Performance Incentive Factor and Summary of Generating Performance Incentive Factor Targets	**Stipulated**
48	Brent C. Caldwell	JBC-1	Final True-Up Hedging Activity Report - January 2013 – December 2013	**Stipulated**
49	Brent C. Caldwell	JBC-2	Risk Management Plan - January 2015 – December 2015	**Stipulated**
50	Brent C. Caldwell	JBC-3	Natural Gas Hedging Report - January 2014 – July 2014	**Stipulated**
STAFF				
51	Simon O. Ojada	SOO-1	Commission Staff's Auditor Report for DEF Hedging Activities Twelve Months Ended July 31, 2014	**Stipulated**
52	Iliana H. Piedra	IHP-1	Commission Staff's Auditor Report for FPL Hedging Activities Twelve Months Ended July 31, 2014	**Stipulated**
53	Debra M. Dobiac	DD-1	Commission Staff's Auditor Report for Gulf Hedging Activities Twelve Months Ended July 31, 2014	**Stipulated**
54	Intesar Terkawi	IT-1	Commission Staff's Auditor Report for TECO Hedging Activities Twelve Months Ended July 31, 2014	**Stipulated**

55			FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-11) *[Bates Nos. 0001- 0015]*	**Stipulated**
56			FPL's Responses to Staff's Second Set of Interrogatories (No. 55) *[Bates Nos. 0016-0017]*	**Stipulated**
57			FPL's Responses to Staff's Fifth Set of Interrogatories (No. 154 **(CONFIDENTIAL** Nos. 155,164 *[Bates Nos. 0018-0035]*	**Stipulated**
58			FPL's Responses to Staff's Sixth Set of Interrogatories,Nos. 165,166 *[Bates Nos. 0036-0039]*	**Stipulated**
59			DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-11) *[Bates Nos. 0040-0053]*	**Stipulated**
60			DEF's Responses to Staff's Second Set of Interrogatories (Nos. 12, 13, 14 **(CONFIDENTIAL)**, 15-17, 18 **(CONFIDENTIAL)**, 19 **(CONFIDENTIAL),** and 20-27) *[Bates Nos. 0054-0072]*	**Stipulated**
61			FPUC's Responses to Staff's First Set of Interrogatories (Nos. 1-2) *[Bates Nos. 0073-0079]*	**Stipulated**
62			FPUC's Responses to Staff's Second Set of Interrogatories (Nos. 3, 4, 5, and Amended 5) *[Bates Nos. 0080-0160]*	**Stipulated**
63			FPUC's Responses to Staff's 4th Set of Interrogatories (Nos. 15-20) *[Bates Nos. 0161-0169]*	**Stipulated**
64			Gulf's Responses to Staff's First Set of Interrogatories (Nos. 1-11) *[Bates Nos. 0170-0185]*	**Stipulated**
65			Gulf's Responses to Staff's Second Set of Interrogatories (Nos. 12 **(CONFIDENTIAL)**, 13, 14 **(CONFIDENTIAL)**, and 15-25) *[Bates Nos. 0186-0207]*	**Stipulated**
66			Gulf's Responses to Staff's Third Set of Interrogatories (No. 26) *[Bates Nos. 0208-0211]*	**Stipulated**

67			TECO's Responses to Staff's First Set of Interrogatories (Nos. 1-11) *[Bates Nos. 0212-0234]*	**Stipulated**
68			TECO's Responses to Staff's Second Set of Interrogatories (Nos. 12 **(CONFIDENTIAL)**, 13, 14, 15 **(CONFIDENTIAL),** 16 **(CONFIDENTIAL)**, and 17-23) *[Bates Nos. 0235-0265]*	**Stipulated**
HEARING EXHIBITS				
Exh No.	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
69	Foster	OPC	RRSSA Excerpt	
70	Foster	OPC	DEF Summary of NEIL Reimbursement	
71	Foster	OPC	Fuel Cost Recovery Schedules	
72	Foster	Duke Energy	2014 AFUDC on CR3/Updated EXH 10	

APPENDIX III

FUEL COST RECOVERY

2013 INCENTIVE MECHANISM RESULTS

GJY-1
DOCKET NO. 140001-EI
FPL WITNESS: GERARD J. YUPP
PAGES 1-4
EXHIBIT ____
MARCH 3, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 2
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: G. J. Yupp GJY-1

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2013 through December 2013

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	876,040	25,150	252,822	1,154,012	1,154,012	0	0	0
February	1,798,400	13,766	468,770	2,280,936	2,280,936	0	0	0
March	1,818,389	91,330	386,343	2,296,061	2,296,061	0	0	0
April	854,235	813,190	1,323,425	2,990,850	2,990,850	0	0	0
May	847,782	29,181	1,260,419	2,137,382	2,137,382	0	0	0
June	563,113	68,212	1,014,037	1,645,363	1,645,363	0	0	0
July	638,137	30,044	1,137,216	1,805,396	1,805,396	0	0	0
August	431,258	531,754	908,988	1,871,999	1,871,999	0	0	0
September	477,686	545,306	1,122,089	2,145,081	2,145,081	0	0	0
October	593,686	948,788	1,016,305	2,558,780	2,558,780	0	0	0
November	1,114,617	102,373	557,181	1,774,171	1,774,171	0	0	0
December	1,139,662	6,653	757,524	1,903,839	1,903,839	0	0	0
Total	**11,153,006**	**3,205,747**	**10,205,119**	**24,563,872**	**24,563,872**	**0**	**0**	**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	1,154,012	0	0	0	0	0	1,154,012	0
February	2,280,936	0	0	0	0	0	2,280,936	0
March	2,296,061	0	0	0	0	0	2,296,061	0
April	2,990,850	0	0	0	0	0	2,990,850	0
May	2,137,382	0	0	0	0	0	2,137,382	0
June	1,645,363	0	0	0	0	0	1,645,363	0
July	1,805,396	0	0	0	0	0	1,805,396	0
August	1,871,999	0	0	0	0	0	1,871,999	0
September	2,145,081	0	0	0	0	0	2,145,081	0
October	2,558,780	0	0	0	0	0	2,558,780	0
November	1,774,171	0	0	0	0	0	1,774,171	0
December	1,903,839	0	0	0	0	0	1,903,839	0
Total	**24,563,872**	**0**	**0**	**0**	**0**	**0**	**24,563,872**	**0**

WHOLESALE POWER DETAIL
Actual for the Period of: January 2013 through December 2013

Wholesale Sales - Table 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Month	OS Wholesale Sales (MWh)	FCBBS Wholesale Sales (MWh)	Total Wholesale Sales (MWh)	OS Gross Gains ($)	FCBBS Gross Gains ($)	Incremental GT O&M Costs ($)	Variable Power Plant O&M Costs ($)	Power Option Premiums ($)	Total Net Wholesale Sales Gains ($)
	Schedule A6	Schedule A6	(2) + (3)	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(5)+(6)+(7)+(8)+(9)
January	142,553	1,358	143,911	867,833	8,207	0	0	0	876,040
February	272,757	4,864	277,621	1,723,631	20,639	(2,640)	0	56,769	1,798,400
March	332,474	6,778	339,252	2,148,552	34,537	0	(364,700)	0	1,818,389
April	202,954	656	203,610	1,054,648	4,668	(5,937)	(315,395)	116,250	854,235
May	150,596	268	150,864	1,021,644	1,627	(8,184)	(227,805)	60,500	847,782
June	82,966	179	83,145	696,460	878	(8,676)	(125,549)	0	563,113
July	100,994	2,015	103,009	782,141	11,539	0	(155,543)	0	638,137
August	83,551	633	84,184	564,544	3,442	(9,610)	(127,118)	0	431,258
September	87,192	818	88,010	612,371	5,213	(7,003)	(132,895)	0	477,686
October	96,375	134	96,509	698,737	707	(12,448)	(145,729)	52,419	593,686
November	184,762	570	185,332	1,257,203	3,060	(6,494)	(262,136)	122,984	1,114,617
December	188,634	682	189,316	1,377,367	3,378	0	(303,582)	62,500	1,139,662
Total	**1,925,808**	**18,955**	**1,944,763**	**12,805,132**	**97,895**	**(60,991)**	**(2,160,452)**	**471,422**	**11,153,006**

Wholesale Purchases - Table 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Month	OS Wholesale Purchases (MWh)	FCBBS Wholesale Purchases (MWh)	Total Wholesale Purchases (MWh)	OS Savings ($)	FCBBS Savings ($)	Total Schedule A9 Savings ($)	Capacity Purchases (MWh)	Net Capacity Purchases Savings ($)	Total Wholesale Purchases Savings ($)
	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A7/A12		(7) + (9)
January	3,035	50	3,085	25,023	127	25,150	0	0	25,150
February	1,955	0	1,955	13,766	0	13,766	0	0	13,766
March	3,420	25	3,445	91,347	(17)	91,330	0	0	91,330
April	30,893	1,087	31,980	805,652	7,537	813,190	0	0	813,190
May	2,756	309	3,065	27,265	1,916	29,181	0	0	29,181
June	4,275	236	4,511	66,471	1,741	68,212	0	0	68,212
July	3,295	197	3,492	29,152	891	30,044	0	0	30,044
August	22,748	39	22,787	531,577	177	531,754	0	0	531,754
September	33,130	298	33,428	543,087	2,219	545,306	0	0	545,306
October	34,603	469	35,072	946,043	2,745	948,788	0	0	948,788
November	4,440	155	4,595	100,909	1,464	102,373	0	0	102,373
December	562	0	562	6,653	0	6,653	0	0	6,653
Total	**145,112**	**2,865**	**147,977**	**3,186,946**	**18,801**	**3,205,747**	**0**	**0**	**3,205,747**

*Capacity Cost Recovery Clause - Option premium gains are inlcuded under Transmission Revenues from Capacity Sales line item.

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2013 through December 2013

(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	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	252,822
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	468,770
March	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	386,343
April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,323,425
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,260,419
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,014,037
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,137,216
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	908,988
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,122,089
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,016,305
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	557,181
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	757,524
Total	**908,857**	**2,649,611**	**678,798**	**3,162,795**	**158,513**	**1,569,554**	**1,076,991**	**10,205,119**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2013 through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Incremental O&M							
Month	Personnel Expenses ($)	Other Expenses* ($)	Wholesale Sales (MWh)	Cumulative Wholesale Sales (MWh)	Wholesale Sales Threshold (MWh)	Wholesale Sales Above Threshold (MWh)	Incremental Variable Power Plant O&M ($)	Total Incremental O&M Expenses ($)
	Schedule A2	Schedule A2					Schedule A2/A6	(2) + (3) + (8)
January	0	0	143,911	143,911	514,000	0	0	0
February	0	0	277,621	421,532	514,000	0	0	0
March	0	0	339,252	760,784	514,000	246,784	364,700	364,700
April	20,622	0	203,610	964,394	514,000	203,610	315,395	336,017
May	21,401	0	150,864	1,115,258	514,000	150,864	227,805	249,206
June	28,231	0	83,145	1,198,403	514,000	83,145	125,549	153,780
July	33,219	0	103,009	1,301,412	514,000	103,009	155,543	188,762
August	32,033	0	84,184	1,385,596	514,000	84,184	127,118	159,151
September	30,798	0	88,010	1,473,606	514,000	88,010	132,895	163,693
October	33,542	0	96,509	1,570,115	514,000	96,509	145,729	179,271
November	30,658	0	185,332	1,755,447	514,000	185,332	262,136	292,794
December	32,904	0	189,316	1,944,763	514,000	189,316	303,582	336,486
Total	**263,407**	**0**	**1,944,763**			**1,430,763**	**2,160,452**	**2,423,859**

*Includes software and hardware expenses

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	YEAR-TO-DATE (JAN - DEC) 2013	FIXED PRICE TRANSACTIONS	[redacted]			[redacted]
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
9						$ 18,253,045
10						
11						
12		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 3
PARTY: FLORIDA POWER & LIGHT
COMPANY (FPL) (DIRECT)
DESCRIPTION: G. J. Yupp GJY-2

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME (BARRELS)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	YEAR-TO-DATE (JAN - DEC) 2013	FIXED PRICE TRANSACTIONS	[redacted]	[redacted]	[redacted]	[redacted]
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
9						$ (710,650)
10						
11						
12		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

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-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
9						
10						
11						
12						

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	January-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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4	March-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	May-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	July-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	August-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	October-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	November-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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APPENDIX III

FUEL COST RECOVERY

2015 RISK MANAGEMENT PLAN

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 4
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: G. J. Yupp GJY-3

GJY-3
DOCKET NO. 140001-EI
FPL WITNESS: G. J. YUPP
EXHIBIT _____
JULY 25, 2014

APPENDIX III

2015 RISK MANAGEMENT PLAN

TABLE OF CONTENTS

PAGES	DESCRIPTION	SPONSOR
1-7	2015 Risk Management Plan	G. J. Yupp
1-60	Trading and Risk Management Procedures Manual	G. J. Yupp
1-27	Energy Trading and Risk Management Policy	G. J. Yupp
1-6	Planned Position Strategy	G. J. Yupp

Florida Power and Light Company
2015 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, either directly or through his delegates. 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.

2015 Hedging Strategy (TFB-4, Items 2 and 8)

FPL plans to hedge a portion of its projected 2016 natural gas requirements during 2015. 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:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2016 natural gas requirements within the Hedging Window during 2015. This hedge percentage is consistent with 2015 hedge levels and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.

2) FPL will utilize [redacted] to hedge its projected natural gas requirements.

3) Should FPL enter into any joint venture transactions for natural gas reserves and these transactions are approved by the FPSC, the expected natural gas production from these transactions will be included as hedged volumes.

4) FPL will execute its natural gas hedges for 2016 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2016 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

5) 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. The monthly tolerance bands for natural gas are [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Heavy Fuel Oil

FPL does not intend to hedge heavy fuel oil for 2016. 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 energy, spot and forward, unrealized profit and loss, VaR, and position amounts. 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 Senior Director 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 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 the new rules will have on its ability to hedge commodity risks or the impact 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.

Energy Marketing & Trading

A division of Florida Power & Light Company

Trading and Risk Management

Procedures Manual

Revision: May 2014

Approved By the EMC on January 2, 2014
(If the original signature is needed, please contact Risk Management at 304-6028)

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 60]

Trading and Risk Management Procedures Manual

APPROVED BY THE EMC ON:

Last approved on January 2, 2014

(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 6]

Planned Position Strategy

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7		BROKER FEES				
8						$ 131,436,091
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11		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 5
PARTY: FLORIDA POWER & LIGHT
COMPANY (FPL) (DIRECT)
DESCRIPTION: G. J. Yupp GJY-4

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4	February-2014	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

GJY-4
Docket No. 140001-EI
FPL Witness: Gerard J. Yupp
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August 13, 2014

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-2014	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-2014	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

GJY-4
Docket No. 140001-EI
FPL Witness: Gerard J. Yupp
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August 13, 2014

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-2014	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
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Docket No. 140001-EI
FPL Witness: Gerard J. Yupp
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August 13, 2014

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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	June-2014	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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9						
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GJY-4
Docket No. 140001-EI
FPL Witness: Gerard J. Yupp
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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	July-2014	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

APPENDIX I

FUEL COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 6
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: G. J. Yupp GJY-5

GJY-5
DOCKET NO. 140001-EI
FPL WITNESS: GERARD J. YUPP
EXHIBIT _____
PAGES 1-4
AUGUST 22, 2014

APPENDIX I

FUEL COST RECOVERY

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PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs	G. J. Yupp
3	Projected Availability of Natural Gas	G. J. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. J. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2015

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	97.37	97.37	97.37	97.32	97.32	97.32	96.14	96.14	96.14	96.14	96.14	96.14
0.7% Sulfur Grade ($/mmBtu)	15.21	15.21	15.21	15.21	15.21	15.21	15.02	15.02	15.02	15.02	15.02	15.02

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	134.83	134.74	134.28	133.72	133.21	132.74	132.52	132.44	132.39	132.35	132.33	132.27
0.05% Sulfur Grade ($/mmBtu)	23.13	23.11	23.03	22.94	22.85	22.77	22.73	22.72	22.71	22.70	22.70	22.69

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	1,150,000	1,150,000	1,150,000	1,239,000	1,324,000	1,324,000	1,324,000	1,324,000	1,324,000	1,239,000	1,150,000	1,150,000
Firm Gulfstream (mmBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Non-Firm FGT (mmBtu/Day)	100,000	100,000	100,000	100,000	75,000	50,000	50,000	50,000	50,000	75,000	100,000	100,000
Non-Firm Gulfstream (mmBtu/Day)	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000
Total Projected Daily Availability (mmBtu/Day)	1,995,000	1,995,000	1,995,000	2,084,000	2,144,000	2,119,000	2,069,000	2,069,000	2,069,000	2,009,000	1,995,000	1,995,000
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)**	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Gulf South Pipeline Company (Gulf South)**	-	-	-	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 ($/mmBtu)	4.10	4.10	4.03	3.81	3.80	3.84	3.88	3.89	3.87	3.88	3.97	4.15
Firm Gulfstream ($/mmBtu)	4.09	4.08	4.02	3.79	3.80	3.83	3.87	3.88	3.87	3.90	3.96	4.14
Non-Firm FGT ($/mmBtu)	4.77	4.77	4.70	4.56	4.56	4.60	4.63	4.64	4.63	4.65	4.65	4.83
Non-Firm Gulfstream ($/mmBtu)	4.98	4.97	4.91	4.77	4.77	4.80	4.84	4.85	4.84	4.86	4.86	5.04

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.49	2.49	2.49	2.49	2.49	2.49	2.51	2.51	2.51	2.51	2.51	2.51
SJRPP ($/mmBtu)	3.19	3.20	3.14	3.19	3.19	3.23	3.21	3.23	3.23	3.24	3.24	3.23

FLORIDA POWER AND LIGHT COMPANY
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 3	1.6	4.6	3.8	04/01/15 - 04/14/15 *	04/03/15 - 04/16/15 *	04/19/15 - 05/02/15 *		
Ft. Myers 2	0.5	4.6	10.6	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 *
Ft. Myers 3	0.3	4.6	7.0	01/24/15 - 02/01/15 *	10/10/15 - 11/20/15 *			
Ft. Myers GTs	0.1	4.6	1.1	06/02/15 - 07/21/15 *				
Lauderdale 4	0.7	4.6	1.1	04/04/15 - 04/07/15				
Lauderdale 5	0.6	4.6	8.2	02/28/15 - 03/29/15				
Lauderdale GTs	0.1	4.6	0.0	NONE				
Manatee 1	0.3	4.6	7.7	04/11/15 - 05/08/15				
Manatee 2	0.3	4.6	2.7	03/21/15 - 03/30/15				
Manatee 3	0.6	4.6	2.9	07/13/15 - 07/19/15	07/20/15 - 07/26/15 *	07/27/15 - 08/02/15 *		
Martin 1	0.1	4.2	23.0	03/07/15 - 05/29/15				
Martin 2	0.1	3.8	27.9	01/01/15 - 02/22/15				
Martin 3	0.6	4.6	2.9	10/31/15 - 11/06/15	10/31/15 - 11/13/15 *			
Martin 4	0.7	4.6	2.9	10/10/15 - 10/16/15	10/10/15 - 10/23/15 *			
Martin 8	0.6	4.6	8.2	01/10/15 - 02/22/15 *	02/07/15 - 02/22/15	02/07/15 - 03/22/15 *		
Port Everglades GTs	0.1	4.6	0.0	NONE				
Putnam 1	0.3	4.6	0.0	NONE				
Putnam 2	0.3	4.6	0.0	NONE				
Riviera 5	0.9	4.6	1.9	03/21/15 - 03/27/15				
Sanford 4	0.5	4.6	4.7	03/07/15 - 03/13/15	11/07/15 - 11/16/15			
Sanford 5	0.4	4.2	14.2	04/25/15 - 06/05/15	11/07/15 - 11/16/15			
Scherer 4	1.0	4.6	0.0	NONE				
Saint Johns River Power Park 1	1.0	4.6	13.7	03/07/15 - 04/25/15				
Saint Johns River Power Park 2	1.0	4.6	0.0	NONE				
St. Lucie 1	1.1	1.1	9.0	03/23/15 - 04/25/15				
St. Lucie 2	1.1	1.1	8.8	09/07/15 - 10/09/15				
Turkey Point 1	0.8	4.6	5.8	NONE				
Turkey Point 3	1.1	1.1	8.2	10/19/15 - 11/18/15				
Turkey Point 4	1.2	1.2	0.0	NONE				
Turkey Point 5	0.6	4.6	2.4	06/06/15 - 06/10/15 *	06/06/15 - 06/12/15 *	06/13/15 - 06/19/15 *		
West County 1	0.6	4.6	2.7	03/14/15 - 03/23/15				
West County 2	0.5	4.6	12.9	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 *
West County 3	0.6	4.6	5.1	03/07/15 - 03/20/15 *	03/14/15 - 03/20/15	09/05/15 - 09/19/15 *	09/19/15 - 10/02/15 *	

* Partial Planned Outage

APPENDIX I

FUEL COST RECOVERY

2013 FINAL TRUE UP CALCULATION

TJK-1
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-4
EXHIBIT ____
MARCH 3, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 7
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-1

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

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	Total
1. End of Period True-up [1]	($143,313,441)
2. Less: Actual Estimated True-up for the same period [2]	($143,214,959)
3. Net True-up for the period	($98,482)

[1] Page 2, Column (14) Lines 37 & 38

[2] Approved in FPSC Order PSC-13-0665-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 2013 THROUGH DECEMBER 2013

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]	$220,037,900	$208,050,632	$234,633,600	$267,219,326	$276,720,275	$286,666,776	$280,951,961	$293,440,680	$264,285,265	$271,357,868	$227,446,862	$239,845,999	$3,070,657,144
3	Nuclear Fuel Disposal Costs (Per A2)	$1,880,395	$1,417,734	$1,144,529	$1,819,397	$2,007,177	$2,256,251	$2,453,484	$2,421,839	$2,299,690	$1,713,969	$2,032,223	$2,264,192	$23,710,879
4	Scherer Coal Cars Depreciation & Return (Per A2)	$0	($181)	($46,136)	($207)	($416)	($416)	($53,299)	($53,089)	$0	$0	$0	$0	($153,745)
5	Fuel Cost of Power Sold (Per A6)	($3,701,519)	($6,549,357)	($8,851,076)	($6,190,755)	($4,716,820)	($3,101,107)	($3,484,994)	($2,681,851)	($2,955,570)	($2,535,310)	($4,702,354)	($5,148,525)	($54,619,237)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($793,680)	($558,376)	($610,581)	($689,423)	($1,258,111)	($1,445,536)	($12,913,597)
7	Fuel Cost of Purchased Power (Per A7)	$7,594,732	$6,358,940	$3,174,645	$14,997,896	$15,862,340	$24,618,502	$21,479,018	$22,953,577	$19,429,563	$21,478,113	$12,128,752	$8,867,546	$178,943,623
8	Energy Payments to Qualifying Facilities (Per A8)	$1,679,537	$1,308,964	$6,001,429	$9,692,457	$10,992,302	$11,182,480	$9,314,906	$10,913,363	$10,145,088	$5,729,241	$7,446,607	$4,332,450	$88,738,823
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$137,962	$1,169,468	$1,273,625	$1,746,818	$174,561	$18,068	$6,778,391
10	Total Fuel Costs & Net Power Transactions	$226,713,812	$208,908,773	$234,022,459	$288,124,015	$299,970,870	$321,120,295	$310,005,357	$327,605,611	$293,867,080	$298,801,275	$243,268,540	$248,734,194	$3,301,142,281
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$0	$0	$0	$20,622	$21,401	$28,231	$33,219	$32,033	$30,798	$33,542	$30,658	$32,904	$263,407
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$155,543	$127,118	$132,895	$145,729	$262,136	$303,582	$2,160,452
15	Total	$0	$0	$364,700	$336,017	$249,206	$153,780	$188,762	$159,151	$163,693	$179,271	$292,794	$336,486	$2,423,859
16	**Adjustments to Fuel Cost**													
17	Sales to City of Key West (CKW)	($664,908)	($570,246)	($522,829)	($597,082)	($689,211)	($801,246)	$0	$0	$0	$0	$0	$0	($3,845,521)
18	Energy Imbalance Fuel Revenues	$56,481	$82,535	$48,854	$75,548	$65,257	$47,061	$47,948	$55,449	$75,579	($28,592)	$26,696	$3,066	$555,882
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	($78,905)	($130,403)	($246,658)	($145,605)	$188,446	($172,902)	($5,010,021)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$1,663,517	$465,892	$0	$0	$0	$1,183,800	$3,047,322
21	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,014	$287,849,938	$299,311,179	$320,490,803	$311,826,680	$328,155,699	$293,859,694	$298,806,349	$243,776,475	$250,084,645	$3,298,313,803
22	**Jurisdictional kWh Sales**													
23	Jurisdictional kWh Sales	7,684,412,091	7,108,916,875	6,977,292,798	7,671,972,198	8,616,263,762	9,110,063,405	9,724,266,549	10,261,768,851	10,390,746,922	9,076,196,297	8,227,451,350	7,934,506,213	102,783,857,311
24	Sales for Resale (excluding CKW) [2]	148,696,550	152,935,981	143,064,345	153,595,635	171,792,467	176,313,367	189,064,624	194,252,476	204,570,260	183,181,514	181,301,034	157,135,776	2,055,904,029
25	Sub-Total Sales (excluding CKW)	7,833,108,641	7,261,852,856	7,120,357,143	7,825,567,833	8,788,056,229	9,286,376,772	9,913,331,173	10,456,021,327	10,595,317,182	9,259,377,811	8,408,752,384	8,091,641,989	104,839,761,340
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	98.14220%	98.06924%	98.02166%	97.84390%	98.05805%	98.03900%
28	**True-up Calculation**													
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$235,363,510	$216,081,517	$211,924,637	$229,504,273	$251,555,289	$267,491,971	$287,935,348	$305,667,934	$309,014,768	$266,585,140	$240,723,076	$230,792,575	$3,052,640,037
30	**Fuel Adjustment Revenues Not Applicable to Period**													
31	Prior Period True-up (Collected)/Refunded This Period [3]	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$48,085,296
32	GPIF, Net of Revenue Taxes [4]	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($7,698,365)
33	Jurisdictional Fuel Revenues Applicable to Period	$238,729,087	$219,447,095	$215,290,214	$232,869,851	$254,920,866	$270,857,548	$291,300,926	$309,033,512	$312,380,346	$269,950,718	$244,088,653	$234,158,152	$3,093,026,968
34	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,014	$287,849,938	$299,311,179	$320,490,803	$311,826,680	$328,155,699	$293,859,694	$298,806,349	$243,776,475	$250,084,645	$3,298,313,803
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	98.14220%	98.06924%	98.02166%	97.84390%	98.05805%	98.03900%
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$221,888,754	$199,492,191	$230,007,842	$282,428,775	$293,697,827	$314,660,569	$306,127,346	$322,320,090	$288,419,400	$293,132,189	$238,713,612	$245,426,761	$3,236,315,354
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	$16,840,334	$19,954,904	($14,717,628)	($49,558,924)	($38,776,960)	($43,803,021)	($14,826,420)	($13,286,578)	$23,960,946	($23,181,471)	$5,375,041	($11,268,608)	($143,288,386)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($4,579)	($5,406)	($5,346)	($5,018)	($6,103)	($8,175)	($25,055)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$60,921,434	$76,874,326	$58,154,312	$4,590,069	($38,195,333)	($86,009,075)	($104,847,182)	($122,146,275)	($102,197,783)	($129,391,380)	($128,029,550)	$48,085,296
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [5]	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)
41	Prior Period True-up Collected/(Refunded) This Period	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($48,085,296)
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	$56,370,780	$72,323,672	$53,603,658	$39,415	($42,745,987)	($90,559,729)	($109,397,836)	($126,696,929)	($106,748,437)	($133,942,034)	($132,580,204)	($147,864,095)	($147,864,095)
43														
44														

45 [1] Actuals include various adjustments as noted on the A-Schedules.

46 [2] Billed KWH includes all wholesale customers except CKW.

47 [3] Prior Period 2011/2012 Net True-up.

48 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.

49 [5] Deferred 2012 Final True-up.

50

51 Note: Amounts may not agree to Actual/Estimated Filing or A-Schedules due to rounding.

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) Revenue/Cost Final Variance Analysis	(2) FINAL TRUE-UP	(3) ACTUAL/ESTIMATED	(4) DIFFERENCE
1	**Jurisdictional Total Fuel Revenues**			
2	Revenues	$3,052,640,037	$3,034,396,944	$18,243,093
3	MWH	102,783,857	102,164,441	619,417
4	$ per MWH	29.69961	29.70111	(0.00150)
5				
6	Variance due to Consumption			$18,397,362
7	Variance due to Price			($154,269)
8	Total Variance			$18,243,093
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,236,315,354	$3,217,971,736	$18,343,618
12	MWH	102,783,857	102,164,441	619,417
13	$ per MWH	31.48661	31.49796	(0.01135)
14				
15	Variance due to Consumption			$19,510,365
16	Variance due to Price			($1,166,747)
17	Total Variance			$18,343,618
18				
19	**Total Variance**			
20	Variance due to Consumption			($1,113,003)
21	Variance due to Price			$1,012,478
22	Total Variance			($100,525)
23	Interest			$2,043
24	Total True-up			($98,482)
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - FINAL TRUE-UP VS. ACTUAL/ESTIMATED TRUE-UP

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) FCR - 2013 Final True-up	(3) FCR - 2013 Actual/Estimated True-up	(4) Dif. FCR - 2013 Actual/Estimated True-up	(5) % Dif. FCR - 2013 Actual/Estimated True-up
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3)	$3,070,657,144	$3,064,223,762	$6,433,383	0.2%
3	Nuclear Fuel Disposal Costs (Per A2)	$23,710,879	$23,905,061	($194,182)	(0.8%)
4	Scherer Coal Cars Depreciation & Return (Per A2)	($153,745)	($100,655)	($53,090)	52.7%
5	Fuel Cost of Power Sold (Per A6)	($54,619,237)	($55,562,090)	$942,853	(1.7%)
6	Gains from Off-System Sales (Per A6)	($12,913,597)	($11,484,069)	($1,429,528)	12.4%
7	Fuel Cost of Purchased Power (Per A7)	$178,943,623	$159,385,962	$19,557,661	12.3%
8	Energy Payments to Qualifying Facilities (Per A8)	$88,738,823	$98,980,415	($10,241,592)	(10.3%)
9	Energy Cost of Economy Purchases (Per A9)	$6,778,391	$5,570,851	$1,207,540	21.7%
10	Total Fuel Costs & Net Power Transactions	$3,301,142,281	$3,284,919,237	$16,223,045	0.5%
11					
12	**Incremental Optimization Costs**				
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$263,407	$263,527	($120)	(0.0%)
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$2,160,452	$1,853,392	$307,060	16.6%
15	Total	$2,423,859	$2,116,919	$306,940	14.5%
16	**Adjustments to Fuel Cost**				
17	Sales to City of Key West (CKW)	($3,845,521)	($3,845,522)	$1	(0.0%)
18	Energy Imbalance Fuel Revenues	$555,882	$423,684	$132,198	31.2%
19	Inventory Adjustments	($5,010,021)	($4,502,899)	($507,122)	11.3%
20	Non Recoverable Oil/Tank Bottoms	$3,047,322	$1,397,630	$1,649,692	118.0%
21	Adjusted Total Fuel Costs & Net Power Transactions	$3,298,313,803	$3,280,509,049	$17,804,754	0.5%
22	**Jurisdictional kWh Sales**				
23	Jurisdictional kWh Sales	102,783,857,311	102,164,440,582	619,416,729	0.6%
24	Sales for Resale (excluding CKW)	2,055,904,029	2,070,531,997	(14,627,968)	(0.7%)
25	Sub-Total Sales (excluding CKW)	104,839,761,340	104,234,972,579	604,788,761	0.6%
26					
27	**Jurisdictional % of Total Sales (Line 23/25)**	N/A	N/A	N/A	N/A
28	**True-up Calculation**				
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,052,640,037	$3,034,396,944	$18,243,093	0.6%
30	**Fuel Adjustment Revenues Not Applicable to Period**				
31	Prior Period True-up (Collected)/Refunded This Period	$48,085,296	$48,085,296	$0	0.0%
32	GPIF, Net of Revenue Taxes [1]	($7,698,365)	($7,698,365)	($0)	0.0%
33	Jurisdictional Fuel Revenues Applicable to Period	$3,093,026,968	$3,074,783,875	$18,243,093	0.6%
34	Adjusted Total Fuel Costs & Net Power Transactions	$3,298,313,803	$3,280,509,049	$17,804,754	0.5%
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	N/A	N/A	N/A	N/A
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$3,236,315,354	$3,217,971,736	$18,343,618	0.6%
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	($143,288,386)	($143,187,861)	($100,525)	0.1%
38	Interest Provision for the Month	($25,055)	($27,098)	$2,043	(7.5%)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$48,085,296	$0	0.0%
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [2]	($4,550,654)	($4,550,654)	$0	0.0%
41	Prior Period True-up Collected/(Refunded) This Period [3]	($48,085,296)	($48,085,296)	$0	0.0%
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	($147,864,095)	($147,765,613)	($98,482)	0.1%
43					
44	[1] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.				
45	[2] Deferred 2012 Final True-up.				
46	[3] Prior Period 2011/2012 Net True-up.				
47					
48	Note: Amounts may not agree to Actual/Estimated Filing or A-Schedules due to rounding.				

APPENDIX II

CAPACITY COST RECOVERY

2013 FINAL TRUE UP CALCULATION

TJK-2
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-8
EXHIBIT ____
MARCH 3, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-2

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		Total
1	End of Period True-up for the period [1]	($14,303,032)
2	Less - Estimated/Actual True-up for the same period [2]	($25,357,191)
3	Net True-up for the period	$11,054,159
4		
5	[1] From Page 2, Column (14), Lines 18+19	
6	[2] Approved in FPSC Order No. 13-0665-FOF-EI	
7		
8	Note: total 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 2013 THROUGH DECEMBER 2013

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	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979	$15,714,068	$16,059,963	$18,026,852	$16,583,199	$16,367,344	$16,510,438	$198,472,373
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194	$23,388,910	$23,174,685	$23,193,201	$23,275,962	$23,207,885	$23,270,698	$279,503,468
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)	($405,655)	($398,781)	($391,907)	($385,034)	($378,160)	($371,286)	($4,901,501)
5	Incremental Plant Security PSC Order No. 02-1761-FOF-EI	$2,742,107	$3,070,332	$3,468,119	$3,248,334	$2,732,257	$3,485,081	$2,485,373	$3,728,780	$4,144,063	$3,209,604	$3,161,608	$4,801,912	$40,277,571
6	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,859	$8,859
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)	$1,138,719	$784,731	$930,009	$882,320	$1,856,565	$2,130,914	$16,516,689
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)	($294,350)	($214,153)	($213,798)	($318,520)	($375,425)	($406,877)	($4,684,204)
10	Total (Lines 1 through 9)	$45,714,174	$46,073,747	$39,385,564	$42,770,476	$41,636,583	$40,564,103	$41,166,083	$42,274,242	$44,827,438	$42,386,550	$42,978,834	$45,083,677	$514,861,472
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%
12	Jurisdictional CCR Charges	$44,786,322	$45,138,597	$38,586,163	$41,902,373	$40,791,494	$39,740,782	$40,330,543	$41,416,210	$43,917,584	$41,526,239	$42,106,501	$44,168,623	$504,411,431
13	Nuclear Cost Recovery Costs [a]	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892	$12,293,132	$12,185,111	$12,000,151	$11,888,604	$11,726,916	$11,774,862	$151,491,400
14	Jurisdictional CCR Charges	$57,035,996	$59,367,796	$53,253,780	$54,915,896	$53,594,213	$52,400,674	$52,623,675	$53,601,321	$55,917,735	$53,414,842	$53,833,418	$55,943,485	$655,902,832
15	CCR Revenues (Net of Revenue Taxes)	$52,434,454	$49,413,054	$49,832,052	$53,331,531	$58,351,845	$61,903,701	$65,986,930	$69,005,856	$69,298,105	$62,290,497	$56,640,817	$53,736,697	$702,225,539
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($60,583,035)
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$47,385,867	$44,364,468	$44,783,466	$48,282,945	$53,303,259	$56,855,115	$60,938,344	$63,957,270	$64,249,519	$57,241,910	$51,592,231	$48,688,111	$641,642,504
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($9,650,129)	($15,003,328)	($8,470,314)	($6,632,952)	($290,954)	$4,454,441	$8,314,669	$10,355,949	$8,331,783	$3,827,068	($2,241,187)	($7,255,375)	($14,260,328)
19	Interest Provision for Month	($4,127)	($6,184)	($6,358)	($5,822)	($5,356)	($4,259)	($3,075)	($2,417)	($1,758)	($1,136)	($981)	($1,231)	($42,704)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($65,188,705)	($75,149,631)	($78,577,717)	($80,167,904)	($75,415,629)	($65,916,860)	($52,556,681)	($37,154,562)	($23,775,950)	($14,901,432)	($12,095,013)	($60,583,035)
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,102,189)	($83,063,115)	($86,491,201)	($88,081,388)	($83,329,113)	($73,830,344)	($60,470,165)	($45,068,046)	($31,689,434)	($22,814,916)	($20,008,497)	($22,216,516)	($22,216,516)
24														
25	[a] As approved on Order No PSC-12-0664-FOF-EI													
26														
27	Total may not add due to rounding													
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) CCR - Final True-up Variance	(2) CCR - 2013 Final True-up	(3) CCR - 2013 Actual/Estimated	(4) Dif. CCR - 2013 Actual/Estimated	(5) % Dif. CCR - 2013 Actual/Estimated
1	Payments to Non-cogenerators	$198,472,373	$197,237,197	$1,235,176	0.6%
2	Payments to Co-generators	$279,503,468	$278,819,477	$683,991	0.2%
3	SJRPP Suspension Accrual	($10,331,784)	($10,331,784)	$0	0.0%
4	Return on SJRPP Suspension Liability	($4,901,501)	($4,901,525)	$24	(0.0%)
5	Incremental Plant Security PSC Order No. 02-1761-FOF-EI	$40,277,571	$46,426,048	($6,148,477)	(13.2%)
6	Incremental Nuclear NRC Compliance Costs O&M	$0	$98,678	($98,678)	(100.0%)
7	Incremental Nuclear NRC Compliance Costs Capital	$8,859	$17,587	($8,727)	(49.6%)
8	Transmission of Electricity by Others	$16,516,689	$18,578,470	($2,061,781)	(11.1%)
9	Transmission Revenues from Capacity Sales	($4,684,204)	($4,157,931)	($526,272)	12.7%
10	Total (Lines 1 through 9)	$514,861,472	$521,786,216	($6,924,745)	(1.3%)
11	Jurisdictional Separation Factor [(a)]	97.97032%	97.97032%	0.00000%	(0.0%)
12	Jurisdictional CCR Charges	$504,411,431	$511,195,626	($6,784,195)	(1.3%)
13	Nuclear Cost Recovery Costs [(a)]	$151,491,400	$151,506,739	($15,339)	(0.0%)
14	Jurisdictional CCR Charges	$655,902,832	$662,702,365	($6,799,533)	(1.0%)
15	CCR Revenues (Net of Revenue Taxes)	$702,225,539	$697,971,665	$4,253,873	0.6%
16	Prior Period True-up Provision	($60,583,035)	($60,583,035)	$0	0.0%
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$641,642,504	$637,388,630	$4,253,873	0.7%
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($14,260,328)	($25,313,735)	$11,053,407	(43.7%)
19	Interest Provision for Month	($42,704)	($43,456)	$752	(1.7%)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($60,583,035)	$0	0.0%
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	$0	0.0%
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$60,583,035	$60,583,035	$0	0.0%
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($22,216,516)	($33,270,675)	$11,054,159	(33.2%)
24					
25	[(a)] As approved on Order No PSC-12-0664-FOF-EI				
26					
27	Columnns and rows may not add due to rounding				
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Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 1 of 2

For the Month of **Dec-13**

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
SWAPC	40	1/1/2012	4/1/2032	QF

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	12,096,169	12,274,083	7,575,325	10,422,060	9,829,336	10,226,750	10,377,201	10,201,288	10,221,794	10,192,154	10,209,504	10,274,578	123,900,241
ICL	11,521,003	11,510,708	11,515,856	11,515,856	11,502,091	11,508,973	11,536,485	11,536,485	11,536,485	11,536,485	11,543,106	11,539,795	138,303,327
BN-NEG '91	317,350	317,350	317,350	317,350	293,172	308,696	301,049	297,937	295,947	408,349	316,300	317,350	3,808,200
BS-NEG '91	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	1,211,700
SWAPC	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,073,200	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	12,280,000
Total	25,038,297	25,205,917	20,512,305	23,359,041	22,728,373	23,148,194	23,388,910	23,174,685	23,193,201	23,275,962	23,207,885	23,270,698	279,503,468

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 2 of 2

For the Month of Dec-13

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

2013 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
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2013 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	16,437,513	16,618,240	17,107,824	16,482,672	16,487,283	16,076,979	15,714,068	16,059,963	18,026,852	16,583,199	16,367,344	16,510,438

Year-to-date Short Term Capacity Payments	198,472,373

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

True ups												
1		[redacted]			[redacted]							
2												
3										[redacted]		
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

INCREMENTAL NUCLEAR NRC COMPLIANCE FOR THE PERIOD JANUARY THROUGH DECEMBER 2013

INCREMENTAL NUCLEAR NRC COMPLIANCE	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	$12,219,384
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [2]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	
7. Base Rate Capital Expenditures Closed to Plant-in-Service [3]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	
9. Adjusted Net Investment (Lines 5 - 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,219,384	
10. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,109,692	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [4]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,411	$7,411
b. Debt Component (Line 6 x debt rate x 1/12) [5]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,448	$1,448
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,859	$8,859

[1] Represents nuclear NRC Compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year base (Docket No.120015) on line 6

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

[3] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service

[4] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9230%, which is based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU

[5] The Debt Component is 1.5658%, which is based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY

COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER 2012 RATE CASE (a)
Docket No 120015-EI Order No PSC-13-0023-S-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	6,253,556,649	29.470%	5.19%	1.53%	1.53%
SHORT TERM DEBT	363,682,507	1.714%	2.11%	0.04%	0.04%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	430,247,132	2.028%	1.99%	0.04%	0.04%
COMMON EQUITY	9,768,463,093	46.034%	10.50%	4.83%	7.87%
DEFERRED INCOME TAX	4,403,202,920	20.750%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	930,822	0.004%	8.43%	0.00%	
TOTAL	$21,220,083,124	100.00%		6.44%	9.48%

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

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$6,253,556,649	39.03%	5.19%	2.03%	2.03%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	9,768,463,093	60.97%	10.50%	6.40%	10.42%
TOTAL	$16,022,019,743	100.00%		8.43%	12.45%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.5301%
SHORT TERM DEBT	0.0361%
CUSTOMER DEPOSITS	0.0404%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.6067%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8336%
TAX CREDITS -WEIGHTED	0.0003%
TOTAL EQUITY	**4.8339%**
TOTAL	6.4406%
PRE-TAX EQUITY	7.8695%
PRE-TAX TOTAL	9.4762%

Note:

(a) Reflects approved capital structure and ROE reflected in Docket No 120015-EI Order No PSC-13-0023-S-EI.
The above capital structure started effective January 2013.

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

This Capital Structure and Cost Rates was used during the period January through June 2013

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2013 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	6,416,467,850	29.591%	4.981%	1.474%	1.474%
SHORT_TERM_DEBT	431,179,727	1.989%	1.833%	0.036%	0.036%
PREFERRED_STOCK	0	0.000%	0.000%	0.000%	0.000%
CUSTOMER_DEPOSITS	428,779,347	1.977%	2.796%	0.055%	0.055%
COMMON_EQUITY	10,165,729,253	46.882%	10.500%	4.923%	8.014%
DEFERRED_INCOME_TAX	4,240,131,465	19.555%	0.000%	0.000%	0.000%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.000%	0.000%	0.000%
WEIGHTED COST	1,324,684	0.006%	8.364%	0.001%	0.001%
TOTAL	$21,683,612,327	100.00%		6.489%	9.580%

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	$6,416,467,850	38.69%	4.981%	1.927%	1.927%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	10,165,729,253	61.31%	10.500%	6.437%	10.480%
TOTAL	$16,582,197,103	100.00%		8.364%	12.407%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4740%
SHORT TERM DEBT	0.0364%
CUSTOMER DEPOSITS	0.0553%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.5658%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9226%
TAX CREDITS -WEIGHTED	0.0004%
TOTAL EQUITY	**4.9230%**
TOTAL	6.4889%
PRE-TAX EQUITY	8.0147%
PRE-TAX TOTAL	9.5805%

Note:

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

This Capital Structure and Cost Rates was used during the period July through December 2013

APPENDIX I

FUEL COST RECOVERY

ACTUAL/ESTIMATED TRUE UP CALCULATION

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TJK-3
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-35
JULY 25, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 9
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-3

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE

SCHEDULE: E1-B

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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]	$249,704,921	$261,698,473	$276,728,131	$327,817,647	$318,300,543	$314,843,954	$332,515,453	$340,367,893	$315,856,058	$301,516,737	$237,029,921	$248,270,812	$3,524,650,543
3	Nuclear Fuel Disposal Costs (Per A2)	$2,459,404	$2,206,487	$1,581,888	$1,368,858	$2,328,964	$2,227,999	($3,392,480)	$0	$0	$0	$0	$0	$8,781,118
4	Fuel Cost of Power Sold (Per A6)	($17,551,697)	($13,007,326)	($10,682,154)	($3,087,997)	($3,490,214)	($2,666,273)	($7,564,157)	($6,466,807)	($5,982,768)	($3,823,100)	($5,902,729)	($6,512,407)	($86,737,631)
5	Gains from Off-System Sales (Per A6)	($27,898,389)	($3,489,980)	($3,185,661)	($703,559)	($713,114)	($1,666,239)	($855,500)	($775,000)	($626,000)	($670,000)	($1,140,000)	($1,320,000)	($43,043,442)
6	Fuel Cost of Purchased Power (Per A7)	$15,810,659	$11,965,752	$14,152,295	$11,187,597	$12,038,150	$20,546,899	$17,621,708	$17,516,399	$16,451,748	$15,194,399	$11,267,133	$11,442,958	$175,195,695
7	Energy Payments to Qualifying Facilities (Per A8)	$3,679,181	$3,211,873	$8,109,727	$8,318,554	$12,056,579	$12,462,904	$16,027,724	$16,712,729	$15,899,726	$11,978,726	$4,697,720	$5,897,721	$119,053,163
8	Energy Cost of Economy Purchases (Per A9)	$14,909	$1,307,551	$199,473	$1,519,318	$821,311	$2,584,878	$1,317,600	$1,651,400	$1,669,200	$1,134,400	$192,600	$50,400	$12,463,040
9	Total Fuel Costs & Net Power Transactions	$226,218,989	$263,892,830	$286,903,697	$346,420,418	$341,342,219	$348,334,121	$355,670,346	$369,006,614	$343,267,963	$325,331,163	$246,144,645	$257,829,484	$3,710,362,488
10														
11	**Incremental Optimization Costs**													
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$33,078	$28,764	$31,903	$33,006	$33,316	$32,338	$34,387	$38,736	$49,161	$50,587	$46,310	$50,587	$462,173
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	($44,399)	$17,182	$470,412	$134,512	$136,818	$129,944	$128,350	$120,800	$105,700	$120,800	$241,600	$279,350	$1,841,069
14	Total	($11,320)	$45,946	$502,315	$167,518	$170,134	$162,282	$162,737	$159,536	$154,861	$171,387	$287,910	$329,937	$2,303,242
15														
16	Dodd Frank Fees	$0	$0	$2,523	$375	$375	$375	$375	$375	$375	$375	$375	$375	$5,898
17														
18	**Adjustments to Fuel Cost**													
19	Energy Imbalance Fuel Revenues	($94,682)	($131,614)	($127,853)	($35,354)	($9,564)	($91,016)	$0	$0	$0	$0	$0	$0	($490,084)
20	Inventory Adjustments	($8,471)	$48,367	($62,667)	$176,147	$337,707	($271,676)	$0	$0	$0	$0	$0	$0	$219,408
21	Non Recoverable Oil/Tank Bottoms	($339,257)	$0	$0	$0	$0	($87,509)	$0	$0	$0	$0	$0	$0	($426,766)
22	Adjusted Total Fuel Costs & Net Power Transactions	$225,765,259	$263,855,528	$287,218,016	$346,729,104	$341,840,872	$348,046,576	$355,833,458	$369,166,525	$343,423,199	$325,502,925	$246,432,930	$258,159,796	$3,711,974,185
23	**Jurisdictional kWh Sales**													
24	Jurisdictional kWh Sales	8,186,450,133	7,489,358,283	7,265,742,238	7,662,815,846	8,998,820,709	9,353,399,776	10,107,788,372	10,536,758,426	10,438,962,071	9,613,587,552	8,080,389,954	7,989,256,624	105,723,329,984
25	Sales for Resale	159,075,376	379,930,801	355,050,303	379,293,900	394,998,170	454,639,060	510,352,295	526,427,841	546,517,614	502,853,788	475,529,454	358,799,599	5,043,468,201
26	Sub-Total Sales	8,345,525,509	7,869,289,084	7,620,792,541	8,042,109,746	9,393,818,879	9,808,038,836	10,618,140,667	11,063,186,267	10,985,479,685	10,116,441,340	8,555,919,408	8,348,056,223	110,766,798,185
27														
28	**Jurisdictional % of Total Sales (Line 24/26)**	98.09388%	95.17198%	95.34103%	95.28365%	95.79513%	95.36463%	95.19358%	95.24163%	95.02509%	95.02934%	94.44210%	95.70200%	95.44677%
29	**True-up Calculation**													
30	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$272,959,294	$248,228,786	$240,098,894	$245,679,724	$293,334,679	$305,444,193	$329,579,666	$343,566,881	$340,378,084	$313,465,504	$263,473,287	$260,501,747	$3,456,710,740
31	**Fuel Adjustment Revenues Not Applicable to Period**													
32	Prior Period True-up (Collected)/Refunded This Period [2]	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($147,765,613)
33	GPIF, Net of Revenue Taxes [3]	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($20,665,080)
34	Jurisdictional Fuel Revenues Applicable to Period	$258,923,403	$234,192,895	$226,063,003	$231,643,833	$279,298,788	$291,408,302	$315,543,775	$329,530,990	$326,342,192	$299,429,613	$249,437,396	$246,465,856	$3,288,280,047
35	Adjusted Total Fuel Costs & Net Power Transactions	$225,765,259	$263,855,528	$287,218,016	$346,729,104	$341,840,872	$348,046,576	$355,833,458	$369,166,525	$343,423,199	$325,502,925	$246,432,930	$258,159,796	$3,711,974,185
36	Jurisdictional Sales % of Total kWh Sales (Line 28)	98.09388%	95.17198%	95.34103%	95.28365%	95.79513%	95.36463%	95.19358%	95.24163%	95.02509%	95.02934%	94.44210%	95.70200%	95.44677%
37	Juris. Total Fuel Costs & Net Power Trans. (Line 35xLine36x1.00169)	$221,836,172	$251,540,918	$274,299,398	$330,934,481	$328,020,326	$332,474,263	$339,303,062	$352,194,420	$326,889,715	$309,846,037	$233,129,759	$247,481,626	$3,547,950,178
38	True-up Provision for the Month - Over/(Under) Recovery (Line 34 - Line 37)	$37,087,231	($17,348,022)	($48,236,395)	($99,290,648)	($48,721,539)	($41,065,960)	($23,759,287)	($22,663,430)	($547,523)	($10,416,424)	$16,307,637	($1,015,770)	($259,670,132)
39	Interest Provision for the Month	($7,698)	($5,474)	($6,584)	($11,433)	($12,232)	($11,560)	($14,867)	($15,412)	($15,378)	($15,037)	($14,275)	($13,277)	($143,226)
40	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($147,765,613)	($98,372,279)	($103,411,974)	($139,341,152)	($226,329,432)	($262,749,401)	($291,513,121)	($302,973,474)	($313,338,515)	($301,587,614)	($299,705,274)	($271,098,111)	($147,765,613)
41	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)
42	Prior Period True-up Collected/(Refunded) This Period [2]	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$147,765,613
43	End of Period Net True-up Amount Over/(Under) Recovery (Lines 38 through 42)	($98,470,761)	($103,510,456)	($139,439,634)	($226,427,914)	($262,847,883)	($291,611,603)	($303,071,956)	($313,436,997)	($301,686,096)	($299,803,756)	($271,196,593)	($259,911,839)	($259,911,839)
44														

45

46 [1] January through June actuals include various adjustments as noted on the A-Schedules.

47 [2] Prior Period 2012/2013 True-up.

48 [3] Generating Performance Incentive Factor is ((20,679,970 / 12) x 99.9280%) - See Order No. PSC-13-0665-FOF-EI.

49 [4] Deferred 2013 Final True-up.

50

51 Note: Totals may not add due to rounding.

52

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) Revenue/Cost Variance Analysis Schedule	(2) ACTUAL/ESTIMATED	(3) PROJECTIONS	(4) DIFFERENCE
1	**Jurisdictional Total Fuel Revenues**			
2	Revenues	$3,456,710,740	$3,499,486,714	($42,775,974)
3	MWH	105,723,330	105,843,225	(119,895)
4	$ per MWH	32.69582	33.06293	(0.36711)
5				
6	Variance due to Consumption			($3,964,084)
7	Variance due to Price			($38,811,890)
8	Total Variance			($42,775,974)
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,547,950,178	$3,331,056,021	$216,894,157
12	MWH	105,723,330	105,843,225	(119,895)
13	$ per MWH	33.55882	31.47160	2.08722
14				
15	Variance due to Consumption			($3,773,292)
16	Variance due to Price			$220,667,450
17	Total Variance			$216,894,157
18				
19	**Total Variance**			
20	Variance due to Consumption			($190,792)
21	Variance due to Price			($259,479,340)
22	Total Variance			($259,670,132)
23	Interest			($143,226)
24	Prior Year True-up			($98,482)
25	Total True-up			($259,911,839)
26				
27				
28	( ) Reflects Underrecovery			
29				
30	Note: Totals may not add down due to rounding.			
31				
32				
33				
34				
35				
36				
37				

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

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) FCR - 2014 Actual Estimated	(3) FCR - 2014 Original Projection	(4) Dif. FCR - 2014 Original Projection	(5) % Dif. FCR - 2014 Original Projection
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3) [1]	$3,524,650,543	$3,248,141,556	$276,508,987	8.5%
3	Nuclear Fuel Disposal Costs (Per A2)	$8,781,118	$26,064,319	($17,283,200)	(66.3%)
4	Fuel Cost of Power Sold (Per A6)	($86,737,631)	($69,688,315)	($17,049,316)	24.5%
5	Gains from Off-System Sales (Per A6)	($43,043,442)	($11,080,000)	($31,963,442)	288.5%
6	Fuel Cost of Purchased Power (Per A7)	$175,195,695	$144,323,495	$30,872,200	21.4%
7	Energy Payments to Qualifying Facilities (Per A8)	$119,053,163	$126,567,361	($7,514,198)	(5.9%)
8	Energy Cost of Economy Purchases (Per A9)	$12,463,040	$13,403,538	($940,498)	(7.0%)
9	Total Fuel Costs & Net Power Transactions	$3,710,362,488	$3,477,731,955	$232,630,533	6.7%
10					
11	**Incremental Optimization Costs**				
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$462,173	$389,472	$72,701	18.67%
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$1,841,069	$1,722,910	$118,159	6.86%
14	Total	$2,303,242	$2,112,382	$190,860	9.04%
15					
16	Dodd Frank Fees	$5,898	$0	$5,898	0.0%
17					
18	**Adjustments to Fuel Cost**				
19	Energy Imbalance Fuel Revenues	($490,084)	$0	($490,084)	N/A
20	Inventory Adjustments	$219,408	$0	$219,408	N/A
21	Non Recoverable Oil/Tank Bottoms	($426,766)	$0	($426,766)	N/A
22	Adjusted Total Fuel Costs & Net Power Transactions	$3,711,974,185	$3,479,844,337	$232,129,849	6.7%
23	**Jurisdictional kWh Sales**				
24	Jurisdictional kWh Sales	105,723,329,984	105,843,225,128	(119,895,144)	(0.1%)
25	Sales for Resale	5,043,468,201	4,924,470,067	118,998,134	2.4%
26	Sub-Total Sales	110,766,798,185	110,767,695,195	(897,010)	(0.0%)
27					
28	**Jurisdictional % of Total Sales (Line 24/26)**	N/A	N/A	N/A	N/A
29	**True-up Calculation**				
30	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,456,710,740	$3,499,486,714	($42,775,974)	(1.2%)
31	**Fuel Adjustment Revenues Not Applicable to Period**				
32	Prior Period True-up (Collected)/Refunded This Period [2]	($147,765,613)	($147,765,613)	$0	0.0%
33	GPIF, Net of Revenue Taxes [3]	($20,665,080)	($20,665,080)	($0)	0.0%
34	Jurisdictional Fuel Revenues Applicable to Period	$3,288,280,047	$3,331,056,021	($42,775,975)	(1.3%)
35	Adjusted Total Fuel Costs & Net Power Transactions	$3,711,974,185	$3,479,844,337	$232,129,849	6.7%
36	Jurisdictional Sales % of Total kWh Sales (Line 28)	N/A	N/A	N/A	N/A
37	Juris. Total Fuel Costs & Net Power Trans. (Line 35xLine36x1.00169)	$3,547,950,178	$3,331,056,021	$216,894,157	6.5%
38	True-up Provision for the Month - Over/(Under) Recovery (Line 34 - Line 37)	($259,670,132)	$0	($259,670,132)	N/A
39	Interest Provision for the Month	($143,226)	$0	($143,226)	N/A
40	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($147,765,613)	($147,765,613)	$0	0.0%
41	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	($98,482)	$0	($98,482)	N/A
42	Prior Period True-up Collected/(Refunded) This Period [2]	$147,765,613	$147,765,613	$0	0.0%
43	End of Period Net True-up Amount Over/(Under) Recovery (Lines 38 through 42)	($259,911,839)	$0	($259,911,839)	0.0%
44					
45	[1] January through June actuals include various adjustments as noted on the A-Schedules.				
46	[2] Prior Period 2012/2013 True-up.				
47	[3] Generating Performance Incentive Factor is ((20,679,970 / 12) x 99.9280%) - See Order No. PSC-13-0665-FOF-EI.				
48	[4] Deferred 2013 Final True-up.				
49					
50	Note: Totals may not add due to rounding.				

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

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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 ($)**													
2	Heavy Oil	47,123	759	6,411,747	15,042,565	740	3,016,115	8,102,957	9,286,917	6,238,334	4,230,730	236,556	3,161,915	55,776,460
3	Light Oil	762,028	1,041,038	490,520	4,450,154	6,875,382	3,608,272	1,613,400	2,368,269	1,631,045	648,321	414,822	437,635	24,340,887
4	Coal	13,345,550	12,473,549	2,505,992	2,347,383	11,724,986	16,592,291	17,783,560	17,365,053	16,392,551	16,271,971	15,262,512	15,893,418	157,958,815
5	Gas	218,270,938	232,998,461	256,026,559	295,715,628	282,592,514	274,738,497	287,397,236	293,729,354	275,767,427	266,398,115	203,919,131	211,007,944	3,098,561,805
6	Nuclear	17,279,295	15,184,666	11,293,311	10,261,857	17,284,784	16,710,915	17,618,300	17,618,300	15,826,700	13,967,600	17,196,900	17,769,900	188,012,529
7	**Total Fuel Cost of System Net Generation ($)**	249,704,935	261,698,473	276,728,131	327,817,587	318,478,407	314,666,090	332,515,453	340,367,893	315,856,058	301,516,737	237,029,921	248,270,812	3,524,650,497
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	80	(725)	38,715	100,486	8	18,457	44,954	53,512	34,833	25,887	1,189	19,271	336,666
11	Light Oil	4,389	4,953	3,293	26,627	41,948	16,704	5,256	8,073	6,889	2,497	1,982	2,094	124,705
12	Coal	419,562	415,391	70,079	68,544	397,316	543,942	604,844	609,019	583,274	583,926	556,488	578,885	5,431,270
13	Gas	5,562,254	5,076,910	6,549,529	7,266,457	7,004,978	6,798,101	7,674,849	7,859,721	7,348,034	7,090,619	5,335,878	5,480,138	79,047,465
14	Nuclear	2,622,754	2,350,979	1,684,820	1,456,898	2,481,492	2,373,909	2,504,803	2,504,803	2,251,099	1,986,095	2,492,104	2,575,172	27,284,928
15	Solar [c]	3,980	4,746	6,108	6,697	7,426	6,431	19,439	18,279	15,996	14,558	11,251	9,668	124,579
16	**Total System Net Generation (MWh)**	8,613,018	7,852,254	8,352,545	8,925,709	9,933,167	9,757,543	10,854,145	11,053,407	10,240,125	9,703,582	8,398,892	8,665,228	112,349,613
17														
18	**Units of Fuel Burned (Unit)** [a]													
19	Heavy Oil	508	9	69,233	162,312	14	32,443	87,115	98,877	65,785	44,422	2,471	33,484	596,672
20	Light Oil	6,095	8,374	4,560	33,066	50,782	31,928	13,488	19,709	13,825	5,326	3,373	3,581	194,107
21	Coal [b]	255,465	238,791	32,392	23,002	235,972	316,085	352,062	353,900	339,841	342,833	325,503	338,023	3,153,868
22	Gas	39,028,492	37,296,668	45,701,103	54,067,874	51,408,101	50,831,758	54,634,832	55,822,946	52,156,487	49,886,571	36,287,303	37,196,734	564,318,868
23	Nuclear	27,822,208	25,950,984	18,110,315	15,996,645	27,738,935	26,826,523	27,047,003	27,047,003	24,267,538	21,326,061	26,177,533	27,050,111	295,360,859
24														
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	3,232	54	439,007	1,026,130	88	206,024	557,538	632,808	421,019	284,299	15,818	214,295	3,800,312
28	Light Oil	35,625	48,912	26,383	195,204	299,981	183,341	78,640	114,908	80,606	31,055	19,662	20,874	1,135,191
29	Coal	4,687,512	4,324,348	707,831	642,431	4,144,201	5,682,884	6,364,488	6,404,932	6,140,181	6,161,466	5,824,762	6,055,671	57,140,707
30	Gas	39,689,518	37,934,296	46,474,783	54,990,123	52,287,869	51,708,713	54,634,832	55,822,946	52,156,487	49,886,571	36,287,303	37,196,734	569,070,175
31	Nuclear	27,822,208	25,950,984	18,110,315	15,996,645	27,738,935	26,826,523	27,047,003	27,047,003	24,267,538	21,326,061	26,177,533	27,050,111	295,360,859
32	**Total BTU Burned (MMBTU)**	72,238,095	68,258,594	65,758,319	72,850,533	84,471,074	84,607,485	88,682,501	90,022,597	83,065,831	77,689,452	68,325,078	70,537,685	926,507,244
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	92.7625	89.2871	92.6111	92.6771	53.6406	92.9654	93.0145	93.9239	94.8291	95.2395	95.7330	94.4306	93.4792
36	Light Oil	125.0251	124.3179	107.5702	134.5840	135.3901	113.0128	119.6174	120.1618	117.9780	121.7276	122.9831	122.2102	125.3993
37	Coal	52.2403	52.2364	77.3636	102.0531	49.6881	52.4931	50.5126	49.0677	48.2359	47.4633	46.8890	47.0187	50.0842
38	Gas	5.5926	6.2472	5.6022	5.4693	5.4970	5.4049	5.2603	5.2618	5.2873	5.3401	5.6196	5.6728	5.4908
39	Nuclear	0.6211	0.5851	0.6236	0.6415	0.6231	0.6229	0.6514	0.6514	0.6522	0.6550	0.6569	0.6569	0.6366
40														
41														

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

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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	0.00%	(0.01%)	0.46%	1.13%	0.00%	0.19%	0.41%	0.48%	0.34%	0.27%	0.01%	0.22%	0.30%
3	Light Oil	0.05%	0.06%	0.04%	0.30%	0.42%	0.17%	0.05%	0.07%	0.07%	0.03%	0.02%	0.02%	0.11%
4	Coal	4.87%	5.29%	0.84%	0.77%	4.00%	5.57%	5.57%	5.51%	5.70%	6.02%	6.63%	6.68%	4.83%
5	Gas	64.58%	64.66%	78.41%	81.41%	70.52%	69.67%	70.71%	71.11%	71.76%	73.07%	63.53%	63.24%	70.36%
6	Nuclear	30.45%	29.94%	20.17%	16.32%	24.98%	24.33%	23.08%	22.66%	21.98%	20.47%	29.67%	29.72%	24.29%
7	Solar [c]	0.05%	0.06%	0.07%	0.08%	0.07%	0.07%	0.18%	0.17%	0.16%	0.15%	0.13%	0.11%	0.11%
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	14.5802	14.0544	14.6051	14.6595	8.4118	14.6396	14.5335	14.6757	14.8172	14.8813	14.9549	14.7550	14.6768
12	Light Oil	21.3903	21.2839	18.5923	22.7975	22.9194	19.6807	20.5163	20.6101	20.2348	20.8766	21.0977	20.9655	21.4421
13	Coal	2.8470	2.8845	3.5404	3.6539	2.8293	2.9197	2.7942	2.7112	2.6697	2.6409	2.6203	2.6246	2.7644
14	Gas	5.4995	6.1422	5.5089	5.3776	5.4046	5.3132	5.2603	5.2618	5.2873	5.3401	5.6196	5.6728	5.4450
15	Nuclear	0.6211	0.5851	0.6236	0.6415	0.6231	0.6229	0.6514	0.6514	0.6522	0.6550	0.6569	0.6569	0.6366
16														
17	**BTU Burned per KWH (BTU/KWH)**													
18	Heavy Oil	40,501	(74)	11,339	10,212	11,579	11,163	12,402	11,826	12,087	10,982	13,304	11,120	11,288
19	Light Oil	8,118	9,875	8,012	7,331	7,151	10,976	14,962	14,234	11,701	12,437	9,920	9,968	9,103
20	Coal	11,172	10,410	10,100	9,372	10,431	10,448	10,523	10,517	10,527	10,552	10,467	10,461	10,521
21	Gas	7,136	7,472	7,096	7,568	7,464	7,606	7,119	7,102	7,098	7,036	6,801	6,788	7,199
22	Nuclear	10,608	11,038	10,749	10,980	11,178	11,301	10,798	10,798	10,780	10,738	10,504	10,504	10,825
23														
24	**Generated Fuel Cost per KWH (cents/KWH)**													
25	Heavy Oil	59.0518	(0.1047)	16.5612	14.9698	9.7400	16.3415	18.0250	17.3548	17.9093	16.3431	19.8954	16.4076	16.5673
26	Light Oil	17.3638	21.0180	14.8954	16.7127	16.3902	21.6015	30.6963	29.3357	23.6761	25.9640	20.9295	20.8995	19.5188
27	Coal	3.1808	3.0028	3.5759	3.4246	2.9511	3.0504	2.9402	2.8513	2.8104	2.7866	2.7426	2.7455	2.9083
28	Gas	3.9241	4.5894	3.9091	4.0696	4.0342	4.0414	3.7447	3.7371	3.7529	3.7571	3.8217	3.8504	3.9199
29	Nuclear	0.6588	0.6459	0.6703	0.7044	0.6965	0.7039	0.7034	0.7034	0.7031	0.7033	0.6901	0.6900	0.6891
30	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.8992	3.3328	3.3131	3.6727	3.2062	3.2248	3.0635	3.0793	3.0845	3.1073	2.8222	2.8651	3.1372
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

36

37

38

39

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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		248					404	5,831,683	2,356	48,325	19.49	119.62
4	Gas		817,736					5,347,768	1,000,000	5,347,768	28,080,978	3.43	5.25
5	Plant Unit Info	1,210	817,984	90.9%	94.5%	93.6%	6,541			5,350,124	N/A	3.44	
6	*Desoto Solar*												
7	Solar		5,083					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,083	27.3%	N/A	50.5%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		3,197					9,969	5,830,274	58,122	1,192,466	37.30	119.62
15	Plant Unit Info	648	3,197	0.7%	95.3%	37.7%	18,180			58,122	N/A	37.30	
16	*Fort Myers 2*												
17	Gas		696,944					5,059,643	1,000,000	5,059,643	26,610,554	3.82	5.26
18	Plant Unit Info	1,380	696,944	67.9%	94.9%	89.7%	7,260			5,059,643	N/A	3.82	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,043	21.66	119.62
21	Gas		30,220					322,076	1,000,000	322,076	1,696,157	5.61	5.27
22	Plant Unit Info	296	30,331	27.6%	95.1%	95.5%	10,657			323,246	N/A	5.67	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,990					44,831	1,000,000	44,831	236,089	11.86	5.27
26	Plant Unit Info	840	1,990	0.3%	95.3%	50.3%	22,528			44,831	N/A	11.86	
27	*Lauderdale 4*												
28	Light Oil		109					201	5,830,846	1,172	24,043	22.06	119.62
29	Gas		68,079					522,159	1,000,000	522,159	2,749,868	4.04	5.27
30	Plant Unit Info	429	68,188	21.4%	94.8%	94.0%	7,675			523,331	N/A	4.07	
31	*Lauderdale 5*												
32	Light Oil		109					202	5,836,634	1,179	24,163	22.17	119.62
33	Gas		84,314					646,677	1,000,000	646,677	3,405,674	4.04	5.27
34	Plant Unit Info	429	84,423	26.5%	94.7%	94.5%	7,674			647,856	N/A	4.06	
35	*Manatee 1*												
36	Heavy Oil		13,438					31,574	6,400,044	202,075	2,936,839	21.85	93.01
37	Gas		76,148					797,745	1,000,000	797,745	4,201,244	5.52	5.27

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	789	89,586	15.3%	95.2%	79.7%	11,160			999,820	N/A	7.97	
2	*Manatee 2*												
3	Heavy Oil		8,289					19,775	6,400,000	126,560	1,839,362	22.19	93.01
4	Gas		46,974					491,229	1,000,000	491,229	2,587,023	5.51	5.27
5	Plant Unit Info	789	55,263	9.4%	95.2%	79.4%	11,179			617,789	N/A	8.01	
6	*Manatee 3*												
7	Gas		416,891					2,899,822	1,000,000	2,899,822	15,271,657	3.66	5.27
8	Plant Unit Info	1,058	416,891	53.0%	78.0%	79.3%	6,956			2,899,822	N/A	3.66	
9	*Martin 1*												
10	Heavy Oil		14,776					23,074	6,399,931	147,672	2,146,216	14.53	93.01
11	Gas		83,731					878,649	1,000,000	878,649	4,627,362	5.53	5.27
12	Plant Unit Info	799	98,507	16.6%	95.3%	66.0%	10,419			1,026,321	N/A	6.88	
13	*Martin 2*												
14	Heavy 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	802	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
17	*Martin 3*												
18	Gas		113,343					853,437	1,000,000	853,437	4,494,577	3.97	5.27
19	Plant Unit Info	438	113,343	34.8%	94.7%	94.8%	7,530			853,437	N/A	3.97	
20	*Martin 4*												
21	Gas		21,760					164,478	1,000,000	164,478	866,191	3.98	5.27
22	Plant Unit Info	437	21,760	6.7%	14.2%	94.0%	7,559			164,478	N/A	3.98	
23	*Martin 8*												
24	Light Oil		240					419	5,832,936	2,444	50,120	20.88	119.62
25	Gas		706,815					4,894,388	1,000,000	4,894,388	25,768,252	3.65	5.26
26	Plant Unit Info	1,111	707,055	85.5%	94.8%	88.0%	6,926			4,896,832	N/A	3.65	
27	*Martin 8 Solar*												
28	Solar		12,594					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	12,594	22.6%	N/A	36.1%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		48					93	5,849,462	544	11,124	23.18	119.62
32	Gas		83,544					784,088	1,000,000	784,088	4,129,361	4.94	5.27
33	Plant Unit Info	247	83,592	45.6%	95.1%	56.0%	9,386			784,632	N/A	4.95	
34	*Putnam 2*												
35	Light Oil		47					91	5,835,165	531	10,885	23.16	119.62
36	Gas		99,732					910,740	1,000,000	910,740	4,796,370	4.81	5.27
37	Plant Unit Info	250	99,779	53.6%	95.1%	64.2%	9,133			911,271	N/A	4.82	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		244					398	5,834,171	2,322	47,608	19.51	119.62
3	Gas		812,178					5,306,090	1,000,000	5,306,090	27,862,162	3.43	5.25
4	Plant Unit Info	1,212	812,422	90.1%	94.4%	92.7%	6,534			5,308,412	N/A	3.44	
5	*Sanford 4*												
6	Gas		253,828					1,851,813	1,000,000	1,851,813	9,742,793	3.84	5.26
7	Plant Unit Info	939	253,828	36.3%	78.8%	79.9%	7,296			1,851,813	N/A	3.84	
8	*Sanford 5*												
9	Gas		357,395					2,613,361	1,000,000	2,613,361	13,747,628	3.85	5.26
10	Plant Unit Info	947	357,395	50.7%	94.9%	94.6%	7,312			2,613,361	N/A	3.85	
11	*Scherer 4*												
12	Coal		449,448					276,172	16,999,986	4,694,920	12,233,553	2.72	44.30
13	Plant Unit Info	641	449,448	94.3%	94.4%	94.3%	10,446			4,694,920	N/A	2.72	
14	*St Johns 1*												
15	Coal		74,285					36,545	21,999,945	803,988	2,672,618	3.60	73.13
16	Plant Unit Info	127	74,285	78.7%	94.4%	78.8%	10,823			803,988	N/A	3.60	
17	*St Johns 2*												
18	Coal		81,111					39,345	21,999,746	865,580	2,877,389	3.55	73.13
19	Plant Unit Info	127	81,111	85.9%	94.4%	85.9%	10,672			865,580	N/A	3.55	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,999,400	0.70	0.67
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	N/A	0.70	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	N/A	0.65	
26	*Space Coast*												
27	Solar		1,762					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,762	23.7%	N/A	43.7%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
30	Heavy Oil		8,451					12,692	6,400,173	81,231	1,180,540	13.97	93.01
31	Gas		46,921					473,548	1,000,000	473,548	2,493,892	5.32	5.27
32	Plant Unit Info	380	55,372	19.6%	94.5%	83.7%	10,019			554,779	N/A	6.64	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	N/A	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,213,700	0.71	0.64

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	N/A	0.71	
2	*Turkey Point 5*												
3	Light Oil		237					414	5,833,333	2,415	49,522	20.90	119.62
4	Gas		684,822					4,751,697	1,000,000	4,751,697	24,983,792	3.65	5.26
5	Plant Unit Info	1,138	685,059	80.9%	94.9%	89.2%	6,940			4,754,112	N/A	3.65	
6	*WCEC 01*												
7	Light Oil		222					365	5,827,397	2,127	43,660	19.67	119.62
8	Gas		780,817					5,405,354	1,000,000	5,405,354	28,466,857	3.65	5.27
9	Plant Unit Info	1,166	781,039	90.1%	94.9%	92.8%	6,923			5,407,481	N/A	3.65	
10	*WCEC 02*												
11	Light Oil		222					366	5,822,404	2,131	43,780	19.72	119.62
12	Gas		641,932					4,426,809	1,000,000	4,426,809	23,254,285	3.62	5.25
13	Plant Unit Info	1,159	642,154	74.5%	83.0%	84.7%	6,897			4,428,940	N/A	3.63	
14	*WCEC 03*												
15	Light Oil		222					365	5,827,397	2,127	43,660	19.67	119.62
16	Gas		748,735					5,188,430	1,000,000	5,188,430	27,324,468	3.65	5.27
17	Plant Unit Info	1,166	748,957	86.4%	94.9%	91.2%	6,930			5,190,557	N/A	3.65	
18	**System Totals**												
19	Plant Unit Info	24,936	10,854,145				8,170			88,682,501	332,515,453	3.06	
20													
21													
22													
23													
24													
25													
26													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		248					404	5,831,683	2,356	48,545	19.57	120.16
4	Gas		819,327					5,358,347	1,000,000	5,358,347	28,141,692	3.43	5.25
5	Plant Unit Info	1,210	819,575	91.1%	94.5%	93.7%	6,541			5,360,703	N/A	3.44	
6	*Desoto Solar*												
7	Solar		4,833					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,833	26.0%	N/A	48.0%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		809					18,215	1,000,000	18,215	95,954	11.86	5.27
12	Plant Unit Info	420	809	0.3%	95.3%	96.3%	22,515			18,215	N/A	11.86	
13	*Fort Myers 1-12*												
14	Light Oil		4,188					13,399	5,830,137	78,118	1,610,048	38.44	120.16
15	Plant Unit Info	648	4,188	0.9%	95.3%	42.1%	18,653			78,118	N/A	38.44	
16	*Fort Myers 2*												
17	Gas		694,132					5,038,562	1,000,000	5,038,562	26,505,946	3.82	5.26
18	Plant Unit Info	1,380	694,132	67.6%	94.9%	90.0%	7,259			5,038,562	N/A	3.82	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,153	21.76	120.16
21	Gas		28,243					301,006	1,000,000	301,006	1,585,733	5.61	5.27
22	Plant Unit Info	296	28,354	25.8%	95.1%	95.5%	10,657			302,176	N/A	5.68	
23	*Lauderdale 1-24*												
24	Light Oil		209					766	5,828,982	4,465	92,044	44.04	120.16
25	Gas		3,290					73,736	1,000,000	73,736	388,472	11.81	5.27
26	Plant Unit Info	840	3,499	0.6%	95.3%	48.2%	22,350			78,201	N/A	13.73	
27	*Lauderdale 4*												
28	Light Oil		915					1,210	5,832,231	7,057	145,396	15.89	120.16
29	Gas		73,316					562,325	1,000,000	562,325	2,962,292	4.04	5.27
30	Plant Unit Info	429	74,231	23.3%	94.8%	94.0%	7,670			569,382	N/A	4.19	
31	*Lauderdale 5*												
32	Light Oil		920					1,218	5,830,049	7,101	146,357	15.91	120.16
33	Gas		85,125					652,895	1,000,000	652,895	3,439,443	4.04	5.27
34	Plant Unit Info	429	86,045	27.0%	94.7%	94.5%	7,670			659,996	N/A	4.17	
35	*Manatee 1*												
36	Heavy Oil		17,761					37,679	6,399,984	241,145	3,538,960	19.93	93.92
37	Gas		69,006					722,648	1,000,000	722,648	3,806,888	5.52	5.27

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	789	86,767	14.8%	95.2%	78.8%	11,108			963,793	N/A	8.47	
2	*Manatee 2*												
3	Heavy Oil		7,803					18,396	6,399,870	117,732	1,727,825	22.14	93.92
4	Gas		44,217					462,505	1,000,000	462,505	2,436,475	5.51	5.27
5	Plant Unit Info	789	52,020	8.9%	95.2%	79.8%	11,154			580,237	N/A	8.01	
6	*Manatee 3*												
7	Gas		496,971					3,450,567	1,000,000	3,450,567	18,177,654	3.66	5.27
8	Plant Unit Info	1,058	496,971	63.2%	85.2%	85.0%	6,943			3,450,567	N/A	3.66	
9	*Martin 1*												
10	Heavy Oil		14,838					23,148	6,400,035	148,148	2,174,151	14.65	93.92
11	Gas		84,083					881,482	1,000,000	881,482	4,643,639	5.52	5.27
12	Plant Unit Info	799	98,921	16.6%	95.3%	65.4%	10,409			1,029,630	N/A	6.89	
13	*Martin 2*												
14	Heavy 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	802	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
17	*Martin 3*												
18	Gas		118,325					890,951	1,000,000	890,951	4,693,546	3.97	5.27
19	Plant Unit Info	438	118,325	36.3%	94.7%	94.8%	7,530			890,951	N/A	3.97	
20	*Martin 4*												
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	437	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
23	*Martin 8*												
24	Light Oil		240					419	5,832,936	2,444	50,348	20.98	120.16
25	Gas		703,827					4,872,592	1,000,000	4,872,592	25,667,169	3.65	5.27
26	Plant Unit Info	1,111	704,067	85.2%	94.8%	87.7%	6,924			4,875,036	N/A	3.65	
27	*Martin 8 Solar*												
28	Solar		11,773					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	11,773	21.1%	N/A	39.0%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		48					93	5,849,462	544	11,175	23.28	120.16
32	Gas		78,760					736,344	1,000,000	736,344	3,879,076	4.93	5.27
33	Plant Unit Info	247	78,808	43.0%	95.1%	58.8%	9,350			736,888	N/A	4.94	
34	*Putnam 2*												
35	Light Oil		47					91	5,835,165	531	10,935	23.27	120.16
36	Gas		86,000					788,925	1,000,000	788,925	4,156,029	4.83	5.27
37	Plant Unit Info	250	86,047	46.3%	95.1%	60.7%	9,175			789,456	N/A	4.84	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		244					398	5,834,171	2,322	47,824	19.60	120.16
3	Gas		811,707					5,303,416	1,000,000	5,303,416	27,853,148	3.43	5.25
4	Plant Unit Info	1,212	811,951	90.1%	94.4%	92.8%	6,535			5,305,738	N/A	3.44	
5	*Sanford 4*												
6	Gas		250,483					1,827,451	1,000,000	1,827,451	9,617,884	3.84	5.26
7	Plant Unit Info	939	250,483	35.9%	77.2%	78.4%	7,296			1,827,451	N/A	3.84	
8	*Sanford 5*												
9	Gas		366,556					2,680,152	1,000,000	2,680,152	14,103,566	3.85	5.26
10	Plant Unit Info	947	366,556	52.0%	94.9%	94.6%	7,312			2,680,152	N/A	3.85	
11	*Scherer 4*												
12	Coal		449,448					276,172	16,999,986	4,694,920	11,794,919	2.62	42.71
13	Plant Unit Info	641	449,448	94.3%	94.4%	94.3%	10,446			4,694,920	N/A	2.62	
14	*St Johns 1*												
15	Coal		77,313					37,852	21,999,921	832,741	2,712,545	3.51	71.66
16	Plant Unit Info	127	77,313	81.9%	94.4%	81.9%	10,771			832,741	N/A	3.51	
17	*St Johns 2*												
18	Coal		82,258					39,876	21,999,975	877,271	2,857,588	3.47	71.66
19	Plant Unit Info	127	82,258	87.1%	94.4%	87.1%	10,665			877,271	N/A	3.47	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,999,400	0.70	0.67
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	N/A	0.70	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	N/A	0.65	
26	*Space Coast*												
27	Solar		1,673					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,673	22.5%	N/A	41.5%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
30	Heavy Oil		13,110					19,654	6,399,868	125,783	1,845,981	14.08	93.92
31	Gas		41,442					417,503	1,000,000	417,503	2,199,429	5.31	5.27
32	Plant Unit Info	380	54,552	19.3%	94.5%	84.7%	9,959			543,286	N/A	7.42	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	N/A	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,213,700	0.71	0.64

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	N/A	0.71	
2	*Turkey Point 5*												
3	Light Oil		237					414	5,833,333	2,415	49,747	20.99	120.16
4	Gas		702,927					4,878,258	1,000,000	4,878,258	25,655,863	3.65	5.26
5	Plant Unit Info	1,138	703,164	83.1%	94.9%	88.6%	6,941			4,880,673	N/A	3.66	
6	*WCEC 01*												
7	Light Oil		222					365	5,827,397	2,127	43,859	19.76	120.16
8	Gas		779,346					5,395,550	1,000,000	5,395,550	28,423,790	3.65	5.27
9	Plant Unit Info	1,166	779,568	89.9%	94.9%	92.6%	6,924			5,397,677	N/A	3.65	
10	*WCEC 02*												
11	Light Oil		222					366	5,822,404	2,131	43,979	19.81	120.16
12	Gas		774,222					5,328,743	1,000,000	5,328,743	28,003,313	3.62	5.26
13	Plant Unit Info	1,159	774,444	89.8%	94.9%	92.4%	6,883			5,330,874	N/A	3.62	
14	*WCEC 03*												
15	Light Oil		222					365	5,827,397	2,127	43,859	19.76	120.16
16	Gas		747,607					5,180,774	1,000,000	5,180,774	27,292,354	3.65	5.27
17	Plant Unit Info	1,166	747,829	86.2%	94.9%	91.1%	6,931			5,182,901	N/A	3.66	
18	**System Totals**												
19	Plant Unit Info	24,936	11,053,407				8,144			90,022,597	340,367,893	3.08	
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													
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31													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		248					404	5,831,683	2,356	47,663	19.22	117.98
4	Gas		792,875					5,185,768	1,000,000	5,185,768	27,366,143	3.45	5.28
5	Plant Unit Info	1,210	793,123	91.1%	94.5%	93.7%	6,541			5,188,124	N/A	3.46	
6	*Desoto Solar*												
7	Solar		4,298					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,298	23.9%	N/A	44.1%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		2,427					54,646	1,000,000	54,646	289,295	11.92	5.29
12	Plant Unit Info	420	2,427	0.8%	95.3%	96.3%	22,516			54,646	N/A	11.92	
13	*Fort Myers 1-12*												
14	Light Oil		1,680					5,593	5,830,324	32,609	659,851	39.28	117.98
15	Plant Unit Info	648	1,680	0.4%	95.3%	53.5%	19,410			32,609	N/A	39.28	
16	*Fort Myers 2*												
17	Gas		609,346					4,425,233	1,000,000	4,425,233	23,391,551	3.84	5.29
18	Plant Unit Info	1,380	609,346	61.3%	94.9%	91.3%	7,262			4,425,233	N/A	3.84	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	23,714	21.36	117.98
21	Gas		28,949					308,531	1,000,000	308,531	1,633,344	5.64	5.29
22	Plant Unit Info	296	29,060	27.3%	95.1%	95.5%	10,657			309,701	N/A	5.70	
23	*Lauderdale 1-24*												
24	Light Oil		305					1,149	5,829,417	6,698	135,557	44.44	117.98
25	Gas		5,194					119,650	1,000,000	119,650	633,464	12.20	5.29
26	Plant Unit Info	840	5,499	0.9%	95.3%	50.4%	22,977			126,348	N/A	13.98	
27	*Lauderdale 4*												
28	Light Oil		1,318					1,715	5,830,904	10,000	202,332	15.35	117.98
29	Gas		59,217					454,185	1,000,000	454,185	2,404,517	4.06	5.29
30	Plant Unit Info	429	60,535	19.6%	94.8%	94.0%	7,668			464,185	N/A	4.31	
31	*Lauderdale 5*												
32	Light Oil		1,745					2,252	5,831,261	13,132	265,686	15.23	117.98
33	Gas		73,355					562,618	1,000,000	562,618	2,978,529	4.06	5.29
34	Plant Unit Info	429	75,100	24.4%	94.7%	94.5%	7,666			575,750	N/A	4.32	
35	*Manatee 1*												
36	Heavy Oil		10,159					24,590	6,399,959	157,375	2,331,848	22.95	94.83
37	Gas		57,565					603,182	1,000,000	603,182	3,193,242	5.55	5.29

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	789	67,724	11.9%	95.2%	75.5%	11,230			760,557	N/A	8.16	
2	*Manatee 2*												
3	Heavy Oil		3,474					8,547	6,399,789	54,699	810,505	23.33	94.83
4	Gas		19,687					206,462	1,000,000	206,462	1,093,017	5.55	5.29
5	Plant Unit Info	789	23,161	4.1%	95.2%	72.4%	11,276			261,161	N/A	8.22	
6	*Manatee 3*												
7	Gas		487,674					3,398,669	1,000,000	3,398,669	17,992,732	3.69	5.29
8	Plant Unit Info	1,078	487,674	62.8%	94.9%	92.7%	6,969			3,398,669	N/A	3.69	
9	*Martin 1*												
10	Heavy Oil		12,292					19,224	6,399,917	123,032	1,822,995	14.83	94.83
11	Gas		69,653					732,042	1,000,000	732,042	3,875,507	5.56	5.29
12	Plant Unit Info	799	81,945	14.2%	95.3%	60.9%	10,435			855,074	N/A	6.95	
13	*Martin 2*												
14	Heavy 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	802	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
17	*Martin 3*												
18	Gas		107,531					809,671	1,000,000	809,671	4,286,477	3.99	5.29
19	Plant Unit Info	438	107,531	34.1%	94.7%	94.8%	7,530			809,671	N/A	3.99	
20	*Martin 4*												
21	Gas		48,857					369,300	1,000,000	369,300	1,955,061	4.00	5.29
22	Plant Unit Info	437	48,857	15.5%	44.9%	94.0%	7,559			369,300	N/A	4.00	
23	*Martin 8*												
24	Light Oil		240					419	5,832,936	2,444	49,433	20.60	117.98
25	Gas		616,271					4,263,748	1,000,000	4,263,748	22,571,917	3.66	5.29
26	Plant Unit Info	1,111	616,511	77.1%	89.0%	86.3%	6,920			4,266,192	N/A	3.67	
27	*Martin 8 Solar*												
28	Solar		10,217					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	10,217	18.9%	N/A	37.8%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		48					93	5,849,462	544	10,972	22.86	117.98
32	Gas		73,359					690,510	1,000,000	690,510	3,655,642	4.98	5.29
33	Plant Unit Info	247	73,407	41.4%	95.1%	55.2%	9,414			691,054	N/A	4.99	
34	*Putnam 2*												
35	Light Oil		47					91	5,835,165	531	10,736	22.84	117.98
36	Gas		87,649					802,177	1,000,000	802,177	4,246,731	4.85	5.29
37	Plant Unit Info	250	87,696	48.7%	95.1%	62.9%	9,153			802,708	N/A	4.85	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		244					398	5,834,171	2,322	46,955	19.24	117.98
3	Gas		786,988					5,142,471	1,000,000	5,142,471	27,137,690	3.45	5.28
4	Plant Unit Info	1,212	787,232	90.3%	94.4%	92.9%	6,535			5,144,793	N/A	3.45	
5	*Sanford 4*												
6	Gas		272,119					1,984,780	1,000,000	1,984,780	10,488,416	3.85	5.28
7	Plant Unit Info	939	272,119	40.3%	94.9%	95.0%	7,294			1,984,780	N/A	3.85	
8	*Sanford 5*												
9	Gas		299,982					2,193,372	1,000,000	2,193,372	11,592,167	3.86	5.29
10	Plant Unit Info	947	299,982	44.0%	94.9%	95.5%	7,312			2,193,372	N/A	3.86	
11	*Scherer 4*												
12	Coal		434,950					267,263	16,999,985	4,543,467	11,187,068	2.57	41.86
13	Plant Unit Info	641	434,950	94.3%	94.4%	94.3%	10,446			4,543,467	N/A	2.57	
14	*St Johns 1*												
15	Coal		70,872					34,925	22,000,115	768,354	2,504,912	3.53	71.72
16	Plant Unit Info	127	70,872	77.6%	94.4%	77.6%	10,841			768,354	N/A	3.53	
17	*St Johns 2*												
18	Coal		77,452					37,653	21,999,841	828,360	2,700,571	3.49	71.72
19	Plant Unit Info	127	77,452	84.8%	94.4%	84.8%	10,695			828,360	N/A	3.49	
20	*St Lucie 1*												
21	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,838,200	0.70	0.67
22	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	N/A	0.70	
23	*St Lucie 2*												
24	Nuclear		589,677					6,189,149	1,000,000	6,189,149	3,847,800	0.65	0.62
25	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,496			6,189,149	N/A	0.65	
26	*Space Coast*												
27	Solar		1,481					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,481	20.6%	N/A	38.0%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
30	Heavy Oil		8,908					13,424	6,399,955	85,913	1,272,986	14.29	94.83
31	Gas		41,080					415,999	1,000,000	415,999	2,202,305	5.36	5.29
32	Plant Unit Info	380	49,988	18.3%	94.5%	80.7%	10,041			501,912	N/A	6.95	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	N/A	0.75	
36	*Turkey Point 4*												
37	Nuclear		403,440					4,449,622	1,000,000	4,449,622	2,854,400	0.71	0.64

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	821	403,440	68.3%	68.3%	97.5%	11,029			4,449,622	N/A	0.71	
2	*Turkey Point 5*												
3	Light Oil		237					414	5,833,333	2,415	48,843	20.61	117.98
4	Gas		623,857					4,329,807	1,000,000	4,329,807	22,880,797	3.67	5.28
5	Plant Unit Info	1,138	624,094	76.2%	94.9%	90.0%	6,942			4,332,222	N/A	3.67	
6	*WCEC 01*												
7	Light Oil		222					365	5,827,397	2,127	43,062	19.40	117.98
8	Gas		713,621					4,946,303	1,000,000	4,946,303	26,186,004	3.67	5.29
9	Plant Unit Info	1,166	713,843	85.1%	90.5%	88.9%	6,932			4,948,430	N/A	3.67	
10	*WCEC 02*												
11	Light Oil		222					366	5,822,404	2,131	43,180	19.45	117.98
12	Gas		748,716					5,153,494	1,000,000	5,153,494	27,222,112	3.64	5.28
13	Plant Unit Info	1,159	748,938	89.8%	94.9%	92.4%	6,884			5,155,625	N/A	3.64	
14	*WCEC 03*												
15	Light Oil		222					365	5,827,397	2,127	43,062	19.40	117.98
16	Gas		722,063					5,003,870	1,000,000	5,003,870	26,490,765	3.67	5.29
17	Plant Unit Info	1,166	722,285	86.1%	94.9%	91.1%	6,931			5,005,997	N/A	3.67	
18	**System Totals**												
19	Plant Unit Info	24,956	10,240,125				8,112			83,065,831	315,856,058	3.08	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		248					404	5,831,683	2,356	49,178	19.83	121.73
4	Gas		814,332					5,326,647	1,000,000	5,326,647	28,340,077	3.48	5.32
5	Plant Unit Info	1,210	814,580	90.5%	94.5%	93.2%	6,542			5,329,003	N/A	3.49	
6	*Desoto Solar*												
7	Solar		4,150					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,150	22.3%	N/A	41.2%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		660					2,172	5,830,571	12,664	264,392	40.06	121.73
15	Plant Unit Info	648	660	0.1%	95.3%	47.1%	19,188			12,664	N/A	40.06	
16	*Fort Myers 2*												
17	Gas		721,546					5,232,435	1,000,000	5,232,435	27,946,093	3.87	5.34
18	Plant Unit Info	1,380	721,546	70.3%	91.2%	86.8%	7,252			5,232,435	N/A	3.87	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,467	22.04	121.73
21	Gas		17,228					183,613	1,000,000	183,613	983,256	5.71	5.36
22	Plant Unit Info	296	17,339	15.8%	95.1%	95.5%	10,657			184,783	N/A	5.81	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,110					24,443	1,000,000	24,443	130,846	11.79	5.35
26	Plant Unit Info	840	1,110	0.2%	95.3%	49.0%	22,021			24,443	N/A	11.79	
27	*Lauderdale 4*												
28	Light Oil		109					201	5,830,846	1,172	24,467	22.45	121.73
29	Gas		57,203					438,737	1,000,000	438,737	2,349,421	4.11	5.35
30	Plant Unit Info	429	57,312	18.0%	94.8%	94.0%	7,676			439,909	N/A	4.14	
31	*Lauderdale 5*												
32	Light Oil		109					202	5,836,634	1,179	24,589	22.56	121.73
33	Gas		74,174					569,205	1,000,000	569,205	3,048,076	4.11	5.35
34	Plant Unit Info	429	74,283	23.3%	94.7%	93.1%	7,679			570,384	N/A	4.14	
35	*Manatee 1*												
36	Heavy Oil		11,163					21,181	6,399,981	135,558	2,017,268	18.07	95.24
37	Gas		18,502					194,141	1,000,000	194,141	1,039,642	5.62	5.36

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	789	29,665	5.1%	95.2%	77.0%	11,114			329,699	N/A	10.30	
2	*Manatee 2*												
3	Heavy Oil		917					2,056	6,399,319	13,157	195,812	21.35	95.24
4	Gas		5,198					54,487	1,000,000	54,487	291,781	5.61	5.36
5	Plant Unit Info	789	6,115	1.0%	95.2%	88.7%	11,062			67,644	N/A	7.97	
6	*Manatee 3*												
7	Gas		595,195					4,148,891	1,000,000	4,148,891	22,217,399	3.73	5.36
8	Plant Unit Info	1,078	595,195	74.2%	94.9%	90.5%	6,971			4,148,891	N/A	3.73	
9	*Martin 1*												
10	Heavy Oil		6,287					9,812	6,399,918	62,796	934,490	14.86	95.24
11	Gas		35,626					373,638	1,000,000	373,638	2,000,793	5.62	5.35
12	Plant Unit Info	799	41,913	7.1%	95.3%	64.9%	10,413			436,434	N/A	7.00	
13	*Martin 2*												
14	Heavy 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	802	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
17	*Martin 3*												
18	Gas		80,959					609,597	1,000,000	609,597	3,264,366	4.03	5.35
19	Plant Unit Info	438	80,959	24.9%	72.1%	94.8%	7,530			609,597	N/A	4.03	
20	*Martin 4*												
21	Gas		98,430					744,064	1,000,000	744,064	3,984,440	4.05	5.35
22	Plant Unit Info	437	98,430	30.3%	94.9%	93.9%	7,559			744,064	N/A	4.05	
23	*Martin 8*												
24	Light Oil		240					419	5,832,936	2,444	51,004	21.25	121.73
25	Gas		710,968					4,922,974	1,000,000	4,922,974	26,339,756	3.70	5.35
26	Plant Unit Info	1,111	711,208	86.0%	94.8%	86.9%	6,925			4,925,418	N/A	3.71	
27	*Martin 8 Solar*												
28	Solar		8,981					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	8,981	16.1%	N/A	24.1%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		48					93	5,849,462	544	11,321	23.58	121.73
32	Gas		59,839					583,148	1,000,000	583,148	3,122,756	5.22	5.35
33	Plant Unit Info	247	59,887	32.7%	95.1%	41.4%	9,747			583,692	N/A	5.23	
34	*Putnam 2*												
35	Light Oil		47					91	5,835,165	531	11,077	23.57	121.73
36	Gas		77,122					706,297	1,000,000	706,297	3,782,266	4.90	5.36
37	Plant Unit Info	250	77,169	41.5%	79.0%	62.4%	9,159			706,828	N/A	4.92	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		244					398	5,834,171	2,322	48,448	19.86	121.73
3	Gas		810,408					5,294,929	1,000,000	5,294,929	28,171,320	3.48	5.32
4	Plant Unit Info	1,212	810,652	89.9%	94.4%	92.6%	6,535			5,297,251	N/A	3.48	
5	*Sanford 4*												
6	Gas		295,141					2,152,694	1,000,000	2,152,694	11,483,379	3.89	5.33
7	Plant Unit Info	939	295,141	42.3%	94.9%	95.0%	7,294			2,152,694	N/A	3.89	
8	*Sanford 5*												
9	Gas		356,000					2,602,726	1,000,000	2,602,726	13,892,447	3.90	5.34
10	Plant Unit Info	947	356,000	50.5%	94.9%	93.3%	7,311			2,602,726	N/A	3.90	
11	*Scherer 4*												
12	Coal		449,448					276,172	16,999,986	4,694,920	11,460,571	2.55	41.50
13	Plant Unit Info	641	449,448	94.3%	94.4%	94.3%	10,446			4,694,920	N/A	2.55	
14	*St Johns 1*												
15	Coal		64,938					32,391	21,999,938	712,600	2,337,890	3.60	72.18
16	Plant Unit Info	127	64,938	68.8%	94.4%	68.8%	10,974			712,600	N/A	3.60	
17	*St Johns 2*												
18	Coal		69,540					34,270	22,000,175	753,946	2,473,510	3.56	72.18
19	Plant Unit Info	127	69,540	73.7%	94.4%	73.6%	10,842			753,946	N/A	3.56	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,999,400	0.70	0.67
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	N/A	0.70	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	N/A	0.65	
26	*Space Coast*												
27	Solar		1,427					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,427	19.2%	N/A	38.4%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
30	Heavy Oil		7,520					11,373	6,400,070	72,788	1,083,159	14.40	95.24
31	Gas		17,303					175,859	1,000,000	175,859	941,694	5.44	5.35
32	Plant Unit Info	380	24,823	8.8%	94.5%	73.9%	10,017			248,647	N/A	8.16	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	N/A	0.75	
36	*Turkey Point 4*												
37	Nuclear		76,846					847,547	1,000,000	847,547	563,000	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	821	76,846	12.6%	12.6%	97.5%	11,029			847,547	N/A	0.73	
2	*Turkey Point 5*												
3	Light Oil		237					414	5,833,333	2,415	50,395	21.26	121.73
4	Gas		681,802					4,731,099	1,000,000	4,731,099	25,240,769	3.70	5.34
5	Plant Unit Info	1,138	682,039	80.6%	94.9%	87.8%	6,940			4,733,514	N/A	3.71	
6	*WCEC 01*												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		52,782					387,681	1,000,000	387,681	2,076,045	3.93	5.36
9	Plant Unit Info	1,166	52,782	6.1%	10.0%	28.6%	7,345			387,681	N/A	3.93	
10	*WCEC 02*												
11	Light Oil		222					366	5,822,404	2,131	44,552	20.07	121.73
12	Gas		763,943					5,259,733	1,000,000	5,259,733	28,069,424	3.67	5.34
13	Plant Unit Info	1,159	764,165	88.6%	94.9%	91.3%	6,886			5,261,864	N/A	3.68	
14	*WCEC 03*												
15	Light Oil		222					365	5,827,397	2,127	44,431	20.01	121.73
16	Gas		745,809					5,169,533	1,000,000	5,169,533	27,682,069	3.71	5.35
17	Plant Unit Info	1,166	746,031	86.0%	94.9%	90.1%	6,932			5,171,660	N/A	3.72	
18	**System Totals**												
19	Plant Unit Info	24,956	9,703,582				8,006			77,689,452	301,516,737	3.11	
20													
21													
22													
23													
24													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,546	20.06	122.98
4	Gas		887,233					5,768,387	1,000,000	5,768,387	32,369,147	3.65	5.61
5	Plant Unit Info	1,355	887,485	91.0%	94.5%	93.7%	6,502			5,770,781	N/A	3.65	
6	*Desoto Solar*												
7	Solar		3,572					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,572	19.9%	N/A	43.3%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
16	*Fort Myers 2*												
17	Gas		242,177					1,752,702	1,000,000	1,752,702	9,868,646	4.07	5.63
18	Plant Unit Info	1,435	242,177	23.4%	46.0%	63.2%	7,237			1,752,702	N/A	4.07	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,720	22.27	122.98
21	Gas		2,701					28,380	1,000,000	28,380	159,759	5.91	5.63
22	Plant Unit Info	314	2,812	2.5%	95.1%	95.5%	10,509			29,550	N/A	6.56	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,703	22.75	122.98
33	Gas		14,070					107,891	1,000,000	107,891	607,532	4.32	5.63
34	Plant Unit Info	442	14,183	4.5%	94.7%	88.5%	7,693			109,109	N/A	4.46	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		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 2014 THROUGH DECEMBER 2014

	(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	795	0	0.0%	61.8%	0.0%	0			0	N/A	0.00	
2	*Manatee 2*												
3	Heavy Oil		632					1,602	6,401,998	10,256	153,364	24.27	95.73
4	Gas		3,582					37,223	1,000,000	37,223	209,565	5.85	5.63
5	Plant Unit Info	795	4,214	0.7%	95.2%	66.4%	11,267			47,479	N/A	8.61	
6	*Manatee 3*												
7	Gas		435,227					2,988,883	1,000,000	2,988,883	16,828,968	3.87	5.63
8	Plant Unit Info	1,134	435,227	53.3%	94.9%	85.5%	6,867			2,988,883	N/A	3.87	
9	*Martin 1*												
10	Heavy Oil		557					869	6,400,460	5,562	83,192	14.94	95.73
11	Gas		3,155					33,095	1,000,000	33,095	186,354	5.91	5.63
12	Plant Unit Info	805	3,712	0.6%	95.3%	53.0%	10,414			38,657	N/A	7.26	
13	*Martin 2*												
14	Heavy 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	808	0	0.0%	0.0%	0.0%	0			0	N/A	0.00	
17	*Martin 3*												
18	Gas		57,452					432,405	1,000,000	432,405	2,434,665	4.24	5.63
19	Plant Unit Info	454	57,452	17.6%	94.7%	84.9%	7,526			432,405	N/A	4.24	
20	*Martin 4*												
21	Gas		34,675					262,262	1,000,000	262,262	1,476,646	4.26	5.63
22	Plant Unit Info	453	34,675	10.6%	94.9%	77.4%	7,563			262,262	N/A	4.26	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,760	21.53	122.98
25	Gas		543,929					3,736,264	1,000,000	3,736,264	21,036,269	3.87	5.63
26	Plant Unit Info	1,147	544,174	66.0%	94.8%	81.4%	6,871			3,738,767	N/A	3.88	
27	*Martin 8 Solar*												
28	Solar		6,459					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	6,459	12.0%	N/A	19.1%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,823	23.53	122.98
32	Gas		1,899					17,938	1,000,000	17,938	100,962	5.32	5.63
33	Plant Unit Info	251	1,945	1.1%	95.1%	57.8%	9,488			18,454	N/A	5.75	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,945	23.79	122.98
36	Gas		2,741					25,308	1,000,000	25,308	142,500	5.20	5.63
37	Plant Unit Info	255	2,787	1.6%	78.5%	65.0%	9,266			25,825	N/A	5.51	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,177	19.99	122.98
3	Gas		883,838					5,737,296	1,000,000	5,737,296	32,194,688	3.64	5.61
4	Plant Unit Info	1,344	884,089	91.4%	94.4%	94.2%	6,492			5,739,677	N/A	3.65	
5	*Sanford 4*												
6	Gas		144,255					1,049,205	1,000,000	1,049,205	5,901,642	4.09	5.62
7	Plant Unit Info	990	144,255	20.3%	94.9%	83.8%	7,273			1,049,205	N/A	4.09	
8	*Sanford 5*												
9	Gas		195,212					1,425,524	1,000,000	1,425,524	8,022,259	4.11	5.63
10	Plant Unit Info	994	195,212	27.3%	80.7%	67.0%	7,302			1,425,524	N/A	4.11	
11	*Scherer 4*												
12	Coal		438,436					267,261	17,000,026	4,543,444	11,036,982	2.52	41.30
13	Plant Unit Info	646	438,436	94.3%	94.4%	94.3%	10,363			4,543,444	N/A	2.52	
14	*St Johns 1*												
15	Coal		56,507					28,231	21,999,894	621,079	2,048,194	3.62	72.55
16	Plant Unit Info	128	56,507	61.2%	94.4%	61.2%	10,991			621,079	N/A	3.62	
17	*St Johns 2*												
18	Coal		61,545					30,011	21,999,900	660,239	2,177,336	3.54	72.55
19	Plant Unit Info	128	61,545	66.7%	94.4%	66.7%	10,728			660,239	N/A	3.54	
20	*St Lucie 1*												
21	Nuclear		704,105					7,272,165	1,000,000	7,272,165	4,838,200	0.69	0.67
22	Plant Unit Info	1,003	704,105	97.5%	97.5%	97.5%	10,328			7,272,165	N/A	0.69	
23	*St Lucie 2*												
24	Nuclear		603,721					6,192,164	1,000,000	6,192,164	3,849,700	0.64	0.62
25	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,257			6,192,164	N/A	0.64	
26	*Space Coast*												
27	Solar		1,220					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,220	17.0%	N/A	37.0%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
30	Heavy Oil		0					0	0	0	0	0.00	0.00
31	Gas		2,026					20,559	1,000,000	20,559	115,772	5.71	5.63
32	Plant Unit Info	380	2,026	0.7%	94.5%	81.7%	10,148			20,559	N/A	5.71	
33	*Turkey Point 3*												
34	Nuclear		588,980					6,356,602	1,000,000	6,356,602	4,286,300	0.73	0.67
35	Plant Unit Info	839	588,980	97.5%	97.5%	97.5%	10,793			6,356,602	N/A	0.73	
36	*Turkey Point 4*												
37	Nuclear		595,298					6,356,602	1,000,000	6,356,602	4,222,700	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	848	595,298	97.5%	97.5%	97.5%	10,678			6,356,602	N/A	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,145	21.55	122.98
4	Gas		86,313					591,127	1,000,000	591,127	3,322,512	3.85	5.62
5	Plant Unit Info	1,166	86,555	10.4%	24.9%	87.1%	6,858			593,600	N/A	3.90	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	45,012	20.28	122.98
8	Gas		410,376					2,812,158	1,000,000	2,812,158	15,787,195	3.85	5.61
9	Plant Unit Info	1,208	410,598	47.3%	48.3%	77.1%	6,854			2,814,292	N/A	3.86	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,996	20.26	122.98
12	Gas		696,164					4,749,844	1,000,000	4,749,844	26,653,637	3.83	5.61
13	Plant Unit Info	1,202	696,391	80.5%	94.9%	82.8%	6,824			4,752,022	N/A	3.83	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,996	20.26	122.98
16	Gas		688,853					4,710,854	1,000,000	4,710,854	26,500,413	3.85	5.63
17	Plant Unit Info	1,207	689,080	79.3%	94.9%	81.9%	6,840			4,713,032	N/A	3.85	
18	**System Totals**												
19	Plant Unit Info	25,955	8,398,892				8,135			68,325,078	237,029,921	2.82	
20													
21													
22													
23													
24													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,228	19.93	122.21
4	Gas		915,058					5,946,987	1,000,000	5,946,987	33,685,625	3.68	5.66
5	Plant Unit Info	1,355	915,310	90.8%	94.5%	93.3%	6,500			5,949,381	N/A	3.69	
6	*Desoto Solar*												
7	Solar		3,244					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,244	17.4%	N/A	38.1%	N/A			N/A	N/A	N/A	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
16	*Fort Myers 2*												
17	Gas		294,811					2,124,202	1,000,000	2,124,202	12,064,850	4.09	5.68
18	Plant Unit Info	1,435	294,811	27.6%	85.8%	74.4%	7,205			2,124,202	N/A	4.09	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,564	22.13	122.21
21	Gas		1,801					18,920	1,000,000	18,920	107,529	5.97	5.68
22	Plant Unit Info	314	1,912	1.7%	95.1%	95.5%	10,507			20,090	N/A	6.91	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	N/A	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,420	22.70	122.21
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	112	0.0%	78.7%	0.0%	10,821			1,212	N/A	22.70	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,542	22.60	122.21
33	Gas		6,891					52,798	1,000,000	52,798	300,149	4.36	5.68
34	Plant Unit Info	442	7,004	2.2%	94.7%	86.7%	7,712			54,016	N/A	4.65	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		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 2014 THROUGH DECEMBER 2014

	(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	795	0	0.0%	95.2%	0.0%	0			0	N/A	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	N/A	0.00	
6	*Manatee 3*												
7	Gas		403,078					2,767,389	1,000,000	2,767,389	15,730,846	3.90	5.68
8	Plant Unit Info	1,134	403,078	47.8%	94.9%	86.5%	6,866			2,767,389	N/A	3.90	
9	*Martin 1*												
10	Heavy Oil		996					1,675	6,400,000	10,720	158,171	15.88	94.43
11	Gas		5,643					63,785	1,000,000	63,785	362,593	6.43	5.68
12	Plant Unit Info	805	6,639	1.1%	95.3%	31.7%	11,222			74,505	N/A	7.84	
13	*Martin 2*												
14	Heavy Oil		18,275					31,809	6,399,918	203,575	3,003,744	16.44	94.43
15	Gas		2,031					23,751	1,000,000	23,751	135,009	6.65	5.68
16	Plant Unit Info	808	20,306	3.4%	16.1%	20.9%	11,195			227,326	N/A	15.46	
17	*Martin 3*												
18	Gas		23,173					175,374	1,000,000	175,374	996,896	4.30	5.68
19	Plant Unit Info	454	23,173	6.9%	94.7%	75.0%	7,568			175,374	N/A	4.30	
20	*Martin 4*												
21	Gas		16,953					127,681	1,000,000	127,681	725,793	4.28	5.68
22	Plant Unit Info	453	16,953	5.0%	94.9%	85.1%	7,531			127,681	N/A	4.28	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,428	21.40	122.21
25	Gas		522,757					3,589,717	1,000,000	3,589,717	20,405,187	3.90	5.68
26	Plant Unit Info	1,147	523,002	61.4%	94.8%	81.7%	6,868			3,592,220	N/A	3.91	
27	*Martin 8 Solar*												
28	Solar		5,345					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	5,345	9.6%	N/A	19.2%	N/A			N/A	N/A	N/A	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,754	23.38	122.21
32	Gas		567					5,404	1,000,000	5,404	30,735	5.42	5.69
33	Plant Unit Info	251	613	0.4%	95.1%	45.2%	9,657			5,920	N/A	6.77	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,877	23.65	122.21
36	Gas		689					6,546	1,000,000	6,546	37,242	5.41	5.69
37	Plant Unit Info	255	735	0.4%	95.1%	45.1%	9,610			7,063	N/A	6.55	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,862	19.87	122.21
3	Gas		686,938					4,456,487	1,000,000	4,456,487	25,242,982	3.67	5.66
4	Plant Unit Info	1,344	687,189	68.8%	71.8%	93.6%	6,489			4,458,868	N/A	3.68	
5	*Sanford 4*												
6	Gas		79,685					582,022	1,000,000	582,022	3,307,142	4.15	5.68
7	Plant Unit Info	990	79,685	10.8%	94.9%	63.9%	7,304			582,022	N/A	4.15	
8	*Sanford 5*												
9	Gas		95,023					692,593	1,000,000	692,593	3,934,159	4.14	5.68
10	Plant Unit Info	994	95,023	12.9%	94.9%	78.4%	7,289			692,593	N/A	4.14	
11	*Scherer 4*												
12	Coal		453,051					276,170	17,000,025	4,694,897	11,383,399	2.51	41.22
13	Plant Unit Info	646	453,051	94.3%	94.4%	94.3%	10,363			4,694,897	N/A	2.51	
14	*St Johns 1*												
15	Coal		61,242					30,426	22,000,033	669,373	2,218,515	3.62	72.92
16	Plant Unit Info	128	61,242	64.2%	94.4%	64.2%	10,930			669,373	N/A	3.62	
17	*St Johns 2*												
18	Coal		64,592					31,427	22,000,223	691,401	2,291,504	3.55	72.92
19	Plant Unit Info	128	64,592	67.7%	94.4%	67.7%	10,704			691,401	N/A	3.55	
20	*St Lucie 1*												
21	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,999,400	0.69	0.67
22	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	N/A	0.69	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	3,978,000	0.64	0.62
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	N/A	0.64	
26	*Space Coast*												
27	Solar		1,079					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,079	14.5%	N/A	34.8%	N/A			N/A	N/A	N/A	
29	*Turkey Point 1*												
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	380	0	0.0%	62.3%	0.0%	0			0	N/A	0.00	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,429,100	0.73	0.67
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	N/A	0.73	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	N/A	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,817	21.41	122.21
4	Gas		323,796					2,222,319	1,000,000	2,222,319	12,610,801	3.89	5.67
5	Plant Unit Info	1,166	324,038	37.4%	94.9%	82.2%	6,866			2,224,792	N/A	3.91	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,729	20.15	122.21
8	Gas		703,543					4,802,942	1,000,000	4,802,942	27,226,216	3.87	5.67
9	Plant Unit Info	1,208	703,765	78.4%	94.9%	83.4%	6,828			4,805,076	N/A	3.88	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,707	20.14	122.21
12	Gas		725,799					4,950,348	1,000,000	4,950,348	28,040,417	3.86	5.66
13	Plant Unit Info	1,202	726,026	81.2%	94.9%	83.5%	6,821			4,952,526	N/A	3.87	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,707	20.14	122.21
16	Gas		671,902					4,587,469	1,000,000	4,587,469	26,063,774	3.88	5.68
17	Plant Unit Info	1,207	672,129	74.9%	94.9%	84.1%	6,829			4,589,647	N/A	3.88	
18	**System Totals**												
19	Plant Unit Info	25,955	8,665,228				8,140			70,537,685	248,270,812	2.87	
20													
21													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Jul - 2014	(3) Aug - 2014	(4) Sep - 2014	(5) Oct - 2014	(6) Nov - 2014	(7) Dec - 2014	(8) Jul:Dec - 2014
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	0	145,000	290,000	145,000	0	0	580,000
4	Unit Cost	0.0000	104.1948	104.0448	102.8271	0.0000	0.0000	103.7779
5	Amount	$0	$15,108,240	$30,172,980	$14,909,934	$0	$0	$60,191,155
6	Burned							
7	Units	87,115	98,876	65,785	44,422	2,471	33,484	332,153
8	Unit Cost	93.0145	93.9249	94.8291	95.2395	95.7330	94.4306	94.1055
9	Amount	$8,102,957	$9,286,917	$6,238,334	$4,230,730	$236,556	$3,161,915	$31,257,410
10	Ending Inventory							
11	Units	2,340,704	2,386,827	2,611,042	2,711,620	2,709,149	2,675,665	2,675,665
12	Unit Cost	93.0453	93.6862	94.8079	95.2297	95.2292	95.2392	95.2392
13	Amount	$217,791,532	$223,612,855	$247,547,502	$258,226,706	$257,990,149	$254,828,234	$254,828,234
14	**#2 Light Oil (BBLS)**							
15	Purchases							
16	Units	80,453	64,203	41,836	0	0	0	186,492
17	Unit Cost	140.0574	139.3428	139.6620	0.0000	0.0000	0.0000	139.7227
18	Amount	$11,268,035	$8,946,224	$5,842,898	$0	$0	$0	$26,057,157
19	Burned							
20	Units	13,488	19,709	13,825	5,326	3,373	3,581	59,302
21	Unit Cost	119.6174	120.1618	117.9780	121.7276	122.9831	122.2102	119.9537
22	Amount	$1,613,400	$2,368,269	$1,631,045	$648,321	$414,822	$437,635	$7,113,492
23	Ending Inventory							
24	Units	1,218,060	1,262,554	1,290,565	1,285,239	1,281,866	1,278,285	1,278,285
25	Unit Cost	119.0079	120.0240	120.6825	120.6782	120.6721	120.6678	120.6678
26	Amount	$144,958,802	$151,536,757	$155,748,610	$155,100,289	$154,685,467	$154,247,832	$154,247,832
27	**Coal - SJRPP (TONS)**							
28	Purchases							
29	Units	70,000	70,000	70,000	70,000	60,000	60,000	400,000
30	Unit Cost	71.4644	70.4552	71.7657	72.4832	72.8660	73.2319	71.9942
31	Amount	$5,002,507	$4,931,865	$5,023,602	$5,073,825	$4,371,960	$4,393,914	$28,797,672
32	Burned							
33	Units	75,890	77,728	72,578	66,661	58,242	61,853	412,952
34	Unit Cost	73.1323	71.6619	71.7226	72.1771	72.5513	72.9151	72.3391
35	Amount	$5,550,007	$5,570,133	$5,205,483	$4,811,400	$4,225,530	$4,510,019	$29,872,572
36	Ending Inventory							
37	Units	57,444	49,716	47,138	50,477	52,235	50,382	50,382
38	Unit Cost	73.1323	71.6619	71.7226	72.1771	72.5513	72.9151	72.9151
39	Amount	$4,201,009	$3,562,741	$3,380,860	$3,643,285	$3,789,715	$3,673,610	$3,673,610
40								

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Jul - 2014	(3) Aug - 2014	(4) Sep - 2014	(5) Oct - 2014	(6) Nov - 2014	(7) Dec - 2014	(8) Jul:Dec - 2014
1	**Coal - Scherer (MMBTU)**							
2	Purchases							
3	Units	3,406,575	4,602,439	4,647,575	4,540,389	4,709,625	4,592,400	26,499,002
4	Unit Cost	2.4092	2.4115	2.4098	2.4178	2.4171	2.4197	2.4144
5	Amount	$8,207,194	$11,098,599	$11,199,518	$10,977,950	$11,383,527	$11,112,039	$63,978,827
6	Burned							
7	Units	4,694,920	4,694,920	4,543,467	4,694,920	4,543,444	4,694,897	27,866,568
8	Unit Cost	2.6057	2.5123	2.4622	2.4411	2.4292	2.4246	2.4795
9	Amount	$12,233,553	$11,794,919	$11,187,068	$11,460,571	$11,036,982	$11,383,399	$69,096,492
10	Ending Inventory							
11	Units	4,966,233	4,873,751	4,977,859	4,823,328	4,989,509	4,887,012	4,887,012
12	Unit Cost	2.6057	2.5123	2.4622	2.4411	2.4292	2.4246	2.4246
13	Amount	$12,940,513	$12,244,193	$12,256,643	$11,774,022	$12,120,567	$11,849,207	$11,849,207
14	**Gas (MCF)**							
15	Burned							
16	Units	54,634,832	55,822,946	52,156,487	49,886,571	36,287,303	37,196,734	285,984,872
17	Unit Cost	5.2603	5.2618	5.2873	5.3401	5.6196	5.6728	5.3787
18	Amount	$287,397,236	$293,729,354	$275,767,427	$266,398,115	$203,919,131	$211,007,944	$1,538,219,208
19	**Nuclear (Other)**							
20	Burned							
21	Units	27,047,003	27,047,003	24,267,538	21,326,061	26,177,533	27,050,111	152,915,249
22	Unit Cost	0.6514	0.6514	0.6522	0.6550	0.6569	0.6569	0.6539
23	Amount	$17,618,300	$17,618,300	$15,826,700	$13,967,600	$17,196,900	$17,769,900	$99,997,700
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FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	85,000	85,000	8.439	9.783	$7,172,950	$8,315,450	$855,500
4	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
5	**Total July Estimated**		137,999	137,999	5.481	6.309	$7,564,157	$8,706,657	$855,500
6									
7	**August Estimated**								
8	Off System	OS	80,000	80,000	7.595	8.876	$6,075,600	$7,100,600	$775,000
9	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
10	**Total August Estimated**		132,999	132,999	4.862	5.633	$6,466,807	$7,491,807	$775,000
11									
12	**September Estimated**								
13	Off System	OS	70,000	70,000	8.024	9.260	$5,616,800	$6,481,800	$626,000
14	St Lucie Reliability Sales		49,580	49,580	0.738	0.738	$365,968	$365,968	$0
15	**Total September Estimated**		119,580	119,580	5.003	5.727	$5,982,768	$6,847,768	$626,000
16									
17	**October Estimated**								
18	Off System	OS	80,000	80,000	4.779	5.929	$3,823,100	$4,743,100	$670,000
19	St Lucie Reliability Sales		0	0	0.000	0.000	$0	$0	$0
20	**Total October Estimated**		80,000	80,000	4.779	5.929	$3,823,100	$4,743,100	$670,000
21									
22	**November Estimated**								
23	Off System	OS	160,000	160,000	3.476	4.501	$5,562,000	$7,202,000	$1,140,000
24	St Lucie Reliability Sales		47,197	47,197	0.722	0.722	$340,729	$340,729	$0
25	**Total November Estimated**		207,197	207,197	2.849	3.640	$5,902,729	$7,542,729	$1,140,000
26									
27	**December Estimated**								
28	Off System	OS	185,000	185,000	3.309	4.344	$6,121,200	$8,036,200	$1,320,000
29	St Lucie Reliability Sales		54,189	54,189	0.722	0.722	$391,207	$391,207	$0
30	**Total December Estimated**		239,189	239,189	2.723	3.523	$6,512,407	$8,427,407	$1,320,000
31									
32	**Period Total**								
33	Off System	OS	660,000	660,000	5.208	6.345	$34,371,650	$41,879,150	$5,386,500
34	St Lucie Reliability Sales		256,964	256,964	0.732	0.732	$1,880,319	$1,880,319	$0
35	**Total Period Total**		916,964	916,964	3.953	4.772	$36,251,969	$43,759,469	$5,386,500
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37									
38									

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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	UPS		219,838	219,838	4.196	$9,224,227
4	SJRPP		232,464	232,464	3.490	$8,114,000
5	St Lucie Reliability		45,379	45,379	0.625	$283,481
6	**Total July Estimated**		497,681	497,681	3.541	$17,621,708
7						
8	**August Estimated**					
9	UPS		215,102	215,102	4.205	$9,044,918
10	SJRPP		238,600	238,600	3.432	$8,188,000
11	St Lucie Reliability		45,379	45,379	0.625	$283,481
12	**Total August Estimated**		499,081	499,081	3.510	$17,516,399
13						
14	**September Estimated**					
15	UPS		197,311	197,311	4.254	$8,392,934
16	SJRPP		221,654	221,654	3.512	$7,784,000
17	St Lucie Reliability		43,920	43,920	0.626	$274,814
18	**Total September Estimated**		462,885	462,885	3.554	$16,451,748
19						
20	**October Estimated**					
21	UPS		185,004	185,004	4.156	$7,688,918
22	SJRPP		200,991	200,991	3.593	$7,222,000
23	St Lucie Reliability		45,379	45,379	0.625	$283,481
24	**Total October Estimated**		431,374	431,374	3.522	$15,194,399
25						
26	**November Estimated**					
27	UPS		118,932	118,932	3.998	$4,754,932
28	SJRPP		173,314	173,314	3.599	$6,237,000
29	St Lucie Reliability		44,965	44,965	0.612	$275,201
30	**Total November Estimated**		337,211	337,211	3.341	$11,267,133
31						
32	**December Estimated**					
33	UPS		114,319	114,319	3.930	$4,492,584
34	SJRPP		185,062	185,062	3.602	$6,666,000
35	St Lucie Reliability		46,464	46,464	0.612	$284,374
36	**Total December Estimated**		345,845	345,845	3.309	$11,442,958
37						
38	**Period Total**					
39	UPS		1,050,506	1,050,506	4.150	$43,598,514
40	SJRPP		1,252,085	1,252,085	3.531	$44,211,000
41	St Lucie Reliability		271,487	271,487	0.621	$1,684,830
42	**Total Period Total**		2,574,078	2,574,078	3.477	$89,494,344
43						
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

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		377,121	377,121	4.250	$16,027,724
4	**Total July Estimated**		377,121	377,121	4.250	$16,027,724
5						
6	**August Estimated**					
7	Qualifying Facilities		378,422	378,422	4.416	$16,712,729
8	**Total August Estimated**		378,422	378,422	4.416	$16,712,729
9						
10	**September Estimated**					
11	Qualifying Facilities		365,925	365,925	4.345	$15,899,726
12	**Total September Estimated**		365,925	365,925	4.345	$15,899,726
13						
14	**October Estimated**					
15	Qualifying Facilities		300,526	300,526	3.986	$11,978,726
16	**Total October Estimated**		300,526	300,526	3.986	$11,978,726
17						
18	**November Estimated**					
19	Qualifying Facilities		137,246	137,246	3.423	$4,697,720
20	**Total November Estimated**		137,246	137,246	3.423	$4,697,720
21						
22	**December Estimated**					
23	Qualifying Facilities		172,542	172,542	3.418	$5,897,721
24	**Total December Estimated**		172,542	172,542	3.418	$5,897,721
25						
26	**Period Total**					
27	Qualifying Facilities		1,731,784	1,731,784	4.112	$71,214,346
28	**Total Period Total**		1,731,784	1,731,784	4.112	$71,214,346
29						
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JULY 2014 THROUGH DECEMBER 2014

	(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	20,800	6.335	$1,317,600	9.577	$1,991,944	$674,344
4	Total July Estimated		20,800	6.335	$1,317,600	9.577	$1,991,944	$674,344
5								
6	**August Estimated**							
7	Economy	OS	26,100	6.327	$1,651,400	9.707	$2,533,647	$882,247
8	Total August Estimated		26,100	6.327	$1,651,400	9.707	$2,533,647	$882,247
9								
10	**September Estimated**							
11	Economy	OS	30,800	5.419	$1,669,200	8.968	$2,762,088	$1,092,888
12	Total September Estimated		30,800	5.419	$1,669,200	8.968	$2,762,088	$1,092,888
13								
14	**October Estimated**							
15	Economy	OS	35,800	3.169	$1,134,400	5.499	$1,968,766	$834,366
16	Total October Estimated		35,800	3.169	$1,134,400	5.499	$1,968,766	$834,366
17								
18	**November Estimated**							
19	Economy	OS	7,800	2.469	$192,600	3.700	$288,630	$96,030
20	Total November Estimated		7,800	2.469	$192,600	3.700	$288,630	$96,030
21								
22	**December Estimated**							
23	Economy	OS	2,400	2.100	$50,400	3.357	$80,568	$30,168
24	Total December Estimated		2,400	2.100	$50,400	3.357	$80,568	$30,168
25								
26	**Period Total**							
27	Economy	OS	123,700	4.863	$6,015,600	7.781	$9,625,643	$3,610,043
28	Total Period Total		123,700	4.863	$6,015,600	7.781	$9,625,643	$3,610,043
29								
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APPENDIX II

CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP CALCULATION

TJK-4
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-6
JULY 25, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 10
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-4

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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) Total
1	Payments to Non-cogenerators	$15,981,900	$16,233,234	$16,358,713	$16,555,580	$16,366,782	$15,991,037	$16,128,756	$16,042,337	$16,887,414	$13,821,184	$13,588,944	$13,615,104	$187,570,984
2	Payments to Co-generators	$23,244,820	$23,622,928	$23,623,265	$23,628,645	$23,617,296	$23,628,851	$23,545,691	$23,545,691	$23,545,691	$23,545,691	$23,545,691	$23,545,691	$282,639,952
3	SJRPP Suspension Accrual	($763,761)	($763,761)	($763,761)	($681,721)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($8,919,012)
4	Return on SJRPP Suspension Liability	($364,800)	($358,703)	($352,605)	($346,835)	($341,147)	($335,213)	($324,533)	($318,685)	($312,837)	($306,988)	($301,140)	($295,291)	($3,958,776)
5	Incremental Plant Security Costs O&M	$2,812,089	$2,361,141	$3,121,461	$2,577,033	$3,021,100	$3,500,438	$3,384,054	$4,191,630	$4,507,458	$3,926,040	$4,694,907	$8,013,341	$46,110,692
6	Incremental Plant Security Costs Capital	$0	$8	$498	$1,556	$3,997	$7,539	$15,583	$28,050	$41,871	$56,948	$71,471	$85,450	$312,971
7	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$417,452	$57,564	$86,790	$45,317	$39,822	$37,178	$1,681,347	$27,840	$24,329	$25,445	$2,443,085
8	Incremental Nuclear NRC Compliance Costs Capital	$22,579	$31,025	$36,604	$44,186	$53,653	$63,646	$90,425	$130,245	$156,356	$173,458	$206,645	$251,052	$1,259,873
9	Transmission of Electricity by Others	$1,594,907	$2,075,397	$2,025,711	$1,887,221	$2,165,572	$618,359	$1,723,829	$1,741,137	$1,703,621	$1,840,637	$2,029,623	$2,060,971	$21,466,986
10	Transmission Revenues from Capacity Sales	($796,807)	($666,444)	($390,253)	($190,943)	($283,539)	($273,311)	($287,000)	($250,000)	($239,000)	($250,000)	($500,000)	($595,000)	($4,722,298)
11	Total (Lines 1 through 10)	$41,730,927	$42,534,826	$44,077,085	$43,532,287	$43,947,254	$42,503,412	$43,573,376	$44,404,332	$47,228,670	$42,091,559	$42,617,218	$45,963,512	$524,204,457
12	Jurisdictional Separation Factor [a]	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	N/A
13	Jurisdictional CCR Charges	$39,730,715	$40,496,082	$41,964,419	$41,445,734	$41,840,811	$40,466,174	$41,484,853	$42,275,981	$44,964,945	$40,074,062	$40,574,525	$43,760,427	$499,078,729
14	Nuclear Cost Recovery Costs	$3,489,048	$3,133,366	$3,699,553	$3,404,690	$3,511,264	$3,747,873	$3,300,047	$3,243,053	$3,715,196	$3,280,068	$3,093,881	$5,843,207	$43,461,246
15	Jurisdictional CCR Charges	$43,219,763	$43,629,448	$45,663,972	$44,850,424	$45,352,074	$44,214,048	$44,784,901	$45,519,034	$48,680,141	$43,354,130	$43,668,406	$49,603,634	$542,539,975
16	CCR Revenues (Net of Revenue Taxes)	$45,101,409	$42,451,927	$40,975,966	$42,967,824	$49,497,111	$51,123,371	$56,057,835	$58,436,904	$57,894,525	$53,316,995	$44,813,875	$44,308,449	586,946,191
17	Prior Period True-up Provision	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($33,270,675)
18	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$42,328,852	$39,679,371	$38,203,410	$40,195,268	$46,724,555	$48,350,814	$53,285,278	$55,664,348	$55,121,969	$50,544,439	$42,041,319	$41,535,893	$553,675,516
19	True-up Provision for Month - Over/(Under) Recovery (Line 18 - Line 15)	($890,911)	($3,950,077)	($7,460,562)	($4,655,156)	$1,372,480	$4,136,767	$8,500,378	$10,145,314	$6,441,828	$7,190,309	($1,627,087)	($8,067,741)	$11,135,541
20	Interest Provision for Month	($1,330)	($1,134)	($1,293)	($1,697)	($1,301)	($854)	($570)	$35	$588	$1,068	$1,345	$1,242	($3,902)
21	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($33,270,675)	($31,390,359)	($32,569,014)	($37,258,313)	($39,142,610)	($34,998,874)	($28,090,405)	($16,818,041)	($3,900,136)	$5,314,836	$15,278,769	$16,425,583	($33,270,675)
22	Deferred True-up - Over/(Under) Recovery	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159
23	Prior Period True-up Provision - Collected/(Refunded) this Month	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$33,270,675
24	End of Period True-up - Over/(Under) Recovery (Sum of Lines 19 through 23)	($20,336,200)	($21,514,855)	($26,204,154)	($28,088,451)	($23,944,715)	($17,036,246)	($5,763,882)	$7,154,023	$16,368,995	$26,332,928	$27,479,742	$22,185,799	$22,185,799
25														
26	[a] As approved on Order No. PSC-13-0665-FOF-EI.													
27														
28	Totals may not add up due to rounding.													
29														
30														
31														
32														
33														
34														
35														
36														
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED VARIANCES
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) CCR - Actual Estimated Variance	(2) CCR - 2014 Actual Estimated	(3) CCR - 2014 Original Projection	(4) Dif. CCR - 2014 Original Projection	(5) % Dif. CCR - 2014 Original Projection
1	Payments to Non-cogenerators	$187,570,984	$195,368,363	($7,797,379)	(4.0%)
2	Payments to Co-generators	$282,639,952	$282,261,087	$378,866	0.1%
3	SJRPP Suspension Accrual	($8,919,012)	($10,331,784)	$1,412,772	(13.7%)
4	Return on SJRPP Suspension Liability	($3,958,776)	($3,919,323)	($39,453)	1.0%
5	Incremental Plant Security Costs O&M	$46,110,692	$52,542,693	($6,432,001)	(12.2%)
6	Incremental Plant Security Costs Capital	$312,971	$546,699	($233,728)	(42.8%)
7	Incremental Nuclear NRC Compliance Costs O&M	$2,443,085	$256,000	$2,187,085	854.33%
8	Incremental Nuclear NRC Compliance Costs Capital	$1,259,873	$1,365,570	($105,697)	(7.74%)
9	Transmission of Electricity by Others	$21,466,986	$21,727,757	($260,772)	(1.2%)
10	Transmission Revenues from Capacity Sales	($4,722,298)	($4,128,750)	($593,548)	14.4%
11	Total (Lines 1 through 10)	$524,204,457	$535,688,312	($11,483,854)	(2.1%)
12	Jurisdictional Separation Factor [(a)]	95.20688%	95.20688%	0.00000%	0.0%
13	Jurisdictional CCR Charges	$499,078,729	$510,012,148	($10,933,419)	(2.1%)
14	Nuclear Cost Recovery Costs	$43,461,246	$43,461,246	$0	0.0%
15	Jurisdictional CCR Charges	$542,539,975	$553,473,394	($10,933,419)	(2.0%)
16	CCR Revenues (Net of Revenue Taxes)	$586,946,191	$586,744,069	$202,123	0.0%
17	Prior Period True-up Provision	($33,270,675)	($33,270,675)	$0	0.0%
18	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$553,675,516	$553,473,394	$202,123	0.0%
19	True-up Provision for Month - Over/(Under) Recovery (Line 18 - Line 15)	$11,135,541	$0	$11,135,541	0.0%
20	Interest Provision for Month	($3,902)	$0	($3,902)	N/A
21	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($33,270,675)	($33,270,675)	$0	0.0%
22	Deferred True-up - Over/(Under) Recovery	$11,054,159	$0	$11,054,159	N/A
23	Prior Period True-up Provision - Collected/(Refunded) this Month	$33,270,675	$33,270,675	$0	0.0%
24	End of Period True-up - Over/(Under) Recovery (Sum of Lines 19 through 23)	$22,185,799	$0	$22,185,799	N/A
25					
26	[(a)] As approved in Order No. PSC-13-0665-FOF-EI				
27					
28	Totals may not add up due to rounding.				
29					
30					
31					
32					
33					
34					
35					
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$1,217,478	$898,407	$499,076	$1,400,274	$971,446	$1,531,920	$5,494,109	$2,828,396	$2,022,085	$2,328,340	$4,465,178	$3,036,323	$26,693,031
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$13,671	$1,788,099	$7,355	$1,508	$1,653,539	$2,149,731	$5,613,902
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [1]	$0	$0	$0	$0	$0	$0	$0	$13,671	$1,801,770	$1,809,125	$1,810,633	$3,464,172	$5,613,902	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$10	$3,095	$9,239	$15,368	$22,716	$32,926	N/A
4. CWIP - Non Interest Bearing	$12,219,384	$13,436,862	$14,335,269	$14,834,345	$16,234,618	$17,206,064	$18,737,984	$24,218,422	$25,258,719	$27,273,449	$29,600,281	$32,411,920	$33,298,513	N/A
5. Net Investment (Lines 2 - 3 + 4)	$12,219,384	$13,436,862	$14,335,269	$14,834,345	$16,234,618	$17,206,064	$18,737,984	$24,232,083	$27,057,394	$29,073,335	$31,395,546	$35,853,376	$38,879,489	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [2]	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$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 [3]	$0	$0	$0	$0	$0	$0	$0	$13,671	$1,801,770	$1,809,125	$1,810,633	$3,464,172	$5,613,902	
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$9,986,329	$8,198,230	$8,190,875	$8,189,367	$6,535,828	$4,386,098	
9. Adjusted Net Investment (Lines 5 - 8)	$2,219,384	$3,436,862	$4,335,269	$4,834,345	$6,234,618	$7,206,064	$8,737,984	$14,245,754	$18,859,163	$20,882,459	$23,206,179	$29,317,548	$34,493,391	
10. Average Net Investment		$2,828,123	$3,886,066	$4,584,807	$5,534,481	$6,720,341	$7,972,024	$11,491,869	$16,552,459	$19,870,811	$22,044,319	$26,261,863	$31,905,469	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [4]		$18,889	$25,955	$30,621	$36,964	$44,884	$53,244	$76,298	$109,897	$131,929	$146,359	$174,361	$211,831	$1,061,231
b. Debt Component (Line 6 x debt rate x 1/12) [5]		$3,690	$5,071	$5,982	$7,221	$8,769	$10,402	$14,127	$20,348	$24,427	$27,099	$32,284	$39,221	$198,641
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$22,579	$31,025	$36,604	$44,186	$53,653	$63,646	$90,425	$130,245	$156,356	$173,458	$206,645	$251,052	$1,259,873

[1] Represents nuclear NRC Compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year base (Docket No.120015) on line 6.

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

[3] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[4] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan-Jun actual period is 4.9230, which based on the May 2013 ROR Surveillance Report per Order No.12-0425-PAA-EU and the monthly Equity Component for Jul-Dec estimated period is 4.8938 % which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity.

[5] The monthly Debt Component for Jan-Jun actual period is 1.5658%, which is based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.The monthly Debt Component for Jul-Dec estimated period is 1.4751 % which based on the on the May 2014 ROR Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL SECURITY														
1. Investments														
a. Expenditures/Additions		$0	$2,124	$120,574	$144,376	$467,198	$419,988	$1,652,214	$1,516,668	$1,996,183	$1,836,143	$1,855,114	$1,533,873	$11,544,455
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$864,786	$864,786
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$864,786	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$649	N/A
4. CWIP - Non Interest Bearing	$0	$0	$2,124	$122,698	$267,074	$734,272	$1,154,260	$2,806,474	$4,323,142	$6,319,325	$8,155,468	$10,010,582	$10,679,668	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$2,124	$122,698	$267,074	$734,272	$1,154,260	$2,806,474	$4,323,142	$6,319,325	$8,155,468	$10,010,582	$11,543,806	N/A
6. Total Estimated Capital Expenditures Included in Base Rates	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Base Rate Capital Expenditures Closed to Plant-in-Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
9. Adjusted Net Investment (Lines 5 - 8)	$0	$0	$2,124	$122,698	$267,074	$734,272	$1,154,260	$2,806,474	$4,323,142	$6,319,325	$8,155,468	$10,010,582	$11,543,806	
10. Average Net Investment		$0	$1,062	$62,411	$194,886	$500,673	$944,266	$1,980,367	$3,564,808	$5,321,233	$7,237,396	$9,083,025	$10,777,194	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [1]		$0	$7	$417	$1,302	$3,344	$6,307	$13,148	$23,668	$35,329	$48,051	$60,305	$71,553	$263,431
b. Debt Component (Line 6 x debt rate x 1/12) [2]		$0	$1	$81	$254	$653	$1,232	$2,434	$4,382	$6,541	$8,897	$11,166	$13,248	$48,892
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$649	$649
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$0	$8	$498	$1,556	$3,997	$7,539	$15,583	$28,050	$41,871	$56,948	$71,471	$85,450	$312,971

[1] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan-Jun actual period is 4.9230, which based on the May 2013 ROR Surveillance Report per Order No.12-0425-PAA-EU and the monthly Equity Component for Jul-Dec estimated period is 4.8938 % which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity.

[2] The monthly Debt Component for Jan-Jun actual period is 1.5658%, which is based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.The monthly Debt Component for Jul-Dec estimated period is 1.4751 % which based on the on the May 2014 ROR Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2013 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	6,416,467,850	29.591%	4.981%	1.474%	1.474%
SHORT_TERM_DEBT	431,179,727	1.989%	1.833%	0.036%	0.036%
PREFERRED_STOCK	0	0.000%	0.000%	0.000%	0.000%
CUSTOMER_DEPOSITS	428,779,347	1.977%	2.796%	0.055%	0.055%
COMMON_EQUITY	10,165,729,253	46.882%	10.500%	4.923%	8.014%
DEFERRED_INCOME_TAX	4,240,131,465	19.555%	0.000%	0.000%	0.000%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.000%	0.000%	0.000%
WEIGHTED COST	1,324,684	0.006%	8.364%	0.001%	0.001%
TOTAL	$21,683,612,327	100.00%		6.489%	9.580%

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	$6,416,467,850	38.69%	4.981%	1.927%	1.927%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	10,165,729,253	61.31%	10.500%	6.437%	10.480%
TOTAL	$16,582,197,103	100.00%		8.364%	12.407%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4740%
SHORT TERM DEBT	0.0364%
CUSTOMER DEPOSITS	0.0553%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.5658%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9226%
TAX CREDITS -WEIGHTED	0.0004%
TOTAL EQUITY	**4.9230%**
TOTAL	6.4889%
PRE-TAX EQUITY	8.0147%
PRE-TAX TOTAL	9.5805%

Note:

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

This Capital Structure and Cost Rates was used during the period July through December 2013

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)

APPENDIX II
FUEL COST RECOVERY
2015 E-SCHEDULES – WITH GAS RESERVES PROJECT

FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

TJK-5
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-78
SEPTEMBER 15, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-5

APPENDIX II
FUEL COST RECOVERY
2015 E SCHEDULES – WITH GAS RESERVES PROJECT
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
(WITH GAS RESERVES)

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,354,353,988	115,113,987	2.9139
2	TOTAL COST OF GENERATED POWER	$3,354,353,988	115,113,987	2.9139
3	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$148,357,080	4,265,509	3.4781
4	Energy Cost of Economy Purchases (E9)	$18,998,000	368,250	5.1590
5	Payments to Qualifying Facilities (E8)	$142,883,700	3,284,130	4.3507
6	TOTAL COST OF PURCHASED POWER	$310,238,780	7,917,890	3.9182
7	TOTAL AVAILABLE MWH (LINE 2 + LINE 6)		123,031,877	
8	Fuel Cost of Economy Sales (E6)	($73,475,400)	(1,750,000)	4.1986
9	Gain from Off-System Sales (E6)	($15,911,250)	N/A	N/A
10	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,351,540)	(573,053)	0.7594
11	TOTAL FUEL COST AND GAINS OF POWER SALES	($93,738,190)	(2,323,053)	4.0351
12	Incremental Personnel, Software, and Hardware Costs	$453,534	N/A	N/A
13	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,866,360	N/A	N/A
14	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,319,894	N/A	N/A
15	Dodd Frank Fees	$4,500	N/A	N/A
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 2 + 6 + 11 + 14 + 15)	$3,573,178,972	120,708,824	2.9602
17	Net Unbilled Sales [1]	($40,569,976)	(1,370,531)	(0.0356)
18	Company Use [1]	$10,719,537	362,126	0.0094
19	T & D Losses [1]	$232,256,633	7,846,074	0.2040
20	SYSTEM MWH SALES	$3,573,178,972	113,871,155	3.1379
21	Wholesale MWH Sales	$177,426,202	5,654,273	3.1379
22	Jurisdictional MWH Sales	$3,395,752,770	108,216,882	3.1379
23	Jurisdictional Loss Multiplier	$5,738,822		1.00169
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,401,491,593	108,216,882	3.1432
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$266,660,688	108,216,882	0.2464
26	TOTAL JURISDICTIONAL FUEL COST	$3,668,152,280	108,216,882	3.3896
27	Revenue Tax Factor	$2,641,070		1.00072
28	Fuel Factor Adjusted for Taxes	$3,670,793,350	108,216,882	3.3920
29	GPIF [2]	$11,814,923	108,216,882	0.0109
30	Fuel Factor including GPIF (Line 28 + Line 29)	$3,682,608,273	108,216,882	3.4029
31	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.403
32				
33	[1] For Informational Purposes Only			
34	[2] Calculation Based on Jurisdictional KWH Sales			
35				
36	Note: Totals may not add due to rounding.			
37				
38				

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

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	($266,562,206)
2	Final over/(under) recovery [2]	($98,482)
3	Total over/(under) recovery to be included in projected period [3]	($266,660,688)
4		
5	Total Jurisdictional Sales (MWH)	108,216,882
6		
7	True-Up Factor (cents/kWh)	(0.2464)
8		
9	[1] Actual/Estimated over/(under) recovery for January 2014 - December 2014	
10	[2] Final over/(under) recovery for January 2013 - December 2013	
11	[3] Projected Period January 2015 - December 2015 (Schedule E1, Line 26)	
12		
13	Note: Totals may not add due to rounding.	
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
(WITH GAS RESERVES)

REVISED - SCHEDULE: E1-B

FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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]	$249,704,921	$261,698,473	$276,728,131	$327,817,647	$318,300,543	$314,843,954	$326,439,785	$340,367,893	$315,856,058	$301,516,737	$237,029,921	$248,270,812	$3,518,574,876
3	Nuclear Fuel Disposal Costs (Per A2)	$2,459,404	$2,206,487	$1,581,888	$1,368,858	$2,328,964	$2,227,999	($3,383,888)	$0	$0	$0	$0	$0	$8,789,711
4	Fuel Cost of Power Sold (Per A6)	($17,551,697)	($13,007,326)	($10,682,154)	($3,087,997)	($3,490,214)	($2,666,273)	($2,776,716)	($6,466,807)	($5,982,768)	($3,823,100)	($5,902,729)	($6,512,407)	($81,950,190)
5	Gains from Off-System Sales (Per A6)	($27,898,389)	($3,489,980)	($3,185,661)	($703,559)	($713,114)	($1,666,239)	($705,488)	($775,000)	($626,000)	($670,000)	($1,140,000)	($1,320,000)	($42,893,430)
6	Fuel Cost of Purchased Power (Per A7)	$15,810,659	$11,965,752	$14,152,295	$11,187,597	$12,038,150	$20,546,899	$27,275,416	$17,516,399	$16,451,748	$15,194,399	$11,267,133	$11,442,958	$184,849,403
7	Energy Payments to Qualifying Facilities (Per A8)	$3,679,181	$3,211,873	$8,109,727	$8,318,554	$12,056,579	$12,462,904	$11,841,249	$16,712,729	$15,899,726	$11,978,726	$4,697,720	$5,897,721	$114,866,688
8	Energy Cost of Economy Purchases (Per A9)	$14,909	$1,307,551	$199,473	$1,519,318	$821,311	$2,584,878	$2,324,301	$1,651,400	$1,669,200	$1,134,400	$192,600	$50,400	$13,469,741
9	Total Fuel Costs & Net Power Transactions	$226,218,989	$263,892,830	$286,903,697	$346,420,418	$341,342,219	$348,334,121	$361,014,659	$369,006,614	$343,267,963	$325,331,163	$246,144,645	$257,829,484	$3,715,706,800
10														
11	**Incremental Optimization Costs**													
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$33,078	$28,764	$31,903	$33,006	$33,316	$32,338	$36,961	$38,736	$49,161	$50,587	$46,310	$50,587	$464,747
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	($44,399)	$17,182	$470,412	$134,512	$136,818	$129,944	$119,936	$120,800	$105,700	$120,800	$241,600	$279,350	$1,832,655
14	Total	($11,320)	45,946	502,315	167,518	170,134	162,282	156,897	159,536	154,861	171,387	287,910	329,937	2,297,402
15														
16	Dodd Frank Fees	$0	$0	$2,523	$375	$375	$375	$375	$375	$375	$375	$375	$375	$5,898
17														
18	**Adjustments to Fuel Cost**													
19	Energy Imbalance Fuel Revenues	($94,682)	($131,614)	($127,853)	($35,354)	($9,564)	($91,016)	($172,851)	$0	$0	$0	$0	$0	($662,934)
20	Inventory Adjustments	($8,471)	$48,367	($62,667)	$176,147	$337,707	($271,676)	$35,859	$0	$0	$0	$0	$0	$255,267
21	Non Recoverable Oil/Tank Bottoms	($339,257)	$0	$0	$0	$0	($87,509)	($282,032)	$0	$0	$0	$0	$0	($708,798)
22	Adjusted Total Fuel Costs & Net Power Transactions	$225,765,259	$263,855,528	$287,218,016	$346,729,104	$341,840,872	$348,046,576	$360,752,907	$369,166,525	$343,423,199	$325,502,925	$246,432,930	$258,159,796	$3,716,893,634
23	**Jurisdictional kWh Sales**													
24	Jurisdictional kWh Sales	8,186,450,133	7,489,358,283	7,265,742,238	7,662,815,846	8,998,820,709	9,353,399,776	9,899,277,406	10,536,758,426	10,438,962,071	9,613,587,552	8,080,389,954	7,989,256,624	105,514,819,018
25	Sales for Resale	159,075,376	379,930,801	355,050,303	379,293,900	394,998,170	454,639,060	566,197,562	526,427,841	546,517,614	502,853,788	475,529,454	358,799,599	5,099,313,468
26	Sub-Total Sales	8,345,525,509	7,869,289,084	7,620,792,541	8,042,109,746	9,393,818,879	9,808,038,836	10,465,474,968	11,063,186,267	10,985,479,685	10,116,441,340	8,555,919,408	8,348,056,223	110,614,132,486
27														
28	**Jurisdictional % of Total Sales (Line 24/26)**	98.09388%	95.17198%	95.34103%	95.28365%	95.79513%	95.36463%	94.58985%	95.24163%	95.02509%	95.02934%	94.44210%	95.70200%	95.39000%
29	**True-up Calculation**													
30	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$272,959,294	$248,228,786	$240,098,894	$245,679,724	$293,334,679	$305,444,193	$325,341,933	$343,566,881	$340,378,084	$313,465,504	$263,473,287	$260,501,747	$3,452,473,007
31	**Fuel Adjustment Revenues Not Applicable to Period**													
32	Prior Period True-up (Collected)/Refunded This Period [2]	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($12,313,801)	($147,765,613)
33	GPIF, Net of Revenue Taxes [3]	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($1,722,090)	($20,665,080)
34	Jurisdictional Fuel Revenues Applicable to Period	$258,923,403	$234,192,895	$226,063,003	$231,643,833	$279,298,788	$291,408,302	$311,306,042	$329,530,990	$326,342,192	$299,429,613	$249,437,396	$246,465,856	$3,284,042,313
35	Adjusted Total Fuel Costs & Net Power Transactions	$225,765,259	$263,855,528	$287,218,016	$346,729,104	$341,840,872	$348,046,576	$360,752,907	$369,166,525	$343,423,199	$325,502,925	$246,432,930	$258,159,796	$3,716,893,634
36	Jurisdictional Sales % of Total kWh Sales (Line 28)	98.09388%	95.17198%	95.34103%	95.28365%	95.79513%	95.36463%	94.58985%	95.24163%	95.02509%	95.02934%	94.44210%	95.70200%	95.39000%
37	Juris. Total Fuel Costs & Net Power Trans. (Line 35xLine36x1.00169)	$221,836,172	$251,540,918	$274,299,398	$330,934,481	$328,020,326	$332,474,263	$341,812,322	$352,194,420	$326,889,715	$309,846,037	$233,129,759	$247,481,626	$3,550,459,438
38	True-up Provision for the Month - Over/(Under) Recovery (Line 34 - Line 37)	$37,087,231	($17,348,022)	($48,236,395)	($99,290,648)	($48,721,539)	($41,065,960)	($30,506,280)	($22,663,430)	($547,523)	($10,416,424)	$16,307,637	($1,015,770)	($266,417,125)
39	Interest Provision for the Month	($7,698)	($5,474)	($6,584)	($11,433)	($12,232)	($11,560)	($15,035)	($15,750)	($15,715)	($15,374)	($14,612)	($13,615)	($145,081)
40	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($147,765,613)	($98,372,279)	($103,411,974)	($139,341,152)	($226,329,432)	($262,749,401)	($291,513,121)	($309,720,635)	($320,086,014)	($308,335,451)	($306,453,448)	($277,846,622)	($147,765,613)
41	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)	($98,482)
42	Prior Period True-up Collected/(Refunded) This Period [2]	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$12,313,801	$147,765,613
43	End of Period Net True-up Amount Over/(Under) Recovery (Lines 38 through 42)	($98,470,761)	($103,510,456)	($139,439,634)	($226,427,914)	($262,847,883)	($291,611,603)	($309,819,117)	($320,184,496)	($308,433,933)	($306,551,930)	($277,945,104)	($266,660,688)	($266,660,688)
44														
45														

[1] January through July Actuals include various adjustments as noted on the A-Schedules.

[2] Prior Period 2012/2013 Net True-up.

[3] Generating Performance Incentive Factor is ((20,679,970 / 12) x 99.9280%) - See Order No. PSC-13-0665-FOF-EI.

[4] Deferred 2013 Final True-up.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
(WITH GAS RESERVES)

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	Annual Total
1. TOTAL AMOUNT OF ADJUSTMENTS	$278,475,611
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$11,814,923
B. TRUE-UP (OVER)/UNDER RECOVERED	$266,660,688
2. TOTAL JURISDICTIONAL SALES (MWH)	108,216,882
3. ADJUSTMENT FACTORS (cents/kWh)	0.2573
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0109
B. TRUE-UP FACTOR	0.2464

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF MARGINAL TIME OF USE MULTIPLIERS
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	E1-D Schedule - Marginal	Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	Total
1	Full Year (January - December)													
2	On-Peak Period													
3	System MWH Requirements	2,375,695	2,139,602	2,214,127	3,100,132	3,299,166	3,684,169	4,011,996	3,744,162	3,844,652	3,338,927	2,101,211	2,472,682	36,326,521
4	Marginal Cost	$137,528,984	$64,765,753	$66,180,256	$178,164,586	$163,671,625	$264,781,226	$324,730,956	$314,359,842	$301,497,610	$260,202,581	$62,721,148	$74,180,460	$2,212,785,027
5	Average Marginal Cost (¢/kWh)	5.789	3.027	2.989	5.747	4.961	7.187	8.094	8.396	7.842	7.793	2.985	3.000	6.091
6	Off-Peak Period													
7	System MWH Requirements	6,655,641	5,929,542	6,832,714	6,230,334	7,339,490	7,374,907	7,799,876	8,278,593	7,342,624	7,215,937	6,802,453	6,721,572	84,523,683
8	Marginal Cost	$267,956,107	$167,390,971	$204,639,784	$245,786,676	$260,478,500	$281,721,447	$313,867,010	$319,470,904	$289,666,517	$351,488,291	$193,733,861	$192,774,685	$3,088,974,754
9	Average Marginal Cost (¢/kWh)	4.026	2.823	2.995	3.945	3.549	3.820	4.024	3.859	3.945	4.871	2.848	2.868	3.655
10	Total Period													
11	System MWH Requirements	9,031,336	8,069,144	9,046,841	9,330,466	10,638,656	11,059,076	11,811,872	12,022,755	11,187,276	10,554,864	8,903,664	9,194,254	120,850,204
12	Marginal Cost	$405,485,090	$232,156,723	$270,820,040	$423,951,262	$424,150,125	$546,502,673	$638,597,966	$633,830,745	$591,164,127	$611,690,872	$256,455,010	$266,955,145	$5,301,759,781
13	Average Marginal Cost (¢/kWh)	4.490	2.877	2.994	4.544	3.987	4.942	5.406	5.272	5.284	5.795	2.880	2.903	4.387
14														
15	Full Year Multiplier													
16	On-Peak Period													
17	Marginal Fuel Cost Weighting Multiplier													1.388
18	Off-Peak Period													
19	Marginal Fuel Cost Weighting Multiplier													0.833
20	Average													
21	Marginal Fuel Cost Weighting Multiplier													1.000
22														
23														
24														
25														
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF TIME OF USE MULTIPLIERS FOR SEASONAL DEMAND TIME OF USE RIDER
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) Jun - 2015	(3) Jul - 2015	(4) Aug - 2015	(5) Sep - 2015	(6) Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,690,973	1,849,254	1,720,742	1,783,060	7,044,029
4	Marginal Cost	$156,076,808	$195,059,312	$191,140,021	$190,840,912	$733,117,053
5	Average Marginal Cost (¢/kWh)	9.230	10.548	11.108	10.703	10.408
6	*Off-Peak Period*					
7	System MWH Requirements	9,368,103	9,962,618	10,302,013	9,404,216	39,036,950
8	Marginal Cost	$386,153,206	$436,063,790	$436,290,251	$396,011,536	$1,654,518,782
9	Average Marginal Cost (¢/kWh)	4.122	4.377	4.235	4.211	4.238
10	*Total Period*					
11	System MWH Requirements	11,059,076	11,811,872	12,022,755	11,187,276	46,080,979
12	Marginal Cost	$542,230,014	$631,123,102	$627,430,272	$586,852,448	$2,387,635,835
13	Average Marginal Cost (¢/kWh)	4.903	5.343	5.219	5.246	5.181
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					2.009
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.818
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
22						
23						
24	Note: Totals may not add due to rounding.					
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

(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	3.403	1.00284	3.090
A	RS-1 all additional kWh	3.403	1.00284	4.090
A	GS-1, SL-2, GSCU-1, WIES-1	3.403	1.00284	3.413
A-1	SL-1, OL-1, PL-1 (1)	3.137	1.00284	3.146
B	GSD-1	3.403	1.00277	3.412
C	GSLD-1, CS-1	3.403	1.00182	3.409
D	GSLD-2, CS-2, OS-2, MET	3.403	0.99347	3.381
E	GSLD-3, CS-3	3.403	0.96714	3.291
A	GST-1 On-Peak	4.723	1.00284	4.736
	GST-1 Off-Peak	2.835	1.00284	2.843
A	RTR-1 On-Peak	-	-	1.323
	RTR-1 Off-Peak	-	-	(0.570)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.723	1.00276	4.736
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.835	1.00276	2.843
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.723	1.00182	4.732
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.835	1.00182	2.840
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.723	0.99407	4.695
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.835	0.99407	2.818
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.723	0.96714	4.568
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.835	0.96714	2.742
F	CILC-1(D), ISST-1(D) On-Peak	4.723	0.99316	4.691
	CILC-1(D), ISST-1(D) Off-Peak	2.835	0.99316	2.816

(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
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	6.837	1.00277	6.856
	GSD(T)-1 Off-Peak	2.784	1.00277	2.792
C	GSLD(T)-1 On-Peak	6.837	1.00182	6.849
	GSLD(T)-1 Off-Peak	2.784	1.00182	2.789
D	GSLD(T)-2 On-Peak	6.837	0.99407	6.796
	GSLD(T)-2 Off-Peak	2.784	0.99407	2.767

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
2015 PROJECTED ENERGY LOSSES BY RATE CLASS
(WITH GAS RESERVES)

Line No.	Rate Class/Voltage Level	Delivered MWH Sales (1)	Expansion Factor (2)	Delivered Energy at Generation (3)	Delivered Efficiency (4)	Losses (5)	Fuel Cost Recovery Multiplier (6)	(7)
1	RS(T)-1							
2	Secondary	56,578,786	1.056879	59,796,907	0.946182	3,218,121		
3	**Total**	56,578,786	1.056879	59,796,907	0.946182	3,218,121	1.00284	
4								
5	CILC-1D							
6	Primary	1,080,386	1.029561	1,112,324	0.971288	31,937		
7	Secondary	1,812,393	1.056879	1,915,480	0.946182	103,086		
8	**Total**	2,892,780	1.046676	3,027,804	0.955405	135,024	0.99316	
9								
10	CILC-1G							
11	Primary	2,223	1.029561	2,289	0.971288	66		
12	Secondary	195,103	1.056879	206,200	0.946182	11,097		
13	**Total**	197,326	1.056571	208,489	0.946458	11,163	1.00255	
14								
15	CILC-1T							
16	Transmission	1,358,886	1.019254	1,385,049	0.981110	26,164		
17	**Total**	1,358,886	1.019254	1,385,049	0.981110	26,164	0.96714	
18								
19	GS(T)-1							
20	Secondary	6,313,623	1.056879	6,672,733	0.946182	359,110		
21	**Total**	6,313,623	1.056879	6,672,733	0.946182	359,110	1.00284	
22								
23	GSCU-1							
24	Secondary	59,983	1.056879	63,395	0.946182	3,412		
25	**Total**	59,983	1.056879	63,395	0.946182	3,412	1.00284	
26								
27	GSD(T)-1							
28	Primary	77,956	1.029561	80,261	0.971288	2,304		
29	Secondary	26,456,691	1.056879	27,961,510	0.946182	1,504,819		
30	**Total**	26,534,647	1.056798	28,041,771	0.946254	1,507,123	1.00277	
31								
32	GSLD(T)-1							
33	Primary	428,195	1.029561	440,853	0.971288	12,658		
34	Secondary	10,422,957	1.056879	11,015,800	0.946182	592,843		
35	**Total**	10,851,153	1.055801	11,456,654	0.947149	605,501	1.00182	
36								
37	GSLD(T)-2							
38	Primary	873,016	1.029561	898,823	0.971288	25,807		
39	Secondary	1,706,020	1.056879	1,803,057	0.946182	97,036		
40	**Total**	2,579,036	1.047631	2,701,880	0.954534	122,843	0.99407	
41								
42	GSLD(T)-3							
43	Transmission	178,230	1.019254	181,662	0.981110	3,432		
44	**Total**	178,230	1.019254	181,662	0.981110	3,432	0.96714	
45								
46	MET							
47	Primary	82,925	1.029561	85,376	0.971288	2,451		
48	**Total**	82,925	1.029561	85,376	0.971288	2,451	0.97692	
49								
50	OL-1							
51	Secondary	99,899	1.056879	105,581	0.946182	5,682		
52	**Total**	99,899	1.056879	105,581	0.946182	5,682	1.00284	
53								
54	OS-2							
55	Primary	11,024	1.029561	11,350	0.971288	326		
56	**Total**	11,024	1.029561	11,350	0.971288	326	0.97692	

FLORIDA POWER & LIGHT COMPANY
2015 PROJECTED ENERGY LOSSES BY RATE CLASS
(WITH GAS RESERVES)

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	523,456	1.056879	553,230	0.946182	29,773	
4	**Total**	523,456	1.056879	553,230	0.946182	29,773	1.00284
5							
6	SL-2						
7	Secondary	33,044	1.056879	34,923	0.946182	1,879	
8	**Total**	33,044	1.056879	34,923	0.946182	1,879	1.00284
9							
10	SST-DST						
11	Primary	9,153	1.029561	9,424	0.971288	271	
12	**Total**	9,153	1.029561	9,424	0.971288	271	0.97692
13							
14	SST-TST						
15	Transmission	89,242	1.019254	90,960	0.981110	1,718	
16	**Total**	89,242	1.019254	90,960	0.981110	1,718	0.96714
17							
18	Total Retail						
19	**Total**	108,393,195	1.055668	114,427,188	0.947268	6,033,993	1.00169
20							
21	FKEC						
22	Transmission	734,388	1.019254	748,528	0.981110	14,140	
23	**Total**	734,388	1.019254	748,528	0.981110	14,140	0.96714
24							
25	SEMINOLE						
26	Transmission	824,943	1.019254	840,827	0.981110	15,883	
27	**Total**	824,943	1.019254	840,827	0.981110	15,883	0.96714
28							
29	LCEC						
30	Transmission	3,670,330	1.019254	3,740,998	0.981110	70,668	
31	**Total**	3,670,330	1.019254	3,740,998	0.981110	70,668	0.96714
32							
33	WAUCHULA						
34	Transmission	59,924	1.019254	61,078	0.981110	1,154	
35	**Total**	59,924	1.019254	61,078	0.981110	1,154	0.96714
36							
37	Blountstown						
38	Transmission	37,745	1.019254	38,472	0.981110	727	
39	**Total**	37,745	1.019254	38,472	0.981110	727	0.96714
40							
41	Total Wholesale						
42	**Total**	5,584,837	1.019254	5,692,367	0.981110	107,529	0.96714
43							
44	Total Company						
45	**Total**	113,978,032	1.053883	120,119,555	0.948872	6,141,523	1.00000
46							
47	Company Use						
48	**Total**	132,525	1.056879	140,063	0.946182	7,538	1.00284
49							
50	Total FPL						
51	**Total**	114,110,557	1.053887	120,259,617	0.948868	6,149,061	1.00000
52							
53	Winter Park						
54	Transmission	257,506	1.019254	262,464	0.981110	4,958	
55	**Total**	257,506	1.019254	262,464	0.981110	4,958	0.96714
56							

FLORIDA POWER & LIGHT COMPANY
2015 PROJECTED ENERGY LOSSES BY RATE CLASS GROUP
(WITH GAS RESERVES)

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	26,534,647	1.056798	28,041,771	0.946254	1,507,123	1.00277
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,851,153	1.055801	11,456,654	0.947149	605,501	1.00182
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,579,036	1.047631	2,701,880	0.954534	122,843	0.99407
4	GSLD3/GSLDT3/CS3/CST3	178,230	1.019254	181,662	0.981110	3,432	0.96714
5	CILC D/CILC G	3,090,106	1.047308	3,236,293	0.954829	146,187	0.99376
6	OL1/SL1/PL1	623,355	1.056879	658,811	0.946182	35,456	1.00284
7	SL2, GSCU1	93,027	1.056879	98,318	0.946182	5,291	1.00284
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	26,731,974	1.056797	28,250,260	0.946256	1,518,286	1.00276
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,672,985	1.046996	2,798,606	0.955113	125,621	0.99347
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,537,116	1.019254	1,566,711	0.981110	29,595	0.96714
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FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
(WITH GAS RESERVES)

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	$255,074,124	$219,211,127	$249,020,824	$265,065,442	$282,055,082	$300,987,307	$328,219,659	$330,199,286	$327,759,208	$295,910,921	$248,370,692	$252,480,315	$3,354,353,988
2	Fuel Cost of Power Sold	(10,468,318)	(9,057,298)	(9,158,456)	(5,453,143)	(5,040,818)	(2,802,811)	(6,999,718)	(5,818,318)	(7,007,161)	(4,928,118)	(5,198,011)	(5,894,768)	(77,826,940)
3	Gain on Economy Sales	(2,900,000)	(2,620,000)	(2,418,750)	(840,000)	(760,000)	(772,500)	(870,000)	(825,000)	(612,500)	(617,500)	(1,135,000)	(1,540,000)	(15,911,250)
4	Fuel Cost of Purchased Power	10,689,741	8,343,156	8,130,775	10,340,447	13,024,289	15,652,245	16,963,644	15,630,868	15,889,250	15,139,228	9,334,892	9,218,544	148,357,080
5	Qualifying Facilities	13,269,887	9,356,887	10,201,887	10,067,898	12,372,888	15,061,892	16,811,895	16,765,899	16,936,900	15,197,892	3,634,887	3,204,887	142,883,700
6	Energy Cost of Economy Purchases	71,750	129,250	244,250	1,061,000	1,861,000	2,768,000	3,318,750	4,218,750	3,528,000	1,419,000	254,250	124,000	18,998,000
7	Total Fuel & Net Power Transactions	$265,737,185	$225,363,122	$256,020,530	$280,241,644	$303,512,442	$330,894,133	$357,444,230	$360,171,485	$356,493,696	$322,121,424	$255,261,710	$257,592,978	$3,570,854,579
8														
9	Incremental Personnel, Software and Hardware Costs	37,302	35,316	38,238	38,238	36,777	38,238	39,698	36,777	38,238	38,238	36,777	39,698	453,534
10	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	84,560	385,050	158,550	143,450	113,250	120,800	120,800	98,150	120,800	241,600	279,350	1,866,360
11	Total	37,302	119,876	423,288	196,788	180,227	151,488	160,498	157,577	136,388	159,038	278,377	319,048	2,319,894
12														
13	Dodd Frank Fees	375	375	375	375	375	375	375	375	375	375	375	375	4,500
14														
15	Adjusted Total Fuel & Net Power Transactions	265,774,861	225,483,374	256,444,193	280,438,807	303,693,043	331,045,995	357,605,104	360,329,436	356,630,459	322,280,836	255,540,462	257,912,401	3,573,178,972
16														
17	System MWH Sales	8,892,771	7,892,774	7,961,266	8,704,079	9,321,302	10,338,801	10,789,415	11,228,743	11,156,066	10,294,037	8,738,000	8,553,901	113,871,155
18														
19	Cost per KWH (¢/KWH)	2.9887	2.8568	3.2211	3.2219	3.2581	3.2020	3.3144	3.2090	3.1967	3.1308	2.9245	3.0151	3.1379
20	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
21	Jurisdictional Cost (¢/KWH)	2.9937	2.8617	3.2266	3.2274	3.2636	3.2074	3.3200	3.2144	3.2021	3.1360	2.9294	3.0202	3.1432
22	True-Up (¢/KWH)	0.2617	0.2975	0.2939	0.2689	0.2508	0.2257	0.2166	0.2081	0.2099	0.2275	0.2694	0.2716	0.2464
23	Total (¢/KWH)	3.2554	3.1592	3.5205	3.4963	3.5144	3.4331	3.5366	3.4225	3.4120	3.3635	3.1988	3.2918	3.3896
24	Revenue Tax Factor (0.00072)	0.0023	0.0023	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0024	0.0023	0.0024	0.0024
25	Recovery Factor Adjusted for Taxes (¢/KWH)	3.2577	3.1615	3.5230	3.4988	3.5169	3.4356	3.5391	3.4250	3.4145	3.3659	3.2011	3.2942	3.3920
26	GPIF (¢/KWH)	0.0116	0.0132	0.0130	0.0119	0.0111	0.0100	0.0096	0.0092	0.0093	0.0101	0.0119	0.0120	0.0109
27	Recovery Factor including GPIF (¢/KWH)	3.2693	3.1747	3.5360	3.5107	3.5280	3.4456	3.5487	3.4342	3.4238	3.3760	3.2130	3.3062	3.4029
28														
29	Recovery Factor Rounded to .001 (¢/KWH)	3.269	3.175	3.536	3.511	3.528	3.446	3.549	3.434	3.424	3.376	3.213	3.306	3.403
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31	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	38,262,636,848	0.030904	$1,182,458,429.73	3.090
2	All Additional KWH	18,224,118,120	0.040904	$745,434,517.33	4.090
3	Total KWH	56,486,754,968		$1,927,892,947.06	
4					
5	Avg Fuel Factor	3.403			
6	RS-1 Loss Multiplier	1.00284			
7	Average Fuel Factor	3.413			
8					
9	Target Fuel Revenues	$1,927,892,947.06			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITH GAS RESERVES)

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	14,446,069	0	81,766	1,635,724	737,235	7,130,438	13,385,409	10,746,818	15,711,063	8,832,863	0	0	72,707,385
3	Light Oil	437,865	384,330	437,865	438,541	438,541	438,541	924,841	438,982	5,070,027	439,219	439,219	439,219	10,327,193
4	Coal	15,813,747	13,386,482	13,211,190	12,477,976	14,569,125	14,761,833	15,486,765	15,466,056	15,070,685	15,372,193	14,162,954	15,123,894	174,902,900
5	Gas	206,606,543	189,390,015	218,971,503	237,229,300	248,751,780	261,664,395	280,864,244	285,989,031	277,993,532	256,438,447	218,939,019	218,996,502	2,901,834,310
6	Nuclear	17,769,900	16,050,300	16,318,500	13,283,900	17,558,400	16,992,100	17,558,400	17,558,400	13,913,900	14,828,200	14,829,500	17,920,700	194,582,200
7	**Total Fuel Cost of System Net Generatic**	255,074,124	219,211,127	249,020,824	265,065,442	282,055,082	300,987,307	328,219,659	330,199,286	327,759,208	295,910,921	248,370,692	252,480,315	3,354,353,988
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	86,034	0	542	9,235	4,544	42,527	80,901	67,915	90,007	55,365	0	0	437,070
11	Light Oil	2,094	1,849	2,094	2,094	2,094	2,094	3,349	2,096	13,613	2,094	2,094	2,094	37,659
12	Coal	573,372	487,304	494,285	457,485	521,980	526,876	550,947	549,023	534,265	545,086	508,075	543,832	6,292,530
13	Gas	5,465,509	5,061,036	5,944,708	6,611,245	6,979,557	7,309,418	7,859,499	8,123,174	7,851,381	7,156,988	6,025,126	5,904,685	80,292,325
14	Nuclear	2,575,172	2,325,963	2,363,945	1,873,068	2,504,803	2,424,002	2,504,803	2,504,803	1,952,261	2,100,856	2,158,347	2,575,172	27,863,195
15	Solar	11,632	9,024	18,353	21,477	21,786	19,960	19,396	18,237	15,960	14,522	11,221	9,640	191,208
16	**Total System Net Generation (MWh)**	8,713,813	7,885,176	8,823,927	8,974,604	10,034,764	10,324,877	11,018,895	11,265,248	10,457,487	9,874,911	8,704,863	9,035,423	115,113,987
17														
18	**Units of Fuel Burned (Unit)** [(a)]													
19	Heavy Oil	152,345		865	17,143	7,772	74,814	140,472	112,919	164,477	92,546			763,353
20	Light Oil	3,581	3,152	3,581	3,581	3,581	3,581	7,537	3,584	40,892	3,581	3,581	3,581	83,813
21	Coal	336,170	289,984	296,328	275,818	310,247	311,012	324,480	323,784	315,064	321,989	302,130	323,196	3,730,202
22	Gas	37,768,177	34,796,530	41,211,755	46,716,771	49,071,858	52,661,957	56,818,936	58,045,397	56,668,209	50,701,681	41,692,330	40,527,942	566,681,542
23	Nuclear	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
24	Total Units of Fuel Burned (Unit)													
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	975,008	0	5,533	109,720	49,743	478,806	899,017	722,688	1,052,650	592,292	0	0	4,885,457
28	Light Oil	20,874	18,371	20,874	20,874	20,874	20,874	43,935	20,892	238,395	20,874	20,874	20,874	488,585
29	Coal	6,013,291	5,136,872	5,165,035	4,837,256	5,534,438	5,570,691	5,820,731	5,801,491	5,645,618	5,763,127	5,360,129	5,727,854	66,376,533
30	Gas	37,768,177	34,796,530	41,211,755	46,716,771	49,071,858	52,661,957	56,818,936	58,045,397	56,668,208	50,701,681	41,692,330	40,527,942	566,681,542
31	Nuclear	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
32	**Total BTU Burned (MMBTU)**	71,827,461	64,384,150	71,271,687	72,041,419	81,723,916	84,906,846	90,629,622	91,637,471	84,828,064	79,719,980	69,648,792	73,326,781	935,946,189
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	94.8247	0.0000	94.5275	95.4164	94.8579	95.3089	95.2888	95.1728	95.5213	95.4429	0.0000	0.0000	95.2474
36	Light Oil	122.2746	121.9321	122.2746	122.4634	122.4634	122.4634	122.7068	122.4837	123.9858	122.6526	122.6526	122.6526	123.2171
37	Coal	47.0409	46.1628	44.5830	45.2399	46.9598	47.4639	47.7279	47.7666	47.8337	47.7414	46.8770	46.7948	46.8883
38	Gas	5.4704	5.4428	5.3133	5.0780	5.0691	4.9688	4.9431	4.9270	4.9056	5.0578	5.2513	5.4036	5.1207
39	Nuclear	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
40	**Total Fuel Cost per Unit ($/Unit)**													
41														
42	**Generation Mix (%)**													
43	Heavy Oil	0.99%	0.00%	0.01%	0.10%	0.05%	0.41%	0.73%	0.60%	0.86%	0.56%	0.00%	0.00%	0.38%

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITH GAS RESERVES)

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.02%	0.13%	0.02%	0.02%	0.02%	0.03%
2	Coal	6.58%	6.18%	5.60%	5.10%	5.20%	5.10%	5.00%	4.87%	5.11%	5.52%	5.84%	6.02%	5.47%
3	Gas	62.72%	64.18%	67.37%	73.67%	69.55%	70.79%	71.33%	72.11%	75.08%	72.48%	69.22%	65.35%	69.75%
4	Nuclear	29.55%	29.50%	26.79%	20.87%	24.96%	23.48%	22.73%	22.23%	18.67%	21.27%	24.79%	28.50%	24.20%
5	Solar	0.13%	0.11%	0.21%	0.24%	0.22%	0.19%	0.18%	0.16%	0.15%	0.15%	0.13%	0.11%	0.17%
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	14.8164	0.0000	14.7779	14.9082	14.8209	14.8921	14.8889	14.8706	14.9252	14.9130	0.0000	0.0000	14.8824
10	Light Oil	20.9766	20.9205	20.9766	21.0090	21.0090	21.0090	21.0502	21.0120	21.2673	21.0414	21.0414	21.0414	21.1369
11	Coal	2.6298	2.6060	2.5578	2.5796	2.6324	2.6499	2.6606	2.6659	2.6694	2.6673	2.6423	2.6404	2.6350
12	Gas	5.4704	5.4428	5.3133	5.0780	5.0691	4.9688	4.9431	4.9270	4.9056	5.0578	5.2513	5.4036	5.1207
13	Nuclear	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	11,333	0	10,208	11,881	10,947	11,259	11,113	10,641	11,695	10,698	0	0	11,178
17	Light Oil	9,968	9,936	9,968	9,968	9,968	9,968	13,119	9,968	17,512	9,968	9,968	9,968	12,974
18	Coal	10,488	10,541	10,450	10,574	10,603	10,573	10,565	10,567	10,567	10,573	10,550	10,532	10,548
19	Gas	6,910	6,875	6,933	7,066	7,031	7,205	7,229	7,146	7,218	7,084	6,920	6,864	7,058
20	Nuclear	10,504	10,504	10,520	10,868	10,798	10,798	10,798	10,798	10,871	10,778	10,460	10,504	10,678
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	16.7911	0.0000	15.0860	17.7122	16.2244	16.7668	16.5454	15.8239	17.4554	15.9539	0.0000	0.0000	16.6352
24	Light Oil	20.9105	20.7858	20.9105	20.9428	20.9428	20.9428	27.6154	20.9438	37.2440	20.9751	20.9751	20.9751	27.4229
25	Coal	2.7580	2.7470	2.6728	2.7275	2.7911	2.8018	2.8109	2.8170	2.8208	2.8201	2.7876	2.7810	2.7795
26	Gas	3.7802	3.7421	3.6835	3.5883	3.5640	3.5798	3.5736	3.5207	3.5407	3.5830	3.6338	3.7089	3.6141
27	Nuclear	0.6900	0.6900	0.6903	0.7092	0.7010	0.7010	0.7010	0.7010	0.7127	0.7058	0.6871	0.6959	0.6983
28	**Total Generated Fuel Cost per KWH (ce**	2.9272	2.7800	2.8221	2.9535	2.8108	2.9152	2.9787	2.9311	3.1342	2.9966	2.8532	2.7943	2.9139
29														
30														
31	[(a)] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,255	19.94	122.27
4	Gas		934,524					6,283,455	1,000,000	6,283,455	34,371,829	3.68	5.47
5	Plant Unit Info	1,355	934,776	92.8%	94.5%	92.7%	6,724			6,285,849	34,422,084	3.68	
6	*Desoto Solar*												
7	Solar		3,129					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,129	16.8%	N/A	36.7%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		273,377					1,990,061	1,000,000	1,990,061	10,886,881	3.98	5.47
18	Plant Unit Info	1,425	273,377	25.8%	95.0%	85.3%	7,280			1,990,061	10,886,881	3.98	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,577	22.14	122.27
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	82.2%	70.6%	10,541			1,170	24,577	22.14	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,433	22.71	122.27
29	Gas		1,725					14,204	1,000,000	14,204	77,749	4.51	5.47
30	Plant Unit Info	442	1,837	0.6%	94.8%	97.7%	8,392			15,416	103,182	5.62	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,555	22.62	122.27
33	Gas		2,158					17,520	1,000,000	17,520	95,889	4.44	5.47
34	Plant Unit Info	442	2,271	0.7%	94.8%	97.7%	8,251			18,738	121,444	5.35	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		353,824					2,472,656	1,000,000	2,472,656	13,527,676	3.82	5.47
8	Plant Unit Info	1,134	353,824	41.9%	94.9%	91.5%	6,988			2,472,656	13,527,676	3.82	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		86,034					152,345	6,400,000	975,008	14,446,069	16.79	94.82
15	Gas		50,863					609,241	1,000,000	609,241	3,332,881	6.55	5.47
16	Plant Unit Info	808	136,897	22.8%	79.3%	24.4%	11,573			1,584,249	17,778,950	12.99	
17	*Martin 3*												
18	Gas		13,124					101,296	1,000,000	101,296	554,192	4.22	5.47
19	Plant Unit Info	454	13,124	3.9%	94.8%	82.6%	7,719			101,296	554,192	4.22	
20	*Martin 4*												
21	Gas		4,561					35,288	1,000,000	35,288	193,090	4.23	5.47
22	Plant Unit Info	453	4,561	1.4%	94.8%	77.5%	7,737			35,288	193,090	4.23	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,456	21.41	122.27
25	Gas		406,906					2,833,477	1,000,000	2,833,477	15,501,773	3.81	5.47
26	Plant Unit Info	1,147	407,151	47.8%	77.1%	76.5%	6,965			2,835,980	15,554,229	3.82	
27	*Martin 8 Solar*												
28	Solar		7,326					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	7,326	13.1%	N/A	28.6%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,760	23.39	122.27
32	Gas		948					9,048	1,000,000	9,048	49,470	5.22	5.47
33	Plant Unit Info	251	994	0.6%	95.1%	94.4%	9,622			9,564	60,230	6.06	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,882	23.66	122.27
36	Gas		959					9,135	1,000,000	9,135	49,946	5.21	5.47
37	Plant Unit Info	255	1,005	0.6%	95.1%	94.2%	9,604			9,652	60,828	6.05	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,888	19.88	122.27
3	Gas		922,626					6,184,726	1,000,000	6,184,726	33,831,759	3.67	5.47
4	Plant Unit Info	1,344	922,877	92.3%	94.5%	92.3%	6,704			6,187,107	33,881,647	3.67	
5	*Sanford 4*												
6	Gas		35,366					261,903	1,000,000	261,903	1,432,844	4.05	5.47
7	Plant Unit Info	975	35,366	4.9%	94.9%	86.3%	7,405			261,903	1,432,844	4.05	
8	*Sanford 5*												
9	Gas		45,244					334,492	1,000,000	334,492	1,829,923	4.04	5.47
10	Plant Unit Info	994	45,244	6.1%	95.0%	82.8%	7,393			334,492	1,829,923	4.04	
11	*Scherer 4*												
12	Coal		453,573					276,491	16,999,975	4,700,340	11,544,604	2.55	41.75
13	Plant Unit Info	646	453,573	94.4%	94.4%	94.4%	10,363			4,700,340	11,544,604	2.55	
14	*St Johns 1*												
15	Coal		59,640					29,852	22,000,100	656,747	2,135,466	3.58	71.54
16	Plant Unit Info	128	59,640	62.5%	94.4%	62.5%	11,012			656,747	2,135,466	3.58	
17	*St Johns 2*												
18	Coal		60,159					29,827	22,000,335	656,204	2,133,677	3.55	71.54
19	Plant Unit Info	128	60,159	63.1%	94.4%	63.1%	10,908			656,204	2,133,677	3.55	
20	*St Lucie 1*												
21	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,999,400	0.69	0.67
22	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,999,400	0.69	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	3,978,000	0.64	0.62
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	3,978,000	0.64	
26	*Space Coast*												
27	Solar		1,177					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,177	15.8%	N/A	34.5%	N/A			0	0	0.00	
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,429,100	0.73	0.67
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,429,100	0.73	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,844	21.42	122.27
4	Gas		352,614					2,473,735	1,000,000	2,473,735	13,533,116	3.84	5.47
5	Plant Unit Info	1,166	352,856	40.7%	94.8%	88.9%	7,018			2,476,208	13,584,961	3.85	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,753	20.16	122.27
8	Gas		747,800					5,121,396	1,000,000	5,121,396	28,015,119	3.75	5.47
9	Plant Unit Info	1,208	748,022	83.3%	94.8%	90.5%	6,849			5,123,530	28,059,871	3.75	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
12	Gas		771,236					5,274,011	1,000,000	5,274,011	28,849,952	3.74	5.47
13	Plant Unit Info	1,202	771,463	86.3%	94.9%	88.1%	6,839			5,276,189	28,895,683	3.75	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
16	Gas		547,655					3,742,534	1,000,000	3,742,534	20,472,454	3.74	5.47
17	Plant Unit Info	1,207	547,882	61.0%	94.9%	91.5%	6,835			3,744,712	20,518,185	3.75	
18	**System Totals**												
19	Plant Unit Info	25,930	8,713,813				8,243			71,827,461	255,074,124	2.93	
20													
21													
22													
23													
24													
25													
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32													
33													
34													
35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,114	19.89	121.93
4	Gas		827,976					5,557,092	1,000,000	5,557,092	30,244,702	3.65	5.44
5	Plant Unit Info	1,355	828,228	91.0%	94.5%	90.9%	6,713			5,559,486	30,294,816	3.66	
6	*Desoto Solar*												
7	Solar		3,571					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,571	21.3%	N/A	46.4%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		266,665					1,943,319	1,000,000	1,943,319	10,577,813	3.97	5.44
18	Plant Unit Info	1,425	266,665	27.9%	95.0%	80.7%	7,287			1,943,319	10,577,813	3.97	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,508	22.08	121.93
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	93.4%	70.6%	10,541			1,170	24,508	22.08	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,362	22.64	121.93
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	112	0.1%	94.8%	25.4%	10,821			1,212	25,362	22.64	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,484	22.55	121.93
33	Gas		4,388					36,665	1,000,000	36,665	199,778	4.55	5.45
34	Plant Unit Info	442	4,501	1.6%	91.3%	82.8%	8,417			37,883	225,261	5.00	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		402,731					2,797,745	1,000,000	2,797,745	15,228,639	3.78	5.44
8	Plant Unit Info	1,134	402,731	52.8%	94.9%	85.6%	6,947			2,797,745	15,228,639	3.78	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	16.7%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		26,311					204,632	1,000,000	204,632	1,114,002	4.23	5.44
19	Plant Unit Info	454	26,311	8.6%	94.8%	69.8%	7,778			204,632	1,114,002	4.23	
20	*Martin 4*												
21	Gas		23,731					185,502	1,000,000	185,502	1,009,886	4.26	5.44
22	Plant Unit Info	453	23,731	7.8%	94.8%	67.2%	7,817			185,502	1,009,886	4.26	
23	*Martin 8*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		126,320					883,536	1,000,000	883,536	4,809,900	3.81	5.44
26	Plant Unit Info	1,147	126,320	16.4%	27.0%	69.7%	6,994			883,536	4,809,900	3.81	
27	*Martin 8 Solar*												
28	Solar		4,190					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	4,190	8.3%	N/A	36.3%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,730	23.33	121.93
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	251	46	0.1%	95.1%	17.9%	11,217			516	10,730	23.33	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,852	23.59	121.93
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	255	46	0.1%	95.1%	17.7%	11,239			517	10,852	23.59	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,748	19.82	121.93
3	Gas		818,960					5,480,457	1,000,000	5,480,457	29,827,614	3.64	5.44
4	Plant Unit Info	1,344	819,211	90.8%	94.5%	90.7%	6,693			5,482,838	29,877,362	3.65	
5	*Sanford 4*												
6	Gas		86,838					648,008	1,000,000	648,008	3,527,690	4.06	5.44
7	Plant Unit Info	975	86,838	13.3%	94.9%	76.1%	7,462			648,008	3,527,690	4.06	
8	*Sanford 5*												
9	Gas		120,850					898,434	1,000,000	898,434	4,890,791	4.05	5.44
10	Plant Unit Info	994	120,850	18.1%	95.0%	74.6%	7,434			898,434	4,890,791	4.05	
11	*Scherer 4*												
12	Coal		407,720					248,555	16,999,972	4,225,428	10,449,482	2.56	42.04
13	Plant Unit Info	646	407,720	94.0%	94.4%	94.0%	10,364			4,225,428	10,449,482	2.56	
14	*St Johns 1*												
15	Coal		38,908					20,408	22,000,245	448,981	1,446,772	3.72	70.89
16	Plant Unit Info	128	38,908	45.2%	94.4%	45.2%	11,540			448,981	1,446,772	3.72	
17	*St Johns 2*												
18	Coal		40,676					21,021	22,000,048	462,463	1,490,229	3.66	70.89
19	Plant Unit Info	128	40,676	47.2%	94.4%	47.2%	11,369			462,463	1,490,229	3.66	
20	*St Lucie 1*												
21	Nuclear		657,165					6,787,360	1,000,000	6,787,360	4,515,600	0.69	0.67
22	Plant Unit Info	1,003	657,165	97.5%	97.5%	97.5%	10,328			6,787,360	4,515,600	0.69	
23	*St Lucie 2*												
24	Nuclear		563,473					5,779,359	1,000,000	5,779,359	3,593,000	0.64	0.62
25	Plant Unit Info	860	563,473	97.5%	97.5%	97.5%	10,257			5,779,359	3,593,000	0.64	
26	*Space Coast*												
27	Solar		1,263					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,263	18.8%	N/A	41.0%	N/A			0	0	0.00	
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		549,713					5,932,829	1,000,000	5,932,829	4,000,500	0.73	0.67
35	Plant Unit Info	839	549,713	97.5%	97.5%	97.5%	10,793			5,932,829	4,000,500	0.73	
36	*Turkey Point 4*												
37	Nuclear		555,612					5,932,829	1,000,000	5,932,829	3,941,200	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	848	555,612	97.5%	97.5%	97.5%	10,678			5,932,829	3,941,200	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,699	21.36	121.93
4	Gas		368,694					2,590,320	1,000,000	2,590,320	14,099,455	3.82	5.44
5	Plant Unit Info	1,166	368,936	47.1%	94.8%	83.0%	7,028			2,592,793	14,151,155	3.84	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,627	20.10	121.93
8	Gas		712,522					4,866,938	1,000,000	4,866,938	26,488,512	3.72	5.44
9	Plant Unit Info	1,208	712,744	87.9%	94.8%	87.8%	6,831			4,869,072	26,533,139	3.72	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,603	20.09	121.93
12	Gas		681,853					4,654,768	1,000,000	4,654,768	25,333,767	3.72	5.44
13	Plant Unit Info	1,202	682,080	84.5%	94.9%	85.4%	6,828			4,656,946	25,379,370	3.72	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,603	20.09	121.93
16	Gas		593,198					4,049,113	1,000,000	4,049,113	22,037,466	3.72	5.44
17	Plant Unit Info	1,207	593,425	73.2%	94.9%	86.8%	6,827			4,051,291	22,083,068	3.72	
18	**System Totals**												
19	Plant Unit Info	25,927	7,885,176				8,165			64,384,150	219,211,127	2.78	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,255	19.94	122.27
4	Gas		934,577					6,269,399	1,000,000	6,269,399	33,309,130	3.56	5.31
5	Plant Unit Info	1,355	934,829	92.8%	94.5%	92.7%	6,709			6,271,793	33,359,385	3.57	
6	*Desoto Solar*												
7	Solar		4,881					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,881	26.3%	N/A	48.5%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		673,583					4,897,496	1,000,000	4,897,496	26,022,860	3.86	5.31
18	Plant Unit Info	1,442	673,583	62.8%	95.0%	87.3%	7,271			4,897,496	26,022,860	3.86	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,577	22.14	122.27
21	Gas		3,226					34,896	1,000,000	34,896	185,453	5.75	5.31
22	Plant Unit Info	314	3,337	2.9%	95.1%	97.8%	10,808			36,066	210,030	6.29	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,433	22.71	122.27
29	Gas		22,744					182,233	1,000,000	182,233	968,810	4.26	5.32
30	Plant Unit Info	442	22,856	7.0%	94.8%	92.0%	8,026			183,445	994,243	4.35	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,555	22.62	122.27
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	442	113	0.1%	1.3%	25.4%	10,779			1,218	25,555	22.62	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	62.9%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		610,421					4,212,797	1,000,000	4,212,797	22,383,694	3.67	5.31
8	Plant Unit Info	1,134	610,421	72.3%	94.9%	88.1%	6,901			4,212,797	22,383,694	3.67	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	14.6%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		421					673	6,396,731	4,305	63,617	15.11	94.53
15	Gas		2,387					29,617	1,000,000	29,617	157,657	6.60	5.32
16	Plant Unit Info	805	2,808	0.5%	95.2%	43.6%	12,079			33,922	221,274	7.88	
17	*Martin 3*												
18	Gas		68,689					526,877	1,000,000	526,877	2,800,198	4.08	5.31
19	Plant Unit Info	454	68,689	20.3%	94.8%	93.9%	7,671			526,877	2,800,198	4.08	
20	*Martin 4*												
21	Gas		51,925					398,361	1,000,000	398,361	2,117,089	4.08	5.31
22	Plant Unit Info	453	51,925	15.4%	94.8%	88.9%	7,672			398,361	2,117,089	4.08	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,456	21.41	122.27
25	Gas		536,120					3,696,049	1,000,000	3,696,049	19,638,608	3.66	5.31
26	Plant Unit Info	1,147	536,365	62.9%	77.1%	74.9%	6,896			3,698,552	19,691,064	3.67	
27	*Martin 8 Solar*												
28	Solar		11,799					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	11,799	21.2%	N/A	29.9%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,760	23.39	122.27
32	Gas		3,382					32,433	1,000,000	32,433	172,393	5.10	5.32
33	Plant Unit Info	251	3,428	1.9%	95.1%	74.9%	9,612			32,949	183,153	5.34	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,882	23.66	122.27
36	Gas		3,786					37,484	1,000,000	37,484	199,379	5.27	5.32
37	Plant Unit Info	255	3,832	2.1%	95.1%	62.0%	9,917			38,001	210,261	5.49	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,888	19.88	122.27
3	Gas		693,041					4,639,870	1,000,000	4,639,870	24,651,490	3.56	5.31
4	Plant Unit Info	1,344	693,292	69.4%	71.9%	91.1%	6,696			4,642,251	24,701,378	3.56	
5	*Sanford 4*												
6	Gas		19,169					142,461	1,000,000	142,461	757,101	3.95	5.31
7	Plant Unit Info	975	19,169	2.6%	72.3%	78.6%	7,432			142,461	757,101	3.95	
8	*Sanford 5*												
9	Gas		240,025					1,794,389	1,000,000	1,794,389	9,537,009	3.97	5.31
10	Plant Unit Info	994	240,025	32.5%	95.0%	88.1%	7,476			1,794,389	9,537,009	3.97	
11	*Scherer 4*												
12	Coal		444,163					270,840	17,000,026	4,604,287	11,426,752	2.57	42.19
13	Plant Unit Info	646	444,163	92.5%	94.4%	92.5%	10,366			4,604,287	11,426,752	2.57	
14	*St Johns 1*												
15	Coal		1,141					603	22,011,609	13,273	42,217	3.70	70.01
16	Plant Unit Info	128	1,141	1.2%	13.8%	6.2%	11,633			13,273	42,217	3.70	
17	*St Johns 2*												
18	Coal		48,981					24,885	22,000,201	547,475	1,742,221	3.56	70.01
19	Plant Unit Info	128	48,981	51.4%	94.4%	51.4%	11,177			547,475	1,742,221	3.56	
20	*St Lucie 1*												
21	Nuclear		516,347					5,332,946	1,000,000	5,332,946	3,548,000	0.69	0.67
22	Plant Unit Info	1,003	516,347	69.2%	69.2%	97.5%	10,328			5,332,946	3,548,000	0.69	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	3,978,000	0.64	0.62
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	3,978,000	0.64	
26	*Space Coast*												
27	Solar		1,673					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,673	22.5%	N/A	41.5%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		121					192	6,395,833	1,228	18,149	15.00	94.53
31	Gas		2,236					25,708	1,000,000	25,708	136,676	6.11	5.32
32	Plant Unit Info	380	2,357	0.8%	94.6%	38.7%	11,430			26,936	154,825	6.57	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,429,100	0.73	0.67
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,429,100	0.73	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,844	21.42	122.27
4	Gas		524,805					3,672,248	1,000,000	3,672,248	19,513,192	3.72	5.31
5	Plant Unit Info	1,166	525,047	60.6%	94.8%	91.5%	6,999			3,674,721	19,565,037	3.73	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,753	20.16	122.27
8	Gas		493,241					3,368,322	1,000,000	3,368,322	17,895,792	3.63	5.31
9	Plant Unit Info	1,208	493,463	55.0%	62.6%	88.4%	6,830			3,370,456	17,940,545	3.64	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
12	Gas		588,306					4,014,199	1,000,000	4,014,199	21,327,322	3.63	5.31
13	Plant Unit Info	1,202	588,533	65.8%	72.3%	86.0%	6,824			4,016,377	21,373,052	3.63	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
16	Gas		473,045					3,236,919	1,000,000	3,236,919	17,197,651	3.64	5.31
17	Plant Unit Info	1,207	473,272	52.7%	64.8%	82.0%	6,844			3,239,097	17,243,382	3.64	
18	**System Totals**												
19	Plant Unit Info	25,944	8,823,927				8,077			71,271,687	249,020,824	2.82	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		362,834					2,486,987	1,000,000	2,486,987	12,627,684	3.48	5.08
5	Plant Unit Info	1,210	363,086	41.7%	50.1%	56.7%	6,856			2,489,381	12,678,016	3.49	
6	*Desoto Solar*												
7	Solar		5,454					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,454	30.3%	N/A	55.9%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		428,019					3,123,384	1,000,000	3,123,384	15,861,442	3.71	5.08
18	Plant Unit Info	1,366	428,019	43.5%	61.1%	80.8%	7,297			3,123,384	15,861,442	3.71	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		17,545					192,397	1,000,000	192,397	977,379	5.57	5.08
22	Plant Unit Info	296	17,656	16.6%	95.1%	98.1%	10,963			193,567	1,001,994	5.68	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		49,214					394,466	1,000,000	394,466	2,004,370	4.07	5.08
30	Plant Unit Info	429	49,326	16.0%	81.4%	97.3%	8,022			395,678	2,029,842	4.12	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		83,808					664,793	1,000,000	664,793	3,377,428	4.03	5.08
34	Plant Unit Info	429	83,921	27.2%	94.8%	97.7%	7,936			666,011	3,403,023	4.06	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	0	0.0%	28.5%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		2,569					6,511	6,400,399	41,673	621,256	24.18	95.42
4	Gas		14,559					152,756	1,000,000	152,756	775,617	5.33	5.08
5	Plant Unit Info	789	17,128	3.0%	95.2%	67.9%	11,352			194,429	1,396,873	8.16	
6	*Manatee 3*												
7	Gas		553,249					3,889,261	1,000,000	3,889,261	19,750,527	3.57	5.08
8	Plant Unit Info	1,078	553,249	71.3%	94.9%	93.4%	7,030			3,889,261	19,750,527	3.57	
9	*Martin 1*												
10	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		6,487					10,356	6,400,058	66,279	988,133	15.23	95.42
15	Gas		36,757					438,357	1,000,000	438,357	2,229,540	6.07	5.09
16	Plant Unit Info	799	43,244	7.5%	95.2%	48.8%	11,669			504,636	3,217,673	7.44	
17	*Martin 3*												
18	Gas		126,261					972,308	1,000,000	972,308	4,938,726	3.91	5.08
19	Plant Unit Info	438	126,261	40.0%	94.8%	97.7%	7,701			972,308	4,938,726	3.91	
20	*Martin 4*												
21	Gas		107,186					829,487	1,000,000	829,487	4,213,394	3.93	5.08
22	Plant Unit Info	437	107,186	34.1%	94.8%	97.4%	7,739			829,487	4,213,394	3.93	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		690,671					4,777,306	1,000,000	4,777,306	24,256,785	3.51	5.08
26	Plant Unit Info	1,111	690,916	86.4%	94.8%	86.3%	6,918			4,779,809	24,309,322	3.52	
27	*Martin 8 Solar*												
28	Solar		14,206					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	14,206	26.3%	N/A	48.6%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		15,794					149,894	1,000,000	149,894	761,746	4.82	5.08
33	Plant Unit Info	247	15,840	9.0%	95.1%	91.5%	9,496			150,410	772,523	4.88	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		18,063					168,120	1,000,000	168,120	854,325	4.73	5.08
37	Plant Unit Info	250	18,109	10.1%	95.1%	95.0%	9,312			168,637	865,224	4.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		800,898					5,394,531	1,000,000	5,394,531	27,390,747	3.42	5.08
4	Plant Unit Info	1,212	801,149	91.9%	94.5%	91.8%	6,736			5,396,912	27,440,712	3.43	
5	*Sanford 4*												
6	Gas		41,326					312,421	1,000,000	312,421	1,587,241	3.84	5.08
7	Plant Unit Info	939	41,326	6.1%	94.9%	97.8%	7,560			312,421	1,587,241	3.84	
8	*Sanford 5*												
9	Gas		318,687					2,386,981	1,000,000	2,386,981	12,124,804	3.80	5.08
10	Plant Unit Info	947	318,687	46.7%	75.0%	95.9%	7,490			2,386,981	12,124,804	3.80	
11	*Scherer 4*												
12	Coal		399,592					246,144	16,999,984	4,184,444	10,399,493	2.60	42.25
13	Plant Unit Info	641	399,592	86.7%	94.4%	86.7%	10,472			4,184,444	10,399,493	2.60	
14	*St Johns 1*												
15	Coal		6,141					3,231	21,997,833	71,075	226,312	3.69	70.04
16	Plant Unit Info	127	6,141	6.7%	11.1%	40.3%	11,574			71,075	226,312	3.69	
17	*St Johns 2*												
18	Coal		51,752					26,443	21,999,660	581,737	1,852,171	3.58	70.04
19	Plant Unit Info	127	51,752	56.7%	94.4%	56.6%	11,241			581,737	1,852,171	3.58	
20	*St Lucie 1*												
21	Nuclear		137,732					1,454,445	1,000,000	1,454,445	927,100	0.67	0.64
22	Plant Unit Info	981	137,732	19.5%	19.5%	97.5%	10,560			1,454,445	927,100	0.67	
23	*St Lucie 2*												
24	Nuclear		589,677					6,189,149	1,000,000	6,189,149	3,847,800	0.65	0.62
25	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,496			6,189,149	3,847,800	0.65	
26	*Space Coast*												
27	Solar		1,817					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,817	25.2%	N/A	46.6%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		179					276	6,405,797	1,768	26,335	14.71	95.42
31	Gas		2,777					30,563	1,000,000	30,563	155,375	5.59	5.08
32	Plant Unit Info	379	2,956	1.1%	24.6%	48.7%	10,936			32,331	181,710	6.15	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		677,810					4,678,708	1,000,000	4,678,708	23,757,120	3.50	5.08
5	Plant Unit Info	1,138	678,052	82.8%	94.8%	89.4%	6,904			4,681,181	23,809,044	3.51	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		763,915					5,295,715	1,000,000	5,295,715	26,889,006	3.52	5.08
9	Plant Unit Info	1,166	764,137	91.1%	94.8%	91.0%	6,933			5,297,849	26,933,828	3.52	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		763,949					5,259,777	1,000,000	5,259,777	26,706,533	3.50	5.08
13	Plant Unit Info	1,159	764,176	91.6%	94.9%	91.5%	6,886			5,261,955	26,752,335	3.50	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		737,922					5,118,561	1,000,000	5,118,561	25,989,509	3.52	5.08
17	Plant Unit Info	1,166	738,149	88.0%	94.9%	88.9%	6,937			5,120,739	26,035,310	3.53	
18	**System Totals**												
19	Plant Unit Info	24,939	8,974,604				8,027			72,041,419	265,065,442	2.95	
20													
21													
22													
23													
24													
25													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		805,608					5,437,271	1,000,000	5,437,271	27,558,380	3.42	5.07
5	Plant Unit Info	1,210	805,860	89.6%	92.4%	91.2%	6,750			5,439,665	27,608,712	3.43	
6	*Desoto Solar*												
7	Solar		5,823					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,823	31.3%	N/A	57.8%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		332,187					2,475,880	1,000,000	2,475,880	12,555,483	3.78	5.07
18	Plant Unit Info	1,366	332,187	32.7%	64.3%	64.5%	7,453			2,475,880	12,555,483	3.78	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		14,210					156,052	1,000,000	156,052	791,372	5.57	5.07
22	Plant Unit Info	296	14,321	13.0%	95.1%	98.1%	10,978			157,222	815,987	5.70	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		58,807					474,040	1,000,000	474,040	2,404,906	4.09	5.07
30	Plant Unit Info	429	58,919	18.5%	94.8%	97.3%	8,066			475,252	2,430,378	4.12	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		79,556					636,195	1,000,000	636,195	3,227,046	4.06	5.07
34	Plant Unit Info	429	79,669	25.0%	94.8%	97.7%	8,001			637,413	3,252,641	4.08	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	0	0.0%	69.4%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		705					1,726	6,400,348	11,047	163,725	23.22	94.86
4	Gas		3,993					41,931	1,000,000	41,931	212,524	5.32	5.07
5	Plant Unit Info	789	4,698	0.8%	95.2%	74.5%	11,277			52,978	376,249	8.01	
6	*Manatee 3*												
7	Gas		501,065					3,541,916	1,000,000	3,541,916	17,956,721	3.58	5.07
8	Plant Unit Info	1,078	501,065	62.5%	94.9%	96.6%	7,069			3,541,916	17,956,721	3.58	
9	*Martin 1*												
10	Heavy 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	799	0	0.0%	1.7%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		2,630					4,157	6,400,289	26,606	394,324	14.99	94.86
15	Gas		14,905					178,306	1,000,000	178,306	905,732	6.08	5.08
16	Plant Unit Info	799	17,535	3.0%	95.2%	54.9%	11,686			204,912	1,300,056	7.41	
17	*Martin 3*												
18	Gas		122,837					948,126	1,000,000	948,126	4,807,731	3.91	5.07
19	Plant Unit Info	438	122,837	37.7%	94.8%	97.7%	7,719			948,126	4,807,731	3.91	
20	*Martin 4*												
21	Gas		105,760					821,025	1,000,000	821,025	4,163,365	3.94	5.07
22	Plant Unit Info	437	105,760	32.6%	94.8%	97.7%	7,763			821,025	4,163,365	3.94	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		727,351					5,035,261	1,000,000	5,035,261	25,520,823	3.51	5.07
26	Plant Unit Info	1,111	727,596	88.0%	94.8%	88.0%	6,924			5,037,764	25,573,360	3.51	
27	*Martin 8 Solar*												
28	Solar		14,070					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	14,070	25.2%	N/A	46.6%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		14,858					141,744	1,000,000	141,744	719,239	4.84	5.07
33	Plant Unit Info	247	14,904	8.2%	95.1%	94.1%	9,545			142,260	730,016	4.90	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		17,569					163,986	1,000,000	163,986	832,016	4.74	5.07
37	Plant Unit Info	250	17,615	9.5%	95.1%	97.5%	9,339			164,503	842,915	4.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		831,274					5,601,395	1,000,000	5,601,395	28,390,227	3.42	5.07
4	Plant Unit Info	1,212	831,525	92.3%	94.5%	92.2%	6,739			5,603,776	28,440,192	3.42	
5	*Sanford 4*												
6	Gas		322,340					2,419,285	1,000,000	2,419,285	12,268,639	3.81	5.07
7	Plant Unit Info	939	322,340	46.1%	94.9%	97.8%	7,505			2,419,285	12,268,639	3.81	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	0.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		419,496					258,200	17,000,031	4,389,408	10,922,674	2.60	42.30
13	Plant Unit Info	641	419,496	88.0%	94.4%	88.0%	10,464			4,389,408	10,922,674	2.60	
14	*St Johns 1*												
15	Coal		45,632					23,334	22,000,300	513,355	1,634,797	3.58	70.06
16	Plant Unit Info	127	45,632	48.3%	94.4%	48.3%	11,250			513,355	1,634,797	3.58	
17	*St Johns 2*												
18	Coal		56,852					28,713	21,999,617	631,675	2,011,654	3.54	70.06
19	Plant Unit Info	127	56,852	60.2%	94.4%	60.2%	11,111			631,675	2,011,654	3.54	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,893					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,893	25.5%	N/A	47.0%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		1,209					1,889	6,400,212	12,090	179,187	14.82	94.86
31	Gas		12,339					138,550	1,000,000	138,550	703,139	5.70	5.07
32	Plant Unit Info	379	13,548	4.8%	94.6%	44.6%	11,119			150,640	882,325	6.51	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		644,863					4,461,483	1,000,000	4,461,483	22,615,306	3.51	5.07
5	Plant Unit Info	1,138	645,105	76.2%	94.8%	93.2%	6,920			4,463,956	22,667,230	3.51	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		798,166					5,533,855	1,000,000	5,533,855	28,047,908	3.51	5.07
9	Plant Unit Info	1,166	798,388	92.1%	94.8%	92.0%	6,934			5,535,989	28,092,730	3.52	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		789,821					5,439,541	1,000,000	5,439,541	27,569,885	3.49	5.07
13	Plant Unit Info	1,159	790,048	91.6%	94.9%	92.6%	6,888			5,441,719	27,615,686	3.50	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		782,050					5,426,017	1,000,000	5,426,017	27,501,340	3.52	5.07
17	Plant Unit Info	1,166	782,277	90.2%	94.9%	90.1%	6,939			5,428,195	27,547,141	3.52	
18	**System Totals**												
19	Plant Unit Info	24,939	10,034,764				8,144			81,723,916	282,055,082	2.81	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		810,222					5,465,921	1,000,000	5,465,921	27,154,211	3.35	4.97
5	Plant Unit Info	1,210	810,474	93.1%	94.5%	93.0%	6,747			5,468,315	27,204,543	3.36	
6	*Desoto Solar*												
7	Solar		5,102					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,102	28.4%	N/A	52.3%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	87.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		316,993					2,427,505	1,000,000	2,427,505	12,065,054	3.81	4.97
18	Plant Unit Info	1,383	316,993	31.8%	47.7%	50.3%	7,658			2,427,505	12,065,054	3.81	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		29,001					317,885	1,000,000	317,885	1,580,069	5.45	4.97
22	Plant Unit Info	296	29,112	27.4%	95.1%	98.1%	10,960			319,055	1,604,684	5.51	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		5,210					117,085	1,000,000	117,085	581,694	11.16	4.97
26	Plant Unit Info	840	5,210	0.9%	95.3%	47.7%	22,473			117,085	581,694	11.16	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		88,836					707,360	1,000,000	707,360	3,516,632	3.96	4.97
30	Plant Unit Info	429	88,948	28.9%	94.8%	97.3%	7,966			708,572	3,542,105	3.98	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		108,531					858,417	1,000,000	858,417	4,267,070	3.93	4.97
34	Plant Unit Info	429	108,644	35.2%	94.8%	97.7%	7,912			859,635	4,292,665	3.95	
35	*Manatee 1*												
36	Heavy Oil		3,117					7,363	6,399,837	47,122	701,759	22.51	95.31
37	Gas		17,665					185,174	1,000,000	185,174	919,928	5.21	4.97

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	20,782	3.7%	95.2%	82.4%	11,178			232,296	1,621,687	7.80	
2	*Manatee 2*												
3	Heavy Oil		8,700					19,825	6,400,050	126,881	1,889,498	21.72	95.31
4	Gas		49,301					516,940	1,000,000	516,940	2,568,112	5.21	4.97
5	Plant Unit Info	789	58,001	10.2%	95.2%	90.8%	11,100			643,821	4,457,610	7.69	
6	*Manatee 3*												
7	Gas		601,979					4,221,875	1,000,000	4,221,875	20,976,425	3.48	4.97
8	Plant Unit Info	1,078	601,979	77.5%	94.9%	94.3%	7,013			4,221,875	20,976,425	3.48	
9	*Martin 1*												
10	Heavy Oil		14,318					22,339	6,399,884	142,967	2,129,105	14.87	95.31
11	Gas		81,136					922,656	1,000,000	922,656	4,590,835	5.66	4.98
12	Plant Unit Info	799	95,454	16.6%	95.3%	75.1%	11,164			1,065,623	6,719,940	7.04	
13	*Martin 2*												
14	Heavy Oil		12,570					19,552	6,400,010	125,133	1,863,479	14.82	95.31
15	Gas		71,231					808,541	1,000,000	808,541	4,023,083	5.65	4.98
16	Plant Unit Info	799	83,801	14.6%	95.2%	75.4%	11,142			933,674	5,886,562	7.02	
17	*Martin 3*												
18	Gas		153,924					1,182,621	1,000,000	1,182,621	5,877,473	3.82	4.97
19	Plant Unit Info	438	153,924	48.8%	94.8%	96.8%	7,683			1,182,621	5,877,473	3.82	
20	*Martin 4*												
21	Gas		138,171					1,067,611	1,000,000	1,067,611	5,306,115	3.84	4.97
22	Plant Unit Info	437	138,171	44.0%	94.8%	97.7%	7,727			1,067,611	5,306,115	3.84	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		715,511					4,956,295	1,000,000	4,956,295	24,622,432	3.44	4.97
26	Plant Unit Info	1,111	715,756	89.5%	94.8%	89.4%	6,928			4,958,798	24,674,969	3.45	
27	*Martin 8 Solar*												
28	Solar		13,207					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	13,207	24.5%	N/A	45.2%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		29,899					280,609	1,000,000	280,609	1,395,201	4.67	4.97
33	Plant Unit Info	247	29,945	16.9%	95.1%	97.8%	9,388			281,125	1,405,978	4.70	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		35,041					322,546	1,000,000	322,546	1,603,568	4.58	4.97
37	Plant Unit Info	250	35,087	19.5%	95.1%	97.9%	9,207			323,063	1,614,467	4.60	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		805,945					5,431,560	1,000,000	5,431,560	26,983,507	3.35	4.97
4	Plant Unit Info	1,212	806,196	92.4%	94.5%	92.4%	6,740			5,433,941	27,033,472	3.35	
5	*Sanford 4*												
6	Gas		384,786					2,872,574	1,000,000	2,872,574	14,277,225	3.71	4.97
7	Plant Unit Info	939	384,786	56.9%	94.9%	97.8%	7,465			2,872,574	14,277,225	3.71	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	78.3%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		413,542					254,313	17,000,008	4,323,323	10,770,663	2.60	42.35
13	Plant Unit Info	641	413,542	89.7%	94.4%	89.7%	10,454			4,323,323	10,770,663	2.60	
14	*St Johns 1*												
15	Coal		50,840					25,571	21,999,609	562,552	1,800,000	3.54	70.39
16	Plant Unit Info	127	50,840	55.7%	94.4%	55.6%	11,065			562,552	1,800,000	3.54	
17	*St Johns 2*												
18	Coal		62,494					31,128	22,000,000	684,816	2,191,170	3.51	70.39
19	Plant Unit Info	127	62,494	68.4%	94.4%	68.4%	10,958			684,816	2,191,170	3.51	
20	*St Lucie 1*												
21	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,635,300	0.67	0.64
22	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,635,300	0.67	
23	*St Lucie 2*												
24	Nuclear		589,677					6,189,149	1,000,000	6,189,149	3,847,800	0.65	0.62
25	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,496			6,189,149	3,847,800	0.65	
26	*Space Coast*												
27	Solar		1,651					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,651	22.9%	N/A	42.3%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		3,822					5,735	6,399,826	36,703	546,596	14.30	95.31
31	Gas		48,432					508,163	1,000,000	508,163	2,526,459	5.22	4.97
32	Plant Unit Info	379	52,254	19.1%	94.6%	74.0%	10,427			544,866	3,073,056	5.88	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		472,534					3,270,439	1,000,000	3,270,439	16,248,880	3.44	4.97
5	Plant Unit Info	1,138	472,776	57.7%	65.7%	87.0%	6,923			3,272,912	16,300,804	3.45	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		788,050					5,459,716	1,000,000	5,459,716	27,123,386	3.44	4.97
9	Plant Unit Info	1,166	788,272	93.9%	94.8%	93.9%	6,929			5,461,850	27,168,208	3.45	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		783,414					5,394,575	1,000,000	5,394,575	26,799,770	3.42	4.97
13	Plant Unit Info	1,159	783,641	93.9%	94.9%	93.8%	6,887			5,396,753	26,845,571	3.43	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		773,608					5,365,890	1,000,000	5,365,890	26,657,266	3.45	4.97
17	Plant Unit Info	1,166	773,835	92.2%	94.9%	92.1%	6,937			5,368,068	26,703,067	3.45	
18	**System Totals**												
19	Plant Unit Info	24,956	10,324,877				8,224			84,906,846	300,987,307	2.92	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,432	20.01	122.71
4	Gas		836,805					5,644,922	1,000,000	5,644,922	27,898,879	3.33	4.94
5	Plant Unit Info	1,210	837,057	93.0%	94.5%	93.0%	6,747			5,647,316	27,949,312	3.34	
6	*Desoto Solar*												
7	Solar		5,051					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,051	27.2%	N/A	50.1%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,255					3,956	5,829,373	23,061	485,428	38.68	122.71
15	Plant Unit Info	648	1,255	0.3%	89.7%	38.7%	18,375			23,061	485,428	38.68	
16	*Fort Myers 2*												
17	Gas		669,972					4,854,185	1,000,000	4,854,185	23,994,065	3.58	4.94
18	Plant Unit Info	1,383	669,972	65.1%	79.4%	79.3%	7,245			4,854,185	23,994,065	3.58	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,664	22.22	122.71
21	Gas		35,816					391,920	1,000,000	391,920	1,938,023	5.41	4.94
22	Plant Unit Info	296	35,927	32.7%	95.1%	98.1%	10,941			393,090	1,962,688	5.46	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,523	22.79	122.71
29	Gas		101,765					810,526	1,000,000	810,526	4,008,844	3.94	4.95
30	Plant Unit Info	429	101,877	32.0%	94.8%	97.3%	7,968			811,738	4,034,367	3.96	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,646	22.70	122.71
33	Gas		119,845					950,194	1,000,000	950,194	4,699,244	3.92	4.95
34	Plant Unit Info	429	119,958	37.6%	94.8%	97.7%	7,931			951,412	4,724,890	3.94	
35	*Manatee 1*												
36	Heavy Oil		19,048					40,331	6,399,965	258,117	3,843,093	20.18	95.29
37	Gas		79,339					831,474	1,000,000	831,474	4,109,389	5.18	4.94

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	98,387	16.8%	95.2%	88.5%	11,075			1,089,591	7,952,482	8.08	
2	*Manatee 2*												
3	Heavy Oil		6,610					15,313	6,400,052	98,004	1,459,157	22.07	95.29
4	Gas		37,456					392,725	1,000,000	392,725	1,940,961	5.18	4.94
5	Plant Unit Info	789	44,066	7.5%	95.2%	86.0%	11,136			490,729	3,400,118	7.72	
6	*Manatee 3*												
7	Gas		180,874					1,282,964	1,000,000	1,282,964	6,342,929	3.51	4.94
8	Plant Unit Info	1,078	180,874	22.5%	62.6%	77.3%	7,093			1,282,964	6,342,929	3.51	
9	*Martin 1*												
10	Heavy Oil		20,439					31,854	6,400,044	203,867	3,035,330	14.85	95.29
11	Gas		115,820					1,313,011	1,000,000	1,313,011	6,499,234	5.61	4.95
12	Plant Unit Info	799	136,259	22.9%	95.3%	74.1%	11,132			1,516,878	9,534,563	7.00	
13	*Martin 2*												
14	Heavy Oil		16,225					25,232	6,399,889	161,482	2,404,327	14.82	95.29
15	Gas		91,944					1,048,816	1,000,000	1,048,816	5,192,274	5.65	4.95
16	Plant Unit Info	799	108,169	18.2%	95.2%	73.6%	11,189			1,210,298	7,596,601	7.02	
17	*Martin 3*												
18	Gas		163,498					1,255,889	1,000,000	1,255,889	6,209,421	3.80	4.94
19	Plant Unit Info	438	163,498	50.2%	94.8%	97.7%	7,681			1,255,889	6,209,421	3.80	
20	*Martin 4*												
21	Gas		144,568					1,117,564	1,000,000	1,117,564	5,525,773	3.82	4.94
22	Plant Unit Info	437	144,568	44.5%	94.8%	97.7%	7,730			1,117,564	5,525,773	3.82	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,641	21.49	122.71
25	Gas		744,751					5,157,895	1,000,000	5,157,895	25,491,847	3.42	4.94
26	Plant Unit Info	1,111	744,996	90.1%	94.8%	90.1%	6,927			5,160,398	25,544,488	3.43	
27	*Martin 8 Solar*												
28	Solar		12,594					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	12,594	22.6%	N/A	36.1%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,798	23.47	122.71
32	Gas		35,616					333,618	1,000,000	333,618	1,650,202	4.63	4.95
33	Plant Unit Info	247	35,662	19.5%	95.1%	96.9%	9,369			334,134	1,661,000	4.66	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,921	23.74	122.71
36	Gas		40,865					375,603	1,000,000	375,603	1,857,714	4.55	4.95
37	Plant Unit Info	250	40,911	22.0%	95.1%	97.8%	9,194			376,120	1,868,635	4.57	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,064	19.95	122.71
3	Gas		832,534					5,610,687	1,000,000	5,610,687	27,729,678	3.33	4.94
4	Plant Unit Info	1,212	832,785	92.4%	94.5%	92.3%	6,740			5,613,068	27,779,743	3.34	
5	*Sanford 4*												
6	Gas		412,378					3,072,914	1,000,000	3,072,914	15,193,554	3.68	4.94
7	Plant Unit Info	939	412,378	59.0%	94.9%	96.3%	7,452			3,072,914	15,193,554	3.68	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		428,612					263,567	16,999,973	4,480,632	11,191,917	2.61	42.46
13	Plant Unit Info	641	428,612	90.0%	94.4%	89.9%	10,454			4,480,632	11,191,917	2.61	
14	*St Johns 1*												
15	Coal		54,729					27,413	22,000,292	603,094	1,932,833	3.53	70.51
16	Plant Unit Info	127	54,729	58.0%	94.4%	58.0%	11,020			603,094	1,932,833	3.53	
17	*St Johns 2*												
18	Coal		67,606					33,500	22,000,149	737,005	2,362,015	3.49	70.51
19	Plant Unit Info	127	67,606	71.6%	94.4%	71.6%	10,901			737,005	2,362,015	3.49	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,751					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,751	23.5%	N/A	43.5%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		18,579					27,742	6,399,935	177,547	2,643,502	14.23	95.29
31	Gas		46,495					489,030	1,000,000	489,030	2,419,168	5.20	4.95
32	Plant Unit Info	379	65,074	23.1%	94.6%	81.3%	10,243			666,577	5,062,670	7.78	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,028	21.50	122.71
4	Gas		740,596					5,099,629	1,000,000	5,099,629	25,204,753	3.40	4.94
5	Plant Unit Info	1,138	740,838	87.5%	94.8%	94.0%	6,887			5,102,102	25,256,781	3.41	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,911	20.23	122.71
8	Gas		800,003					5,538,184	1,000,000	5,538,184	27,371,346	3.42	4.94
9	Plant Unit Info	1,166	800,225	92.3%	94.8%	92.2%	6,923			5,540,318	27,416,257	3.43	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,892	20.22	122.71
12	Gas		817,593					5,627,299	1,000,000	5,627,299	27,811,781	3.40	4.94
13	Plant Unit Info	1,159	817,820	94.9%	94.9%	94.8%	6,884			5,629,477	27,857,674	3.41	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,892	20.22	122.71
16	Gas		810,968					5,619,890	1,000,000	5,619,890	27,775,164	3.42	4.94
17	Plant Unit Info	1,166	811,195	93.5%	94.9%	93.5%	6,931			5,622,068	27,821,056	3.43	
18	**System Totals**												
19	Plant Unit Info	24,956	11,018,895				8,225			90,629,622	328,219,659	2.98	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,341	19.98	122.48
4	Gas		837,651					5,651,073	1,000,000	5,651,073	27,838,029	3.32	4.93
5	Plant Unit Info	1,210	837,903	93.1%	94.5%	93.0%	6,747			5,653,467	27,888,370	3.33	
6	*Desoto Solar*												
7	Solar		4,802					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,802	25.8%	N/A	47.7%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		735,620					5,303,497	1,000,000	5,303,497	26,130,761	3.55	4.93
18	Plant Unit Info	1,400	735,620	70.6%	95.0%	94.3%	7,210			5,303,497	26,130,761	3.55	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,619	22.18	122.48
21	Gas		28,566					313,649	1,000,000	313,649	1,546,082	5.41	4.93
22	Plant Unit Info	296	28,677	26.1%	95.1%	98.1%	10,978			314,819	1,570,702	5.48	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		755					16,511	1,000,000	16,511	81,309	10.77	4.92
26	Plant Unit Info	840	755	0.1%	95.3%	44.9%	21,869			16,511	81,309	10.77	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,477	22.75	122.48
29	Gas		85,917					686,968	1,000,000	686,968	3,387,096	3.94	4.93
30	Plant Unit Info	429	86,029	27.0%	94.8%	97.3%	7,999			688,180	3,412,572	3.97	
31	*Lauderdale 5*												
32	Light Oil		115					212	5,830,189	1,236	25,967	22.58	122.48
33	Gas		103,500					824,830	1,000,000	824,830	4,066,577	3.93	4.93
34	Plant Unit Info	429	103,615	32.5%	94.8%	97.7%	7,972			826,066	4,092,543	3.95	
35	*Manatee 1*												
36	Heavy Oil		16,265					31,599	6,400,076	202,236	3,007,365	18.49	95.17
37	Gas		40,105					420,039	1,000,000	420,039	2,069,175	5.16	4.93

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	56,370	9.6%	95.2%	87.2%	11,039			622,275	5,076,540	9.01	
2	*Manatee 2*												
3	Heavy Oil		6,403					11,846	6,400,135	75,816	1,127,417	17.61	95.17
4	Gas		10,148					106,200	1,000,000	106,200	523,157	5.16	4.93
5	Plant Unit Info	789	16,551	2.8%	95.2%	87.4%	10,997			182,016	1,650,574	9.97	
6	*Manatee 3*												
7	Gas		588,587					4,136,187	1,000,000	4,136,187	20,379,110	3.46	4.93
8	Plant Unit Info	1,078	588,587	73.4%	93.2%	94.3%	7,027			4,136,187	20,379,110	3.46	
9	*Martin 1*												
10	Heavy Oil		15,210					23,726	6,399,941	151,845	2,258,070	14.85	95.17
11	Gas		86,189					983,479	1,000,000	983,479	4,853,262	5.63	4.93
12	Plant Unit Info	799	101,399	17.1%	95.3%	71.7%	11,197			1,135,324	7,111,332	7.01	
13	*Martin 2*												
14	Heavy Oil		12,032					18,712	6,400,118	119,759	1,780,873	14.80	95.17
15	Gas		68,181					776,569	1,000,000	776,569	3,832,313	5.62	4.93
16	Plant Unit Info	799	80,213	13.5%	95.2%	71.7%	11,174			896,328	5,613,186	7.00	
17	*Martin 3*												
18	Gas		148,945					1,146,314	1,000,000	1,146,314	5,649,607	3.79	4.93
19	Plant Unit Info	438	148,945	45.7%	94.8%	97.7%	7,696			1,146,314	5,649,607	3.79	
20	*Martin 4*												
21	Gas		131,774					1,020,859	1,000,000	1,020,859	5,031,596	3.82	4.93
22	Plant Unit Info	437	131,774	40.6%	94.8%	97.7%	7,747			1,020,859	5,031,596	3.82	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,546	21.45	122.48
25	Gas		743,406					5,147,426	1,000,000	5,147,426	25,356,989	3.41	4.93
26	Plant Unit Info	1,111	743,651	90.0%	94.8%	89.9%	6,925			5,149,929	25,409,534	3.42	
27	*Martin 8 Solar*												
28	Solar		11,773					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	11,773	21.1%	N/A	39.0%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,779	23.43	122.48
32	Gas		27,104					255,570	1,000,000	255,570	1,260,285	4.65	4.93
33	Plant Unit Info	247	27,150	14.8%	95.1%	97.3%	9,432			256,086	1,271,064	4.68	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,901	23.70	122.48
36	Gas		31,763					293,580	1,000,000	293,580	1,447,537	4.56	4.93
37	Plant Unit Info	250	31,809	17.1%	95.1%	97.6%	9,246			294,097	1,458,438	4.58	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,973	19.91	122.48
3	Gas		833,741					5,619,403	1,000,000	5,619,403	27,682,018	3.32	4.93
4	Plant Unit Info	1,212	833,992	92.5%	94.5%	92.5%	6,741			5,621,784	27,731,991	3.33	
5	*Sanford 4*												
6	Gas		381,113					2,847,981	1,000,000	2,847,981	14,036,907	3.68	4.93
7	Plant Unit Info	939	381,113	54.6%	94.9%	97.8%	7,473			2,847,981	14,036,907	3.68	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		429,907					264,351	17,000,019	4,493,972	11,259,950	2.62	42.59
13	Plant Unit Info	641	429,907	90.2%	94.4%	90.2%	10,453			4,493,972	11,259,950	2.62	
14	*St Johns 1*												
15	Coal		52,949					26,614	21,999,662	585,499	1,883,487	3.56	70.77
16	Plant Unit Info	127	52,949	56.1%	94.4%	56.1%	11,058			585,499	1,883,487	3.56	
17	*St Johns 2*												
18	Coal		66,167					32,819	22,000,061	722,020	2,322,619	3.51	70.77
19	Plant Unit Info	127	66,167	70.1%	94.4%	70.1%	10,912			722,020	2,322,619	3.51	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,662					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,662	22.4%	N/A	41.3%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		18,005					27,036	6,400,059	173,032	2,573,092	14.29	95.17
31	Gas		34,699					370,831	1,000,000	370,831	1,828,968	5.27	4.93
32	Plant Unit Info	379	52,704	18.7%	94.6%	72.3%	10,319			543,863	4,402,060	8.35	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,933	21.46	122.48
4	Gas		795,378					5,467,325	1,000,000	5,467,325	26,932,858	3.39	4.93
5	Plant Unit Info	1,138	795,620	94.0%	94.8%	93.9%	6,875			5,469,798	26,984,791	3.39	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,829	20.19	122.48
8	Gas		802,480					5,555,294	1,000,000	5,555,294	27,366,206	3.41	4.93
9	Plant Unit Info	1,166	802,702	92.6%	94.8%	92.5%	6,923			5,557,428	27,411,035	3.41	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,809	20.18	122.48
12	Gas		795,756					5,477,161	1,000,000	5,477,161	26,981,312	3.39	4.93
13	Plant Unit Info	1,159	795,983	92.3%	94.9%	92.3%	6,884			5,479,339	27,027,121	3.40	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,809	20.18	122.48
16	Gas		811,797					5,624,653	1,000,000	5,624,653	27,707,878	3.41	4.93
17	Plant Unit Info	1,166	812,024	93.6%	94.9%	93.6%	6,929			5,626,831	27,753,686	3.42	
18	**System Totals**												
19	Plant Unit Info	24,973	11,265,248				8,135			91,637,471	330,199,286	2.93	
20													
21													
22													
23													
24													
25													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,958	20.22	123.99
4	Gas		811,270					5,473,519	1,000,000	5,473,519	26,846,156	3.31	4.90
5	Plant Unit Info	1,210	811,522	93.2%	94.5%	93.1%	6,748			5,475,913	26,897,115	3.31	
6	*Desoto Solar*												
7	Solar		4,271					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,271	23.7%	N/A	43.8%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		11,495					37,280	5,830,016	217,343	4,622,191	40.21	123.99
15	Plant Unit Info	648	11,495	2.5%	95.3%	42.2%	18,908			217,343	4,622,191	40.21	
16	*Fort Myers 2*												
17	Gas		743,033					5,347,104	1,000,000	5,347,104	26,230,933	3.53	4.91
18	Plant Unit Info	1,400	743,033	73.7%	95.0%	93.9%	7,196			5,347,104	26,230,933	3.53	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,921	22.45	123.99
21	Gas		35,091					384,793	1,000,000	384,793	1,888,725	5.38	4.91
22	Plant Unit Info	296	35,202	33.1%	95.1%	98.1%	10,964			385,963	1,913,646	5.44	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		5,454					121,606	1,000,000	121,606	596,446	10.94	4.90
26	Plant Unit Info	840	5,454	0.9%	95.3%	46.4%	22,297			121,606	596,446	10.94	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,789	23.03	123.99
29	Gas		98,846					787,134	1,000,000	787,134	3,864,380	3.91	4.91
30	Plant Unit Info	429	98,958	32.1%	94.8%	97.3%	7,966			788,346	3,890,169	3.93	
31	*Lauderdale 5*												
32	Light Oil		137					240	5,816,667	1,396	29,757	21.72	123.99
33	Gas		118,983					942,578	1,000,000	942,578	4,626,944	3.89	4.91
34	Plant Unit Info	429	119,120	38.6%	94.8%	97.7%	7,925			943,974	4,656,700	3.91	
35	*Manatee 1*												
36	Heavy Oil		27,733					57,592	6,399,951	368,586	5,501,265	19.84	95.52
37	Gas		104,851					1,097,970	1,000,000	1,097,970	5,385,251	5.14	4.90

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	132,584	23.4%	95.2%	85.3%	11,061			1,466,556	10,886,516	8.21	
2	*Manatee 2*												
3	Heavy Oil		19,675					41,898	6,400,043	268,149	4,002,153	20.34	95.52
4	Gas		77,616					812,474	1,000,000	812,474	3,984,969	5.13	4.90
5	Plant Unit Info	789	97,291	17.1%	95.2%	85.1%	11,107			1,080,623	7,987,122	8.21	
6	*Manatee 3*												
7	Gas		646,090					4,518,529	1,000,000	4,518,529	22,164,511	3.43	4.91
8	Plant Unit Info	1,078	646,090	83.2%	94.9%	95.2%	6,994			4,518,529	22,164,511	3.43	
9	*Martin 1*												
10	Heavy Oil		20,529					32,061	6,400,050	205,192	3,062,510	14.92	95.52
11	Gas		116,328					1,324,892	1,000,000	1,324,892	6,511,514	5.60	4.91
12	Plant Unit Info	799	136,857	23.8%	95.3%	72.0%	11,180			1,530,084	9,574,024	7.00	
13	*Martin 2*												
14	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		147,233					1,132,623	1,000,000	1,132,623	5,558,253	3.78	4.91
19	Plant Unit Info	438	147,233	46.7%	94.8%	97.7%	7,693			1,132,623	5,558,253	3.78	
20	*Martin 4*												
21	Gas		137,744					1,065,188	1,000,000	1,065,188	5,227,503	3.80	4.91
22	Plant Unit Info	437	137,744	43.8%	94.8%	97.7%	7,733			1,065,188	5,227,503	3.80	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	53,190	21.71	123.99
25	Gas		725,267					5,021,677	1,000,000	5,021,677	24,629,992	3.40	4.90
26	Plant Unit Info	1,111	725,512	90.7%	94.8%	90.6%	6,925			5,024,180	24,683,181	3.40	
27	*Martin 8 Solar*												
28	Solar		10,217					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	10,217	18.9%	N/A	37.8%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,911	23.72	123.99
32	Gas		35,937					337,089	1,000,000	337,089	1,655,155	4.61	4.91
33	Plant Unit Info	247	35,983	20.3%	95.1%	96.5%	9,382			337,605	1,666,066	4.63	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	11,035	23.99	123.99
36	Gas		41,606					382,774	1,000,000	382,774	1,879,253	4.52	4.91
37	Plant Unit Info	250	41,652	23.2%	95.1%	97.2%	9,202			383,291	1,890,288	4.54	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,586	20.15	123.99
3	Gas		807,164					5,440,514	1,000,000	5,440,514	26,684,276	3.31	4.90
4	Plant Unit Info	1,212	807,415	92.6%	94.5%	92.5%	6,741			5,442,895	26,734,862	3.31	
5	*Sanford 4*												
6	Gas		368,256					2,752,004	1,000,000	2,752,004	13,506,254	3.67	4.91
7	Plant Unit Info	939	368,256	54.5%	94.9%	97.8%	7,473			2,752,004	13,506,254	3.67	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		418,248					257,159	16,999,996	4,371,702	10,965,875	2.62	42.64
13	Plant Unit Info	641	418,248	90.7%	94.4%	90.7%	10,452			4,371,702	10,965,875	2.62	
14	*St Johns 1*												
15	Coal		52,049					26,126	21,999,809	574,767	1,852,038	3.56	70.89
16	Plant Unit Info	127	52,049	57.0%	94.4%	57.0%	11,043			574,767	1,852,038	3.56	
17	*St Johns 2*												
18	Coal		63,968					31,779	22,000,346	699,149	2,252,772	3.52	70.89
19	Plant Unit Info	127	63,968	70.0%	94.4%	70.0%	10,930			699,149	2,252,772	3.52	
20	*St Lucie 1*												
21	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,635,300	0.67	0.64
22	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,635,300	0.67	
23	*St Lucie 2*												
24	Nuclear		117,936					1,237,824	1,000,000	1,237,824	769,600	0.65	0.62
25	Plant Unit Info	840	117,936	19.5%	19.5%	97.5%	10,496			1,237,824	769,600	0.65	
26	*Space Coast*												
27	Solar		1,472					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,472	20.5%	N/A	37.8%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		22,070					32,926	6,399,897	210,723	3,145,136	14.25	95.52
31	Gas		45,767					482,228	1,000,000	482,228	2,368,187	5.17	4.91
32	Plant Unit Info	379	67,837	24.8%	94.6%	82.0%	10,215			692,951	5,513,323	8.13	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,570	21.72	123.99
4	Gas		743,930					5,116,691	1,000,000	5,116,691	25,096,516	3.37	4.90
5	Plant Unit Info	1,138	744,172	90.8%	94.8%	94.4%	6,879			5,119,164	25,149,086	3.38	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	45,379	20.44	123.99
8	Gas		776,157					5,373,097	1,000,000	5,373,097	26,353,612	3.40	4.90
9	Plant Unit Info	1,166	776,379	92.5%	94.8%	92.5%	6,923			5,375,231	26,398,991	3.40	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	46,371	20.43	123.99
12	Gas		769,936					5,299,131	1,000,000	5,299,131	25,990,830	3.38	4.90
13	Plant Unit Info	1,159	770,163	92.3%	94.9%	92.2%	6,883			5,301,309	26,037,200	3.38	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	46,371	20.43	123.99
16	Gas		494,821					3,454,595	1,000,000	3,454,595	16,943,872	3.42	4.90
17	Plant Unit Info	1,166	495,048	59.0%	66.0%	69.3%	6,983			3,456,773	16,990,243	3.43	
18	**System Totals**												
19	Plant Unit Info	24,973	10,457,487				8,112			84,828,065	327,759,208	3.13	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		836,187					5,640,354	1,000,000	5,640,354	28,522,644	3.41	5.06
5	Plant Unit Info	1,210	836,439	93.0%	94.5%	92.9%	6,746			5,642,748	28,573,054	3.42	
6	*Desoto Solar*												
7	Solar		4,123					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,123	22.2%	N/A	40.9%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		778,931					5,595,160	1,000,000	5,595,160	28,298,274	3.63	5.06
18	Plant Unit Info	1,400	778,931	74.8%	95.0%	92.1%	7,183			5,595,160	28,298,274	3.63	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		15,984					200,570	1,000,000	200,570	1,015,341	6.35	5.06
22	Plant Unit Info	296	16,095	14.6%	59.7%	68.4%	12,535			201,740	1,039,995	6.46	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		69,234					555,012	1,000,000	555,012	2,810,134	4.06	5.06
30	Plant Unit Info	429	69,346	21.8%	94.8%	97.3%	8,021			556,224	2,835,645	4.09	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		104,163					823,264	1,000,000	823,264	4,166,655	4.00	5.06
34	Plant Unit Info	429	104,276	32.7%	94.8%	96.4%	7,907			824,482	4,192,290	4.02	
35	*Manatee 1*												
36	Heavy Oil		18,850					34,292	6,400,035	219,470	3,272,929	17.36	95.44
37	Gas		25,933					276,586	1,000,000	276,586	1,398,665	5.39	5.06

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	44,783	7.6%	95.2%	60.4%	11,077			496,056	4,671,595	10.43	
2	*Manatee 2*												
3	Heavy Oil		11,210					19,304	6,399,865	123,543	1,842,431	16.44	95.44
4	Gas		4,193					43,813	1,000,000	43,813	221,556	5.28	5.06
5	Plant Unit Info	789	15,403	2.6%	95.2%	81.4%	10,865			167,356	2,063,987	13.40	
6	*Manatee 3*												
7	Gas		592,399					4,155,277	1,000,000	4,155,277	21,016,737	3.55	5.06
8	Plant Unit Info	1,078	592,399	73.8%	94.9%	94.7%	7,014			4,155,277	21,016,737	3.55	
9	*Martin 1*												
10	Heavy Oil		13,037					20,520	6,400,049	131,329	1,958,489	15.02	95.44
11	Gas		56,707					659,811	1,000,000	659,811	3,345,443	5.90	5.07
12	Plant Unit Info	799	69,744	11.7%	95.3%	59.4%	11,344			791,140	5,303,933	7.60	
13	*Martin 2*												
14	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		131,825					1,014,204	1,000,000	1,014,204	5,131,907	3.89	5.06
19	Plant Unit Info	438	131,825	40.5%	91.6%	97.7%	7,694			1,014,204	5,131,907	3.89	
20	*Martin 4*												
21	Gas		62,049					491,271	1,000,000	491,271	2,486,566	4.01	5.06
22	Plant Unit Info	437	62,049	19.1%	60.9%	74.4%	7,917			491,271	2,486,566	4.01	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		740,364					5,125,097	1,000,000	5,125,097	25,917,047	3.50	5.06
26	Plant Unit Info	1,111	740,609	89.6%	94.8%	89.5%	6,923			5,127,600	25,969,665	3.51	
27	*Martin 8 Solar*												
28	Solar		8,981					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	8,981	16.1%	N/A	24.1%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		22,573					212,843	1,000,000	212,843	1,077,765	4.77	5.06
33	Plant Unit Info	247	22,619	12.4%	95.1%	97.4%	9,433			213,359	1,088,559	4.81	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		26,235					243,228	1,000,000	243,228	1,231,573	4.69	5.06
37	Plant Unit Info	250	26,281	14.2%	95.1%	97.1%	9,275			243,745	1,242,489	4.73	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		832,262					5,608,614	1,000,000	5,608,614	28,362,141	3.41	5.06
4	Plant Unit Info	1,212	832,513	92.4%	94.5%	92.3%	6,740			5,610,995	28,412,183	3.41	
5	*Sanford 4*												
6	Gas		335,196					2,506,462	1,000,000	2,506,462	12,683,957	3.78	5.06
7	Plant Unit Info	939	335,196	48.0%	94.9%	97.8%	7,478			2,506,462	12,683,957	3.78	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		429,486					264,128	17,000,027	4,490,183	11,261,606	2.62	42.64
13	Plant Unit Info	641	429,486	90.1%	94.4%	90.1%	10,455			4,490,183	11,261,606	2.62	
14	*St Johns 1*												
15	Coal		51,126					25,803	22,000,233	567,672	1,833,108	3.59	71.04
16	Plant Unit Info	127	51,126	54.2%	94.4%	54.2%	11,103			567,672	1,833,108	3.59	
17	*St Johns 2*												
18	Coal		64,474					32,058	21,999,875	705,272	2,277,479	3.53	71.04
19	Plant Unit Info	127	64,474	68.3%	94.4%	68.3%	10,939			705,272	2,277,479	3.53	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		452,088					4,744,989	1,000,000	4,744,989	3,103,200	0.69	0.65
25	Plant Unit Info	840	452,088	72.3%	72.3%	97.5%	10,496			4,744,989	3,103,200	0.69	
26	*Space Coast*												
27	Solar		1,418					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,418	19.1%	N/A	38.1%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		12,268					18,430	6,399,891	117,950	1,759,013	14.34	95.44
31	Gas		24,988					267,554	1,000,000	267,554	1,355,278	5.42	5.07
32	Plant Unit Info	379	37,256	13.2%	94.6%	70.6%	10,347			385,504	3,114,291	8.36	
33	*Turkey Point 3*												
34	Nuclear		341,592					3,813,961	1,000,000	3,813,961	2,571,800	0.75	0.67
35	Plant Unit Info	811	341,592	56.6%	56.6%	97.5%	11,165			3,813,961	2,571,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		757,702					5,215,766	1,000,000	5,215,766	26,376,324	3.48	5.06
5	Plant Unit Info	1,138	757,944	89.5%	94.8%	93.0%	6,885			5,218,239	26,428,329	3.49	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		791,910					5,484,321	1,000,000	5,484,321	27,733,603	3.50	5.06
9	Plant Unit Info	1,166	792,132	91.3%	94.8%	91.3%	6,926			5,486,455	27,778,494	3.51	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		181,834					1,269,532	1,000,000	1,269,532	6,419,882	3.53	5.06
13	Plant Unit Info	1,159	182,061	21.2%	22.9%	59.6%	6,985			1,271,710	6,465,755	3.55	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		766,319					5,312,941	1,000,000	5,312,941	26,866,953	3.51	5.06
17	Plant Unit Info	1,166	766,546	88.4%	92.7%	91.3%	6,934			5,315,119	26,912,825	3.51	
18	**System Totals**												
19	Plant Unit Info	24,973	9,874,911				8,073			79,719,980	295,910,921	3.00	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		888,714					5,962,540	1,000,000	5,962,540	31,306,098	3.52	5.25
5	Plant Unit Info	1,355	888,966	91.2%	94.5%	91.1%	6,710			5,964,934	31,356,508	3.53	
6	*Desoto Solar*												
7	Solar		3,550					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,550	19.7%	N/A	43.0%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		643,114					4,605,326	1,000,000	4,605,326	24,186,241	3.76	5.25
18	Plant Unit Info	1,476	643,114	60.5%	95.0%	87.0%	7,161			4,605,326	24,186,241	3.76	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		2,745					29,640	1,000,000	29,640	155,784	5.68	5.26
22	Plant Unit Info	314	2,856	2.6%	61.8%	97.0%	10,788			30,810	180,437	6.32	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		19,599					157,127	1,000,000	157,127	826,190	4.22	5.26
30	Plant Unit Info	442	19,711	6.2%	94.8%	90.6%	8,033			158,339	851,702	4.32	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		25,139					201,543	1,000,000	201,543	1,059,795	4.22	5.26
34	Plant Unit Info	442	25,252	8.0%	94.8%	89.0%	8,030			202,761	1,085,430	4.30	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		568,135					3,929,834	1,000,000	3,929,834	20,637,532	3.63	5.25
8	Plant Unit Info	1,134	568,135	69.6%	94.9%	89.8%	6,917			3,929,834	20,637,532	3.63	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	48.6%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		37,736					293,238	1,000,000	293,238	1,541,198	4.08	5.26
19	Plant Unit Info	454	37,736	11.5%	63.2%	81.5%	7,771			293,238	1,541,198	4.08	
20	*Martin 4*												
21	Gas		21,002					172,129	1,000,000	172,129	905,318	4.31	5.26
22	Plant Unit Info	453	21,002	6.4%	94.8%	48.8%	8,196			172,129	905,318	4.31	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		680,085					4,677,395	1,000,000	4,677,395	24,559,112	3.61	5.25
26	Plant Unit Info	1,147	680,330	82.5%	94.8%	84.7%	6,879			4,679,898	24,611,730	3.62	
27	*Martin 8 Solar*												
28	Solar		6,459					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	6,459	12.0%	N/A	19.1%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		2,193					21,931	1,000,000	21,931	115,448	5.26	5.26
33	Plant Unit Info	251	2,239	1.3%	95.1%	58.3%	10,024			22,447	126,241	5.64	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		2,976					28,602	1,000,000	28,602	150,474	5.06	5.26
37	Plant Unit Info	255	3,022	1.7%	95.1%	73.0%	9,636			29,119	161,390	5.34	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		887,760					5,946,183	1,000,000	5,946,183	31,220,216	3.52	5.25
4	Plant Unit Info	1,344	888,011	91.8%	94.5%	91.7%	6,699			5,948,564	31,270,258	3.52	
5	*Sanford 4*												
6	Gas		186,601					1,400,534	1,000,000	1,400,534	7,360,719	3.94	5.26
7	Plant Unit Info	990	186,601	26.2%	61.6%	92.0%	7,505			1,400,534	7,360,719	3.94	
8	*Sanford 5*												
9	Gas		270,302					2,017,358	1,000,000	2,017,358	10,600,450	3.92	5.25
10	Plant Unit Info	994	270,302	37.8%	61.6%	88.3%	7,463			2,017,358	10,600,450	3.92	
11	*Scherer 4*												
12	Coal		421,907					257,346	17,000,004	4,374,883	10,977,550	2.60	42.66
13	Plant Unit Info	646	421,907	90.8%	94.4%	90.8%	10,369			4,374,883	10,977,550	2.60	
14	*St Johns 1*												
15	Coal		39,676					21,088	22,000,379	463,944	1,499,951	3.78	71.13
16	Plant Unit Info	128	39,676	43.0%	94.4%	43.0%	11,693			463,944	1,499,951	3.78	
17	*St Johns 2*												
18	Coal		46,492					23,696	21,999,578	521,302	1,685,453	3.63	71.13
19	Plant Unit Info	128	46,492	50.4%	94.4%	50.4%	11,213			521,302	1,685,453	3.63	
20	*St Lucie 1*												
21	Nuclear		704,105					7,272,165	1,000,000	7,272,165	4,635,300	0.66	0.64
22	Plant Unit Info	1,003	704,105	97.5%	97.5%	97.5%	10,328			7,272,165	4,635,300	0.66	
23	*St Lucie 2*												
24	Nuclear		603,721					6,192,164	1,000,000	6,192,164	4,049,700	0.67	0.65
25	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,257			6,192,164	4,049,700	0.67	
26	*Space Coast*												
27	Solar		1,212					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,212	16.8%	N/A	36.7%	N/A			0	0	0.00	
29	*Turkey Point 1*												
30	Heavy Oil		0					0	0	0	0	0.00	0.00
31	Gas		1,219					13,881	1,000,000	13,881	73,063	5.99	5.26
32	Plant Unit Info	380	1,219	0.5%	94.6%	40.1%	11,384			13,881	73,063	5.99	
33	*Turkey Point 3*												
34	Nuclear		255,223					2,754,528	1,000,000	2,754,528	1,921,800	0.75	0.70
35	Plant Unit Info	839	255,223	42.3%	42.3%	97.5%	10,793			2,754,528	1,921,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,298					6,356,602	1,000,000	6,356,602	4,222,700	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	848	595,298	97.5%	97.5%	97.5%	10,678			6,356,602	4,222,700	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		141,911					993,719	1,000,000	993,719	5,219,084	3.68	5.25
5	Plant Unit Info	1,166	142,153	17.0%	94.8%	88.8%	7,008			996,192	5,271,089	3.71	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		754,463					5,143,450	1,000,000	5,143,450	27,005,498	3.58	5.25
9	Plant Unit Info	1,208	754,685	86.9%	94.8%	89.0%	6,818			5,145,584	27,050,389	3.58	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		226,910					1,565,302	1,000,000	1,565,302	8,218,559	3.62	5.25
13	Plant Unit Info	1,202	227,137	26.3%	36.0%	64.6%	6,901			1,567,480	8,264,431	3.64	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		664,522					4,532,598	1,000,000	4,532,598	23,798,240	3.58	5.25
17	Plant Unit Info	1,207	664,749	76.5%	94.9%	87.1%	6,822			4,534,776	23,844,112	3.59	
18	**System Totals**												
19	Plant Unit Info	25,993	8,704,863				8,001			69,648,792	248,370,692	2.85	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		894,837					5,998,542	1,000,000	5,998,542	32,408,512	3.62	5.40
5	Plant Unit Info	1,355	895,089	88.8%	94.5%	88.8%	6,704			6,000,936	32,458,922	3.63	
6	*Desoto Solar*												
7	Solar		3,223					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,223	17.3%	N/A	37.8%	N/A			0	0	0.00	
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		348,379					2,516,749	1,000,000	2,516,749	13,605,708	3.91	5.41
18	Plant Unit Info	1,476	348,379	31.7%	95.0%	84.0%	7,224			2,516,749	13,605,708	3.91	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	95.1%	70.6%	10,541			1,170	24,653	22.21	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	112	0.1%	94.8%	25.4%	10,821			1,212	25,512	22.78	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	442	113	0.1%	94.8%	25.4%	10,779			1,218	25,634	22.69	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		440,454					3,072,274	1,000,000	3,072,274	16,607,563	3.77	5.41
8	Plant Unit Info	1,134	440,454	52.2%	94.9%	88.9%	6,975			3,072,274	16,607,563	3.77	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	95.2%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		17,432					133,440	1,000,000	133,440	721,199	4.14	5.40
19	Plant Unit Info	454	17,432	5.2%	94.8%	75.3%	7,655			133,440	721,199	4.14	
20	*Martin 4*												
21	Gas		8,502					65,190	1,000,000	65,190	352,331	4.14	5.40
22	Plant Unit Info	453	8,502	2.5%	94.8%	75.1%	7,667			65,190	352,331	4.14	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		608,368					4,194,646	1,000,000	4,194,646	22,665,629	3.73	5.40
26	Plant Unit Info	1,147	608,613	71.4%	94.8%	79.7%	6,896			4,197,149	22,718,247	3.73	
27	*Martin 8 Solar*												
28	Solar		5,345					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	5,345	9.6%	N/A	19.2%	N/A			0	0	0.00	
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	251	46	0.1%	95.1%	17.9%	11,217			516	10,793	23.46	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	255	46	0.1%	95.1%	17.7%	11,239			517	10,916	23.73	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		903,643					6,044,727	1,000,000	6,044,727	32,658,033	3.61	5.40
4	Plant Unit Info	1,344	903,894	90.4%	94.5%	90.4%	6,690			6,047,108	32,708,076	3.62	
5	*Sanford 4*												
6	Gas		72,242					539,164	1,000,000	539,164	2,915,055	4.04	5.41
7	Plant Unit Info	990	72,242	9.8%	94.9%	77.7%	7,463			539,164	2,915,055	4.04	
8	*Sanford 5*												
9	Gas		98,641					740,280	1,000,000	740,280	4,003,347	4.06	5.41
10	Plant Unit Info	994	98,641	13.3%	95.0%	78.1%	7,505			740,280	4,003,347	4.06	
11	*Scherer 4*												
12	Coal		453,573					276,491	16,999,975	4,700,340	11,803,124	2.60	42.69
13	Plant Unit Info	646	453,573	94.4%	94.4%	94.4%	10,363			4,700,340	11,803,124	2.60	
14	*St Johns 1*												
15	Coal		44,163					23,038	21,999,913	506,834	1,638,024	3.71	71.10
16	Plant Unit Info	128	44,163	46.3%	94.4%	46.3%	11,476			506,834	1,638,024	3.71	
17	*St Johns 2*												
18	Coal		46,096					23,667	22,000,254	520,680	1,682,746	3.65	71.10
19	Plant Unit Info	128	46,096	48.3%	94.4%	48.3%	11,296			520,680	1,682,746	3.65	
20	*St Lucie 1*												
21	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,789,800	0.66	0.64
22	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,789,800	0.66	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	4,184,700	0.67	0.65
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	4,184,700	0.67	
26	*Space Coast*												
27	Solar		1,072					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,072	14.4%	N/A	34.6%	N/A			0	0	0.00	
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,582,800	0.75	0.70
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,582,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITH GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		400,920					2,823,481	1,000,000	2,823,481	15,262,770	3.81	5.41
5	Plant Unit Info	1,166	401,162	46.3%	94.8%	89.8%	7,044			2,825,954	15,314,775	3.82	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		764,118					5,212,872	1,000,000	5,212,872	28,163,745	3.69	5.40
9	Plant Unit Info	1,208	764,340	85.1%	94.8%	86.0%	6,823			5,215,006	28,208,636	3.69	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		746,954					5,093,750	1,000,000	5,093,750	27,520,160	3.68	5.40
13	Plant Unit Info	1,202	747,181	83.6%	94.9%	83.5%	6,820			5,095,928	27,566,032	3.69	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		600,195					4,092,828	1,000,000	4,092,828	22,112,449	3.68	5.40
17	Plant Unit Info	1,207	600,422	66.9%	94.9%	85.6%	6,820			4,095,006	22,158,321	3.69	
18	**System Totals**												
19	Plant Unit Info	25,993	9,035,423				8,115			73,326,781	252,480,315	2.79	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
(WITH GAS RESERVES)

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	2015
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	145,000	0	0	0	0	0	145,000	145,000	0	145,000	0	0	580,000
4	Unit Cost	97.8739	0.0000	0.0000	0.0000	0.0000	0.0000	96.6389	95.6389	0.0000	95.6389	0.0000	0.0000	96.4477
5	Amount	$14,191,719	$0	$0	$0	$0	$0	$14,012,644	$13,867,644	$0	$13,867,644	$0	$0	$55,939,651
6	Burned													
7	Units	152,345	0	865	17,143	7,772	74,814	140,472	112,919	164,477	92,546	0	0	763,353
8	Unit Cost	94.8247	0.0000	94.5275	95.4164	94.8579	95.3089	95.2888	95.1728	95.5213	95.4429	0.0000	0.0000	95.2474
9	Amount	$14,446,069	$0	$81,766	$1,635,724	$737,235	$7,130,438	$13,385,409	$10,746,818	$15,711,063	$8,832,863	$0	$0	$72,707,385
10	Ending Inventory													
11	Units	2,668,320	2,668,320	2,667,455	2,650,312	2,642,540	2,567,726	2,572,254	2,604,335	2,439,858	2,492,312	2,492,312	2,492,312	2,492,312
12	Unit Cost	95.4061	95.4061	95.4063	95.4063	95.4079	95.4108	95.4867	95.5088	95.5079	95.5179	95.5179	95.5179	95.5179
13	Amount	$254,573,884	$254,573,884	$254,492,118	$252,856,394	$252,119,159	$244,988,721	$245,615,956	$248,736,782	$233,025,719	$238,060,500	$238,060,500	$238,060,500	$238,060,500
14	**#2 Light Oil (BBLS)**													
15	Purchases													
16	Units	10,674	0	0	5,204	0	0	13,932	0	37,682	15,164	133,000	0	215,656
17	Unit Cost	134.8278	0.0000	0.0000	133.7190	0.0000	0.0000	132.5178	0.0000	132.3876	132.3540	132.3330	0.0000	132.5129
18	Amount	$1,439,152	$0	$0	$695,874	$0	$0	$1,846,238	$0	$4,988,628	$2,007,016	$17,600,285	$0	$28,577,192
19	Burned													
20	Units	3,581	3,152	3,581	3,581	3,581	3,581	7,537	3,584	40,892	3,581	3,581	3,581	83,813
21	Unit Cost	122.2746	121.9321	122.2746	122.4634	122.4634	122.4634	122.7068	122.4837	123.9858	122.6526	122.6526	122.6526	123.2171
22	Amount	$437,865	$384,330	$437,865	$438,541	$438,541	$438,541	$924,841	$438,982	$5,070,027	$439,219	$439,219	$439,219	$10,327,193
23	Ending Inventory													
24	Units	1,285,378	1,282,226	1,278,645	1,280,268	1,276,687	1,273,106	1,279,501	1,275,917	1,272,707	1,284,290	1,413,709	1,410,128	1,410,128
25	Unit Cost	120.7809	120.7781	120.7739	120.8218	120.8172	120.8125	120.9288	120.9245	121.1655	121.2935	122.3286	122.3278	122.3278
26	Amount	$155,249,118	$154,864,788	$154,426,923	$154,684,255	$154,245,714	$153,807,172	$154,728,568	$154,289,587	$154,208,188	$155,775,984	$172,937,050	$172,497,831	$172,497,831
27	**Coal - SJRPP (TONS)**													
28	Purchases													
29	Units	49,385	49,385	49,385	49,385	49,385	49,385	49,385	49,385	49,385	49,385	49,385	49,385	592,617
30	Unit Cost	70.1272	70.3707	69.1533	70.0920	70.0920	70.9896	70.6992	71.1436	71.0325	71.2030	71.2030	71.0747	70.5984
31	Amount	$3,463,214	$3,475,238	$3,415,120	$3,461,476	$3,461,476	$3,505,804	$3,491,462	$3,513,409	$3,507,922	$3,516,342	$3,516,342	$3,510,005	$41,837,810
32	Burned													
33	Units	59,679	41,429	25,488	29,674	52,047	56,699	60,913	59,433	57,905	57,861	44,784	46,705	592,617
34	Unit Cost	71.5351	70.8924	70.0109	70.0439	70.0607	70.3922	70.5079	70.7705	70.8887	71.0424	71.1282	71.1010	70.7526
35	Amount	$4,269,143	$2,937,001	$1,784,438	$2,078,483	$3,646,452	$3,991,170	$4,294,848	$4,206,106	$4,104,811	$4,110,587	$3,185,404	$3,320,770	$41,929,212
36	Ending Inventory													
37	Units	40,088	48,044	71,940	91,651	88,989	81,675	70,146	60,098	51,578	43,102	47,702	50,382	50,382
38	Unit Cost	71.5351	70.8924	70.0109	70.0439	70.0607	70.3922	70.5079	70.7705	70.8887	71.0424	71.1282	71.1010	71.1010
39	Amount	$2,867,681	$3,405,918	$5,036,601	$6,419,594	$6,234,618	$5,749,252	$4,945,866	$4,253,168	$3,656,280	$3,062,036	$3,392,974	$3,582,208	$3,582,208
40														

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
(WITH GAS RESERVES)

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	2015
1	**Coal - Scherer (MMBTU)**													
2	Purchases													
3	Units	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	4,444,912	53,338,942
4	Unit Cost	2.4907	2.4906	2.4913	2.4890	2.4919	2.4945	2.5054	2.5144	2.5116	2.5077	2.5106	2.5133	2.5009
5	Amount	$11,071,128	$11,070,439	$11,073,736	$11,063,301	$11,076,346	$11,087,981	$11,136,294	$11,176,369	$11,163,683	$11,146,396	$11,159,206	$11,171,483	$133,396,361
6	Burned													
7	Units	4,700,340	4,225,428	4,604,287	4,184,444	4,389,408	4,323,323	4,480,632	4,493,972	4,371,702	4,490,183	4,374,883	4,700,340	53,338,942
8	Unit Cost	2.4561	2.4730	2.4818	2.4853	2.4884	2.4913	2.4978	2.5056	2.5084	2.5081	2.5092	2.5111	2.4930
9	Amount	$11,544,604	$10,449,482	$11,426,752	$10,399,493	$10,922,674	$10,770,663	$11,191,917	$11,259,950	$10,965,875	$11,261,606	$10,977,550	$11,803,124	$132,973,689
10	Ending Inventory													
11	Units	4,631,584	4,851,068	4,691,692	4,952,160	5,007,664	5,129,253	5,093,533	5,044,473	5,117,682	5,072,411	5,142,440	4,887,012	4,887,012
12	Unit Cost	2.4561	2.4730	2.4818	2.4853	2.4884	2.4913	2.4978	2.5056	2.5084	2.5081	2.5092	2.5111	2.5111
13	Amount	$11,375,731	$11,996,688	$11,643,672	$12,307,479	$12,461,152	$12,778,470	$12,722,847	$12,639,266	$12,837,075	$12,721,864	$12,903,520	$12,271,879	$12,271,879
14	**Gas (MCF)**													
15	Burned													
16	Units	37,768,177	34,796,530	41,211,755	46,716,771	49,071,858	52,661,957	56,818,936	58,045,397	56,668,209	50,701,681	41,692,330	40,527,942	566,681,542
17	Unit Cost	5.4704	5.4428	5.3133	5.0780	5.0691	4.9688	4.9431	4.9270	4.9056	5.0578	5.2513	5.4036	5.1207
18	Amount	$206,606,543	$189,390,015	$218,971,503	$237,229,300	$248,751,780	$261,664,395	$280,864,244	$285,989,031	$277,993,532	$256,438,447	$218,939,019	$218,996,502	$2,901,834,310
19	**Nuclear (Other)**													
20	Burned													
21	Units	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
22	Unit Cost	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
23	Amount	$17,769,900	$16,050,300	$16,318,500	$13,283,900	$17,558,400	$16,992,100	$17,558,400	$17,558,400	$13,913,900	$14,828,200	$14,829,500	$17,920,700	$194,582,200
24														
25	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
POWER SOLD
(WITH GAS RESERVES)

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	300,000	300,000	3.354	4.579	$10,062,000	$13,737,000	$2,900,000
4	St Lucie Reliability Sales		54,189	54,189	0.750	0.750	$406,318	$406,318	$0
5	**Total January Estimated**		354,189	354,189	2.956	3.993	$10,468,318	$14,143,318	$2,900,000
6									
7	**February Estimated**								
8	Off System	OS	270,000	270,000	3.219	4.452	$8,690,300	$12,020,300	$2,620,000
9	St Lucie Reliability Sales		48,945	48,945	0.750	0.750	$366,998	$366,998	$0
10	**Total February Estimated**		318,945	318,945	2.840	3.884	$9,057,298	$12,387,298	$2,620,000
11									
12	**March Estimated**								
13	Off System	OS	255,000	255,000	3.478	4.690	$8,870,100	$11,960,100	$2,418,750
14	St Lucie Reliability Sales		38,457	38,457	0.750	0.750	$288,356	$288,356	$0
15	**Total March Estimated**		293,457	293,457	3.121	4.174	$9,158,456	$12,248,456	$2,418,750
16									
17	**April Estimated**								
18	Off System	OS	105,000	105,000	5.119	6.195	$5,374,500	$6,504,500	$840,000
19	St Lucie Reliability Sales		10,258	10,258	0.767	0.767	$78,643	$78,643	$0
20	**Total April Estimated**		115,258	115,258	4.731	5.712	$5,453,143	$6,583,143	$840,000
21									
22	**May Estimated**								
23	Off System	OS	95,000	95,000	4.878	5.959	$4,634,500	$5,660,750	$760,000
24	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
25	**Total May Estimated**		147,999	147,999	3.406	4.099	$5,040,818	$6,067,068	$760,000
26									
27	**June Estimated**								
28	Off System	OS	75,000	75,000	3.213	4.518	$2,409,600	$3,388,350	$772,500
29	St Lucie Reliability Sales		51,289	51,289	0.767	0.767	$393,211	$393,211	$0
30	**Total June Estimated**		126,289	126,289	2.219	2.994	$2,802,811	$3,781,561	$772,500
31									
32	**6 Month Period**								
33	Off System	OS	1,100,000	1,100,000	3.640	4.843	$40,041,000	$53,271,000	$10,311,250
34	St Lucie Reliability Sales		256,137	256,137	0.757	0.757	$1,939,844	$1,939,844	$0
35	**Total 6 Month Period**		1,356,137	1,356,137	3.096	4.071	$41,980,844	$55,210,844	$10,311,250
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
POWER SOLD
(WITH GAS RESERVES)

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	80,000	80,000	8.242	9.598	$6,593,400	$7,678,400	$870,000
4	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
5	**Total July Estimated**		132,999	132,999	5.263	6.079	$6,999,718	$8,084,718	$870,000
6									
7	**August Estimated**								
8	Off System	OS	80,000	80,000	6.765	8.049	$5,412,000	$6,439,500	$825,000
9	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
10	**Total August Estimated**		132,999	132,999	4.375	5.147	$5,818,318	$6,845,818	$825,000
11									
12	**September Estimated**								
13	Off System	OS	65,000	65,000	10.175	11.389	$6,613,950	$7,402,700	$612,500
14	St Lucie Reliability Sales		51,289	51,289	0.767	0.767	$393,211	$393,211	$0
15	**Total September Estimated**		116,289	116,289	6.026	6.704	$7,007,161	$7,795,911	$612,500
16									
17	**October Estimated**								
18	Off System	OS	80,000	80,000	5.652	6.677	$4,521,800	$5,341,800	$617,500
19	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
20	**Total October Estimated**		132,999	132,999	3.705	4.322	$4,928,118	$5,748,118	$617,500
21									
22	**November Estimated**								
23	Off System	OS	160,000	160,000	3.003	3.966	$4,804,800	$6,344,800	$1,135,000
24	St Lucie Reliability Sales		52,441	52,441	0.750	0.750	$393,211	$393,211	$0
25	**Total November Estimated**		212,441	212,441	2.447	3.172	$5,198,011	$6,738,011	$1,135,000
26									
27	**December Estimated**								
28	Off System	OS	185,000	185,000	2.967	4.059	$5,488,450	$7,508,450	$1,540,000
29	St Lucie Reliability Sales		54,189	54,189	0.750	0.750	$406,318	$406,318	$0
30	**Total December Estimated**		239,189	239,189	2.464	3.309	$5,894,768	$7,914,768	$1,540,000
31									
32	**12 Month Period**								
33	Off System	OS	1,750,000	1,750,000	4.199	5.371	$73,475,400	$93,986,650	$15,911,250
34	St Lucie Reliability Sales		573,053	573,053	0.759	0.759	$4,351,540	$4,351,540	$0
35	**Total 12 Month Period**		2,323,053	2,323,053	3.350	4.233	$77,826,940	$98,338,190	$15,911,250
36									
37									
38	Note: Totals may not add due to rounding.								

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
(WITH GAS RESERVES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	**January Estimated**					
3	UPS		103,656	103,656	4.052	$4,200,614
4	SJRPP		175,723	175,723	3.498	$6,147,000
5	St Lucie Reliability		46,461	46,461	0.736	$342,127
6	**Total January Estimated**		325,840	325,840	3.281	$10,689,741
7						
8	**February Estimated**					
9	UPS		88,070	88,070	4.240	$3,734,138
10	SJRPP		117,159	117,159	3.670	$4,300,000
11	St Lucie Reliability		41,965	41,965	0.736	$309,019
12	**Total February Estimated**		247,194	247,194	3.375	$8,343,156
13						
14	**March Estimated**					
15	UPS		116,799	116,799	4.112	$4,802,648
16	SJRPP		84,444	84,444	3.536	$2,986,000
17	St Lucie Reliability		46,461	46,461	0.736	$342,127
18	**Total March Estimated**		247,704	247,704	3.282	$8,130,775
19						
20	**April Estimated**					
21	UPS		168,116	168,116	4.104	$6,899,678
22	SJRPP		86,314	86,314	3.603	$3,110,000
23	St Lucie Reliability		43,917	43,917	0.753	$330,769
24	**Total April Estimated**		298,347	298,347	3.466	$10,340,447
25						
26	**May Estimated**					
27	UPS		165,461	165,461	4.100	$6,783,494
28	SJRPP		165,645	165,645	3.561	$5,899,000
29	St Lucie Reliability		45,381	45,381	0.753	$341,795
30	**Total May Estimated**		376,487	376,487	3.459	$13,024,289
31						
32	**June Estimated**					
33	UPS		218,373	218,373	4.029	$8,798,476
34	SJRPP		183,628	183,628	3.552	$6,523,000
35	St Lucie Reliability		43,917	43,917	0.753	$330,769
36	**Total June Estimated**		445,918	445,918	3.510	$15,652,245
37						
38	**6 Month Period**					
39	UPS		860,475	860,475	4.093	$35,219,047
40	SJRPP		812,913	812,913	3.563	$28,965,000
41	St Lucie Reliability		268,101	268,101	0.745	$1,996,607
42	**Total 6 Month Period**		1,941,489	1,941,489	3.409	$66,180,654
43						
44						
45						
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FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
(WITH GAS RESERVES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	UPS		240,256	240,256	4.018	$9,652,849
4	SJRPP		197,889	197,889	3.522	$6,969,000
5	St Lucie Reliability		45,381	45,381	0.753	$341,795
6	**Total July Estimated**		483,526	483,526	3.508	$16,963,644
7						
8	**August Estimated**					
9	UPS		207,483	207,483	4.070	$8,445,073
10	SJRPP		192,692	192,692	3.552	$6,844,000
11	St Lucie Reliability		45,381	45,381	0.753	$341,795
12	**Total August Estimated**		445,556	445,556	3.508	$15,630,868
13						
14	**September Estimated**					
15	UPS		225,422	225,422	4.066	$9,165,097
16	SJRPP		187,750	187,750	3.546	$6,658,000
17	St Lucie Reliability		8,783	8,783	0.753	$66,154
18	**Total September Estimated**		421,955	421,955	3.766	$15,889,250
19						
20	**October Estimated**					
21	UPS		202,713	202,713	4.050	$8,209,640
22	SJRPP		187,223	187,223	3.566	$6,676,000
23	St Lucie Reliability		33,670	33,670	0.753	$253,588
24	**Total October Estimated**		423,606	423,606	3.574	$15,139,228
25						
26	**November Estimated**					
27	UPS		101,421	101,421	4.240	$4,299,801
28	SJRPP		126,932	126,932	3.706	$4,704,000
29	St Lucie Reliability		44,962	44,962	0.736	$331,091
30	**Total November Estimated**		273,315	273,315	3.415	$9,334,892
31						
32	**December Estimated**					
33	UPS		96,488	96,488	4.118	$3,973,417
34	SJRPP		133,113	133,113	3.683	$4,903,000
35	St Lucie Reliability		46,461	46,461	0.736	$342,127
36	**Total December Estimated**		276,062	276,062	3.339	$9,218,544
37						
38	**12 Month Period**					
39	UPS		1,934,258	1,934,258	4.082	$78,964,923
40	SJRPP		1,838,512	1,838,512	3.575	$65,719,000
41	St Lucie Reliability		492,739	492,739	0.745	$3,673,157
42	**Total 12 Month Period**		4,265,509	4,265,509	3.478	$148,357,080
43						
44						
45	Note: Totals may not add due to rounding.					
46						
47						
48						
49						
50						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
(WITH GAS RESERVES)

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	**January Estimated**					
3	Qualifying Facilities		324,657	324,657	4.087	$13,269,887
4	**Total January Estimated**		324,657	324,657	4.087	$13,269,887
5						
6	**February Estimated**					
7	Qualifying Facilities		234,692	234,692	3.987	$9,356,887
8	**Total February Estimated**		234,692	234,692	3.987	$9,356,887
9						
10	**March Estimated**					
11	Qualifying Facilities		255,927	255,927	3.986	$10,201,887
12	**Total March Estimated**		255,927	255,927	3.986	$10,201,887
13						
14	**April Estimated**					
15	Qualifying Facilities		191,526	191,526	5.257	$10,067,898
16	**Total April Estimated**		191,526	191,526	5.257	$10,067,898
17						
18	**May Estimated**					
19	Qualifying Facilities		306,359	306,359	4.039	$12,372,888
20	**Total May Estimated**		306,359	306,359	4.039	$12,372,888
21						
22	**June Estimated**					
23	Qualifying Facilities		344,410	344,410	4.373	$15,061,892
24	**Total June Estimated**		344,410	344,410	4.373	$15,061,892
25						
26	**6 Month Period**					
27	Qualifying Facilities		1,657,573	1,657,573	4.243	$70,331,340
28	**Total 6 Month Period**		1,657,573	1,657,573	4.243	$70,331,340
29						
30						
31						
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
(WITH GAS RESERVES)

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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		367,993	367,993	4.569	$16,811,895
4	**Total July Estimated**		367,993	367,993	4.569	$16,811,895
5						
6	**August Estimated**					
7	Qualifying Facilities		355,473	355,473	4.717	$16,765,899
8	**Total August Estimated**		355,473	355,473	4.717	$16,765,899
9						
10	**September Estimated**					
11	Qualifying Facilities		355,645	355,645	4.762	$16,936,900
12	**Total September Estimated**		355,645	355,645	4.762	$16,936,900
13						
14	**October Estimated**					
15	Qualifying Facilities		340,225	340,225	4.467	$15,197,892
16	**Total October Estimated**		340,225	340,225	4.467	$15,197,892
17						
18	**November Estimated**					
19	Qualifying Facilities		109,163	109,163	3.330	$3,634,887
20	**Total November Estimated**		109,163	109,163	3.330	$3,634,887
21						
22	**December Estimated**					
23	Qualifying Facilities		98,057	98,057	3.268	$3,204,887
24	**Total December Estimated**		98,057	98,057	3.268	$3,204,887
25						
26	**12 Month Period**					
27	Qualifying Facilities		3,284,130	3,284,130	4.351	$142,883,700
28	**Total 12 Month Period**		3,284,130	3,284,130	4.351	$142,883,700
29						
30						
31	Note: Totals may not add due to rounding.					
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES
(WITH GAS RESERVES)

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	2,750	2.609	$71,750	3.524	$96,915	$25,165
4	Total January Estimated		2,750	2.609	$71,750	3.524	$96,915	$25,165
5								
6	**February Estimated**							
7	Economy	OS	5,250	2.462	$129,250	3.341	$175,428	$46,178
8	Total February Estimated		5,250	2.462	$129,250	3.341	$175,428	$46,178
9								
10	**March Estimated**							
11	Economy	OS	10,250	2.383	$244,250	3.633	$372,385	$128,135
12	Total March Estimated		10,250	2.383	$244,250	3.633	$372,385	$128,135
13								
14	**April Estimated**							
15	Economy	OS	30,500	3.479	$1,061,000	5.484	$1,672,505	$611,505
16	Total April Estimated		30,500	3.479	$1,061,000	5.484	$1,672,505	$611,505
17								
18	**May Estimated**							
19	Economy	OS	50,500	3.685	$1,861,000	5.125	$2,587,890	$726,890
20	Total May Estimated		50,500	3.685	$1,861,000	5.125	$2,587,890	$726,890
21								
22	**June Estimated**							
23	Economy	OS	50,750	5.454	$2,768,000	7.789	$3,953,083	$1,185,083
24	Total June Estimated		50,750	5.454	$2,768,000	7.789	$3,953,083	$1,185,083
25								
26	**6 Month Period**							
27	Economy	OS	150,000	4.090	$6,135,250	5.905	$8,858,205	$2,722,955
28	Total 6 Month Period		150,000	4.090	$6,135,250	5.905	$8,858,205	$2,722,955
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES
(WITH GAS RESERVES)

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	55,750	5.953	$3,318,750	9.646	$5,377,718	$2,058,968
4	Total July Estimated		55,750	5.953	$3,318,750	9.646	$5,377,718	$2,058,968
5								
6	**August Estimated**							
7	Economy	OS	70,750	5.963	$4,218,750	8.753	$6,192,863	$1,974,113
8	Total August Estimated		70,750	5.963	$4,218,750	8.753	$6,192,863	$1,974,113
9								
10	**September Estimated**							
11	Economy	OS	45,750	7.711	$3,528,000	12.121	$5,545,448	$2,017,448
12	Total September Estimated		45,750	7.711	$3,528,000	12.121	$5,545,448	$2,017,448
13								
14	**October Estimated**							
15	Economy	OS	30,500	4.652	$1,419,000	6.927	$2,112,655	$693,655
16	Total October Estimated		30,500	4.652	$1,419,000	6.927	$2,112,655	$693,655
17								
18	**November Estimated**							
19	Economy	OS	10,250	2.480	$254,250	3.152	$323,045	$68,795
20	Total November Estimated		10,250	2.480	$254,250	3.152	$323,045	$68,795
21								
22	**December Estimated**							
23	Economy	OS	5,250	2.362	$124,000	3.040	$159,618	$35,618
24	Total December Estimated		5,250	2.362	$124,000	3.040	$159,618	$35,618
25								
26	**12 Month Period**							
27	Economy	OS	368,250	5.159	$18,998,000	7.758	$28,569,550	$9,571,550
28	Total 12 Month Period		368,250	5.159	$18,998,000	7.758	$28,569,550	$9,571,550
29								
30								
31	Note: Totals may not add due to rounding.							
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FLORIDA POWER & LIGHT COMPANY
(WITH GAS RESERVES)

SCHEDULE: E10

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	CURRENT SEPT 14	PROPOSED JAN 15 - DEC 15	DIFFERENCE $	DIFFERENCE %
BASE	$54.87	$54.87	$0.00	0.00%
FUEL	$29.47	$30.90	$1.43	4.85%
CONSERVATION [1]	$3.37	$1.89	-$1.48	-43.92%
CAPACITY PAYMENT	$7.86	$6.35	-$1.51	-19.21%
ENVIRONMENTAL	$2.24	$2.06	-$0.18	-8.04%
STORM RESTORATION SURCHARGE [2]	$1.16	$1.16	$0.00	0.00%
SUBTOTAL	$98.97	$97.23	-$1.74	-1.76%
GROSS RECEIPTS TAX	$2.54	$2.49	-$0.05	-1.97%
TOTAL	**$101.51**	**$99.72**	-$1.79	-1.76%

[1] Proposed Jan 15 - Dec 15 is based on estimates of the Conservation factor to be filed on August 27, 2014.
[2] Reflects true-up adjustment in storm charges effective September 2, 2014.

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITH GAS RESERVES)

SCHEDULE: H1

Line No.	H1 Schedule	2012	2013	2014	2015	% Diff 2012 to 2013	% Diff 2013 to 2014	% Diff 2014 to 2015
1	**Fuel Cost of System Net Generation ($)**							
2	Heavy Oil	61,871,530	13,972,361	50,400,481	72,707,385	(77.4%)	260.7%	44.3%
3	Light Oil	8,584,943	19,348,495	25,883,288	10,327,193	125.4%	33.8%	(60.1%)
4	Coal	142,583,650	171,113,652	156,846,539	174,902,900	20.0%	(8.3%)	11.5%
5	Gas	2,999,049,429	2,697,913,238	3,098,319,410	2,901,834,310	(10.0%)	14.8%	(6.3%)
6	Nuclear	106,563,067	168,309,387	187,125,111	194,582,200	57.9%	11.2%	4.0%
7	**Total Fuel Cost of System Net Generation ($)**	3,318,652,620	3,070,657,133	3,518,574,830	3,354,353,988	(7.5%)	14.6%	(4.7%)
8								
9	**System Net Generation (MWh)**							
10	Heavy Oil	377,642	75,138	307,340	437,070	(80.1%)	309.0%	42.2%
11	Light Oil	54,367	120,475	134,222	37,659	121.6%	11.4%	(71.9%)
12	Coal	4,745,211	5,980,723	5,362,752	6,292,530	26.0%	(10.3%)	17.3%
13	Gas	80,593,957	75,208,098	79,020,442	80,292,325	(6.7%)	5.1%	1.6%
14	Nuclear	16,915,746	25,243,030	27,100,803	27,863,195	49.2%	7.4%	2.8%
15	Solar	70,534	67,991	111,506	191,208	(3.6%)	64.0%	71.5%
16	**Total System Net Generation (MWh)**	102,757,457	106,695,455	112,037,065	115,113,987	3.8%	5.0%	2.7%
17								
18	**Units of Fuel Burned (Unit)**							
19	Heavy Oil	701,587	150,170	538,901	763,353	(78.6%)	258.9%	41.7%
20	Light Oil	72,767	154,726	211,355	83,813	112.6%	36.6%	(60.3%)
21	Coal	578,328	621,264	3,112,900	3,730,202	7.4%	401.1%	19.8%
22	Gas	595,396,296	550,405,680	565,175,954	566,681,542	(7.6%)	2.7%	0.3%
23	Nuclear	188,199,021	273,897,430	294,569,803	297,514,072	45.5%	7.5%	1.0%
24	**Total Units of Fuel Burned (Unit)**							
25								
26	**BTU Burned (MMBTU)**							
27	Heavy Oil	4,479,893	955,983	3,429,961	4,885,457	(78.7%)	258.8%	42.4%
28	Light Oil	418,444	903,455	1,229,549	488,585	115.9%	36.1%	(60.3%)
29	Coal	49,417,119	63,095,100	56,406,267	66,376,533	27.7%	(10.6%)	17.7%
30	Gas	603,981,012	558,740,029	571,160,551	566,681,542	(7.5%)	2.2%	(0.8%)
31	Nuclear	188,199,025	273,897,430	294,569,803	297,514,072	45.5%	7.5%	1.0%
32	**Total BTU Burned (MMBTU)**	846,495,493	897,591,997	926,796,131	935,946,189	6.0%	3.3%	1.0%
33								
34	**Generation Mix (%MWH)**							
35	Heavy Oil	0.37%	0.07%	0.27%	0.38%	-	-	-
36	Light Oil	0.05%	0.11%	0.12%	0.03%	-	-	-
37	Coal	4.62%	5.61%	4.79%	5.47%	-	-	-
38	Gas	78.43%	70.49%	70.53%	69.75%	-	-	-
39	Nuclear	16.46%	23.66%	24.19%	24.20%	-	-	-
40	Solar	0.07%	0.06%	0.10%	0.17%	-	-	-
41	**Total Generation Mix (%MWH)**	100.00%	100.00%	100.00%	100.00%	-	-	-
42								
43	**Fuel Cost per Unit ($/Unit)**							
44	Heavy Oil	88.1880	93.0436	93.5246	95.2474	5.5%	0.5%	1.8%
45	Light Oil	117.9785	125.0501	122.4636	123.2171	6.0%	(2.1%)	0.6%
46	Coal	82.6550	74.4202	50.3860	46.8883	(10.0%)	(32.3%)	(6.9%)
47	Gas	5.0371	4.9017	5.4820	5.1207	(2.7%)	11.8%	(6.6%)
48	Nuclear	0.5662	0.6145	0.6352	0.6540	8.5%	3.4%	3.0%
49								

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITH GAS RESERVES)

SCHEDULE: H1

Line No.	H1 Schedule	2012	2013	2014	2015	% Diff 2012 to 2013	% Diff 2013 to 2014	% Diff 2014 to 2015
1	**Fuel Cost per MMBTU ($/MMBTU)**							
2	Heavy Oil	13.8109	14.6157	14.6942	14.8824	5.8%	0.5%	1.3%
3	Light Oil	20.5163	21.4161	21.0510	21.1369	4.4%	(1.7%)	0.4%
4	Coal	2.8853	2.7120	2.7807	2.6350	(6.0%)	2.5%	(5.2%)
5	Gas	4.9655	4.8286	5.4246	5.1207	(2.8%)	12.3%	(5.6%)
6	Nuclear	0.5662	0.6145	0.6352	0.6540	8.5%	3.4%	3.0%
7	**Total Fuel Cost per MMBTU ($/MMBTU)**	3.9205	3.4210	3.7965	3.5839	(12.7%)	11.0%	(5.6%)
8								
9	**BTU Burned per KWH (BTU/KWH)**							
10	Heavy Oil	11,863	12,723	11,160	11,178	7.3%	(12.3%)	0.2%
11	Light Oil	7,697	7,499	9,161	12,974	(2.6%)	22.2%	41.6%
12	Coal	10,414	10,550	10,518	10,548	1.3%	(0.3%)	0.3%
13	Gas	7,494	7,429	7,228	7,058	(0.9%)	(2.7%)	(2.4%)
14	Nuclear	11,126	10,850	10,869	10,678	(2.5%)	0.2%	(1.8%)
15	**Total BTU Burned per KWH (BTU/KWH)**	8,238	8,413	8,272	8,131	2.1%	(1.7%)	(1.7%)
16								
17	**Generated Fuel Cost per KWH (cents/KWH)**							
18	Heavy Oil	16.3836	18.5957	16.3989	16.6352	13.5%	(11.8%)	1.4%
19	Light Oil	15.7907	16.0602	19.2839	27.4229	1.7%	20.1%	42.2%
20	Coal	3.0048	2.8611	2.9247	2.7795	(4.8%)	2.2%	(5.0%)
21	Gas	3.7212	3.5873	3.9209	3.6141	(3.6%)	9.3%	(7.8%)
22	Nuclear	0.6300	0.6668	0.6905	0.6983	5.8%	3.6%	1.1%
23	**Total Generated Fuel Cost per KWH (cents/KWH)**	3.2296	2.8780	3.1405	2.9139	(10.9%)	9.1%	(7.2%)
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FLORIDA POWER & LIGHT COMPANY

Forty-Second Revised Sheet No. 10.101
Cancels Forty-First Revised Sheet No. 10.101

(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 .0129¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2015 – December 31, 2015	5.72	3.07	3.91
January 1, 2016 – December 31, 2016	5.68	3.48	4.17

A MW block size ranging from 86 MW to 95 MW has been used to calculate the estimated As-Available 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	1.0104
Secondary Voltage Delivery	1.0401

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
2014	66.3	0.3	5.1	23.6	4.5	0.2		4.08	38.50	2.80	0.75	0.00
2015	64.1	0.7	5.5	23.0	6.6	0.1		4.24	36.71	2.99	0.76	0.00
2016	67.9	0.6	3.1	23.1	5.1	0.2		4.50	37.63	3.65	0.78	0.00
2017	67.1	0.2	4.4	22.6	5.5	0.2		4.92	37.73	3.57	0.80	0.00
2018	66.6	0.4	5.1	22.1	5.6	0.2		5.98	40.54	3.70	0.82	0.00
2019	66.5	0.1	5.4	22.4	5.4	0.2		6.13	41.17	3.52	0.84	0.00
2020	67.8	0.1	5.4	21.8	4.7	0.2		6.29	42.28	3.52	0.86	0.00
2021	68.1	0.3	5.3	21.6	4.6	0.1		6.39	44.26	3.60	0.88	0.00
2022	64.3	0.2	5.2	25.6	4.6	0.1		6.60	46.22	3.69	0.90	0.00
2023	57.7	0.1	5.1	32.4	4.5	0.1		6.91	48.19	3.79	0.91	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)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective:

(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	0.115%
Distribution Equipment	0.182%
Transmission Equipment	0.110%

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
FUEL COST RECOVERY
2015 E-SCHEDULES – WITHOUT GAS RESERVES PROJECT

FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

TJK-6
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-72
SEPTEMBER 15, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 12
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-6

APPENDIX III
FUEL COST RECOVERY
2015 E SCHEDULES – WITHOUT GAS RESERVES PROJECT
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
(WITHOUT GAS RESERVES)

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,360,508,830	115,090,514	2.9199
2	TOTAL COST OF GENERATED POWER	$3,360,508,830	115,090,514	2.9199
3	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$148,813,194	4,280,646	3.4764
4	Energy Cost of Economy Purchases (E9)	$18,998,000	368,250	5.1590
5	Payments to Qualifying Facilities (E8)	$143,413,703	3,292,475	4.3558
6	TOTAL COST OF PURCHASED POWER	$311,224,897	7,941,372	3.9190
7	TOTAL AVAILABLE MWH (LINE 2 + LINE 6)		123,031,886	
8	Fuel Cost of Economy Sales (E6)	($73,540,950)	(1,750,000)	4.2023
9	Gain from Off-System Sales (E6)	($15,911,250)	N/A	N/A
10	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,351,540)	(573,053)	0.7594
11	TOTAL FUEL COST AND GAINS OF POWER SALES	($93,803,740)	(2,323,053)	4.0380
12	Incremental Personnel, Software, and Hardware Costs	$453,534	N/A	N/A
13	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,866,360	N/A	N/A
14	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,319,894	N/A	N/A
15	Dodd Frank Fees	$4,500	N/A	N/A
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 2 + 6 + 11 + 14 + 15)	$3,580,254,381	120,708,833	2.9660
17	Net Unbilled Sales [1]	($40,650,058)	(1,370,523)	(0.0357)
18	Company Use [1]	$10,740,763	362,126	0.0094
19	T & D Losses [1]	$232,716,535	7,846,074	0.2044
20	SYSTEM MWH SALES	$3,580,254,381	113,871,155	3.1441
21	Wholesale MWH Sales	$177,777,531	5,654,273	3.1441
22	Jurisdictional MWH Sales	$3,402,476,850	108,216,882	3.1441
23	Jurisdictional Loss Multiplier	$5,750,186		1.00169
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,408,227,036	108,216,882	3.1494
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$266,660,688	108,216,882	0.2464
26	TOTAL JURISDICTIONAL FUEL COST	$3,674,887,723	108,216,882	3.3959
27	Revenue Tax Factor	$2,645,919		1.00072
28	Fuel Factor Adjusted for Taxes	$3,677,533,642	108,216,882	3.3983
29	GPIF [2]	$11,814,923	108,216,882	0.0109
30	Fuel Factor including GPIF (Line 28 + Line 29)	$3,689,348,565	108,216,882	3.4092
31	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.409
32				
33	[1] For Informational Purposes Only			
34	[2] Calculation Based on Jurisdictional KWH Sales			
35				
36	Note: Totals may not add due to rounding.			
37				
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF MARGINAL TIME OF USE MULTIPLIERS
(WITHOUT GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	E1-D Schedule - Marginal	Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	Total
1	Full Year (January - December)													
2	On-Peak Period													
3	System MWH Requirements	2,375,695	2,139,602	2,214,127	3,100,132	3,299,166	3,684,169	4,011,996	3,744,162	3,844,652	3,338,927	2,101,211	2,472,682	36,326,521
4	Marginal Cost	$137,600,254	$64,851,337	$66,268,821	$178,257,590	$163,704,617	$264,818,068	$324,771,076	$314,359,842	$301,574,503	$260,202,581	$62,868,233	$74,304,094	$2,213,581,016
5	Average Marginal Cost (¢/kWh)	5.792	3.031	2.993	5.750	4.962	7.188	8.095	8.396	7.844	7.793	2.992	3.005	6.094
6	Off-Peak Period													
7	System MWH Requirements	6,655,641	5,929,542	6,832,714	6,230,334	7,339,490	7,374,907	7,799,876	8,278,593	7,342,624	7,215,937	6,802,453	6,721,572	84,523,683
8	Marginal Cost	$268,222,332	$167,746,743	$204,913,093	$246,035,890	$260,772,080	$281,942,695	$314,023,008	$319,719,262	$289,739,943	$351,488,291	$194,142,009	$193,110,764	$3,091,856,108
9	Average Marginal Cost (¢/kWh)	4.030	2.829	2.999	3.949	3.553	3.823	4.026	3.862	3.946	4.871	2.854	2.873	3.658
10	Total Period													
11	System MWH Requirements	9,031,336	8,069,144	9,046,841	9,330,466	10,638,656	11,059,076	11,811,872	12,022,755	11,187,276	10,554,864	8,903,664	9,194,254	120,850,204
12	Marginal Cost	$405,822,587	$232,598,080	$271,181,914	$424,293,480	$424,476,697	$546,760,762	$638,794,084	$634,079,103	$591,314,446	$611,690,872	$257,010,242	$267,414,858	$5,305,437,124
13	Average Marginal Cost (¢/kWh)	4.493	2.883	2.998	4.547	3.990	4.944	5.408	5.274	5.286	5.795	2.887	2.908	4.390
14														
15	Full Year Multiplier													
16	On-Peak Period													
17	Marginal Fuel Cost Weighting Multiplier													1.388
18	Off-Peak Period													
19	Marginal Fuel Cost Weighting Multiplier													0.833
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
(WITHOUT GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) Jun - 2015	(3) Jul - 2015	(4) Aug - 2015	(5) Sep - 2015	(6) Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,690,973	1,849,254	1,720,742	1,783,060	7,044,029
4	Marginal Cost	$156,093,718	$195,059,312	$191,140,021	$190,876,573	$733,169,624
5	Average Marginal Cost (¢/kWh)	9.231	10.548	11.108	10.705	10.408
6	*Off-Peak Period*					
7	System MWH Requirements	9,368,103	9,962,618	10,302,013	9,404,216	39,036,950
8	Marginal Cost	$386,434,249	$436,362,668	$436,599,311	$396,293,662	$1,655,689,890
9	Average Marginal Cost (¢/kWh)	4.125	4.380	4.238	4.214	4.241
10	*Total Period*					
11	System MWH Requirements	11,059,076	11,811,872	12,022,755	11,187,276	46,080,979
12	Marginal Cost	$542,527,966	$631,421,980	$627,739,332	$587,170,235	$2,388,859,514
13	Average Marginal Cost (¢/kWh)	4.906	5.346	5.221	5.249	5.184
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					2.008
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.818
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
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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)
(WITHOUT GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

(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	3.409	1.00284	3.096
A	RS-1 all additional kWh	3.409	1.00284	4.096
A	GS-1, SL-2, GSCU-1, WIES-1	3.409	1.00284	3.419
A-1	SL-1, OL-1, PL-1 [1]	3.142	1.00284	3.151
B	GSD-1	3.409	1.00277	3.418
C	GSLD-1, CS-1	3.409	1.00182	3.415
D	GSLD-2, CS-2, OS-2, MET	3.409	0.99347	3.387
E	GSLD-3, CS-3	3.409	0.96714	3.297
A	GST-1 On-Peak	4.732	1.00284	4.745
	GST-1 Off-Peak	2.840	1.00284	2.848
A	RTR-1 On-Peak	-	-	1.326
	RTR-1 Off-Peak	-	-	(0.571)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.732	1.00276	4.745
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.840	1.00276	2.848
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.732	1.00182	4.741
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.840	1.00182	2.845
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.732	0.99407	4.704
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.840	0.99407	2.823
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.732	0.96714	4.577
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.840	0.96714	2.747
F	CILC-1(D), ISST-1(D) On-Peak	4.732	0.99316	4.700
	CILC-1(D), ISST-1(D) Off-Peak	2.840	0.99316	2.821

[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
(WITHOUT GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	6.845	1.00277	6.864
	GSD(T)-1 Off-Peak	2.789	1.00277	2.797
C	GSLD(T)-1 On-Peak	6.845	1.00182	6.857
	GSLD(T)-1 Off-Peak	2.789	1.00182	2.794
D	GSLD(T)-2 On-Peak	6.845	0.99407	6.804
	GSLD(T)-2 Off-Peak	2.789	0.99407	2.772

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
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
(WITHOUT GAS RESERVES)

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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) 12 Month Period
1	Fuel Cost of System Generation (E3)	$255,338,306	$219,204,384	$249,297,892	$265,322,196	$282,528,678	$301,478,404	$328,735,352	$330,722,421	$328,498,913	$296,727,084	$249,100,043	$253,555,156	$3,360,508,830
2	Fuel Cost of Power Sold (E6)	(10,481,318)	(9,075,498)	(9,166,106)	(5,455,643)	(5,043,318)	(2,802,811)	(7,001,118)	(5,820,018)	(7,008,261)	(4,928,618)	(5,206,411)	(5,903,368)	(77,892,490)
3	Gain on Economy Sales (E6)	(2,900,000)	(2,620,000)	(2,418,750)	(840,000)	(760,000)	(772,500)	(870,000)	(825,000)	(612,500)	(617,500)	(1,135,000)	(1,540,000)	(15,911,250)
4	Fuel Cost of Purchased Power (E7)	10,692,030	8,464,570	8,185,025	10,354,587	13,024,289	15,654,245	16,984,111	15,652,423	15,913,786	15,155,228	9,394,392	9,338,507	148,813,194
5	Qualifying Facilities (E8)	13,342,888	9,504,887	10,309,887	10,067,898	12,370,888	15,061,892	17,015,897	17,016,900	17,041,901	14,840,891	3,634,887	3,204,887	143,413,703
6	Energy Cost of Economy Purchases (E9)	71,750	129,250	244,250	1,061,000	1,861,000	2,768,000	3,318,750	4,218,750	3,528,000	1,419,000	254,250	124,000	18,998,000
7	Total Fuel & Net Power Transactions	$266,063,655	$225,607,593	$256,452,197	$280,510,038	$303,981,537	$331,387,230	$358,182,992	$360,965,476	$357,361,838	$322,596,086	$256,042,162	$258,779,183	$3,577,929,987
8														
9	Incremental Personnel, Software and Hardware Costs	37,302	35,316	38,238	38,238	36,777	38,238	39,698	36,777	38,238	38,238	36,777	39,698	453,534
10	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	84,560	385,050	158,550	143,450	113,250	120,800	120,800	98,150	120,800	241,600	279,350	1,866,360
11	Total	37,302	119,876	423,288	196,788	180,227	151,488	160,498	157,577	136,388	159,038	278,377	319,048	2,319,894
12														
13	Dodd Frank Fees	375	375	375	375	375	375	375	375	375	375	375	375	4,500
14														
15	Adjusted Total Fuel & Net Power Transactions	266,101,332	225,727,845	256,875,860	280,707,200	304,162,139	331,539,093	358,343,865	361,123,428	357,498,601	322,755,498	256,320,914	259,098,606	3,580,254,381
16														
17	System MWH Sales	8,892,771	7,892,774	7,961,266	8,704,079	9,321,302	10,338,801	10,789,415	11,228,743	11,156,066	10,294,037	8,738,000	8,553,901	113,871,155
18														
19	Cost per KWH (¢/KWH)	2.9923	2.8599	3.2266	3.2250	3.2631	3.2067	3.3213	3.2161	3.2045	3.1354	2.9334	3.0290	3.1441
20	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
21	Jurisdictional Cost (¢/KWH)	2.9974	2.8648	3.2320	3.2305	3.2686	3.2122	3.3269	3.2215	3.2099	3.1407	2.9384	3.0341	3.1494
22	True-Up (¢/KWH)	0.2617	0.2975	0.2939	0.2689	0.2508	0.2257	0.2166	0.2081	0.2099	0.2275	0.2694	0.2716	0.2464
23	Total (¢/KWH)	3.2591	3.1623	3.5259	3.4994	3.5194	3.4379	3.5435	3.4296	3.4198	3.3682	3.2078	3.3057	3.3958
24	Revenue Tax Factor (0.00072)	0.0023	0.0023	0.0025	0.0025	0.0025	0.0025	0.0026	0.0025	0.0025	0.0024	0.0023	0.0024	0.0024
25	Recovery Factor Adjusted for Taxes (¢/KWH)	3.2614	3.1646	3.5284	3.5019	3.5219	3.4404	3.5461	3.4321	3.4223	3.3706	3.2101	3.3081	3.3982
26	GPIF (¢/KWH)	0.0116	0.0132	0.0130	0.0119	0.0111	0.0100	0.0096	0.0092	0.0093	0.0101	0.0119	0.0120	0.0109
27	Recovery Factor including GPIF (¢/KWH)	3.2730	3.1778	3.5414	3.5138	3.5330	3.4504	3.5557	3.4413	3.4316	3.3807	3.2220	3.3201	3.4091
28														
29	Recovery Factor Rounded to .001 (¢/KWH)	3.273	3.178	3.541	3.514	3.533	3.450	3.556	3.441	3.432	3.381	3.222	3.320	3.409
30														
31	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITHOUT GAS RESERVES)

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	38,262,636,848	0.030964	$1,184,754,187.94	3.096
2	All Additional KWH	18,224,118,120	0.040964	$746,527,964.41	4.096
3	Total KWH	56,486,754,968		$1,931,282,152.36	
4					
5	Avg Fuel Factor	3.409			
6	RS-1 Loss Multiplier	1.00284			
7	Average Fuel Factor	3.419			
8					
9	Target Fuel Revenues	$1,931,282,152.36			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITHOUT GAS RESERVES)

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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 ($)**													
2	Heavy Oil	14,436,586	0	81,766	1,635,724	737,235	7,130,438	13,339,683	10,730,420	15,683,532	8,830,013	0	0	72,605,397
3	Light Oil	437,865	384,330	437,865	438,541	438,541	438,541	924,841	438,982	5,070,027	439,219	439,219	439,219	10,327,193
4	Coal	15,813,782	13,451,562	13,211,245	12,562,923	14,569,180	14,769,554	15,528,773	15,473,880	15,084,068	15,379,506	14,163,000	15,139,220	175,146,691
5	Gas	206,880,172	189,318,193	219,248,515	237,401,107	249,225,322	262,147,771	281,383,655	286,520,740	278,747,386	257,250,147	219,668,324	220,056,018	2,907,847,349
6	Nuclear	17,769,900	16,050,300	16,318,500	13,283,900	17,558,400	16,992,100	17,558,400	17,558,400	13,913,900	14,828,200	14,829,500	17,920,700	194,582,200
7	**Total Fuel Cost of System Net Generation ($)**	255,338,306	219,204,384	249,297,892	265,322,196	282,528,678	301,478,404	328,735,352	330,722,421	328,498,913	296,727,084	249,100,043	253,555,156	3,360,508,830
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	85,978	0	542	9,235	4,544	42,527	80,577	67,802	89,821	55,346	0	0	436,372
11	Light Oil	2,094	1,849	2,094	2,094	2,094	2,094	3,349	2,096	13,613	2,094	2,094	2,094	37,659
12	Coal	573,372	489,799	494,285	460,907	521,980	527,166	552,582	549,294	534,737	545,343	508,075	544,336	6,301,876
13	Gas	5,465,488	5,049,639	5,939,454	6,607,377	6,979,559	7,309,081	7,857,512	8,122,302	7,850,295	7,156,181	6,023,138	5,900,178	80,260,204
14	Nuclear	2,575,172	2,325,963	2,363,945	1,873,068	2,504,803	2,424,002	2,504,803	2,504,803	1,952,261	2,100,856	2,158,347	2,575,172	27,863,195
15	Solar	11,632	9,024	18,353	21,477	21,786	19,960	19,396	18,237	15,960	14,522	11,221	9,640	191,208
16	**Total System Net Generation (MWh)**	8,713,736	7,876,274	8,818,673	8,974,158	10,034,766	10,324,830	11,018,219	11,264,534	10,456,687	9,874,342	8,702,875	9,031,420	115,090,514
17														
18	**Units of Fuel Burned (Unit)** [(a)]													
19	Heavy Oil	152,245		865	17,143	7,772	74,814	139,985	112,747	164,189	92,516			762,276
20	Light Oil	3,581	3,152	3,581	3,581	3,581	3,581	7,537	3,584	40,892	3,581	3,581	3,581	83,813
21	Coal	336,170	291,381	296,328	277,752	310,247	311,181	325,466	323,892	315,251	322,091	302,130	323,411	3,735,300
22	Gas	37,768,150	34,716,771	41,173,297	46,690,246	49,071,848	52,659,472	56,806,368	58,039,018	56,660,518	50,695,612	41,678,869	40,498,200	566,458,370
23	Nuclear	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
24	Total Units of Fuel Burned (Unit)													
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	974,368	0	5,533	109,720	49,743	478,806	895,906	721,578	1,050,812	592,100	0	0	4,878,566
28	Light Oil	20,874	18,371	20,874	20,874	20,874	20,874	43,935	20,892	238,395	20,874	20,874	20,874	488,585
29	Coal	6,013,291	5,161,711	5,165,035	4,870,711	5,534,438	5,573,663	5,837,502	5,803,862	5,649,719	5,765,368	5,360,129	5,732,571	66,468,000
30	Gas	37,768,150	34,716,771	41,173,297	46,690,246	49,071,848	52,659,472	56,806,368	58,039,018	56,660,518	50,695,612	41,678,869	40,498,200	566,458,369
31	Nuclear	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
32	**Total BTU Burned (MMBTU)**	71,826,794	64,329,230	71,233,229	72,048,349	81,723,906	84,907,333	90,630,714	91,632,353	84,822,637	79,715,960	69,635,331	73,301,756	935,807,592
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	94.8247	0.0000	94.5275	95.4164	94.8579	95.3089	95.2937	95.1726	95.5212	95.4431	0.0000	0.0000	95.2482
36	Light Oil	122.2746	121.9321	122.2746	122.4634	122.4634	122.4634	122.7068	122.4837	123.9858	122.6526	122.6526	122.6526	123.2171
37	Coal	47.0410	46.1649	44.5832	45.2307	46.9599	47.4629	47.7124	47.7748	47.8478	47.7489	46.8772	46.8111	46.8896
38	Gas	5.4776	5.4532	5.3250	5.0846	5.0788	4.9782	4.9534	4.9367	4.9196	5.0744	5.2705	5.4337	5.1334
39	Nuclear	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
40	**Total Fuel Cost per Unit ($/Unit)**													
41														
42	**Generation Mix (%)**													
43	Heavy Oil	0.99%	0.00%	0.01%	0.10%	0.05%	0.41%	0.73%	0.60%	0.86%	0.56%	0.00%	0.00%	0.38%

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITHOUT GAS RESERVES)

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.02%	0.13%	0.02%	0.02%	0.02%	0.03%
2	Coal	6.58%	6.22%	5.60%	5.14%	5.20%	5.11%	5.02%	4.88%	5.11%	5.52%	5.84%	6.03%	5.48%
3	Gas	62.72%	64.11%	67.35%	73.63%	69.55%	70.79%	71.31%	72.11%	75.07%	72.47%	69.21%	65.33%	69.74%
4	Nuclear	29.55%	29.53%	26.81%	20.87%	24.96%	23.48%	22.73%	22.24%	18.67%	21.28%	24.80%	28.51%	24.21%
5	Solar	0.13%	0.11%	0.21%	0.24%	0.22%	0.19%	0.18%	0.16%	0.15%	0.15%	0.13%	0.11%	0.17%
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	14.8164	0.0000	14.7779	14.9082	14.8209	14.8921	14.8896	14.8708	14.9252	14.9130	0.0000	0.0000	14.8825
10	Light Oil	20.9766	20.9205	20.9766	21.0090	21.0090	21.0090	21.0502	21.0120	21.2673	21.0414	21.0414	21.0414	21.1369
11	Coal	2.6298	2.6060	2.5578	2.5793	2.6325	2.6499	2.6602	2.6661	2.6699	2.6676	2.6423	2.6409	2.6351
12	Gas	5.4776	5.4532	5.3250	5.0846	5.0788	4.9782	4.9534	4.9367	4.9196	5.0744	5.2705	5.4337	5.1334
13	Nuclear	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	11,333	0	10,208	11,881	10,947	11,259	11,119	10,642	11,699	10,698	0	0	11,180
17	Light Oil	9,968	9,936	9,968	9,968	9,968	9,968	13,119	9,968	17,512	9,968	9,968	9,968	12,974
18	Coal	10,488	10,538	10,450	10,568	10,603	10,573	10,564	10,566	10,565	10,572	10,550	10,531	10,547
19	Gas	6,910	6,875	6,932	7,066	7,031	7,205	7,230	7,146	7,218	7,084	6,920	6,864	7,058
20	Nuclear	10,504	10,504	10,520	10,868	10,798	10,798	10,798	10,798	10,871	10,778	10,460	10,504	10,678
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	16.7910	0.0000	15.0860	17.7122	16.2244	16.7668	16.5552	15.8261	17.4609	15.9542	0.0000	0.0000	16.6384
24	Light Oil	20.9105	20.7858	20.9105	20.9428	20.9428	20.9428	27.6154	20.9438	37.2440	20.9751	20.9751	20.9751	27.4229
25	Coal	2.7580	2.7463	2.6728	2.7257	2.7911	2.8017	2.8102	2.8170	2.8208	2.8202	2.7876	2.7812	2.7793
26	Gas	3.7852	3.7491	3.6914	3.5930	3.5708	3.5866	3.5811	3.5276	3.5508	3.5948	3.6471	3.7297	3.6230
27	Nuclear	0.6900	0.6900	0.6903	0.7092	0.7010	0.7010	0.7010	0.7010	0.7127	0.7058	0.6871	0.6959	0.6983
28	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.9303	2.7831	2.8269	2.9565	2.8155	2.9199	2.9836	2.9360	3.1415	3.0050	2.8623	2.8075	2.9199
29														
30														
31	[a] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
32														
33														
34														
35														
36														
37														
38														
39														
40														
41														
42														
43														

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,255	19.94	122.27
4	Gas		934,523					6,283,429	1,000,000	6,283,429	34,418,369	3.68	5.48
5	Plant Unit Info	1,355	934,775	92.8%	94.5%	92.7%	6,724			6,285,823	34,468,624	3.69	
6	*Desoto Solar*												
7	Solar		3,129					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,129	16.8%	N/A	36.7%	N/A						
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		273,377					1,990,061	1,000,000	1,990,061	10,900,836	3.99	5.48
18	Plant Unit Info	1,425	273,377	25.8%	95.0%	85.3%	7,280			1,990,061	10,900,836	3.99	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,577	22.14	122.27
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	82.2%	0.0%	10,541			1,170	24,577	22.14	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,433	22.71	122.27
29	Gas		1,725					14,204	1,000,000	14,204	77,808	4.51	5.48
30	Plant Unit Info	442	1,837	0.6%	94.8%	97.7%	8,392			15,416	103,241	5.62	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,555	22.62	122.27
33	Gas		2,158					17,520	1,000,000	17,520	95,971	4.45	5.48
34	Plant Unit Info	442	2,271	0.7%	94.8%	97.7%	8,251			18,738	121,527	5.35	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		353,824					2,472,656	1,000,000	2,472,656	13,544,260	3.83	5.48
8	Plant Unit Info	1,134	353,824	41.9%	94.9%	91.5%	6,988			2,472,656	13,544,260	3.83	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		85,978					152,245	6,400,000	974,368	14,436,586	16.79	94.82
15	Gas		50,920					609,915	1,000,000	609,915	3,340,908	6.56	5.48
16	Plant Unit Info	808	136,898	22.8%	79.3%	24.4%	11,573			1,584,283	17,777,495	12.99	
17	*Martin 3*												
18	Gas		13,124					101,296	1,000,000	101,296	554,831	4.23	5.48
19	Plant Unit Info	454	13,124	3.9%	94.8%	82.6%	7,718			101,296	554,831	4.23	
20	*Martin 4*												
21	Gas		4,561					35,288	1,000,000	35,288	193,317	4.24	5.48
22	Plant Unit Info	453	4,561	1.4%	94.8%	77.5%	7,737			35,288	193,317	4.24	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,456	21.41	122.27
25	Gas		406,906					2,833,477	1,000,000	2,833,477	15,520,785	3.81	5.48
26	Plant Unit Info	1,147	407,151	47.8%	77.1%	76.5%	6,965			2,835,980	15,573,241	3.82	
27	*Martin 8 Solar*												
28	Solar		7,326					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	7,326	13.1%	N/A	28.6%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,760	23.39	122.27
32	Gas		869					8,375	1,000,000	8,375	45,827	5.27	5.47
33	Plant Unit Info	251	915	0.5%	95.1%	86.6%	9,717			8,891	56,587	6.18	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,882	23.66	122.27
36	Gas		959					9,135	1,000,000	9,135	49,990	5.21	5.47
37	Plant Unit Info	255	1,005	0.6%	95.1%	94.2%	9,604			9,652	60,872	6.06	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,888	19.88	122.27
3	Gas		922,625					6,184,725	1,000,000	6,184,725	33,877,706	3.67	5.48
4	Plant Unit Info	1,344	922,876	92.3%	94.5%	92.3%	6,704			6,187,106	33,927,594	3.68	
5	*Sanford 4*												
6	Gas		35,366					261,903	1,000,000	261,903	1,434,584	4.06	5.48
7	Plant Unit Info	975	35,366	4.9%	94.9%	86.3%	7,405			261,903	1,434,584	4.06	
8	*Sanford 5*												
9	Gas		45,244					334,492	1,000,000	334,492	1,832,202	4.05	5.48
10	Plant Unit Info	994	45,244	6.1%	95.0%	82.8%	7,393			334,492	1,832,202	4.05	
11	*Scherer 4*												
12	Coal		453,573					276,491	16,999,975	4,700,340	11,544,706	2.55	41.75
13	Plant Unit Info	646	453,573	94.4%	94.4%	94.4%	10,363			4,700,340	11,544,706	2.55	
14	*St Johns 1*												
15	Coal		59,640					29,852	22,000,100	656,747	2,135,432	3.58	71.53
16	Plant Unit Info	128	59,640	62.5%	94.4%	62.5%	11,012			656,747	2,135,432	3.58	
17	*St Johns 2*												
18	Coal		60,159					29,827	22,000,335	656,204	2,133,643	3.55	71.53
19	Plant Unit Info	128	60,159	63.1%	94.4%	63.1%	10,908			656,204	2,133,643	3.55	
20	*St Lucie 1*												
21	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,999,400	0.69	0.67
22	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,999,400	0.69	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	3,978,000	0.64	0.62
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	3,978,000	0.64	
26	*Space Coast*												
27	Solar		1,177					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,177	15.8%	N/A	34.5%	N/A						
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,429,100	0.73	0.67
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,429,100	0.73	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,844	21.42	122.27
4	Gas		352,614					2,473,738	1,000,000	2,473,738	13,550,233	3.84	5.48
5	Plant Unit Info	1,166	352,856	40.7%	94.8%	88.9%	7,018			2,476,211	13,602,077	3.85	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,753	20.16	122.27
8	Gas		747,801					5,121,396	1,000,000	5,121,396	28,053,173	3.75	5.48
9	Plant Unit Info	1,208	748,023	83.3%	94.8%	90.5%	6,849			5,123,530	28,097,925	3.76	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
12	Gas		771,236					5,274,008	1,000,000	5,274,008	28,889,122	3.75	5.48
13	Plant Unit Info	1,202	771,463	86.3%	94.9%	88.1%	6,839			5,276,186	28,934,853	3.75	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
16	Gas		547,655					3,742,532	1,000,000	3,742,532	20,500,249	3.74	5.48
17	Plant Unit Info	1,207	547,882	61.0%	94.9%	91.5%	6,835			3,744,710	20,545,979	3.75	
18	**System Totals**												
19	Plant Unit Info	25,930	8,713,736				8,243			71,826,794	255,338,306	2.93	
20													
21													
22													
23													
24													
25													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,114	19.89	121.93
4	Gas		827,976					5,557,080	1,000,000	5,557,080	30,303,995	3.66	5.45
5	Plant Unit Info	1,355	828,228	91.0%	94.5%	90.9%	6,712			5,559,474	30,354,109	3.66	
6	*Desoto Solar*												
7	Solar		3,571					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,571	21.3%	N/A	46.4%	N/A						
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		266,665					1,943,320	1,000,000	1,943,320	10,597,297	3.97	5.45
18	Plant Unit Info	1,425	266,665	27.9%	95.0%	80.7%	7,288			1,943,320	10,597,297	3.97	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,508	22.08	121.93
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	93.4%	35.3%	10,541			1,170	24,508	22.08	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,362	22.64	121.93
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	112	0.1%	94.8%	25.4%	10,821			1,212	25,362	22.64	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,484	22.55	121.93
33	Gas		4,388					36,665	1,000,000	36,665	199,976	4.56	5.45
34	Plant Unit Info	442	4,501	1.6%	91.3%	82.8%	8,417			37,883	225,460	5.01	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		401,405					2,788,053	1,000,000	2,788,053	15,203,818	3.79	5.45
8	Plant Unit Info	1,134	401,405	52.7%	94.9%	85.3%	6,946			2,788,053	15,203,818	3.79	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	16.7%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		26,311					204,632	1,000,000	204,632	1,115,878	4.24	5.45
19	Plant Unit Info	454	26,311	8.6%	94.8%	69.8%	7,777			204,632	1,115,878	4.24	
20	*Martin 4*												
21	Gas		23,731					185,502	1,000,000	185,502	1,011,558	4.26	5.45
22	Plant Unit Info	453	23,731	7.8%	94.8%	67.2%	7,817			185,502	1,011,558	4.26	
23	*Martin 8*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		126,319					883,536	1,000,000	883,536	4,818,061	3.81	5.45
26	Plant Unit Info	1,147	126,319	16.4%	27.0%	69.7%	6,994			883,536	4,818,061	3.81	
27	*Martin 8 Solar*												
28	Solar		4,190					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	4,190	8.3%	N/A	36.3%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,730	23.33	121.93
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	251	46	0.1%	95.1%	17.9%	11,217			516	10,730	23.33	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,852	23.59	121.93
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	255	46	0.1%	95.1%	17.7%	11,239			517	10,852	23.59	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,748	19.82	121.93
3	Gas		817,001					5,468,074	1,000,000	5,468,074	29,818,625	3.65	5.45
4	Plant Unit Info	1,344	817,252	90.5%	94.5%	90.5%	6,694			5,470,455	29,868,373	3.65	
5	*Sanford 4*												
6	Gas		86,838					648,008	1,000,000	648,008	3,533,758	4.07	5.45
7	Plant Unit Info	975	86,838	13.3%	94.9%	76.1%	7,462			648,008	3,533,758	4.07	
8	*Sanford 5*												
9	Gas		120,850					898,435	1,000,000	898,435	4,899,398	4.05	5.45
10	Plant Unit Info	994	120,850	18.1%	95.0%	74.6%	7,434			898,435	4,899,398	4.05	
11	*Scherer 4*												
12	Coal		409,679					249,733	16,999,968	4,245,453	10,499,053	2.56	42.04
13	Plant Unit Info	646	409,679	94.4%	94.4%	94.4%	10,363			4,245,453	10,499,053	2.56	
14	*St Johns 1*												
15	Coal		39,444					20,627	22,000,048	453,795	1,462,289	3.71	70.89
16	Plant Unit Info	128	39,444	45.8%	94.4%	45.8%	11,505			453,795	1,462,289	3.71	
17	*St Johns 2*												
18	Coal		40,676					21,021	22,000,048	462,463	1,490,220	3.66	70.89
19	Plant Unit Info	128	40,676	47.2%	94.4%	47.2%	11,369			462,463	1,490,220	3.66	
20	*St Lucie 1*												
21	Nuclear		657,165					6,787,360	1,000,000	6,787,360	4,515,600	0.69	0.67
22	Plant Unit Info	1,003	657,165	97.5%	97.5%	97.5%	10,328			6,787,360	4,515,600	0.69	
23	*St Lucie 2*												
24	Nuclear		563,473					5,779,359	1,000,000	5,779,359	3,593,000	0.64	0.62
25	Plant Unit Info	860	563,473	97.5%	97.5%	97.5%	10,257			5,779,359	3,593,000	0.64	
26	*Space Coast*												
27	Solar		1,263					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,263	18.8%	N/A	41.0%	N/A						
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		549,713					5,932,829	1,000,000	5,932,829	4,000,500	0.73	0.67
35	Plant Unit Info	839	549,713	97.5%	97.5%	97.5%	10,793			5,932,829	4,000,500	0.73	
36	*Turkey Point 4*												
37	Nuclear		555,612					5,932,829	1,000,000	5,932,829	3,941,200	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	555,612	97.5%	97.5%	97.5%	10,678			5,932,829	3,941,200	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,699	21.36	121.93
4	Gas		368,694					2,590,323	1,000,000	2,590,323	14,125,630	3.83	5.45
5	Plant Unit Info	1,166	368,936	47.1%	94.8%	83.0%	7,028			2,592,796	14,177,330	3.84	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,627	20.10	121.93
8	Gas		710,944					4,856,787	1,000,000	4,856,787	26,485,141	3.73	5.45
9	Plant Unit Info	1,208	711,166	87.7%	94.8%	87.6%	6,832			4,858,921	26,529,768	3.73	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,603	20.09	121.93
12	Gas		680,116					4,643,585	1,000,000	4,643,585	25,322,505	3.72	5.45
13	Plant Unit Info	1,202	680,343	84.3%	94.9%	85.2%	6,829			4,645,763	25,368,108	3.73	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,603	20.09	121.93
16	Gas		588,400					4,012,774	1,000,000	4,012,774	21,882,552	3.72	5.45
17	Plant Unit Info	1,207	588,627	72.6%	94.9%	86.1%	6,821			4,014,952	21,928,155	3.73	
18	**System Totals**												
19	Plant Unit Info	25,927	7,876,274				8,167			64,329,230	219,204,384	2.78	
20													
21													
22													
23													
24													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,255	19.94	122.27
4	Gas		934,576					6,269,381	1,000,000	6,269,381	33,384,587	3.57	5.33
5	Plant Unit Info	1,355	934,828	92.8%	94.5%	92.7%	6,709			6,271,775	33,434,841	3.58	
6	*Desoto Solar*												
7	Solar		4,881					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,881	26.3%	N/A	48.5%	N/A						
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		672,105					4,887,846	1,000,000	4,887,846	26,027,827	3.87	5.33
18	Plant Unit Info	1,442	672,105	62.7%	95.0%	87.1%	7,272			4,887,846	26,027,827	3.87	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,577	22.14	122.27
21	Gas		3,226					34,896	1,000,000	34,896	185,798	5.76	5.32
22	Plant Unit Info	314	3,337	2.9%	95.1%	97.8%	10,808			36,066	210,375	6.30	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,433	22.71	122.27
29	Gas		22,328					179,056	1,000,000	179,056	953,482	4.27	5.33
30	Plant Unit Info	442	22,440	6.9%	94.8%	90.3%	8,033			180,268	978,915	4.36	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,555	22.62	122.27
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	442	113	0.1%	1.3%	25.4%	10,779			1,218	25,555	22.62	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	62.9%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		610,421					4,212,796	1,000,000	4,212,796	22,433,235	3.68	5.33
8	Plant Unit Info	1,134	610,421	72.3%	94.9%	88.1%	6,901			4,212,796	22,433,235	3.68	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	14.6%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		421					673	6,396,731	4,305	63,617	15.11	94.53
15	Gas		2,388					29,617	1,000,000	29,617	157,714	6.60	5.33
16	Plant Unit Info	805	2,809	0.5%	95.2%	43.6%	12,076			33,922	221,331	7.88	
17	*Martin 3*												
18	Gas		68,689					526,877	1,000,000	526,877	2,805,639	4.08	5.33
19	Plant Unit Info	454	68,689	20.3%	94.8%	93.9%	7,670			526,877	2,805,639	4.08	
20	*Martin 4*												
21	Gas		51,925					398,361	1,000,000	398,361	2,121,286	4.09	5.33
22	Plant Unit Info	453	51,925	15.4%	94.8%	88.9%	7,672			398,361	2,121,286	4.09	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,456	21.41	122.27
25	Gas		536,120					3,696,044	1,000,000	3,696,044	19,681,487	3.67	5.33
26	Plant Unit Info	1,147	536,365	62.9%	77.1%	74.9%	6,896			3,698,547	19,733,943	3.68	
27	*Martin 8 Solar*												
28	Solar		11,799					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	11,799	21.2%	N/A	29.9%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,760	23.39	122.27
32	Gas		3,354					32,194	1,000,000	32,194	171,397	5.11	5.32
33	Plant Unit Info	251	3,400	1.9%	95.1%	74.3%	9,621			32,710	182,157	5.36	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,882	23.66	122.27
36	Gas		3,583					35,817	1,000,000	35,817	190,765	5.32	5.33
37	Plant Unit Info	255	3,629	2.0%	95.1%	58.6%	10,012			36,334	201,648	5.56	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,888	19.88	122.27
3	Gas		693,041					4,639,870	1,000,000	4,639,870	24,707,405	3.57	5.33
4	Plant Unit Info	1,344	693,292	69.3%	71.9%	91.1%	6,696			4,642,251	24,757,293	3.57	
5	*Sanford 4*												
6	Gas		19,169					142,460	1,000,000	142,460	758,649	3.96	5.33
7	Plant Unit Info	975	19,169	2.6%	72.3%	78.6%	7,432			142,460	758,649	3.96	
8	*Sanford 5*												
9	Gas		240,025					1,794,389	1,000,000	1,794,389	9,555,136	3.98	5.33
10	Plant Unit Info	994	240,025	32.5%	95.0%	88.1%	7,476			1,794,389	9,555,136	3.98	
11	*Scherer 4*												
12	Coal		444,163					270,840	17,000,026	4,604,287	11,426,844	2.57	42.19
13	Plant Unit Info	646	444,163	92.5%	94.4%	92.5%	10,366			4,604,287	11,426,844	2.57	
14	*St Johns 1*												
15	Coal		1,141					603	22,011,609	13,273	42,216	3.70	70.01
16	Plant Unit Info	128	1,141	1.2%	13.8%	6.2%	11,633			13,273	42,216	3.70	
17	*St Johns 2*												
18	Coal		48,981					24,885	22,000,201	547,475	1,742,185	3.56	70.01
19	Plant Unit Info	128	48,981	51.4%	94.4%	51.4%	11,177			547,475	1,742,185	3.56	
20	*St Lucie 1*												
21	Nuclear		516,347					5,332,946	1,000,000	5,332,946	3,548,000	0.69	0.67
22	Plant Unit Info	1,003	516,347	69.2%	69.2%	97.5%	10,328			5,332,946	3,548,000	0.69	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	3,978,000	0.64	0.62
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	3,978,000	0.64	
26	*Space Coast*												
27	Solar		1,673					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,673	22.5%	N/A	41.5%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		121					192	6,395,833	1,228	18,149	15.00	94.53
31	Gas		2,235					25,708	1,000,000	25,708	136,852	6.12	5.32
32	Plant Unit Info	380	2,356	0.8%	94.6%	38.7%	11,433			26,936	155,001	6.58	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,429,100	0.73	0.67
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,429,100	0.73	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,844	21.42	122.27
4	Gas		524,805					3,672,257	1,000,000	3,672,257	19,554,772	3.73	5.33
5	Plant Unit Info	1,166	525,047	60.6%	94.8%	91.5%	6,999			3,674,730	19,606,617	3.73	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,753	20.16	122.27
8	Gas		493,242					3,368,318	1,000,000	3,368,318	17,936,365	3.64	5.33
9	Plant Unit Info	1,208	493,464	55.0%	62.6%	88.4%	6,830			3,370,452	17,981,117	3.64	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
12	Gas		588,307					4,014,196	1,000,000	4,014,196	21,375,678	3.63	5.33
13	Plant Unit Info	1,202	588,534	65.8%	72.3%	86.0%	6,824			4,016,374	21,421,408	3.64	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,731	20.15	122.27
16	Gas		469,915					3,213,215	1,000,000	3,213,215	17,110,441	3.64	5.33
17	Plant Unit Info	1,207	470,142	52.4%	64.8%	81.4%	6,839			3,215,393	17,156,172	3.65	
18	**System Totals**												
19	Plant Unit Info	25,944	8,818,673				8,078			71,233,229	249,297,892	2.83	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		362,834					2,486,987	1,000,000	2,486,987	12,645,177	3.49	5.08
5	Plant Unit Info	1,210	363,086	41.7%	50.1%	56.7%	6,856			2,489,381	12,695,509	3.50	
6	*Desoto Solar*												
7	Solar		5,454					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,454	30.3%	N/A	55.9%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		428,019					3,123,384	1,000,000	3,123,384	15,881,226	3.71	5.08
18	Plant Unit Info	1,366	428,019	43.5%	61.1%	80.8%	7,297			3,123,384	15,881,226	3.71	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		17,545					192,397	1,000,000	192,397	978,319	5.58	5.08
22	Plant Unit Info	296	17,656	16.6%	95.1%	98.1%	10,963			193,567	1,002,934	5.68	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		49,214					394,466	1,000,000	394,466	2,005,844	4.08	5.08
30	Plant Unit Info	429	49,326	16.0%	81.4%	97.3%	8,022			395,678	2,031,316	4.12	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		83,808					664,793	1,000,000	664,793	3,380,421	4.03	5.08
34	Plant Unit Info	429	83,921	27.2%	94.8%	97.7%	7,936			666,011	3,406,016	4.06	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	0	0.0%	28.5%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		2,569					6,511	6,400,399	41,673	621,256	24.18	95.42
4	Gas		14,559					152,755	1,000,000	152,755	776,688	5.33	5.08
5	Plant Unit Info	789	17,128	3.0%	95.2%	67.9%	11,351			194,428	1,397,945	8.16	
6	*Manatee 3*												
7	Gas		553,249					3,889,261	1,000,000	3,889,261	19,775,407	3.57	5.08
8	Plant Unit Info	1,078	553,249	71.3%	94.9%	93.4%	7,030			3,889,261	19,775,407	3.57	
9	*Martin 1*												
10	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		6,487					10,356	6,400,058	66,279	988,133	15.23	95.42
15	Gas		36,758					438,357	1,000,000	438,357	2,229,256	6.06	5.09
16	Plant Unit Info	799	43,245	7.5%	95.2%	48.8%	11,669			504,636	3,217,389	7.44	
17	*Martin 3*												
18	Gas		126,261					972,308	1,000,000	972,308	4,943,913	3.92	5.08
19	Plant Unit Info	438	126,261	40.0%	94.8%	97.7%	7,701			972,308	4,943,913	3.92	
20	*Martin 4*												
21	Gas		107,186					829,487	1,000,000	829,487	4,217,760	3.93	5.08
22	Plant Unit Info	437	107,186	34.1%	94.8%	97.4%	7,739			829,487	4,217,760	3.93	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		690,670					4,777,300	1,000,000	4,777,300	24,290,357	3.52	5.08
26	Plant Unit Info	1,111	690,915	86.4%	94.8%	86.3%	6,918			4,779,803	24,342,894	3.52	
27	*Martin 8 Solar*												
28	Solar		14,206					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	14,206	26.3%	N/A	48.6%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		15,259					145,380	1,000,000	145,380	739,275	4.84	5.09
33	Plant Unit Info	247	15,305	8.7%	95.1%	88.4%	9,533			145,896	750,052	4.90	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		17,926					166,958	1,000,000	166,958	848,988	4.74	5.09
37	Plant Unit Info	250	17,972	10.0%	95.1%	94.2%	9,319			167,475	859,888	4.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		800,898					5,394,531	1,000,000	5,394,531	27,428,691	3.42	5.08
4	Plant Unit Info	1,212	801,149	91.8%	94.5%	91.8%	6,736			5,396,912	27,478,656	3.43	
5	*Sanford 4*												
6	Gas		41,326					312,421	1,000,000	312,421	1,588,593	3.84	5.08
7	Plant Unit Info	939	41,326	6.1%	94.9%	97.8%	7,560			312,421	1,588,593	3.84	
8	*Sanford 5*												
9	Gas		318,650					2,386,717	1,000,000	2,386,717	12,135,880	3.81	5.08
10	Plant Unit Info	947	318,650	46.7%	75.0%	95.9%	7,490			2,386,717	12,135,880	3.81	
11	*Scherer 4*												
12	Coal		402,751					247,963	16,999,996	4,215,370	10,476,410	2.60	42.25
13	Plant Unit Info	641	402,751	87.3%	94.4%	87.3%	10,466			4,215,370	10,476,410	2.60	
14	*St Johns 1*												
15	Coal		6,141					3,231	21,997,833	71,075	226,309	3.69	70.04
16	Plant Unit Info	127	6,141	6.7%	11.1%	40.3%	11,574			71,075	226,309	3.69	
17	*St Johns 2*												
18	Coal		52,015					26,558	21,999,623	584,266	1,860,204	3.58	70.04
19	Plant Unit Info	127	52,015	56.9%	94.4%	56.9%	11,233			584,266	1,860,204	3.58	
20	*St Lucie 1*												
21	Nuclear		137,732					1,454,445	1,000,000	1,454,445	927,100	0.67	0.64
22	Plant Unit Info	981	137,732	19.5%	19.5%	97.5%	10,560			1,454,445	927,100	0.67	
23	*St Lucie 2*												
24	Nuclear		589,677					6,189,149	1,000,000	6,189,149	3,847,800	0.65	0.62
25	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,496			6,189,149	3,847,800	0.65	
26	*Space Coast*												
27	Solar		1,817					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,817	25.2%	N/A	46.6%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		179					276	6,405,797	1,768	26,335	14.71	95.42
31	Gas		2,777					30,563	1,000,000	30,563	155,455	5.60	5.09
32	Plant Unit Info	379	2,956	1.1%	24.6%	48.7%	10,937			32,331	181,790	6.15	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		677,811					4,678,730	1,000,000	4,678,730	23,789,311	3.51	5.08
5	Plant Unit Info	1,138	678,053	82.8%	94.8%	89.4%	6,904			4,681,203	23,841,235	3.52	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		760,756					5,275,113	1,000,000	5,275,113	26,821,505	3.53	5.08
9	Plant Unit Info	1,166	760,978	90.7%	94.8%	90.6%	6,935			5,277,247	26,866,327	3.53	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		763,949					5,259,777	1,000,000	5,259,777	26,743,529	3.50	5.08
13	Plant Unit Info	1,159	764,176	91.6%	94.9%	91.5%	6,886			5,261,955	26,789,330	3.51	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		737,922					5,118,561	1,000,000	5,118,561	26,025,511	3.53	5.08
17	Plant Unit Info	1,166	738,149	88.0%	94.9%	88.9%	6,937			5,120,739	26,071,312	3.53	
18	**System Totals**												
19	Plant Unit Info	24,939	8,974,158				8,028			72,048,349	265,322,196	2.96	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		805,608					5,437,271	1,000,000	5,437,271	27,614,471	3.43	5.08
5	Plant Unit Info	1,210	805,860	89.6%	92.4%	91.2%	6,750			5,439,665	27,664,804	3.43	
6	*Desoto Solar*												
7	Solar		5,823					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,823	31.3%	N/A	57.8%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		332,187					2,475,880	1,000,000	2,475,880	12,574,769	3.79	5.08
18	Plant Unit Info	1,366	332,187	32.7%	64.3%	64.5%	7,453			2,475,880	12,574,769	3.79	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		14,210					156,052	1,000,000	156,052	792,559	5.58	5.08
22	Plant Unit Info	296	14,321	13.0%	95.1%	98.1%	10,978			157,222	817,174	5.71	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		58,807					474,040	1,000,000	474,040	2,407,685	4.09	5.08
30	Plant Unit Info	429	58,919	18.5%	94.8%	97.3%	8,066			475,252	2,433,158	4.13	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		79,556					636,195	1,000,000	636,195	3,231,223	4.06	5.08
34	Plant Unit Info	429	79,669	25.0%	94.8%	97.7%	8,001			637,413	3,256,818	4.09	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	0	0.0%	69.4%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		705					1,726	6,400,348	11,047	163,725	23.22	94.86
4	Gas		3,993					41,931	1,000,000	41,931	212,957	5.33	5.08
5	Plant Unit Info	789	4,698	0.8%	95.2%	74.5%	11,277			52,978	376,681	8.02	
6	*Manatee 3*												
7	Gas		501,065					3,541,916	1,000,000	3,541,916	17,988,799	3.59	5.08
8	Plant Unit Info	1,078	501,065	62.5%	94.9%	96.6%	7,069			3,541,916	17,988,799	3.59	
9	*Martin 1*												
10	Heavy 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	799	0	0.0%	1.7%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		2,630					4,157	6,400,289	26,606	394,324	14.99	94.86
15	Gas		14,905					178,306	1,000,000	178,306	905,735	6.08	5.08
16	Plant Unit Info	799	17,535	3.0%	95.2%	54.9%	11,686			204,912	1,300,059	7.41	
17	*Martin 3*												
18	Gas		122,837					948,126	1,000,000	948,126	4,815,384	3.92	5.08
19	Plant Unit Info	438	122,837	37.7%	94.8%	97.7%	7,719			948,126	4,815,384	3.92	
20	*Martin 4*												
21	Gas		105,760					821,025	1,000,000	821,025	4,169,854	3.94	5.08
22	Plant Unit Info	437	105,760	32.6%	94.8%	97.7%	7,763			821,025	4,169,854	3.94	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		727,350					5,035,260	1,000,000	5,035,260	25,572,763	3.52	5.08
26	Plant Unit Info	1,111	727,595	88.0%	94.8%	88.0%	6,924			5,037,763	25,625,300	3.52	
27	*Martin 8 Solar*												
28	Solar		14,070					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	14,070	25.2%	N/A	46.6%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		14,858					141,744	1,000,000	141,744	719,967	4.85	5.08
33	Plant Unit Info	247	14,904	8.2%	95.1%	94.1%	9,545			142,260	730,744	4.90	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		17,569					163,986	1,000,000	163,986	832,927	4.74	5.08
37	Plant Unit Info	250	17,615	9.5%	95.1%	97.5%	9,339			164,503	843,827	4.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		831,274					5,601,394	1,000,000	5,601,394	28,448,011	3.42	5.08
4	Plant Unit Info	1,212	831,525	92.2%	94.5%	92.2%	6,739			5,603,775	28,497,977	3.43	
5	*Sanford 4*												
6	Gas		322,340					2,419,285	1,000,000	2,419,285	12,287,337	3.81	5.08
7	Plant Unit Info	939	322,340	46.1%	94.9%	97.8%	7,505			2,419,285	12,287,337	3.81	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	0.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		419,496					258,200	17,000,031	4,389,408	10,922,755	2.60	42.30
13	Plant Unit Info	641	419,496	88.0%	94.4%	88.0%	10,464			4,389,408	10,922,755	2.60	
14	*St Johns 1*												
15	Coal		45,632					23,334	22,000,300	513,355	1,634,785	3.58	70.06
16	Plant Unit Info	127	45,632	48.3%	94.4%	48.3%	11,250			513,355	1,634,785	3.58	
17	*St Johns 2*												
18	Coal		56,852					28,713	21,999,617	631,675	2,011,639	3.54	70.06
19	Plant Unit Info	127	56,852	60.2%	94.4%	60.2%	11,111			631,675	2,011,639	3.54	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,893					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,893	25.5%	N/A	47.0%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		1,209					1,889	6,400,212	12,090	179,187	14.82	94.86
31	Gas		12,339					138,549	1,000,000	138,549	703,739	5.70	5.08
32	Plant Unit Info	379	13,548	4.8%	94.6%	44.6%	11,119			150,639	882,925	6.52	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		644,863					4,461,499	1,000,000	4,461,499	22,658,936	3.51	5.08
5	Plant Unit Info	1,138	645,105	76.2%	94.8%	93.2%	6,920			4,463,972	22,710,861	3.52	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		798,166					5,533,833	1,000,000	5,533,833	28,104,887	3.52	5.08
9	Plant Unit Info	1,166	798,388	92.1%	94.8%	92.0%	6,934			5,535,967	28,149,708	3.53	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		789,821					5,439,541	1,000,000	5,439,541	27,626,000	3.50	5.08
13	Plant Unit Info	1,159	790,048	91.6%	94.9%	92.6%	6,888			5,441,719	27,671,801	3.50	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		782,050					5,426,017	1,000,000	5,426,017	27,557,318	3.52	5.08
17	Plant Unit Info	1,166	782,277	90.2%	94.9%	90.1%	6,939			5,428,195	27,603,119	3.53	
18	**System Totals**												
19	Plant Unit Info	24,939	10,034,766				8,144			81,723,906	282,528,678	2.82	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,332	19.97	122.46
4	Gas		810,222					5,465,921	1,000,000	5,465,921	27,210,019	3.36	4.98
5	Plant Unit Info	1,210	810,474	93.1%	94.5%	93.0%	6,747			5,468,315	27,260,351	3.36	
6	*Desoto Solar*												
7	Solar		5,102					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,102	28.4%	N/A	52.3%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	87.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		316,993					2,427,505	1,000,000	2,427,505	12,084,714	3.81	4.98
18	Plant Unit Info	1,383	316,993	31.8%	47.7%	50.3%	7,658			2,427,505	12,084,714	3.81	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,615	22.18	122.46
21	Gas		29,001					317,885	1,000,000	317,885	1,582,494	5.46	4.98
22	Plant Unit Info	296	29,112	27.4%	95.1%	98.1%	10,960			319,055	1,607,109	5.52	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		5,210					117,085	1,000,000	117,085	582,873	11.19	4.98
26	Plant Unit Info	840	5,210	0.9%	95.3%	47.7%	22,473			117,085	582,873	11.19	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,472	22.74	122.46
29	Gas		88,836					707,360	1,000,000	707,360	3,521,431	3.96	4.98
30	Plant Unit Info	429	88,948	28.9%	94.8%	97.3%	7,966			708,572	3,546,903	3.99	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,595	22.65	122.46
33	Gas		108,531					858,417	1,000,000	858,417	4,273,411	3.94	4.98
34	Plant Unit Info	429	108,644	35.2%	94.8%	97.7%	7,912			859,635	4,299,006	3.96	
35	*Manatee 1*												
36	Heavy Oil		3,117					7,363	6,399,837	47,122	701,759	22.51	95.31
37	Gas		17,665					185,174	1,000,000	185,174	921,819	5.22	4.98

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	20,782	3.7%	95.2%	82.4%	11,178			232,296	1,623,578	7.81	
2	*Manatee 2*												
3	Heavy Oil		8,700					19,825	6,400,050	126,881	1,889,498	21.72	95.31
4	Gas		49,301					516,940	1,000,000	516,940	2,573,390	5.22	4.98
5	Plant Unit Info	789	58,001	10.2%	95.2%	90.8%	11,100			643,821	4,462,889	7.69	
6	*Manatee 3*												
7	Gas		601,979					4,221,875	1,000,000	4,221,875	21,017,186	3.49	4.98
8	Plant Unit Info	1,078	601,979	77.5%	94.9%	94.3%	7,013			4,221,875	21,017,186	3.49	
9	*Martin 1*												
10	Heavy Oil		14,318					22,339	6,399,884	142,967	2,129,105	14.87	95.31
11	Gas		81,136					922,655	1,000,000	922,655	4,593,537	5.66	4.98
12	Plant Unit Info	799	95,454	16.6%	95.3%	75.1%	11,164			1,065,622	6,722,642	7.04	
13	*Martin 2*												
14	Heavy Oil		12,570					19,552	6,400,010	125,133	1,863,479	14.82	95.31
15	Gas		71,231					808,541	1,000,000	808,541	4,025,370	5.65	4.98
16	Plant Unit Info	799	83,801	14.6%	95.2%	75.4%	11,142			933,674	5,888,849	7.03	
17	*Martin 3*												
18	Gas		153,924					1,182,621	1,000,000	1,182,621	5,887,385	3.82	4.98
19	Plant Unit Info	438	153,924	48.8%	94.8%	96.8%	7,683			1,182,621	5,887,385	3.82	
20	*Martin 4*												
21	Gas		138,171					1,067,611	1,000,000	1,067,611	5,314,851	3.85	4.98
22	Plant Unit Info	437	138,171	44.0%	94.8%	97.7%	7,727			1,067,611	5,314,851	3.85	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,537	21.44	122.46
25	Gas		715,511					4,956,290	1,000,000	4,956,290	24,673,018	3.45	4.98
26	Plant Unit Info	1,111	715,756	89.5%	94.8%	89.4%	6,928			4,958,793	24,725,554	3.45	
27	*Martin 8 Solar*												
28	Solar		13,207					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	13,207	24.5%	N/A	45.2%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,777	23.43	122.46
32	Gas		29,808					279,837	1,000,000	279,837	1,393,104	4.67	4.98
33	Plant Unit Info	247	29,854	16.9%	95.1%	97.5%	9,391			280,353	1,403,881	4.70	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,899	23.69	122.46
36	Gas		35,041					322,546	1,000,000	322,546	1,605,696	4.58	4.98
37	Plant Unit Info	250	35,087	19.5%	95.1%	97.9%	9,207			323,063	1,616,595	4.61	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,965	19.91	122.46
3	Gas		805,944					5,431,552	1,000,000	5,431,552	27,038,928	3.35	4.98
4	Plant Unit Info	1,212	806,195	92.4%	94.5%	92.4%	6,740			5,433,933	27,088,893	3.36	
5	*Sanford 4*												
6	Gas		384,786					2,872,574	1,000,000	2,872,574	14,300,401	3.72	4.98
7	Plant Unit Info	939	384,786	56.9%	94.9%	97.8%	7,465			2,872,574	14,300,401	3.72	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	78.3%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		413,790					254,464	16,999,988	4,325,885	10,777,125	2.60	42.35
13	Plant Unit Info	641	413,790	89.7%	94.4%	89.7%	10,454			4,325,885	10,777,125	2.60	
14	*St Johns 1*												
15	Coal		50,882					25,589	22,000,156	562,962	1,801,263	3.54	70.39
16	Plant Unit Info	127	50,882	55.7%	94.4%	55.7%	11,064			562,962	1,801,263	3.54	
17	*St Johns 2*												
18	Coal		62,494					31,128	22,000,000	684,816	2,191,165	3.51	70.39
19	Plant Unit Info	127	62,494	68.4%	94.4%	68.4%	10,958			684,816	2,191,165	3.51	
20	*St Lucie 1*												
21	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,635,300	0.67	0.64
22	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,635,300	0.67	
23	*St Lucie 2*												
24	Nuclear		589,677					6,189,149	1,000,000	6,189,149	3,847,800	0.65	0.62
25	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,496			6,189,149	3,847,800	0.65	
26	*Space Coast*												
27	Solar		1,651					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,651	22.9%	N/A	42.3%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		3,822					5,735	6,399,826	36,703	546,596	14.30	95.31
31	Gas		48,432					508,163	1,000,000	508,163	2,529,801	5.22	4.98
32	Plant Unit Info	379	52,254	19.1%	94.6%	74.0%	10,427			544,866	3,076,397	5.89	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,924	21.46	122.46
4	Gas		472,286					3,268,762	1,000,000	3,268,762	16,272,416	3.45	4.98
5	Plant Unit Info	1,138	472,528	57.7%	65.7%	87.0%	6,923			3,271,235	16,324,341	3.45	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,822	20.19	122.46
8	Gas		788,050					5,459,694	1,000,000	5,459,694	27,179,023	3.45	4.98
9	Plant Unit Info	1,166	788,272	93.9%	94.8%	93.9%	6,929			5,461,828	27,223,844	3.45	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
12	Gas		783,414					5,394,575	1,000,000	5,394,575	26,854,850	3.43	4.98
13	Plant Unit Info	1,159	783,641	93.9%	94.9%	93.8%	6,887			5,396,753	26,900,651	3.43	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,801	20.18	122.46
16	Gas		773,609					5,365,890	1,000,000	5,365,890	26,712,055	3.45	4.98
17	Plant Unit Info	1,166	773,836	92.2%	94.9%	92.1%	6,937			5,368,068	26,757,856	3.46	
18	**System Totals**												
19	Plant Unit Info	24,956	10,324,830				8,224			84,907,333	301,478,404	2.92	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,432	20.01	122.71
4	Gas		836,805					5,644,922	1,000,000	5,644,922	27,961,206	3.34	4.95
5	Plant Unit Info	1,210	837,057	93.0%	94.5%	93.0%	6,747			5,647,316	28,011,638	3.35	
6	*Desoto Solar*												
7	Solar		5,051					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	5,051	27.2%	N/A	50.1%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,255					3,956	5,829,373	23,061	485,428	38.68	122.71
15	Plant Unit Info	648	1,255	0.3%	89.7%	38.7%	18,375			23,061	485,428	38.68	
16	*Fort Myers 2*												
17	Gas		669,444					4,850,580	1,000,000	4,850,580	24,026,705	3.59	4.95
18	Plant Unit Info	1,383	669,444	65.1%	79.4%	79.2%	7,246			4,850,580	24,026,705	3.59	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,664	22.22	122.71
21	Gas		35,816					391,920	1,000,000	391,920	1,941,392	5.42	4.95
22	Plant Unit Info	296	35,927	32.7%	95.1%	98.1%	10,941			393,090	1,966,056	5.47	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,523	22.79	122.71
29	Gas		101,765					810,526	1,000,000	810,526	4,014,973	3.95	4.95
30	Plant Unit Info	429	101,877	32.0%	94.8%	97.3%	7,968			811,738	4,040,496	3.97	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,646	22.70	122.71
33	Gas		119,845					950,194	1,000,000	950,194	4,706,821	3.93	4.95
34	Plant Unit Info	429	119,958	37.6%	94.8%	97.7%	7,931			951,412	4,732,467	3.95	
35	*Manatee 1*												
36	Heavy Oil		19,005					40,264	6,400,035	257,691	3,836,904	20.19	95.29
37	Gas		79,382					831,922	1,000,000	831,922	4,120,791	5.19	4.95

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	98,387	16.8%	95.2%	88.5%	11,075			1,089,613	7,957,695	8.09	
2	*Manatee 2*												
3	Heavy Oil		6,610					15,313	6,400,052	98,004	1,459,232	22.08	95.29
4	Gas		37,456					392,725	1,000,000	392,725	1,945,300	5.19	4.95
5	Plant Unit Info	789	44,066	7.5%	95.2%	86.0%	11,136			490,729	3,404,532	7.73	
6	*Manatee 3*												
7	Gas		180,874					1,282,964	1,000,000	1,282,964	6,355,065	3.51	4.95
8	Plant Unit Info	1,078	180,874	22.5%	62.6%	77.3%	7,093			1,282,964	6,355,065	3.51	
9	*Martin 1*												
10	Heavy Oil		20,439					31,854	6,400,044	203,867	3,035,484	14.85	95.29
11	Gas		115,819					1,313,010	1,000,000	1,313,010	6,504,328	5.62	4.95
12	Plant Unit Info	799	136,258	22.9%	95.3%	74.1%	11,132			1,516,877	9,539,812	7.00	
13	*Martin 2*												
14	Heavy Oil		16,225					25,232	6,399,889	161,482	2,404,450	14.82	95.29
15	Gas		91,944					1,048,816	1,000,000	1,048,816	5,195,581	5.65	4.95
16	Plant Unit Info	799	108,169	18.2%	95.2%	73.6%	11,189			1,210,298	7,600,030	7.03	
17	*Martin 3*												
18	Gas		163,498					1,255,889	1,000,000	1,255,889	6,220,954	3.80	4.95
19	Plant Unit Info	438	163,498	50.2%	94.8%	97.7%	7,681			1,255,889	6,220,954	3.80	
20	*Martin 4*												
21	Gas		144,567					1,117,564	1,000,000	1,117,564	5,535,784	3.83	4.95
22	Plant Unit Info	437	144,567	44.5%	94.8%	97.7%	7,730			1,117,564	5,535,784	3.83	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,641	21.49	122.71
25	Gas		744,751					5,157,904	1,000,000	5,157,904	25,548,841	3.43	4.95
26	Plant Unit Info	1,111	744,996	90.1%	94.8%	90.1%	6,927			5,160,407	25,601,482	3.44	
27	*Martin 8 Solar*												
28	Solar		12,594					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	12,594	22.6%	N/A	36.1%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,798	23.47	122.71
32	Gas		35,616					333,618	1,000,000	333,618	1,652,616	4.64	4.95
33	Plant Unit Info	247	35,662	19.5%	95.1%	96.9%	9,369			334,134	1,663,415	4.66	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,921	23.74	122.71
36	Gas		40,720					374,398	1,000,000	374,398	1,854,576	4.55	4.95
37	Plant Unit Info	250	40,766	21.9%	95.1%	97.4%	9,197			374,915	1,865,497	4.58	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,064	19.95	122.71
3	Gas		832,533					5,610,686	1,000,000	5,610,686	27,791,623	3.34	4.95
4	Plant Unit Info	1,212	832,784	92.3%	94.5%	92.3%	6,740			5,613,067	27,841,688	3.34	
5	*Sanford 4*												
6	Gas		412,378					3,072,914	1,000,000	3,072,914	15,221,487	3.69	4.95
7	Plant Unit Info	939	412,378	59.0%	94.9%	96.3%	7,452			3,072,914	15,221,487	3.69	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		430,247					264,553	17,000,008	4,497,403	11,233,930	2.61	42.46
13	Plant Unit Info	641	430,247	90.3%	94.4%	90.3%	10,453			4,497,403	11,233,930	2.61	
14	*St Johns 1*												
15	Coal		54,729					27,413	22,000,292	603,094	1,932,831	3.53	70.51
16	Plant Unit Info	127	54,729	58.0%	94.4%	58.0%	11,020			603,094	1,932,831	3.53	
17	*St Johns 2*												
18	Coal		67,606					33,500	22,000,149	737,005	2,362,012	3.49	70.51
19	Plant Unit Info	127	67,606	71.6%	94.4%	71.6%	10,901			737,005	2,362,012	3.49	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,751					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,751	23.5%	N/A	43.5%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		18,298					27,322	6,400,044	174,862	2,603,613	14.23	95.29
31	Gas		46,776					491,849	1,000,000	491,849	2,436,417	5.21	4.95
32	Plant Unit Info	379	65,074	23.1%	94.6%	81.3%	10,245			666,711	5,040,031	7.75	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,028	21.50	122.71
4	Gas		738,961					5,088,574	1,000,000	5,088,574	25,205,459	3.41	4.95
5	Plant Unit Info	1,138	739,203	87.3%	94.8%	93.8%	6,887			5,091,047	25,257,487	3.42	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,911	20.23	122.71
8	Gas		800,003					5,538,214	1,000,000	5,538,214	27,432,648	3.43	4.95
9	Plant Unit Info	1,166	800,225	92.3%	94.8%	92.2%	6,923			5,540,348	27,477,558	3.43	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,892	20.22	122.71
12	Gas		817,592					5,627,290	1,000,000	5,627,290	27,873,871	3.41	4.95
13	Plant Unit Info	1,159	817,819	94.9%	94.9%	94.8%	6,884			5,629,468	27,919,763	3.41	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,892	20.22	122.71
16	Gas		810,968					5,619,890	1,000,000	5,619,890	27,837,216	3.43	4.95
17	Plant Unit Info	1,166	811,195	93.5%	94.9%	93.5%	6,931			5,622,068	27,883,109	3.44	
18	**System Totals**												
19	Plant Unit Info	24,956	11,018,219				8,226			90,630,714	328,735,352	2.98	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,341	19.98	122.48
4	Gas		837,651					5,651,073	1,000,000	5,651,073	27,897,354	3.33	4.94
5	Plant Unit Info	1,210	837,903	93.1%	94.5%	93.0%	6,747			5,653,467	27,947,695	3.34	
6	*Desoto Solar*												
7	Solar		4,802					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,802	25.8%	N/A	47.7%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		735,620					5,303,496	1,000,000	5,303,496	26,181,756	3.56	4.94
18	Plant Unit Info	1,400	735,620	70.6%	95.0%	94.3%	7,210			5,303,496	26,181,756	3.56	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,619	22.18	122.48
21	Gas		28,566					313,649	1,000,000	313,649	1,548,443	5.42	4.94
22	Plant Unit Info	296	28,677	26.1%	95.1%	98.1%	10,978			314,819	1,573,062	5.49	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		755					16,511	1,000,000	16,511	81,476	10.79	4.93
26	Plant Unit Info	840	755	0.1%	95.3%	44.9%	21,869			16,511	81,476	10.79	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,477	22.75	122.48
29	Gas		85,917					686,968	1,000,000	686,968	3,391,470	3.95	4.94
30	Plant Unit Info	429	86,029	27.0%	94.8%	97.3%	7,999			688,180	3,416,947	3.97	
31	*Lauderdale 5*												
32	Light Oil		115					212	5,830,189	1,236	25,967	22.58	122.48
33	Gas		103,500					824,830	1,000,000	824,830	4,072,095	3.93	4.94
34	Plant Unit Info	429	103,615	32.5%	94.8%	97.7%	7,972			826,066	4,098,061	3.96	
35	*Manatee 1*												
36	Heavy Oil		16,193					31,488	6,399,930	201,521	2,996,793	18.51	95.17
37	Gas		40,177					420,791	1,000,000	420,791	2,077,297	5.17	4.94

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	56,370	9.6%	95.2%	87.2%	11,040			622,312	5,074,090	9.00	
2	*Manatee 2*												
3	Heavy Oil		6,403					11,846	6,400,051	75,815	1,127,414	17.61	95.17
4	Gas		10,148					106,201	1,000,000	106,201	524,277	5.17	4.94
5	Plant Unit Info	789	16,551	2.8%	95.2%	87.4%	10,997			182,016	1,651,691	9.98	
6	*Manatee 3*												
7	Gas		588,587					4,136,187	1,000,000	4,136,187	20,419,068	3.47	4.94
8	Plant Unit Info	1,078	588,587	73.4%	93.2%	94.3%	7,027			4,136,187	20,419,068	3.47	
9	*Martin 1*												
10	Heavy Oil		15,210					23,726	6,399,941	151,845	2,258,064	14.85	95.17
11	Gas		86,189					983,479	1,000,000	983,479	4,855,480	5.63	4.94
12	Plant Unit Info	799	101,399	17.1%	95.3%	71.7%	11,197			1,135,324	7,113,544	7.02	
13	*Martin 2*												
14	Heavy Oil		12,032					18,712	6,400,118	119,759	1,780,869	14.80	95.17
15	Gas		68,181					776,569	1,000,000	776,569	3,833,980	5.62	4.94
16	Plant Unit Info	799	80,213	13.5%	95.2%	71.7%	11,174			896,328	5,614,849	7.00	
17	*Martin 3*												
18	Gas		148,945					1,146,314	1,000,000	1,146,314	5,659,128	3.80	4.94
19	Plant Unit Info	438	148,945	45.7%	94.8%	97.7%	7,696			1,146,314	5,659,128	3.80	
20	*Martin 4*												
21	Gas		131,774					1,020,859	1,000,000	1,020,859	5,039,801	3.82	4.94
22	Plant Unit Info	437	131,774	40.6%	94.8%	97.7%	7,747			1,020,859	5,039,801	3.82	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,546	21.45	122.48
25	Gas		743,406					5,147,426	1,000,000	5,147,426	25,411,027	3.42	4.94
26	Plant Unit Info	1,111	743,651	90.0%	94.8%	89.9%	6,925			5,149,929	25,463,572	3.42	
27	*Martin 8 Solar*												
28	Solar		11,773					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	11,773	21.1%	N/A	39.0%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,779	23.43	122.48
32	Gas		27,104					255,570	1,000,000	255,570	1,261,753	4.66	4.94
33	Plant Unit Info	247	27,150	14.8%	95.1%	97.3%	9,432			256,086	1,272,531	4.69	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,901	23.70	122.48
36	Gas		31,580					292,066	1,000,000	292,066	1,441,879	4.57	4.94
37	Plant Unit Info	250	31,626	17.0%	95.1%	97.1%	9,251			292,583	1,452,780	4.59	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	49,973	19.91	122.48
3	Gas		833,741					5,619,403	1,000,000	5,619,403	27,741,011	3.33	4.94
4	Plant Unit Info	1,212	833,992	92.5%	94.5%	92.5%	6,741			5,621,784	27,790,984	3.33	
5	*Sanford 4*												
6	Gas		381,113					2,847,981	1,000,000	2,847,981	14,059,898	3.69	4.94
7	Plant Unit Info	939	381,113	54.6%	94.9%	97.8%	7,473			2,847,981	14,059,898	3.69	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		429,907					264,351	17,000,019	4,493,972	11,260,146	2.62	42.60
13	Plant Unit Info	641	429,907	90.2%	94.4%	90.2%	10,453			4,493,972	11,260,146	2.62	
14	*St Johns 1*												
15	Coal		52,949					26,614	21,999,662	585,499	1,883,480	3.56	70.77
16	Plant Unit Info	127	52,949	56.1%	94.4%	56.1%	11,058			585,499	1,883,480	3.56	
17	*St Johns 2*												
18	Coal		66,438					32,927	21,999,909	724,391	2,330,253	3.51	70.77
19	Plant Unit Info	127	66,438	70.4%	94.4%	70.4%	10,903			724,391	2,330,253	3.51	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		609,333					6,395,458	1,000,000	6,395,458	3,976,100	0.65	0.62
25	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,496			6,395,458	3,976,100	0.65	
26	*Space Coast*												
27	Solar		1,662					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,662	22.4%	N/A	41.3%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		17,964					26,975	6,399,926	172,638	2,567,280	14.29	95.17
31	Gas		34,740					371,245	1,000,000	371,245	1,832,810	5.28	4.94
32	Plant Unit Info	379	52,704	18.7%	94.6%	72.3%	10,320			543,883	4,400,089	8.35	
33	*Turkey Point 3*												
34	Nuclear		588,294					6,568,489	1,000,000	6,568,489	4,429,100	0.75	0.67
35	Plant Unit Info	811	588,294	97.5%	97.5%	97.5%	11,165			6,568,489	4,429,100	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	51,933	21.46	122.48
4	Gas		795,378					5,467,357	1,000,000	5,467,357	26,990,413	3.39	4.94
5	Plant Unit Info	1,138	795,620	94.0%	94.8%	93.9%	6,875			5,469,830	27,042,346	3.40	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,829	20.19	122.48
8	Gas		802,480					5,555,315	1,000,000	5,555,315	27,424,631	3.42	4.94
9	Plant Unit Info	1,166	802,702	92.6%	94.8%	92.5%	6,923			5,557,449	27,469,460	3.42	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,809	20.18	122.48
12	Gas		794,953					5,471,075	1,000,000	5,471,075	27,008,768	3.40	4.94
13	Plant Unit Info	1,159	795,180	92.2%	94.9%	92.2%	6,883			5,473,253	27,054,576	3.40	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,809	20.18	122.48
16	Gas		811,797					5,624,653	1,000,000	5,624,653	27,766,928	3.42	4.94
17	Plant Unit Info	1,166	812,024	93.6%	94.9%	93.6%	6,929			5,626,831	27,812,737	3.43	
18	**System Totals**												
19	Plant Unit Info	24,973	11,264,534				8,135			91,632,353	330,722,421	2.94	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,958	20.22	123.99
4	Gas		811,270					5,473,519	1,000,000	5,473,519	26,927,328	3.32	4.92
5	Plant Unit Info	1,210	811,522	93.2%	94.5%	93.1%	6,748			5,475,913	26,978,286	3.32	
6	*Desoto Solar*												
7	Solar		4,271					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,271	23.7%	N/A	43.8%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		11,495					37,280	5,830,016	217,343	4,622,191	40.21	123.99
15	Plant Unit Info	648	11,495	2.5%	95.3%	42.2%	18,908			217,343	4,622,191	40.21	
16	*Fort Myers 2*												
17	Gas		741,904					5,338,631	1,000,000	5,338,631	26,263,983	3.54	4.92
18	Plant Unit Info	1,400	741,904	73.6%	95.0%	93.8%	7,196			5,338,631	26,263,983	3.54	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,921	22.45	123.99
21	Gas		35,091					384,793	1,000,000	384,793	1,893,113	5.39	4.92
22	Plant Unit Info	296	35,202	33.1%	95.1%	98.1%	10,964			385,963	1,918,034	5.45	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		5,454					121,606	1,000,000	121,606	598,220	10.97	4.92
26	Plant Unit Info	840	5,454	0.9%	95.3%	46.4%	22,297			121,606	598,220	10.97	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,789	23.03	123.99
29	Gas		98,846					787,134	1,000,000	787,134	3,872,513	3.92	4.92
30	Plant Unit Info	429	98,958	32.1%	94.8%	97.3%	7,966			788,346	3,898,302	3.94	
31	*Lauderdale 5*												
32	Light Oil		137					240	5,816,667	1,396	29,757	21.72	123.99
33	Gas		118,983					942,578	1,000,000	942,578	4,637,259	3.90	4.92
34	Plant Unit Info	429	119,120	38.6%	94.8%	97.7%	7,925			943,974	4,667,016	3.92	
35	*Manatee 1*												
36	Heavy Oil		27,597					57,380	6,399,965	367,230	5,481,007	19.86	95.52
37	Gas		104,987					1,099,393	1,000,000	1,099,393	5,408,535	5.15	4.92

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	132,584	23.4%	95.2%	85.3%	11,062			1,466,623	10,889,542	8.21	
2	*Manatee 2*												
3	Heavy Oil		19,675					41,898	6,400,043	268,149	4,002,148	20.34	95.52
4	Gas		77,616					812,475	1,000,000	812,475	3,997,023	5.15	4.92
5	Plant Unit Info	789	97,291	17.1%	95.2%	85.1%	11,107			1,080,624	7,999,171	8.22	
6	*Manatee 3*												
7	Gas		646,090					4,518,529	1,000,000	4,518,529	22,229,327	3.44	4.92
8	Plant Unit Info	1,078	646,090	83.2%	94.9%	95.2%	6,994			4,518,529	22,229,327	3.44	
9	*Martin 1*												
10	Heavy Oil		20,529					32,061	6,400,050	205,192	3,062,505	14.92	95.52
11	Gas		116,328					1,324,892	1,000,000	1,324,892	6,518,462	5.60	4.92
12	Plant Unit Info	799	136,857	23.8%	95.3%	72.0%	11,180			1,530,084	9,580,968	7.00	
13	*Martin 2*												
14	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		147,233					1,132,623	1,000,000	1,132,623	5,572,121	3.78	4.92
19	Plant Unit Info	438	147,233	46.7%	94.8%	97.7%	7,693			1,132,623	5,572,121	3.78	
20	*Martin 4*												
21	Gas		137,744					1,065,188	1,000,000	1,065,188	5,240,370	3.80	4.92
22	Plant Unit Info	437	137,744	43.8%	94.8%	97.7%	7,733			1,065,188	5,240,370	3.80	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	53,190	21.71	123.99
25	Gas		725,268					5,021,676	1,000,000	5,021,676	24,704,461	3.41	4.92
26	Plant Unit Info	1,111	725,513	90.7%	94.8%	90.6%	6,925			5,024,179	24,757,651	3.41	
27	*Martin 8 Solar*												
28	Solar		10,217					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	10,217	18.9%	N/A	37.8%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,911	23.72	123.99
32	Gas		35,937					337,089	1,000,000	337,089	1,658,444	4.61	4.92
33	Plant Unit Info	247	35,983	20.3%	95.1%	96.5%	9,382			337,605	1,669,355	4.64	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	11,035	23.99	123.99
36	Gas		41,464					381,608	1,000,000	381,608	1,877,423	4.53	4.92
37	Plant Unit Info	250	41,510	23.1%	95.1%	96.9%	9,206			382,125	1,888,458	4.55	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,586	20.15	123.99
3	Gas		807,164					5,440,514	1,000,000	5,440,514	26,764,957	3.32	4.92
4	Plant Unit Info	1,212	807,415	92.5%	94.5%	92.5%	6,741			5,442,895	26,815,544	3.32	
5	*Sanford 4*												
6	Gas		368,256					2,752,004	1,000,000	2,752,004	13,539,010	3.68	4.92
7	Plant Unit Info	939	368,256	54.5%	94.9%	97.8%	7,473			2,752,004	13,539,010	3.68	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		418,248					257,159	16,999,996	4,371,702	10,966,015	2.62	42.64
13	Plant Unit Info	641	418,248	90.7%	94.4%	90.7%	10,452			4,371,702	10,966,015	2.62	
14	*St Johns 1*												
15	Coal		52,049					26,126	21,999,809	574,767	1,852,032	3.56	70.89
16	Plant Unit Info	127	52,049	57.0%	94.4%	57.0%	11,043			574,767	1,852,032	3.56	
17	*St Johns 2*												
18	Coal		64,440					31,966	21,999,937	703,250	2,266,021	3.52	70.89
19	Plant Unit Info	127	64,440	70.5%	94.4%	70.5%	10,913			703,250	2,266,021	3.52	
20	*St Lucie 1*												
21	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,635,300	0.67	0.64
22	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,635,300	0.67	
23	*St Lucie 2*												
24	Nuclear		117,936					1,237,824	1,000,000	1,237,824	769,600	0.65	0.62
25	Plant Unit Info	840	117,936	19.5%	19.5%	97.5%	10,496			1,237,824	769,600	0.65	
26	*Space Coast*												
27	Solar		1,472					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,472	20.5%	N/A	37.8%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		22,020					32,850	6,400,030	210,241	3,137,872	14.25	95.52
31	Gas		45,818					482,734	1,000,000	482,734	2,374,972	5.18	4.92
32	Plant Unit Info	379	67,838	24.8%	94.6%	82.0%	10,215			692,975	5,512,844	8.13	
33	*Turkey Point 3*												
34	Nuclear		569,316					6,356,602	1,000,000	6,356,602	4,286,300	0.75	0.67
35	Plant Unit Info	811	569,316	97.5%	97.5%	97.5%	11,165			6,356,602	4,286,300	0.75	
36	*Turkey Point 4*												
37	Nuclear		576,343					6,356,602	1,000,000	6,356,602	4,222,700	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	576,343	97.5%	97.5%	97.5%	11,029			6,356,602	4,222,700	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,570	21.72	123.99
4	Gas		743,930					5,116,714	1,000,000	5,116,714	25,172,073	3.38	4.92
5	Plant Unit Info	1,138	744,172	90.8%	94.8%	94.4%	6,879			5,119,187	25,224,643	3.39	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	45,379	20.44	123.99
8	Gas		776,156					5,373,117	1,000,000	5,373,117	26,433,396	3.41	4.92
9	Plant Unit Info	1,166	776,378	92.5%	94.8%	92.5%	6,923			5,375,251	26,478,775	3.41	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	46,371	20.43	123.99
12	Gas		769,937					5,299,106	1,000,000	5,299,106	26,069,294	3.39	4.92
13	Plant Unit Info	1,159	770,164	92.3%	94.9%	92.2%	6,883			5,301,284	26,115,665	3.39	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	46,371	20.43	123.99
16	Gas		494,821					3,454,595	1,000,000	3,454,595	16,995,103	3.43	4.92
17	Plant Unit Info	1,166	495,048	59.0%	66.0%	69.3%	6,983			3,456,773	17,041,474	3.44	
18	**System Totals**												
19	Plant Unit Info	24,973	10,456,687				8,112			84,822,637	328,498,913	3.14	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		836,187					5,640,354	1,000,000	5,640,354	28,621,193	3.42	5.07
5	Plant Unit Info	1,210	836,439	93.0%	94.5%	92.9%	6,746			5,642,748	28,671,603	3.43	
6	*Desoto Solar*												
7	Solar		4,123					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	4,123	22.2%	N/A	40.9%	N/A						
9	*Everglades 1-12*												
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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		778,930					5,595,165	1,000,000	5,595,165	28,392,064	3.65	5.07
18	Plant Unit Info	1,400	778,930	74.8%	95.0%	92.1%	7,183			5,595,165	28,392,064	3.65	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		15,983					200,570	1,000,000	200,570	1,017,867	6.37	5.07
22	Plant Unit Info	296	16,094	14.6%	59.7%	68.4%	12,535			201,740	1,042,520	6.48	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		69,234					555,012	1,000,000	555,012	2,816,481	4.07	5.07
30	Plant Unit Info	429	69,346	21.8%	94.8%	97.3%	8,021			556,224	2,841,993	4.10	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		104,162					823,264	1,000,000	823,264	4,177,691	4.01	5.07
34	Plant Unit Info	429	104,275	32.7%	94.8%	96.4%	7,907			824,482	4,203,325	4.03	
35	*Manatee 1*												
36	Heavy Oil		18,850					34,292	6,400,006	219,469	3,272,934	17.36	95.44
37	Gas		25,933					276,587	1,000,000	276,587	1,403,500	5.41	5.07

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	789	44,783	7.6%	95.2%	60.4%	11,077			496,056	4,676,434	10.44	
2	*Manatee 2*												
3	Heavy Oil		11,210					19,304	6,399,865	123,543	1,842,433	16.44	95.44
4	Gas		4,193					43,813	1,000,000	43,813	222,321	5.30	5.07
5	Plant Unit Info	789	15,403	2.6%	95.2%	81.4%	10,865			167,356	2,064,755	13.40	
6	*Manatee 3*												
7	Gas		592,398					4,155,292	1,000,000	4,155,292	21,085,648	3.56	5.07
8	Plant Unit Info	1,078	592,398	73.8%	94.9%	94.7%	7,014			4,155,292	21,085,648	3.56	
9	*Martin 1*												
10	Heavy Oil		13,018					20,490	6,400,098	131,138	1,955,629	15.02	95.44
11	Gas		56,726					660,012	1,000,000	660,012	3,349,615	5.90	5.08
12	Plant Unit Info	799	69,744	11.7%	95.3%	59.4%	11,344			791,150	5,305,244	7.61	
13	*Martin 2*												
14	Heavy 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	799	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		131,825					1,014,204	1,000,000	1,014,204	5,146,610	3.90	5.07
19	Plant Unit Info	438	131,825	40.5%	91.6%	97.7%	7,694			1,014,204	5,146,610	3.90	
20	*Martin 4*												
21	Gas		62,049					491,271	1,000,000	491,271	2,493,029	4.02	5.07
22	Plant Unit Info	437	62,049	19.1%	60.9%	74.4%	7,917			491,271	2,493,029	4.02	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		740,364					5,125,097	1,000,000	5,125,097	26,006,593	3.51	5.07
26	Plant Unit Info	1,111	740,609	89.6%	94.8%	89.5%	6,923			5,127,600	26,059,211	3.52	
27	*Martin 8 Solar*												
28	Solar		8,981					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	8,981	16.1%	N/A	24.1%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		22,573					212,843	1,000,000	212,843	1,080,088	4.78	5.07
33	Plant Unit Info	247	22,619	12.4%	95.1%	97.4%	9,433			213,359	1,090,882	4.82	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		26,235					243,228	1,000,000	243,228	1,234,288	4.70	5.07
37	Plant Unit Info	250	26,281	14.2%	95.1%	97.1%	9,275			243,745	1,245,204	4.74	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		832,262					5,608,577	1,000,000	5,608,577	28,459,945	3.42	5.07
4	Plant Unit Info	1,212	832,513	92.3%	94.5%	92.3%	6,740			5,610,958	28,509,987	3.42	
5	*Sanford 4*												
6	Gas		335,196					2,506,462	1,000,000	2,506,462	12,719,154	3.79	5.07
7	Plant Unit Info	939	335,196	48.0%	94.9%	97.8%	7,478			2,506,462	12,719,154	3.79	
8	*Sanford 5*												
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	947	0	0.0%	95.0%	0.0%	0			0	0	0.00	
11	*Scherer 4*												
12	Coal		429,486					264,128	17,000,027	4,490,183	11,261,679	2.62	42.64
13	Plant Unit Info	641	429,486	90.1%	94.4%	90.1%	10,455			4,490,183	11,261,679	2.62	
14	*St Johns 1*												
15	Coal		51,126					25,803	22,000,233	567,672	1,833,105	3.59	71.04
16	Plant Unit Info	127	51,126	54.2%	94.4%	54.2%	11,103			567,672	1,833,105	3.59	
17	*St Johns 2*												
18	Coal		64,731					32,160	21,999,782	707,513	2,284,721	3.53	71.04
19	Plant Unit Info	127	64,731	68.6%	94.4%	68.6%	10,930			707,513	2,284,721	3.53	
20	*St Lucie 1*												
21	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,789,800	0.67	0.64
22	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,789,800	0.67	
23	*St Lucie 2*												
24	Nuclear		452,088					4,744,989	1,000,000	4,744,989	3,103,200	0.69	0.65
25	Plant Unit Info	840	452,088	72.3%	72.3%	97.5%	10,496			4,744,989	3,103,200	0.69	
26	*Space Coast*												
27	Solar		1,418					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,418	19.1%	N/A	38.1%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		12,268					18,430	6,399,891	117,950	1,759,016	14.34	95.44
31	Gas		24,988					267,553	1,000,000	267,553	1,357,814	5.43	5.07
32	Plant Unit Info	379	37,256	13.2%	94.6%	70.6%	10,347			385,503	3,116,830	8.37	
33	*Turkey Point 3*												
34	Nuclear		341,592					3,813,961	1,000,000	3,813,961	2,571,800	0.75	0.67
35	Plant Unit Info	811	341,592	56.6%	56.6%	97.5%	11,165			3,813,961	2,571,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,554					6,568,489	1,000,000	6,568,489	4,363,400	0.73	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	821	595,554	97.5%	97.5%	97.5%	11,029			6,568,489	4,363,400	0.73	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		757,702					5,215,755	1,000,000	5,215,755	26,466,643	3.49	5.07
5	Plant Unit Info	1,138	757,944	89.5%	94.8%	93.0%	6,885			5,218,228	26,518,648	3.50	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		791,086					5,478,077	1,000,000	5,478,077	27,797,741	3.51	5.07
9	Plant Unit Info	1,166	791,308	91.3%	94.8%	91.2%	6,926			5,480,211	27,842,632	3.52	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		181,834					1,269,532	1,000,000	1,269,532	6,442,064	3.54	5.07
13	Plant Unit Info	1,159	182,061	21.2%	22.9%	59.6%	6,985			1,271,710	6,487,936	3.56	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		766,320					5,312,945	1,000,000	5,312,945	26,959,799	3.52	5.07
17	Plant Unit Info	1,166	766,547	88.4%	92.7%	91.3%	6,934			5,315,123	27,005,671	3.52	
18	**System Totals**												
19	Plant Unit Info	24,973	9,874,342				8,073			79,715,960	296,727,084	3.01	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		888,714					5,962,540	1,000,000	5,962,540	31,425,250	3.54	5.27
5	Plant Unit Info	1,355	888,966	91.2%	94.5%	91.1%	6,710			5,964,934	31,475,660	3.54	
6	*Desoto Solar*												
7	Solar		3,550					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,550	19.7%	N/A	43.0%	N/A						
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		643,114					4,605,328	1,000,000	4,605,328	24,272,481	3.77	5.27
18	Plant Unit Info	1,476	643,114	60.5%	95.0%	87.0%	7,161			4,605,328	24,272,481	3.77	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		2,745					29,640	1,000,000	29,640	156,244	5.69	5.27
22	Plant Unit Info	314	2,856	2.6%	61.8%	97.0%	10,788			30,810	180,897	6.33	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		19,599					157,127	1,000,000	157,127	828,176	4.23	5.27
30	Plant Unit Info	442	19,711	6.2%	94.8%	90.6%	8,033			158,339	853,688	4.33	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		25,139					201,543	1,000,000	201,543	1,062,339	4.23	5.27
34	Plant Unit Info	442	25,252	8.0%	94.8%	89.0%	8,030			202,761	1,087,974	4.31	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		568,135					3,929,834	1,000,000	3,929,834	20,712,208	3.65	5.27
8	Plant Unit Info	1,134	568,135	69.6%	94.9%	89.8%	6,917			3,929,834	20,712,208	3.65	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	48.6%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		37,736					293,238	1,000,000	293,238	1,545,606	4.10	5.27
19	Plant Unit Info	454	37,736	11.5%	63.2%	81.5%	7,771			293,238	1,545,606	4.10	
20	*Martin 4*												
21	Gas		21,001					172,129	1,000,000	172,129	907,307	4.32	5.27
22	Plant Unit Info	453	21,001	6.4%	94.8%	48.8%	8,196			172,129	907,307	4.32	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		678,098					4,663,931	1,000,000	4,663,931	24,581,029	3.62	5.27
26	Plant Unit Info	1,147	678,343	82.2%	94.8%	84.5%	6,879			4,666,434	24,633,647	3.63	
27	*Martin 8 Solar*												
28	Solar		6,459					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	6,459	12.0%	N/A	19.1%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		2,193					21,931	1,000,000	21,931	115,639	5.27	5.27
33	Plant Unit Info	251	2,239	1.3%	95.1%	58.3%	10,025			22,447	126,433	5.65	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		2,976					28,602	1,000,000	28,602	150,798	5.07	5.27
37	Plant Unit Info	255	3,022	1.7%	95.1%	73.0%	9,636			29,119	161,714	5.35	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		887,760					5,946,178	1,000,000	5,946,178	31,339,018	3.53	5.27
4	Plant Unit Info	1,344	888,011	91.7%	94.5%	91.7%	6,699			5,948,559	31,389,060	3.53	
5	*Sanford 4*												
6	Gas		186,601					1,400,534	1,000,000	1,400,534	7,381,815	3.96	5.27
7	Plant Unit Info	990	186,601	26.2%	61.6%	92.0%	7,506			1,400,534	7,381,815	3.96	
8	*Sanford 5*												
9	Gas		270,302					2,017,359	1,000,000	2,017,359	10,632,789	3.93	5.27
10	Plant Unit Info	994	270,302	37.8%	61.6%	88.3%	7,463			2,017,359	10,632,789	3.93	
11	*Scherer 4*												
12	Coal		421,907					257,346	17,000,004	4,374,883	10,977,597	2.60	42.66
13	Plant Unit Info	646	421,907	90.8%	94.4%	90.8%	10,369			4,374,883	10,977,597	2.60	
14	*St Johns 1*												
15	Coal		39,676					21,088	22,000,379	463,944	1,499,950	3.78	71.13
16	Plant Unit Info	128	39,676	43.0%	94.4%	43.0%	11,693			463,944	1,499,950	3.78	
17	*St Johns 2*												
18	Coal		46,492					23,696	21,999,578	521,302	1,685,452	3.63	71.13
19	Plant Unit Info	128	46,492	50.4%	94.4%	50.4%	11,213			521,302	1,685,452	3.63	
20	*St Lucie 1*												
21	Nuclear		704,105					7,272,165	1,000,000	7,272,165	4,635,300	0.66	0.64
22	Plant Unit Info	1,003	704,105	97.5%	97.5%	97.5%	10,328			7,272,165	4,635,300	0.66	
23	*St Lucie 2*												
24	Nuclear		603,721					6,192,164	1,000,000	6,192,164	4,049,700	0.67	0.65
25	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,257			6,192,164	4,049,700	0.67	
26	*Space Coast*												
27	Solar		1,212					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,212	16.8%	N/A	36.7%	N/A						
29	*Turkey Point 1*												
30	Heavy Oil		0					0	0	0	0	0.00	0.00
31	Gas		1,219					13,881	1,000,000	13,881	73,191	6.00	5.27
32	Plant Unit Info	380	1,219	0.5%	94.6%	40.1%	11,387			13,881	73,191	6.00	
33	*Turkey Point 3*												
34	Nuclear		255,223					2,754,528	1,000,000	2,754,528	1,921,800	0.75	0.70
35	Plant Unit Info	839	255,223	42.3%	42.3%	97.5%	10,793			2,754,528	1,921,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		595,298					6,356,602	1,000,000	6,356,602	4,222,700	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	595,298	97.5%	97.5%	97.5%	10,678			6,356,602	4,222,700	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		141,911					993,718	1,000,000	993,718	5,237,457	3.69	5.27
5	Plant Unit Info	1,166	142,153	17.0%	94.8%	88.8%	7,008			996,191	5,289,461	3.72	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		754,462					5,143,458	1,000,000	5,143,458	27,108,322	3.59	5.27
9	Plant Unit Info	1,208	754,684	86.9%	94.8%	89.0%	6,818			5,145,592	27,153,212	3.60	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		226,911					1,565,300	1,000,000	1,565,300	8,249,833	3.64	5.27
13	Plant Unit Info	1,202	227,138	26.3%	36.0%	64.6%	6,901			1,567,478	8,295,705	3.65	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		664,523					4,532,599	1,000,000	4,532,599	23,888,822	3.59	5.27
17	Plant Unit Info	1,207	664,750	76.5%	94.9%	87.1%	6,822			4,534,777	23,934,694	3.60	
18	**System Totals**												
19	Plant Unit Info	25,993	8,702,875				8,001			69,635,331	249,100,043	2.86	
20													
21													
22													
23													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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 - 2015**												
2	*CCEC 3*												
3	Light Oil		252					411	5,824,818	2,394	50,410	20.00	122.65
4	Gas		894,837					5,998,543	1,000,000	5,998,543	32,594,171	3.64	5.43
5	Plant Unit Info	1,355	895,089	88.8%	94.5%	88.8%	6,704			6,000,937	32,644,582	3.65	
6	*Desoto Solar*												
7	Solar		3,223					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	25	3,223	17.3%	N/A	37.8%	N/A						
9	*Everglades 1-12*												
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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		348,379					2,516,750	1,000,000	2,516,750	13,675,639	3.93	5.43
18	Plant Unit Info	1,476	348,379	31.7%	95.0%	84.0%	7,224			2,516,750	13,675,639	3.93	
19	*Fort Myers 3A_B*												
20	Light Oil		111					201	5,820,896	1,170	24,653	22.21	122.65
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	111	0.1%	95.1%	35.3%	10,541			1,170	24,653	22.21	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		112					208	5,826,923	1,212	25,512	22.78	122.65
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	442	112	0.1%	94.8%	25.4%	10,821			1,212	25,512	22.78	
31	*Lauderdale 5*												
32	Light Oil		113					209	5,827,751	1,218	25,634	22.69	122.65
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	442	113	0.1%	94.8%	25.4%	10,779			1,218	25,634	22.69	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
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	795	0	0.0%	95.2%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		440,454					3,072,274	1,000,000	3,072,274	16,694,171	3.79	5.43
8	Plant Unit Info	1,134	440,454	52.2%	94.9%	88.9%	6,975			3,072,274	16,694,171	3.79	
9	*Martin 1*												
10	Heavy 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	805	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy 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	805	0	0.0%	95.2%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		17,269					132,269	1,000,000	132,269	718,676	4.16	5.43
19	Plant Unit Info	454	17,269	5.1%	94.8%	74.6%	7,659			132,269	718,676	4.16	
20	*Martin 4*												
21	Gas		8,502					65,190	1,000,000	65,190	354,206	4.17	5.43
22	Plant Unit Info	453	8,502	2.5%	94.8%	75.1%	7,668			65,190	354,206	4.17	
23	*Martin 8*												
24	Light Oil		245					429	5,834,499	2,503	52,618	21.48	122.65
25	Gas		608,368					4,194,646	1,000,000	4,194,646	22,792,520	3.75	5.43
26	Plant Unit Info	1,147	608,613	71.4%	94.8%	79.7%	6,896			4,197,149	22,845,138	3.75	
27	*Martin 8 Solar*												
28	Solar		5,345					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75	5,345	9.6%	N/A	19.2%	N/A						
30	*Putnam 1*												
31	Light Oil		46					88	5,863,636	516	10,793	23.46	122.65
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	251	46	0.1%	95.1%	17.9%	11,217			516	10,793	23.46	
34	*Putnam 2*												
35	Light Oil		46					89	5,808,989	517	10,916	23.73	122.65
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	255	46	0.1%	95.1%	17.7%	11,239			517	10,916	23.73	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	*Riviera 5*												
2	Light Oil		251					408	5,835,784	2,381	50,042	19.94	122.65
3	Gas		903,643					6,044,722	1,000,000	6,044,722	32,845,091	3.63	5.43
4	Plant Unit Info	1,344	903,894	90.4%	94.5%	90.4%	6,690			6,047,103	32,895,133	3.64	
5	*Sanford 4*												
6	Gas		72,242					539,164	1,000,000	539,164	2,929,751	4.06	5.43
7	Plant Unit Info	990	72,242	9.8%	94.9%	77.7%	7,463			539,164	2,929,751	4.06	
8	*Sanford 5*												
9	Gas		98,528					739,482	1,000,000	739,482	4,018,340	4.08	5.43
10	Plant Unit Info	994	98,528	13.3%	95.0%	78.1%	7,505			739,482	4,018,340	4.08	
11	*Scherer 4*												
12	Coal		453,573					276,491	16,999,975	4,700,340	11,803,163	2.60	42.69
13	Plant Unit Info	646	453,573	94.4%	94.4%	94.4%	10,363			4,700,340	11,803,163	2.60	
14	*St Johns 1*												
15	Coal		44,215					23,059	21,999,827	507,294	1,639,517	3.71	71.10
16	Plant Unit Info	128	44,215	46.4%	94.4%	46.4%	11,473			507,294	1,639,517	3.71	
17	*St Johns 2*												
18	Coal		46,548					23,861	21,999,790	524,937	1,696,540	3.64	71.10
19	Plant Unit Info	128	46,548	48.8%	94.4%	48.8%	11,277			524,937	1,696,540	3.64	
20	*St Lucie 1*												
21	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,789,800	0.66	0.64
22	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,789,800	0.66	
23	*St Lucie 2*												
24	Nuclear		623,845					6,398,566	1,000,000	6,398,566	4,184,700	0.67	0.65
25	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,257			6,398,566	4,184,700	0.67	
26	*Space Coast*												
27	Solar		1,072					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	10	1,072	14.4%	N/A	34.6%	N/A						
29	*Turkey Point 1*												
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	380	0	0.0%	94.6%	0.0%	0			0	0	0.00	
33	*Turkey Point 3*												
34	Nuclear		608,613					6,568,489	1,000,000	6,568,489	4,582,800	0.75	0.70
35	Plant Unit Info	839	608,613	97.5%	97.5%	97.5%	10,793			6,568,489	4,582,800	0.75	
36	*Turkey Point 4*												
37	Nuclear		615,140					6,568,489	1,000,000	6,568,489	4,363,400	0.71	0.66

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS
(WITHOUT GAS RESERVES)

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	Plant Unit Info	848	615,140	97.5%	97.5%	97.5%	10,678			6,568,489	4,363,400	0.71	
2	*Turkey Point 5*												
3	Light Oil		242					424	5,832,547	2,473	52,005	21.49	122.65
4	Gas		400,920					2,823,487	1,000,000	2,823,487	15,342,362	3.83	5.43
5	Plant Unit Info	1,166	401,162	46.3%	94.8%	89.8%	7,044			2,825,960	15,394,367	3.84	
6	*WCEC 01*												
7	Light Oil		222					366	5,830,601	2,134	44,891	20.22	122.65
8	Gas		760,571					5,190,034	1,000,000	5,190,034	28,200,991	3.71	5.43
9	Plant Unit Info	1,208	760,793	84.7%	94.8%	85.6%	6,825			5,192,168	28,245,881	3.71	
10	*WCEC 02*												
11	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
12	Gas		746,954					5,093,748	1,000,000	5,093,748	27,677,804	3.71	5.43
13	Plant Unit Info	1,202	747,181	83.6%	94.9%	83.5%	6,820			5,095,926	27,723,676	3.71	
14	*WCEC 03*												
15	Light Oil		227					374	5,823,529	2,178	45,872	20.21	122.65
16	Gas		599,511					4,087,891	1,000,000	4,087,891	22,212,297	3.71	5.43
17	Plant Unit Info	1,207	599,738	66.8%	94.9%	85.5%	6,820			4,090,069	22,258,169	3.71	
18	**System Totals**												
19	Plant Unit Info	25,993	9,031,420				8,116			73,301,756	253,555,156	2.81	
20													
21													
22													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
(WITHOUT GAS RESERVES)

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	2015
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	145,000	0	0	0	0	0	145,000	145,000	0	145,000	0	0	580,000
4	Unit Cost	97.8739	0.0000	0.0000	0.0000	0.0000	0.0000	96.6389	95.6389	0.0000	95.6389	0.0000	0.0000	96.4477
5	Amount	$14,191,719	$0	$0	$0	$0	$0	$14,012,644	$13,867,644	$0	$13,867,644	$0	$0	$55,939,651
6	Burned													
7	Units	152,245	0	865	17,143	7,772	74,814	139,985	112,747	164,189	92,516	0	0	762,276
8	Unit Cost	94.8247	0.0000	94.5275	95.4164	94.8579	95.3089	95.2937	95.1726	95.5212	95.4431	0.0000	0.0000	95.2482
9	Amount	$14,436,586	$0	$81,766	$1,635,724	$737,235	$7,130,438	$13,339,683	$10,730,420	$15,683,532	$8,830,013	$0	$0	$72,605,397
10	Ending Inventory													
11	Units	2,668,420	2,668,420	2,667,555	2,650,412	2,642,640	2,567,826	2,572,841	2,605,094	2,440,905	2,493,389	2,493,389	2,493,389	2,493,389
12	Unit Cost	95.4060	95.4060	95.4063	95.4063	95.4079	95.4107	95.4863	95.5084	95.5076	95.5176	95.5176	95.5176	95.5176
13	Amount	$254,583,367	$254,583,367	$254,501,601	$252,865,877	$252,128,641	$244,998,203	$245,671,165	$248,808,389	$233,124,857	$238,162,488	$238,162,488	$238,162,488	$238,162,488
14	**#2 Light Oil (BBLS)**													
15	Purchases													
16	Units	10,674	0	0	5,204	0	0	13,932	0	37,682	15,164	133,000	0	215,656
17	Unit Cost	134.8278	0.0000	0.0000	133.7190	0.0000	0.0000	132.5178	0.0000	132.3876	132.3540	132.3330	0.0000	132.5129
18	Amount	$1,439,152	$0	$0	$695,874	$0	$0	$1,846,238	$0	$4,988,628	$2,007,016	$17,600,285	$0	$28,577,192
19	Burned													
20	Units	3,581	3,152	3,581	3,581	3,581	3,581	7,537	3,584	40,892	3,581	3,581	3,581	83,813
21	Unit Cost	122.2746	121.9321	122.2746	122.4634	122.4634	122.4634	122.7068	122.4837	123.9858	122.6526	122.6526	122.6526	123.2171
22	Amount	$437,865	$384,330	$437,865	$438,541	$438,541	$438,541	$924,841	$438,982	$5,070,027	$439,219	$439,219	$439,219	$10,327,193
23	Ending Inventory													
24	Units	1,285,378	1,282,226	1,278,645	1,280,268	1,276,687	1,273,106	1,279,501	1,275,917	1,272,707	1,284,290	1,413,709	1,410,128	1,410,128
25	Unit Cost	120.7809	120.7781	120.7739	120.8218	120.8172	120.8125	120.9288	120.9245	121.1655	121.2935	122.3286	122.3278	122.3278
26	Amount	$155,249,118	$154,864,788	$154,426,923	$154,684,255	$154,245,714	$153,807,172	$154,728,568	$154,289,587	$154,208,188	$155,775,984	$172,937,050	$172,497,831	$172,497,831
27	**Coal - SJRPP (TONS)**													
28	Purchases													
29	Units	49,465	49,465	49,465	49,465	49,465	49,465	49,465	49,465	49,465	49,465	49,465	49,465	593,581
30	Unit Cost	70.1272	70.3707	69.1533	70.0920	70.0920	70.9896	70.6992	71.1436	71.0325	71.2030	71.2030	71.0747	70.5984
31	Amount	$3,468,848	$3,480,891	$3,420,675	$3,467,107	$3,467,107	$3,511,506	$3,497,142	$3,519,124	$3,513,629	$3,522,062	$3,522,062	$3,515,714	$41,905,867
32	Burned													
33	Units	59,679	41,648	25,488	29,789	52,047	56,717	60,913	59,541	58,092	57,963	44,784	46,920	593,581
34	Unit Cost	71.5340	70.8920	70.0095	70.0431	70.0602	70.3921	70.5078	70.7703	70.8885	71.0423	71.1281	71.1010	70.7524
35	Amount	$4,269,075	$2,952,509	$1,784,401	$2,086,513	$3,646,425	$3,992,429	$4,294,843	$4,213,734	$4,118,053	$4,117,827	$3,185,403	$3,336,057	$41,997,269
36	Ending Inventory													
37	Units	40,168	47,985	71,962	91,638	89,056	81,805	70,357	60,281	51,654	43,156	47,837	50,382	50,382
38	Unit Cost	71.5340	70.8920	70.0095	70.0431	70.0602	70.3921	70.5078	70.7703	70.8885	71.0423	71.1281	71.1010	71.1010
39	Amount	$2,873,382	$3,401,764	$5,038,038	$6,418,631	$6,239,313	$5,758,391	$4,960,690	$4,266,080	$3,661,655	$3,065,891	$3,402,551	$3,582,208	$3,582,208
40														

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
(WITHOUT GAS RESERVES)

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) Jan - 2015	Feb - 2015	Mar - 2015	Apr - 2015	May - 2015	Jun - 2015	Jul - 2015	Aug - 2015	Sep - 2015	Oct - 2015	Nov - 2015	Dec - 2015	(14) 2015
1	**Coal - Scherer (MMBTU)**													
2	Purchases													
3	Units	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	4,450,769	53,409,226
4	Unit Cost	2.4907	2.4906	2.4913	2.4890	2.4919	2.4945	2.5054	2.5144	2.5116	2.5077	2.5106	2.5133	2.5009
5	Amount	$11,085,716	$11,085,027	$11,088,328	$11,077,879	$11,090,941	$11,102,591	$11,150,968	$11,191,096	$11,178,393	$11,161,083	$11,173,910	$11,186,203	$133,572,135
6	Burned													
7	Units	4,700,340	4,245,453	4,604,287	4,215,370	4,389,408	4,325,885	4,497,403	4,493,972	4,371,702	4,490,183	4,374,883	4,700,340	53,409,226
8	Unit Cost	2.4561	2.4730	2.4818	2.4853	2.4884	2.4913	2.4979	2.5056	2.5084	2.5081	2.5092	2.5111	2.4930
9	Amount	$11,544,706	$10,499,053	$11,426,844	$10,476,410	$10,922,755	$10,777,125	$11,233,930	$11,260,146	$10,966,015	$11,261,679	$10,977,597	$11,803,163	$133,149,422
10	Ending Inventory													
11	Units	4,637,441	4,842,757	4,689,238	4,924,637	4,985,998	5,110,882	5,064,248	5,021,045	5,100,111	5,060,697	5,136,583	4,887,012	4,887,012
12	Unit Cost	2.4561	2.4730	2.4818	2.4853	2.4884	2.4913	2.4979	2.5056	2.5084	2.5081	2.5092	2.5111	2.5111
13	Amount	$11,390,217	$11,976,191	$11,637,675	$12,239,144	$12,407,330	$12,732,796	$12,649,834	$12,580,785	$12,793,163	$12,692,567	$12,888,880	$12,271,920	$12,271,920
14	**Gas (MCF)**													
15	Burned													
16	Units	37,768,150	34,716,771	41,173,297	46,690,246	49,071,848	52,659,472	56,806,368	58,039,018	56,660,518	50,695,612	41,678,869	40,498,200	566,458,370
17	Unit Cost	5.4776	5.4532	5.3250	5.0846	5.0788	4.9782	4.9534	4.9367	4.9196	5.0744	5.2705	5.4337	5.1334
18	Amount	$206,880,172	$189,318,193	$219,248,515	$237,401,107	$249,225,322	$262,147,771	$281,383,655	$286,520,740	$278,747,386	$257,250,147	$219,668,324	$220,056,018	$2,907,847,349
19	**Nuclear (Other)**													
20	Burned													
21	Units	27,050,111	24,432,377	24,868,490	20,356,798	27,047,003	26,174,518	27,047,003	27,047,003	21,223,193	22,642,006	22,575,459	27,050,111	297,514,072
22	Unit Cost	0.6569	0.6569	0.6562	0.6526	0.6492	0.6492	0.6492	0.6492	0.6556	0.6549	0.6569	0.6625	0.6540
23	Amount	$17,769,900	$16,050,300	$16,318,500	$13,283,900	$17,558,400	$16,992,100	$17,558,400	$17,558,400	$13,913,900	$14,828,200	$14,829,500	$17,920,700	$194,582,200
24														
25	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
POWER SOLD
(WITHOUT GAS RESERVES)

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
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	**January Estimated**								
3	Off System	OS	300,000	300,000	3.358	4.583	$10,075,000	$13,750,000	$2,900,000
4	St Lucie Reliability Sales		54,189	54,189	0.750	0.750	$406,318	$406,318	$0
5	**Total January Estimated**		354,189	354,189	2.959	3.997	$10,481,318	$14,156,318	$2,900,000
6									
7	**February Estimated**								
8	Off System	OS	270,000	270,000	3.225	4.459	$8,708,500	$12,038,500	$2,620,000
9	St Lucie Reliability Sales		48,945	48,945	0.750	0.750	$366,998	$366,998	$0
10	**Total February Estimated**		318,945	318,945	2.845	3.890	$9,075,498	$12,405,498	$2,620,000
11									
12	**March Estimated**								
13	Off System	OS	255,000	255,000	3.481	4.693	$8,877,750	$11,967,750	$2,418,750
14	St Lucie Reliability Sales		38,457	38,457	0.750	0.750	$288,356	$288,356	$0
15	**Total March Estimated**		293,457	293,457	3.123	4.176	$9,166,106	$12,256,106	$2,418,750
16									
17	**April Estimated**								
18	Off System	OS	105,000	105,000	5.121	6.197	$5,377,000	$6,507,000	$840,000
19	St Lucie Reliability Sales		10,258	10,258	0.767	0.767	$78,643	$78,643	$0
20	**Total April Estimated**		115,258	115,258	4.733	5.714	$5,455,643	$6,585,643	$840,000
21									
22	**May Estimated**								
23	Off System	OS	95,000	95,000	4.881	5.961	$4,637,000	$5,663,250	$760,000
24	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
25	**Total May Estimated**		147,999	147,999	3.408	4.101	$5,043,318	$6,069,568	$760,000
26									
27	**June Estimated**								
28	Off System	OS	75,000	75,000	3.213	4.518	$2,409,600	$3,388,350	$772,500
29	St Lucie Reliability Sales		51,289	51,289	0.767	0.767	$393,211	$393,211	$0
30	**Total June Estimated**		126,289	126,289	2.219	2.994	$2,802,811	$3,781,561	$772,500
31									
32	**6 Month Period**								
33	Off System	OS	1,100,000	1,100,000	3.644	4.847	$40,084,850	$53,314,850	$10,311,250
34	St Lucie Reliability Sales		256,137	256,137	0.757	0.757	$1,939,844	$1,939,844	$0
35	**Total 6 Month Period**		1,356,137	1,356,137	3.099	4.074	$42,024,694	$55,254,694	$10,311,250
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
POWER SOLD
(WITHOUT GAS RESERVES)

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	80,000	80,000	8.244	9.600	$6,594,800	$7,679,800	$870,000
4	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
5	**Total July Estimated**		132,999	132,999	5.264	6.080	$7,001,118	$8,086,118	$870,000
6									
7	**August Estimated**								
8	Off System	OS	80,000	80,000	6.767	8.052	$5,413,700	$6,441,200	$825,000
9	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
10	**Total August Estimated**		132,999	132,999	4.376	5.149	$5,820,018	$6,847,518	$825,000
11									
12	**September Estimated**								
13	Off System	OS	65,000	65,000	10.177	11.390	$6,615,050	$7,403,800	$612,500
14	St Lucie Reliability Sales		51,289	51,289	0.767	0.767	$393,211	$393,211	$0
15	**Total September Estimated**		116,289	116,289	6.027	6.705	$7,008,261	$7,797,011	$612,500
16									
17	**October Estimated**								
18	Off System	OS	80,000	80,000	5.653	6.678	$4,522,300	$5,342,300	$617,500
19	St Lucie Reliability Sales		52,999	52,999	0.767	0.767	$406,318	$406,318	$0
20	**Total October Estimated**		132,999	132,999	3.706	4.322	$4,928,618	$5,748,618	$617,500
21									
22	**November Estimated**								
23	Off System	OS	160,000	160,000	3.008	3.971	$4,813,200	$6,353,200	$1,135,000
24	St Lucie Reliability Sales		52,441	52,441	0.750	0.750	$393,211	$393,211	$0
25	**Total November Estimated**		212,441	212,441	2.451	3.176	$5,206,411	$6,746,411	$1,135,000
26									
27	**December Estimated**								
28	Off System	OS	185,000	185,000	2.971	4.063	$5,497,050	$7,517,050	$1,540,000
29	St Lucie Reliability Sales		54,189	54,189	0.750	0.750	$406,318	$406,318	$0
30	**Total December Estimated**		239,189	239,189	2.468	3.313	$5,903,368	$7,923,368	$1,540,000
31									
32	**12 Month Period**								
33	Off System	OS	1,750,000	1,750,000	4.202	5.374	$73,540,950	$94,052,200	$15,911,250
34	St Lucie Reliability Sales		573,053	573,053	0.759	0.759	$4,351,540	$4,351,540	$0
35	**Total 12 Month Period**		2,323,053	2,323,053	3.353	4.236	$77,892,490	$98,403,740	$15,911,250
36									
37									
38	Note: Totals may not add due to rounding.								

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
(WITHOUT GAS RESERVES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	UPS		103,735	103,735	4.052	$4,202,903
4	SJRPP		175,723	175,723	3.498	$6,147,000
5	St Lucie Reliability		46,461	46,461	0.736	$342,127
6	**Total January Estimated**		325,919	325,919	3.281	$10,692,030
7						
8	**February Estimated**					
9	UPS		91,385	91,385	4.195	$3,833,551
10	SJRPP		117,948	117,948	3.664	$4,322,000
11	St Lucie Reliability		41,965	41,965	0.736	$309,019
12	**Total February Estimated**		251,298	251,298	3.368	$8,464,570
13						
14	**March Estimated**					
15	UPS		118,509	118,509	4.098	$4,856,897
16	SJRPP		84,444	84,444	3.536	$2,986,000
17	St Lucie Reliability		46,461	46,461	0.736	$342,127
18	**Total March Estimated**		249,414	249,414	3.282	$8,185,025
19						
20	**April Estimated**					
21	UPS		168,153	168,153	4.104	$6,900,818
22	SJRPP		86,723	86,723	3.601	$3,123,000
23	St Lucie Reliability		43,917	43,917	0.753	$330,769
24	**Total April Estimated**		298,793	298,793	3.465	$10,354,587
25						
26	**May Estimated**					
27	UPS		165,461	165,461	4.100	$6,783,494
28	SJRPP		165,645	165,645	3.561	$5,899,000
29	St Lucie Reliability		45,381	45,381	0.753	$341,795
30	**Total May Estimated**		376,487	376,487	3.459	$13,024,289
31						
32	**June Estimated**					
33	UPS		218,373	218,373	4.029	$8,798,476
34	SJRPP		183,677	183,677	3.552	$6,525,000
35	St Lucie Reliability		43,917	43,917	0.753	$330,769
36	**Total June Estimated**		445,967	445,967	3.510	$15,654,245
37						
38	**6 Month Period**					
39	UPS		865,616	865,616	4.087	$35,376,139
40	SJRPP		814,160	814,160	3.562	$29,002,000
41	St Lucie Reliability		268,101	268,101	0.745	$1,996,607
42	**Total 6 Month Period**		1,947,877	1,947,877	3.408	$66,374,745
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FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
(WITHOUT GAS RESERVES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	(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	UPS		240,931	240,931	4.015	$9,673,316
4	SJRPP		197,889	197,889	3.522	$6,969,000
5	St Lucie Reliability		45,381	45,381	0.753	$341,795
6	**Total July Estimated**		484,201	484,201	3.508	$16,984,111
7						
8	**August Estimated**					
9	UPS		207,635	207,635	4.070	$8,450,628
10	SJRPP		193,255	193,255	3.550	$6,860,000
11	St Lucie Reliability		45,381	45,381	0.753	$341,795
12	**Total August Estimated**		446,271	446,271	3.507	$15,652,423
13						
14	**September Estimated**					
15	UPS		225,564	225,564	4.066	$9,170,633
16	SJRPP		188,408	188,408	3.544	$6,677,000
17	St Lucie Reliability		8,783	8,783	0.753	$66,154
18	**Total September Estimated**		422,755	422,755	3.764	$15,913,786
19						
20	**October Estimated**					
21	UPS		202,713	202,713	4.050	$8,209,640
22	SJRPP		187,791	187,791	3.564	$6,692,000
23	St Lucie Reliability		33,670	33,670	0.753	$253,588
24	**Total October Estimated**		424,174	424,174	3.573	$15,155,228
25						
26	**November Estimated**					
27	UPS		103,407	103,407	4.216	$4,359,301
28	SJRPP		126,932	126,932	3.706	$4,704,000
29	St Lucie Reliability		44,962	44,962	0.736	$331,091
30	**Total November Estimated**		275,301	275,301	3.412	$9,394,392
31						
32	**December Estimated**					
33	UPS		100,035	100,035	4.078	$4,079,380
34	SJRPP		133,571	133,571	3.681	$4,917,000
35	St Lucie Reliability		46,461	46,461	0.736	$342,127
36	**Total December Estimated**		280,067	280,067	3.334	$9,338,507
37						
38	**12 Month Period**					
39	UPS		1,945,901	1,945,901	4.076	$79,319,037
40	SJRPP		1,842,006	1,842,006	3.573	$65,821,000
41	St Lucie Reliability		492,739	492,739	0.745	$3,673,157
42	**Total 12 Month Period**		4,280,646	4,280,646	3.476	$148,813,194
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45	Note: Totals may not add due to rounding.					
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
(WITHOUT GAS RESERVES)

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	**January Estimated**					
3	Qualifying Facilities		324,657	324,657	4.110	$13,342,888
4	**Total January Estimated**		324,657	324,657	4.110	$13,342,888
5						
6	**February Estimated**					
7	Qualifying Facilities		239,490	239,490	3.969	$9,504,887
8	**Total February Estimated**		239,490	239,490	3.969	$9,504,887
9						
10	**March Estimated**					
11	Qualifying Facilities		259,474	259,474	3.973	$10,309,887
12	**Total March Estimated**		259,474	259,474	3.973	$10,309,887
13						
14	**April Estimated**					
15	Qualifying Facilities		191,526	191,526	5.257	$10,067,898
16	**Total April Estimated**		191,526	191,526	5.257	$10,067,898
17						
18	**May Estimated**					
19	Qualifying Facilities		306,359	306,359	4.038	$12,370,888
20	**Total May Estimated**		306,359	306,359	4.038	$12,370,888
21						
22	**June Estimated**					
23	Qualifying Facilities		344,410	344,410	4.373	$15,061,892
24	**Total June Estimated**		344,410	344,410	4.373	$15,061,892
25						
26	**6 Month Period**					
27	Qualifying Facilities		1,665,918	1,665,918	4.241	$70,658,340
28	**Total 6 Month Period**		1,665,918	1,665,918	4.241	$70,658,340
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
(WITHOUT GAS RESERVES)

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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		367,993	367,993	4.624	$17,015,897
4	**Total July Estimated**		367,993	367,993	4.624	$17,015,897
5						
6	**August Estimated**					
7	Qualifying Facilities		355,473	355,473	4.787	$17,016,900
8	**Total August Estimated**		355,473	355,473	4.787	$17,016,900
9						
10	**September Estimated**					
11	Qualifying Facilities		355,645	355,645	4.792	$17,041,901
12	**Total September Estimated**		355,645	355,645	4.792	$17,041,901
13						
14	**October Estimated**					
15	Qualifying Facilities		340,225	340,225	4.362	$14,840,891
16	**Total October Estimated**		340,225	340,225	4.362	$14,840,891
17						
18	**November Estimated**					
19	Qualifying Facilities		109,163	109,163	3.330	$3,634,887
20	**Total November Estimated**		109,163	109,163	3.330	$3,634,887
21						
22	**December Estimated**					
23	Qualifying Facilities		98,057	98,057	3.268	$3,204,887
24	**Total December Estimated**		98,057	98,057	3.268	$3,204,887
25						
26	**12 Month Period**					
27	Qualifying Facilities		3,292,475	3,292,475	4.356	$143,413,703
28	**Total 12 Month Period**		3,292,475	3,292,475	4.356	$143,413,703
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31	Note: Totals may not add due to rounding.					
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES
(WITHOUT GAS RESERVES)

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	2,750	2.609	$71,750	3.528	$97,028	$25,278
4	Total January Estimated		2,750	2.609	$71,750	3.528	$97,028	$25,278
5								
6	**February Estimated**							
7	Economy	OS	5,250	2.462	$129,250	3.358	$176,278	$47,028
8	Total February Estimated		5,250	2.462	$129,250	3.358	$176,278	$47,028
9								
10	**March Estimated**							
11	Economy	OS	10,250	2.383	$244,250	3.636	$372,693	$128,443
12	Total March Estimated		10,250	2.383	$244,250	3.636	$372,693	$128,443
13								
14	**April Estimated**							
15	Economy	OS	30,500	3.479	$1,061,000	5.486	$1,673,125	$612,125
16	Total April Estimated		30,500	3.479	$1,061,000	5.486	$1,673,125	$612,125
17								
18	**May Estimated**							
19	Economy	OS	50,500	3.685	$1,861,000	5.127	$2,588,920	$727,920
20	Total May Estimated		50,500	3.685	$1,861,000	5.127	$2,588,920	$727,920
21								
22	**June Estimated**							
23	Economy	OS	50,750	5.454	$2,768,000	7.789	$3,953,113	$1,185,113
24	Total June Estimated		50,750	5.454	$2,768,000	7.789	$3,953,113	$1,185,113
25								
26	**6 Month Period**							
27	Economy	OS	150,000	4.090	$6,135,250	5.907	$8,861,155	$2,725,905
28	Total 6 Month Period		150,000	4.090	$6,135,250	5.907	$8,861,155	$2,725,905
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES
(WITHOUT GAS RESERVES)

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

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	55,750	5.953	$3,318,750	9.647	$5,378,298	$2,059,548
4	Total July Estimated		55,750	5.953	$3,318,750	9.647	$5,378,298	$2,059,548
5								
6	**August Estimated**							
7	Economy	OS	70,750	5.963	$4,218,750	8.754	$6,193,593	$1,974,843
8	Total August Estimated		70,750	5.963	$4,218,750	8.754	$6,193,593	$1,974,843
9								
10	**September Estimated**							
11	Economy	OS	45,750	7.711	$3,528,000	12.122	$5,545,928	$2,017,928
12	Total September Estimated		45,750	7.711	$3,528,000	12.122	$5,545,928	$2,017,928
13								
14	**October Estimated**							
15	Economy	OS	30,500	4.652	$1,419,000	6.928	$2,112,955	$693,955
16	Total October Estimated		30,500	4.652	$1,419,000	6.928	$2,112,955	$693,955
17								
18	**November Estimated**							
19	Economy	OS	10,250	2.480	$254,250	3.158	$323,655	$69,405
20	Total November Estimated		10,250	2.480	$254,250	3.158	$323,655	$69,405
21								
22	**December Estimated**							
23	Economy	OS	5,250	2.362	$124,000	3.044	$159,833	$35,833
24	Total December Estimated		5,250	2.362	$124,000	3.044	$159,833	$35,833
25								
26	**12 Month Period**							
27	Economy	OS	368,250	5.159	$18,998,000	7.760	$28,575,415	$9,577,415
28	Total 12 Month Period		368,250	5.159	$18,998,000	7.760	$28,575,415	$9,577,415
29								
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31	Note: Totals may not add due to rounding.							
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FLORIDA POWER & LIGHT COMPANY
(WITHOUT GAS RESERVES)

SCHEDULE: E10

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	CURRENT SEPT 14	PROPOSED JAN 15 - DEC 15	DIFFERENCE $	DIFFERENCE %
BASE	$54.87	$54.87	$0.00	0.00%
FUEL	$29.47	$30.96	$1.49	5.06%
CONSERVATION [1]	$3.37	$1.89	-$1.48	-43.92%
CAPACITY PAYMENT	$7.86	$6.35	-$1.51	-19.21%
ENVIRONMENTAL	$2.24	$2.06	-$0.18	-8.04%
STORM RESTORATION SURCHARGE [2]	$1.16	$1.16	$0.00	0.00%
SUBTOTAL	$98.97	$97.29	-$1.68	-1.70%
GROSS RECEIPTS TAX	$2.54	$2.49	-$0.05	-1.97%
TOTAL	**$101.51**	**$99.78**	-$1.73	-1.70%

[1] Proposed Jan 15 - Dec 15 is based on estimates of the Conservation factor to be filed on August 27, 2014.
[2] Reflects true-up adjustment in storm charges effective September 2, 2014.

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITHOUT GAS RESERVES)

SCHEDULE: H1

Line No.	H1 Schedule	2012	2013	2014	2015	% Diff 2012 to 2013	% Diff 2013 to 2014	% Diff 2014 to 2015
1	**Fuel Cost of System Net Generation ($)**							
2	Heavy Oil	61,871,530	13,972,361	50,400,481	72,605,397	(77.4%)	260.7%	44.1%
3	Light Oil	8,584,943	19,348,495	25,883,288	10,327,193	125.4%	33.8%	(60.1%)
4	Coal	142,583,650	171,113,652	156,846,539	175,146,691	20.0%	(8.3%)	11.7%
5	Gas	2,999,049,429	2,697,913,238	3,098,319,410	2,907,847,349	(10.0%)	14.8%	(6.1%)
6	Nuclear	106,563,067	168,309,387	187,125,111	194,582,200	57.9%	11.2%	4.0%
7	**Total Fuel Cost of System Net Generation ($)**	3,318,652,620	3,070,657,133	3,518,574,830	3,360,508,830	(7.5%)	14.6%	(4.5%)
8								
9	**System Net Generation (MWh)**							
10	Heavy Oil	377,642	75,138	307,340	436,372	(80.1%)	309.0%	42.0%
11	Light Oil	54,367	120,475	134,222	37,659	121.6%	11.4%	(71.9%)
12	Coal	4,745,211	5,980,723	5,362,752	6,301,876	26.0%	(10.3%)	17.5%
13	Gas	80,593,957	75,208,098	79,020,442	80,260,204	(6.7%)	5.1%	1.6%
14	Nuclear	16,915,746	25,243,030	27,100,803	27,863,195	49.2%	7.4%	2.8%
15	Solar	70,534	67,991	111,506	191,208	(3.6%)	64.0%	71.5%
16	**Total System Net Generation (MWh)**	102,757,457	106,695,455	112,037,065	115,090,514	3.8%	5.0%	2.7%
17								
18	**Units of Fuel Burned (Unit)**							
19	Heavy Oil	701,587	150,170	538,901	762,276	(78.6%)	258.9%	41.5%
20	Light Oil	72,767	154,726	211,355	83,813	112.6%	36.6%	(60.3%)
21	Coal	578,328	621,264	3,112,900	3,735,300	7.4%	401.1%	20.0%
22	Gas	595,396,296	550,405,680	565,175,954	566,458,370	(7.6%)	2.7%	0.2%
23	Nuclear	188,199,021	273,897,430	294,569,803	297,514,072	45.5%	7.5%	1.0%
24	**Total Units of Fuel Burned (Unit)**							
25								
26	**BTU Burned (MMBTU)**							
27	Heavy Oil	4,479,893	955,983	3,429,961	4,878,566	(78.7%)	258.8%	42.2%
28	Light Oil	418,444	903,455	1,229,549	488,585	115.9%	36.1%	(60.3%)
29	Coal	49,417,119	63,095,100	56,406,267	66,468,000	27.7%	(10.6%)	17.8%
30	Gas	603,981,012	558,740,029	571,160,551	566,458,369	(7.5%)	2.2%	(0.8%)
31	Nuclear	188,199,025	273,897,430	294,569,803	297,514,072	45.5%	7.5%	1.0%
32	**Total BTU Burned (MMBTU)**	846,495,493	897,591,997	926,796,131	935,807,592	6.0%	3.3%	1.0%
33								
34	**Generation Mix (%MWH)**							
35	Heavy Oil	0.37%	0.07%	0.27%	0.38%	-	-	-
36	Light Oil	0.05%	0.11%	0.12%	0.03%	-	-	-
37	Coal	4.62%	5.61%	4.79%	5.48%	-	-	-
38	Gas	78.43%	70.49%	70.53%	69.74%	-	-	-
39	Nuclear	16.46%	23.66%	24.19%	24.21%	-	-	-
40	Solar	0.07%	0.06%	0.10%	0.17%	-	-	-
41	**Total Generation Mix (%MWH)**	100.00%	100.00%	100.00%	100.00%	-	-	-
42								
43	**Fuel Cost per Unit ($/Unit)**							
44	Heavy Oil	88.1880	93.0436	93.5246	95.2482	5.5%	0.5%	1.8%
45	Light Oil	117.9785	125.0501	122.4636	123.2171	6.0%	(2.1%)	0.6%
46	Coal	82.6550	74.4202	50.3860	46.8896	(10.0%)	(32.3%)	(6.9%)
47	Gas	5.0371	4.9017	5.4820	5.1334	(2.7%)	11.8%	(6.4%)
48	Nuclear	0.5662	0.6145	0.6352	0.6540	8.5%	3.4%	3.0%
49								
50	**Fuel Cost per MMBTU ($/MMBTU)**							

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
(WITHOUT GAS RESERVES)

SCHEDULE: H1

Line No.	H1 Schedule	2012	2013	2014	2015	% Diff 2012 to 2013	% Diff 2013 to 2014	% Diff 2014 to 2015
1	Heavy Oil	13.8109	14.6157	14.6942	14.8825	5.8%	0.5%	1.3%
2	Light Oil	20.5163	21.4161	21.0510	21.1369	4.4%	(1.7%)	0.4%
3	Coal	2.8853	2.7120	2.7807	2.6351	(6.0%)	2.5%	(5.2%)
4	Gas	4.9655	4.8286	5.4246	5.1334	(2.8%)	12.3%	(5.4%)
5	Nuclear	0.5662	0.6145	0.6352	0.6540	8.5%	3.4%	3.0%
6	**Total Fuel Cost per MMBTU ($/MMBTU)**	3.9205	3.4210	3.7965	3.5910	(12.7%)	11.0%	(5.4%)
7								
8	**BTU Burned per KWH (BTU/KWH)**							
9	Heavy Oil	11,863	12,723	11,160	11,180	7.3%	(12.3%)	0.2%
10	Light Oil	7,697	7,499	9,161	12,974	(2.6%)	22.2%	41.6%
11	Coal	10,414	10,550	10,518	10,547	1.3%	(0.3%)	0.3%
12	Gas	7,494	7,429	7,228	7,058	(0.9%)	(2.7%)	(2.4%)
13	Nuclear	11,126	10,850	10,869	10,678	(2.5%)	0.2%	(1.8%)
14	**Total BTU Burned per KWH (BTU/KWH)**	8,238	8,413	8,272	8,131	2.1%	(1.7%)	(1.7%)
15								
16	**Generated Fuel Cost per KWH (cents/KWH)**							
17	Heavy Oil	16.3836	18.5957	16.3989	16.6384	13.5%	(11.8%)	1.5%
18	Light Oil	15.7907	16.0602	19.2839	27.4229	1.7%	20.1%	42.2%
19	Coal	3.0048	2.8611	2.9247	2.7793	(4.8%)	2.2%	(5.0%)
20	Gas	3.7212	3.5873	3.9209	3.6230	(3.6%)	9.3%	(7.6%)
21	Nuclear	0.6300	0.6668	0.6905	0.6983	5.8%	3.6%	1.1%
22	**Total Generated Fuel Cost per KWH (cents/KWH)**	3.2296	2.8780	3.1405	2.9199	(10.9%)	9.1%	(7.0%)
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Forty-Second Revised Sheet No. 10.101
FLORIDA POWER & LIGHT COMPANY **Cancels Forty-First Revised Sheet No. 10.101**

(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 .0129¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2015 – December 31, 2015	5.88	3.05	3.94
January 1, 2016 – December 31, 2016	5.68	3.48	4.17

A MW block size ranging from 86 MW to 95 MW has been used to calculate the estimated As-Available 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	1.0104
Secondary Voltage Delivery	1.0401

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
2014	66.3	0.3	5.1	23.6	4.5	0.2		4.08	38.50	2.80	0.75	0.00
2015	64.1	0.7	5.5	23.0	6.6	0.1		4.24	36.71	2.99	0.76	0.00
2016	67.9	0.6	3.1	23.1	5.1	0.2		4.50	37.63	3.65	0.78	0.00
2017	67.1	0.2	4.4	22.6	5.5	0.2		4.92	37.73	3.57	0.80	0.00
2018	66.6	0.4	5.1	22.1	5.6	0.2		5.98	40.54	3.70	0.82	0.00
2019	66.5	0.1	5.4	22.4	5.4	0.2		6.13	41.17	3.52	0.84	0.00
2020	67.8	0.1	5.4	21.8	4.7	0.2		6.29	42.28	3.52	0.86	0.00
2021	68.1	0.3	5.3	21.6	4.6	0.1		6.39	44.26	3.60	0.88	0.00
2022	64.3	0.2	5.2	25.6	4.6	0.1		6.60	46.22	3.69	0.90	0.00
2023	57.7	0.1	5.1	32.4	4.5	0.1		6.91	48.19	3.79	0.91	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)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective:

(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	0.115%
Distribution Equipment	0.182%
Transmission Equipment	0.110%

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 IV

CAPACITY COST RECOVERY – WITH GAS RESERVES PROJECT

JANUARY 2015 – DECEMBER 2015 FACTORS

TJK-7
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____
PAGES 1-15
SEPTEMBER 15, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 13
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-7

APPENDIX IV
CAPACITY COST RECOVERY – WITH GAS RESERVES PROJECT

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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 2014 THROUGH DECEMBER 2014

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	$15,981,900	$16,233,234	$16,358,713	$16,555,580	$16,366,782	$15,991,037	$16,262,201	$16,042,337	$16,887,414	$13,821,184	$13,588,944	$13,615,104	$187,704,429
2	Payments to Co-generators	$23,244,820	$23,622,928	$23,623,265	$23,628,645	$23,617,296	$23,628,851	$23,625,996	$23,545,691	$23,545,691	$23,545,691	$23,545,691	$23,545,691	$282,720,257
3	SJRPP Suspension Accrual	($763,761)	($763,761)	($763,761)	($681,721)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($8,919,012)
4	Return on SJRPP Suspension Liability	($364,800)	($358,703)	($352,605)	($346,835)	($341,147)	($335,213)	($324,533)	($318,685)	($312,837)	($306,988)	($301,140)	($295,291)	($3,958,776)
5	Incremental Plant Security Costs O&M	$2,812,089	$2,361,141	$3,121,461	$2,577,033	$3,021,100	$3,500,438	$2,763,956	$4,191,630	$4,507,458	$3,926,040	$4,694,907	$8,013,341	$45,490,594
6	Incremental Plant Security Costs Capital	$0	$8	$498	$1,556	$3,997	$7,539	$17,598	$32,081	$45,902	$60,979	$75,501	$89,576	$335,236
7	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$417,452	$57,564	$86,790	$45,317	$8,880	$37,178	$1,681,347	$27,840	$24,329	$25,445	$2,412,143
8	Incremental Nuclear NRC Compliance Costs Capital	$22,579	$31,025	$36,604	$44,186	$53,653	$63,646	$79,726	$101,823	$120,906	$138,021	$164,749	$194,262	$1,051,178
9	Transmission of Electricity by Others	$1,594,907	$2,075,397	$2,025,711	$1,887,221	$2,165,572	$618,359	$936,268	$1,741,137	$1,703,621	$1,840,637	$2,029,623	$2,060,971	$20,679,425
10	Transmission Revenues from Capacity Sales	($796,807)	($666,444)	($390,253)	($190,943)	($283,539)	($273,311)	($219,499)	($250,000)	($239,000)	($250,000)	($500,000)	($595,000)	($4,654,797)
11	Total (Lines 1 through 10)	$41,730,927	$42,534,826	$44,077,085	$43,532,287	$43,947,254	$42,503,412	$42,407,343	$44,379,941	$47,197,251	$42,060,153	$42,579,353	$45,910,847	$522,860,678
12	Jurisdictional Separation Factor [a]	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	N/A
13	Jurisdictional CCR Charges	$39,730,715	$40,496,082	$41,964,419	$41,445,734	$41,840,811	$40,466,174	$40,374,710	$42,252,759	$44,935,032	$40,044,161	$40,538,475	$43,710,287	$497,799,358
14	Nuclear Cost Recovery Costs	$3,489,048	$3,133,366	$3,699,553	$3,404,690	$3,511,264	$3,747,873	$3,300,047	$3,243,053	$3,715,196	$3,280,068	$3,093,881	$5,843,207	$43,461,246
15	Jurisdictional CCR Charges	$43,219,763	$43,629,448	$45,663,972	$44,850,424	$45,352,074	$44,214,048	$43,674,757	$45,495,812	$48,650,228	$43,324,229	$43,632,355	$49,553,494	$541,260,604
16	CCR Revenues (Net of Revenue Taxes)	$45,101,409	$42,451,927	$40,975,966	$42,967,824	$49,497,111	$51,123,371	$53,946,292	$58,436,904	$57,894,525	$53,316,995	$44,813,875	$44,308,449	584,834,648
17	Prior Period True-up Provision	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($2,772,556)	($33,270,675)
18	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$42,328,852	$39,679,371	$38,203,410	$40,195,268	$46,724,555	$48,350,814	$51,173,735	$55,664,348	$55,121,969	$50,544,439	$42,041,319	$41,535,893	$551,563,973
19	True-up Provision for Month - Over/(Under) Recovery (Line 18 - Line 15)	($890,911)	($3,950,077)	($7,460,562)	($4,655,156)	$1,372,480	$4,136,767	$7,498,978	$10,168,536	$6,471,741	$7,220,210	($1,591,037)	($8,017,601)	$10,303,369
20	Interest Provision for Month	($1,330)	($1,134)	($1,293)	($1,697)	($1,301)	($854)	($595)	($15)	$540	$1,021	$1,300	$1,199	($4,159)
21	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($33,270,675)	($31,390,359)	($32,569,014)	($37,258,313)	($39,142,610)	($34,998,874)	($28,090,405)	($17,819,466)	($4,878,388)	$4,366,449	$14,360,236	$15,543,056	($33,270,675)
22	Deferred True-up - Over/(Under) Recovery	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159	$11,054,159
23	Prior Period True-up Provision - Collected/(Refunded) this Month	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$2,772,556	$33,270,675
24	End of Period True-up - Over/(Under) Recovery (Sum of Lines 19 through 23)	($20,336,200)	($21,514,855)	($26,204,154)	($28,088,451)	($23,944,715)	($17,036,246)	($6,765,307)	$6,175,771	$15,420,608	$25,414,395	$26,597,215	$21,353,369	$21,353,369
25														
26	[a] As approved on Order No. PSC-13-0665-FOF-EI.													
27														
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

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	$13,886,909	$13,888,005	$13,890,818	$13,888,283	$13,837,611	$13,835,268	$13,834,239	$13,836,911	$13,838,210	$13,852,964	$13,849,178	$13,851,804	$166,290,201
2	Capacity Payments To Cogenerators	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$287,947,898
3	SJRPP Suspension Accrual	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($8,919,012)
4	Return Requirements On SJRPP Suspension Liability	($289,443)	($283,595)	($277,746)	($271,898)	($266,050)	($260,201)	($254,353)	($248,505)	($242,656)	($236,808)	($230,960)	($225,111)	($3,087,326)
5	Incremental Plant Security Costs O&M	$3,548,308	$3,336,539	$4,230,333	$3,800,522	$4,124,988	$3,682,222	$3,461,800	$3,584,732	$3,599,886	$3,582,685	$3,872,678	$4,166,455	$44,991,146
6	Incremental Plant Security Costs Capital	$99,762	$106,623	$116,143	$125,489	$135,930	$157,489	$173,580	$176,333	$180,079	$184,812	$187,175	$193,587	1,837,001
7	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,624	$18,421	$36,045
8	Incremental Nuclear NRC Compliance Costs Capital	$226,478	$270,880	$322,351	$372,717	$409,334	$437,090	$464,548	$506,007	$552,783	$598,218	$627,739	$655,866	$5,444,010
9	Transmission Of Electricity By Others	$1,949,942	$1,972,418	$1,901,907	$1,743,878	$1,799,061	$1,654,080	$1,645,706	$1,765,483	$1,627,459	$1,737,916	$2,080,754	$2,076,139	$21,954,742
10	Transmission Revenues From Capacity Sales	($775,000)	($710,000)	($671,250)	($290,000)	($266,250)	($206,250)	($215,000)	($202,500)	($176,250)	($202,500)	($405,000)	($480,000)	($4,600,000)
11	System Total	$41,899,362	$41,833,278	$42,764,963	$42,621,397	$43,027,031	$42,552,105	$42,362,928	$42,670,868	$42,631,918	$42,769,694	$43,251,595	$43,509,568	$511,894,705
12	Jurisdictional % *													94.64598%
13	Jurisdictionalized Capacity Payments													$484,487,754
14	2013 FINAL TRUE-UP -- (Over)/Under Recovery													($11,054,159)
15	2014 ACT/EST TRUE-UP -- (Over)/Under Recovery													($10,299,210)
16	Nuclear Cost Recovery Clause													$14,287,862
17	Total (Lines 13+14+15+16)													$477,422,247
18	Revenue Tax Multiplier													1.00072
19	Total Recoverable Capacity Payments													$477,765,991
20														
21	*Calculation of Jurisdictional %													
22	.....AVG. 12CP													
23	.....AT GEN (MW).....%													
24	FPSC.....19,228.343.....94.64598%													
25	FERC.....1,087.727.....5.35402%													
26	TOTAL.....20,316.070.....100.00000%													
27														
28	* Based on 2015 Estimated Data													
29	Totals may not add up due to rounding.													
30														
31														
32														
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39														

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

(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	62.339%	56,486,754,968	10,343,916	1.07273422	1.05687858	59,699,641,379	11,096,273	52.25760%	57.70790%
GS1/GST1/WIES1	70.132%	6,303,353,434	1,026,010	1.07273422	1.05687858	6,661,879,227	1,100,636	5.83142%	5.72403%
GSD1/GSDT1/HLFT1	76.094%	26,491,485,933	3,974,214	1.07263018	1.05679832	27,996,157,828	4,262,862	24.50621%	22.16968%
OS2	74.112%	11,006,147	1,695	1.06372574	1.02956109	11,331,501	1,803	0.00992%	0.00938%
GSLD1/GSLDT1/CS1/CST1/HLFT2	76.113%	10,833,502,128	1,624,817	1.07131612	1.05580061	11,438,018,155	1,740,693	10.01218%	9.05274%
GSLD2/GSLDT2/CS2/CST2/HLFT3	87.059%	2,574,841,239	337,623	1.06110282	1.04763148	2,697,484,738	358,253	2.36122%	1.86315%
GSLD3/GSLDT3/CS3/CST3	89.410%	177,940,556	22,719	1.02378679	1.01925379	181,366,586	23,259	0.15876%	0.12096%
SST1T	93.724%	89,096,934	10,852	1.02378679	1.01925379	90,812,388	11,110	0.07949%	0.05778%
SST1D1/SST1D2/SST1D3	75.410%	9,138,135	1,383	1.03714120	1.02956109	9,408,268	1,434	0.00824%	0.00746%
CILC D/CILC G	90.403%	3,085,079,885	389,564	1.05992932	1.04730798	3,231,028,782	412,910	2.82826%	2.14740%
CILC T	91.694%	1,356,675,191	168,901	1.02378679	1.01925379	1,382,796,330	172,919	1.21042%	0.89929%
MET	71.762%	82,790,174	13,170	1.03714120	1.02956109	85,237,542	13,659	0.07461%	0.07104%
OL1/SL1/PL1	359.698%	622,341,281	19,751	1.07273422	1.05687858	657,739,169	21,188	0.57575%	0.11019%
SL2, GSCU1	100.263%	92,875,590	10,574	1.07273422	1.05687858	98,158,222	11,343	0.08592%	0.05899%
TOTAL		108,216,881,595	17,945,189			114,241,060,116	19,228,342	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2011-2013 load research data and 2015 projections.

[b] Projected kwh sales for the period January 2015 through December 2015.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on 2014 demand losses.

[e] Based on 2014 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
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

(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	52.25760%	57.70790%	$19,205,312	$254,500,369	$273,705,682	56,486,754,968	-	-	-	0.00485	-	-
GS1/GST1/WIES1	5.83142%	5.72403%	$2,143,120	$25,243,817	$27,386,937	6,303,353,434	-	-	-	0.00434	-	-
GSD1/GSDT1/HLFT1	24.50621%	22.16968%	$9,006,335	$97,771,563	$106,777,898	26,491,485,933	51.60099%	70,327,546	1.52	-	-	-
OS2	0.00992%	0.00938%	$3,645	$41,353	$44,999	11,006,147	-	-	-	0.00409	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.01218%	9.05274%	$3,679,599	$39,923,940	$43,603,538	10,833,502,128	55.38079%	26,797,044	1.63	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.36122%	1.86315%	$867,778	$8,216,764	$9,084,542	2,574,841,239	66.25224%	5,323,865	1.71	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.15876%	0.12096%	$58,345	$533,470	$591,815	177,940,556	70.94077%	343,602	1.72	-	-	-
SST1T	0.07949%	0.05778%	$29,214	$254,818	$284,033	89,096,934	13.15150%	928,036	-	-	$0.21	$0.10
SST1D1/SST1D2/SST1D3	0.00824%	0.00746%	$3,027	$32,898	$35,925	9,138,135	26.99741%	46,367	-	-	$0.21	$0.10
CILC D/CILC G	2.82826%	2.14740%	$1,039,419	$9,470,372	$10,509,790	3,085,079,885	74.21337%	5,694,576	1.85	-	-	-
CILC T	1.21042%	0.89929%	$444,844	$3,966,003	$4,410,847	1,356,675,191	76.87427%	2,417,531	1.82	-	-	-
MET	0.07461%	0.07104%	$27,421	$313,282	$340,702	82,790,174	65.26192%	173,779	1.96	-	-	-
OL1/SL1/PL1	0.57575%	0.11019%	$211,594	$485,951	$697,545	622,341,281	-	-	-	0.00112	-	-
SL2, GSCU1	0.08592%	0.05899%	$31,577	$260,161	$291,739	92,875,590	-	-	-	0.00314	-	-
TOTAL			$36,751,230	$441,014,761	$477,765,991	108,216,881,595		112,052,346				

[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 2015 through December 2015.

[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
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$5,152,258	$5,863,566	$6,535,249	$4,274,868	$3,102,566	$3,044,683	$3,121,771	$6,666,126	$4,481,578	$1,923,705	$488,821	$388,981	$45,044,172
b. Clearings to Plant		$338,152	$2,583,019	$949,946	$8,720,727	$553,900	$4,089,428	$136,569	$4,054,215	$129,154	$24,863,932	$82,977	$12,385,129	$58,887,148
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [a]			$203,908	$1,153,854	$9,874,582	$10,428,482	$14,517,910	$14,654,479	$18,708,693	$18,837,847	$43,701,779	$43,784,756	$56,169,886	N/A
3. Less: Accumulated Depreciation		$0	$1,068	$4,845	$16,519	$35,908	$59,036	$85,557	$115,249	$148,105	$201,536	$275,497	$374,815	N/A
4. CWIP - Non Interest Bearing	$28,923,896	$33,738,002	$37,018,550	$42,603,852	$38,157,993	$40,706,659	$39,661,914	$42,647,116	$45,259,027	$49,611,451	$26,671,225	$27,077,069	$15,080,920	N/A
5. Net Investment (Lines 2 - 3 + 4)	$28,923,896	$33,738,002	$37,221,390	$43,752,862	$48,016,055	$51,099,232	$54,120,788	$57,216,038	$63,852,472	$68,301,194	$70,171,468	$70,586,327	$70,875,991	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	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
7. Base Rate Capital Expenditures Closed to Plant-in-Service [c]	$7,282,738	$7,620,890	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$2,717,262	$2,379,110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$26,206,634	$31,358,892	$37,221,390	$43,752,862	$48,016,055	$51,099,232	$54,120,788	$57,216,038	$63,852,472	$68,301,194	$70,171,468	$70,586,327	$70,875,991	N/A
10. Average Net Investment		$28,782,763	$34,290,141	$40,487,126	$45,884,459	$49,557,644	$52,610,010	$55,668,413	$60,534,255	$66,076,833	$69,236,331	$70,378,898	$70,731,159	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$191,096	$227,661	$268,805	$304,639	$329,026	$349,292	$369,597	$401,903	$438,701	$459,678	$467,264	$469,603	$4,277,265
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$35,381	$42,151	$49,769	$56,403	$60,919	$64,671	$68,430	$74,412	$81,225	$85,109	$86,513	$86,946	$791,930
12. Investment Expenses														
a. Depreciation		$0	$1,068	$3,778	$11,674	$19,389	$23,127	$26,521	$29,692	$32,857	$53,431	$73,962	$99,317	$374,815
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$226,478	$270,880	$322,351	$372,717	$409,334	$437,090	$464,548	$506,007	$552,783	$598,218	$627,739	$655,866	$5,444,010

[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.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
(WITH GAS RESERVES)

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$1,217,478	$898,407	$499,076	$1,400,274	$971,446	$1,531,920	$2,788,328	$2,828,396	$2,022,085	$2,328,340	$4,465,178	$3,036,323	$23,987,250
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$1,697,004	$7,355	$1,508	$1,653,539	$3,923,331	$7,282,738
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [a]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
4. CWIP - Non Interest Bearing	$12,219,384	$13,436,862	$14,335,269	$14,834,345	$16,234,618	$17,206,064	$18,737,984	$21,526,312	$22,657,704	$24,672,434	$26,999,266	$29,810,905	$28,923,896	N/A
5. Net Investment (Lines 2 - 3 + 4)	$12,219,384	$13,436,862	$14,335,269	$14,834,345	$16,234,618	$17,206,064	$18,737,984	$21,526,312	$22,657,704	$24,672,434	$26,999,266	$29,810,905	$28,923,896	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	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
7. Base Rate Capital Expenditures Closed to Plant-in-Service [c]	$0	$0	$0	$0	$0	$0	$0	$0	$1,697,004	$1,704,359	$1,705,867	$3,359,406	$7,282,738	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$8,302,996	$8,295,641	$8,294,133	$6,640,594	$2,717,262	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$2,219,384	$3,436,862	$4,335,269	$4,834,345	$6,234,618	$7,206,064	$8,737,984	$11,526,312	$14,354,708	$16,376,793	$18,705,133	$23,170,311	$26,206,634	N/A
10. Average Net Investment		$2,828,123	$3,886,066	$4,584,807	$5,534,481	$6,720,341	$7,972,024	$10,132,148	$12,940,510	$15,365,750	$17,540,963	$20,937,722	$24,688,472	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$18,889	$25,955	$30,621	$36,964	$44,884	$53,244	$67,270	$85,915	$102,017	$116,459	$139,011	$163,913	$885,143
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$3,690	$5,071	$5,982	$7,222	$8,769	$10,402	$12,455	$15,907	$18,888	$21,562	$25,738	$30,348	$166,035
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$22,579	$31,025	$36,604	$44,186	$53,653	$63,646	$79,726	$101,823	$120,906	$138,021	$164,749	$194,262	$1,051,178

[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.

[1] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan-Jun actual period is 4.9230%, which based on the May 2013 ROR Surveillance Report per Order No.12-0425-PAA-EU and the monthly Equity Component for Jul-Dec estimated period is 4.8938 % which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL SECURITY														
1. Investments														
a. Expenditures/Additions		$868,421	$878,432	$1,361,825	$835,730	$851,108	$1,128,585	$301,490	$298,569	$714,027	$298,569	$110,779	$553,850	$8,201,385
b. Clearings to Plant		$0	$0	$960,630	$0	$3,567,272	$8,945,482	$593,863	$5,006	$5,006	$793,455	$17,435	$4,378,037	$19,266,187
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base	$992,005	$992,005	$992,005	$1,952,635	$1,952,635	$5,519,908	$14,465,390	$15,059,253	$15,064,259	$15,069,265	$15,862,720	$15,880,155	$20,258,192	N/A
3. Less: Accumulated Depreciation	$744	$2,232	$3,720	$5,929	$8,858	$15,629	$36,280	$67,599	$99,560	$131,534	$164,514	$198,509	$236,585	N/A
4. CWIP - Non Interest Bearing	$11,064,802	$11,933,223	$12,811,655	$13,212,850	$14,048,580	$11,332,415	$3,515,518	$3,223,145	$3,516,708	$4,225,729	$3,730,843	$3,824,187	($0)	N/A
5. Net Investment (Lines 2 - 3 + 4)	$12,056,063	$12,922,996	$13,799,940	$15,159,557	$15,992,358	$16,836,694	$17,944,628	$18,214,799	$18,481,408	$19,163,460	$19,429,049	$19,505,833	$20,021,607	N/A
6. Average Net Investment		$12,489,530	$13,361,468	$14,479,748	$15,575,957	$16,414,526	$17,390,661	$18,079,714	$18,348,103	$18,822,434	$19,296,255	$19,467,441	$19,763,720	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [1]		$82,921	$88,710	$96,135	$103,413	$108,980	$115,461	$120,036	$121,818	$124,967	$128,113	$129,249	$131,217	$1,351,020
b. Debt Component (Line 6 x debt rate x 1/12) [2]		$15,353	$16,425	$17,799	$19,147	$20,178	$21,377	$22,224	$22,554	$23,137	$23,720	$23,930	$24,295	$250,140
8. Investment Expenses														
a. Depreciation		$1,488	$1,488	$2,208	$2,929	$6,772	$20,650	$31,320	$31,960	$31,975	$32,980	$33,996	$38,076	$235,841
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$99,762	$106,623	$116,143	$125,489	$135,930	$157,489	$173,580	$176,333	$180,079	$184,812	$187,175	$193,587	$1,837,001

[1] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan-Dec 2015 estimated period is 4.8938%, which based on the May 2014 ROR Surveillance Report per Order No.12-0425-PAA-EU

[2] The monthly Debt Component for Jan-Dec 2015 estimated period is 1.4751%, which is based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

REVISED

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
(WITH GAS RESERVES)

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL SECURITY														
1. Investments														
a. Expenditures/Additions		$0	$2,124	$120,574	$144,376	$467,198	$419,988	$2,164,567	$1,516,668	$1,996,183	$1,836,143	$1,855,114	$1,533,873	$12,056,807
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$992,005	$992,005
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$992,005	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$744	N/A
4. CWIP - Non Interest Bearing	$0	$0	$2,124	$122,698	$267,074	$734,272	$1,154,260	$3,318,826	$4,835,494	$6,831,677	$8,667,820	$10,522,934	$11,064,802	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$2,124	$122,698	$267,074	$734,272	$1,154,260	$3,318,826	$4,835,494	$6,831,677	$8,667,820	$10,522,934	$12,056,063	N/A
6. Average Net Investment		$0	$1,062	$62,411	$194,886	$500,673	$944,266	$2,236,543	$4,077,160	$5,833,586	$7,749,749	$9,595,377	$11,289,499	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [1]		$0	$7	$417	$1,302	$3,344	$6,307	$14,849	$27,069	$38,731	$51,453	$63,706	$74,954	$282,138
b. Debt Component (Line 6 x debt rate x 1/12) [2]		$0	$1	$81	$254	$653	$1,232	$2,749	$5,012	$7,171	$9,526	$11,795	$13,878	$52,354
8. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$744	$744
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$0	$8	$498	$1,556	$3,997	$7,539	$17,598	$32,081	$45,902	$60,979	$75,501	$89,576	$335,236

[1] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan-Jun actual period is 4.9230%, which based on the May 2013 ROR Surveillance Report per Order No.12-0425-PAA-EU and the monthly Equity Component for Jul-Dec estimated period is 4.8938 % which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity.

[2] The monthly Debt Component for Jan-Jun actual period is 1.5658%, which is based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.The monthly Debt Component for Jul-Dec estimated period is 1.4751 % which based on the on the May 2014 ROR Surveillance Report.

Florida Power & Light Company
Schedule E12 - Capacity Costs
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2015 Projection

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
SWAPBC	40	1/1/2012	4/1/2032	QF

QF = Qualifying Facility

2015 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	10,891,255	130,695,060
ICL	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	11,571,783	138,861,398
BN-NEG '91	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	3,981,120
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
SWAPBC	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	1,095,300	13,143,600
Total	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	23,995,658	287,947,898

Florida Power & Light Company
Schedule E12 - Capacity Costs
Page 2 of 2

2015 Projection

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Southern Company - UPS Scherer	Other Entity	June 1, 2010	December 31, 2015
2	Southern Company - UPS Harris	Other Entity	June 1, 2010	December 31, 2015
3	Southern Company - UPS Franklin	Other Entity	June 1, 2010	December 31, 2015
4	JEA - SJRPP	Other Entity	April 2, 1982	September 30, 2021

2015 Capacity in MW

Contract	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
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
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2015 Capacity in Dollars

Contract	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
1												
2												
3												
4												
Total	13,886,909	13,888,005	13,890,818	13,888,283	13,837,611	13,835,268	13,834,239	13,836,911	13,838,210	13,852,964	13,849,178	13,851,804

Total Capacity Payments to Non-Cogenerators for 2015	166,290,201	(1)

(1) Revised September 15, 2014 Projection Filing, Appendix IV, page 2, line 1

FLORIDA POWER & LIGHT COMPANY
BASED ON RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

	Rate	Demand & Energy Component[1] $000s	Allocation	2015 WC3 Revenue Requirement Allocation @ 10.5% ROE
	(a)	(b)	(c)	(d)
1	CILC-1D	22,378	2.1%	$3,116,883
2	CILC-1G	1,442	0.1%	$200,815
3	CILC-1T	9,888	0.9%	$1,377,214
4	GS1	61,812	5.8%	$8,609,440
5	GSCU-1	288	0.0%	$40,125
6	GSD1	237,906	22.1%	$33,136,361
7	GSLD1	105,089	9.8%	$14,637,120
8	GSLD2	20,042	1.9%	$2,791,550
9	GSLD3	1,575	0.1%	$219,343
10	MET	936	0.1%	$130,431
11	OL-1	274	0.0%	$38,133
12	OS-2	101	0.0%	$14,048
13	RS1	609,861	56.8%	$84,943,507
14	SL-1	1,438	0.1%	$200,260
15	SL-2	256	0.0%	$35,656
16	SST-DST	49	0.0%	$6,777
17	SST-TST	849	0.1%	$118,198
18				
19	Total	1,074,183	100.0%	$149,615,862

Notes:
[1] Docket 120015-EI 2013 Test Year MFR E-6b attachment 2 of 2 lines 5 + 17 Other Production revenue requirement

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3
(WITH GAS RESERVES)

	(a)	Total Revenue[1] (b)	Total WC3 Costs (c)		% Increase (d)
1	RS1/RTR1	$5,735,574,686	$84,943,507		1.48%
2	GS1/GST1	$640,657,649	$8,609,440		1.34%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,248,875,554	$33,136,361		1.47%
4	OS2	$1,481,160	$14,048		0.95%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$828,798,537	$14,637,120		1.77%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$184,717,533	$2,791,550		1.51%
7	GSLD3/GSLDT3/CS3/CST3	$11,852,831	$219,343		1.85%
8	ISST1D	$0	$0		0.00%
9	ISST1T	$0	$0		0.00%
10	SST1T	$7,828,660	$118,198		1.51%
11	SST1D1/SST1D2/SST1D3	$1,018,401	$6,777		0.67%
12	CILC D/CILC G	$199,147,708	$3,317,698		1.67%
13	CILC T	$76,139,941	$1,377,214		1.81%
14	MET	$7,105,708	$130,431		1.84%
15	OL1/SL1/PL1	$126,726,148	$238,393		0.19%
16	SL2, GSCU1	$8,888,101	$75,782		0.85%
17					
18	TOTAL	$10,078,812,617	$149,615,862		1.48%
				1.5x	2.23%
				Max	1.85%

Notes
1) Based on Projections of 2015 base and clause revenues.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JANUARY 2015 THROUGH DECEMBER 2015
(WITH GAS RESERVES)

	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	56,486,754,968	-	-	$84,943,507		0.00150
2	GS1/GST1/WIES1	6,303,353,434	-	-	$8,609,440		0.00137
3	GSD1/GSDT1/HLFT1	26,491,485,933	51.60099%	70,327,546	$33,136,361	0.47	
4	OS2	11,006,147	-	-	$14,048		0.00128
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,833,502,128	55.38079%	26,797,044	$14,637,120	0.55	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,574,841,239	66.25224%	5,323,865	$2,791,550	0.52	
7	GSLD3/GSLDT3/CS3/CST3	177,940,556	70.94077%	343,602	$219,343	0.64	
8	SST1T	89,096,934	13.15150%	928,036	$118,198		
9	SST1D1/SST1D2/SST1D3	9,138,135	26.99741%	46,367	$6,777		
10	CILC D/CILC G	3,085,079,885	74.21337%	5,694,576	$3,317,698	0.58	
11	CILC T	1,356,675,191	76.87427%	2,417,531	$1,377,214	0.57	
12	MET	82,790,174	65.26192%	173,779	$130,431	0.75	
13	OL1/SL1/PL1	622,341,281	-	-	$238,393		0.00038
14	SL2, GSCU1	92,875,590	-	-	$75,782		0.00082
		108,216,881,595		112,052,346	$149,615,862		

(1) Projected kwh sales for the period January 2015 through December 2015
(2) Billing kW Load Factor based on 2011-2013 load research data and 2015 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	$0.07	$0.03
ISST1T	$0.07	$0.03
SST1T	$0.07	$0.03
SST1D1/SST1D2/SST1I	$0.07	$0.03

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3
(WITH GAS RESERVES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2014 - Dec 2014 Capacity Recovery Factor				2014 WCEC-3 Capacity Recovery Factor				Total Jan 2014 - Dec 2014 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	-	0.00485	-	-	-	0.00150	-	-	-	0.00635	-	-
GS1/GST1/WIES1	-	0.00434	-	-	-	0.00137	-	-	-	0.00571	-	-
GSD1/GSDT1/HLFT1	1.52	-	-	-	0.47	-	-	-	1.99	-	-	-
OS2	-	0.00409	-	-	-	0.00128	-	-	-	0.00537	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.63	-	-	-	0.55	-	-	-	2.18	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.71	-	-	-	0.52	-	-	-	2.23	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.72	-	-	-	0.64	-	-	-	2.36	-	-	-
SST1T	-	-	$0.21	$0.10	-	-	$0.07	$0.03	-	-	$0.28	$0.13
SST1D1/SST1D2/SST1D3	-	-	$0.21	$0.10	-	-	$0.07	$0.03	-	-	$0.28	$0.13
CILC D/CILC G	1.85	-	-	-	0.58	-	-	-	2.43	-	-	-
CILC T	1.82	-	-	-	0.57	-	-	-	2.39	-	-	-
MET	1.96	-	-	-	0.75	-	-	-	2.71	-	-	-
OL1/SL1/PL1	-	0.00112	-	-	-	0.00038	-	-	-	0.00150	-	-
SL2, GSCU1	-	0.00314	-	-	-	0.00082	-	-	-	0.00396	-	-

[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.

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)

APPENDIX V

CAPACITY COST RECOVERY – WITHOUT GAS RESERVES PROJECT

JANUARY 2015 – DECEMBER 2015 FACTORS

TJK-8
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____
PAGES 1-4
SEPTEMBER 15, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-8

APPENDIX V
CAPACITY COST RECOVERY – WITHOUT GAS RESERVES PROJECT

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1	2015 Projected Capacity Payments	T. J. Keith
2	Calculation of Energy & Demand Allocation % By Rate Class	T. J. Keith
3	Calculation of 2015 Capacity Recovery Factor	T. J. Keith
4	Calculation of Capacity Recovery Factor including West County Energy Center Unit 3 for January 2015 through December 2015	T.J. Keith

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITHOUT GAS RESERVES)

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	$13,886,909	$13,888,005	$13,890,818	$13,888,283	$13,837,611	$13,835,268	$13,834,239	$13,836,911	$13,838,210	$13,852,964	$13,849,178	$13,851,804	$166,290,201
2	Capacity Payments To Cogenerators	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$23,995,658	$287,947,898
3	SJRPP Suspension Accrual	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($743,251)	($8,919,012)
4	Return Requirements On SJRPP Suspension Liability	($289,443)	($283,595)	($277,746)	($271,898)	($266,050)	($260,201)	($254,353)	($248,505)	($242,656)	($236,808)	($230,960)	($225,111)	($3,087,326)
5	Incremental Plant Security Costs O&M	$3,548,308	$3,336,539	$4,230,333	$3,800,522	$4,124,988	$3,682,222	$3,461,800	$3,584,732	$3,599,886	$3,582,685	$3,872,678	$4,166,455	$44,991,146
6	Incremental Plant Security Costs Capital	$99,762	$106,623	$116,143	$125,489	$135,930	$157,489	$173,580	$176,333	$180,079	$184,812	$187,175	$193,587	1,837,001
7	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,624	$18,421	$36,045
8	Incremental Nuclear NRC Compliance Costs Capital	$226,478	$270,880	$322,351	$372,717	$409,334	$437,090	$464,548	$506,007	$552,783	$598,218	$627,739	$655,866	$5,444,010
9	Transmission Of Electricity By Others	$1,949,653	$1,959,004	$1,895,658	$1,743,738	$1,799,061	$1,654,080	$1,643,240	$1,764,927	$1,626,923	$1,737,916	$2,073,254	$2,063,175	$21,910,628
10	Transmission Revenues From Capacity Sales	($775,000)	($710,000)	($671,250)	($290,000)	($266,250)	($206,250)	($215,000)	($202,500)	($176,250)	($202,500)	($405,000)	($480,000)	($4,600,000)
11	System Total	$41,899,073	$41,819,864	$42,758,713	$42,621,257	$43,027,031	$42,552,105	$42,360,461	$42,670,312	$42,631,381	$42,769,694	$43,244,095	$43,496,604	$511,850,591
12	Jurisdictional % *													94.64598%
13	Jurisdictionalized Capacity Payments													$484,446,002
14	2013 FINAL TRUE-UP -- (Over)/Under Recovery													($11,054,159)
15	2014 ACT/EST TRUE-UP -- (Over)/Under Recovery													($10,299,210)
16	Nuclear Cost Recovery Clause													$14,287,862
17	Total (Lines 13+14+15+16)													$477,380,495
18	Revenue Tax Multiplier													1.00072
19	Total Recoverable Capacity Payments													$477,724,209
20														
21	*Calculation of Jurisdictional %													
22	.....AVG. 12CP													
23	.....AT GEN (MW).....%													
24	FPSC.....19,228.343.....94.64598%													
25	FERC.....1,087.727.....5.35402%													
26	TOTAL.....20,316.070.....100.00000%													
27														
28	* Based on 2015 Estimated Data													
29	Totals may not add up due to rounding.													
30														
31														
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 2015 THROUGH DECEMBER 2015
(WITHOUT GAS RESERVES)

(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	62.339%	56,486,754,968	10,343,916	1.07273422	1.05687858	59,699,641,379	11,096,273	52.25760%	57.70790%
GS1/GST1/WIES1	70.132%	6,303,353,434	1,026,010	1.07273422	1.05687858	6,661,879,227	1,100,636	5.83142%	5.72403%
GSD1/GSDT1/HLFT1	76.094%	26,491,485,933	3,974,214	1.07263018	1.05679832	27,996,157,828	4,262,862	24.50621%	22.16968%
OS2	74.112%	11,006,147	1,695	1.06372574	1.02956109	11,331,501	1,803	0.00992%	0.00938%
GSLD1/GSLDT1/CS1/CST1/HLFT2	76.113%	10,833,502,128	1,624,817	1.07131612	1.05580061	11,438,018,155	1,740,693	10.01218%	9.05274%
GSLD2/GSLDT2/CS2/CST2/HLFT3	87.059%	2,574,841,239	337,623	1.06110282	1.04763148	2,697,484,738	358,253	2.36122%	1.86315%
GSLD3/GSLDT3/CS3/CST3	89.410%	177,940,556	22,719	1.02378679	1.01925379	181,366,586	23,259	0.15876%	0.12096%
SST1T	93.724%	89,096,934	10,852	1.02378679	1.01925379	90,812,388	11,110	0.07949%	0.05778%
SST1D1/SST1D2/SST1D3	75.410%	9,138,135	1,383	1.03714120	1.02956109	9,408,268	1,434	0.00824%	0.00746%
CILC D/CILC G	90.403%	3,085,079,885	389,564	1.05992932	1.04730798	3,231,028,782	412,910	2.82826%	2.14740%
CILC T	91.694%	1,356,675,191	168,901	1.02378679	1.01925379	1,382,796,330	172,919	1.21042%	0.89929%
MET	71.762%	82,790,174	13,170	1.03714120	1.02956109	85,237,542	13,659	0.07461%	0.07104%
OL1/SL1/PL1	359.698%	622,341,281	19,751	1.07273422	1.05687858	657,739,169	21,188	0.57575%	0.11019%
SL2, GSCU1	100.263%	92,875,590	10,574	1.07273422	1.05687858	98,158,222	11,343	0.08592%	0.05899%
TOTAL		108,216,881,595	17,945,189			114,241,060,116	19,228,342	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2011-2013 load research data and 2015 projections.

[b] Projected kwh sales for the period January 2015 through December 2015.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on 2015 demand losses.

[e] Based on 2015 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
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015
(WITHOUT GAS RESERVES)

(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	52.25760%	57.70790%	$19,203,633	$254,478,113	$273,681,745	56,486,754,968	-	-	-	0.00485	-	-
GS1/GST1/WIES1	5.83142%	5.72403%	$2,142,932	$25,241,609	$27,384,542	6,303,353,434	-	-	-	0.00434	-	-
GSD1/GSDT1/HLFT1	24.50621%	22.16968%	$9,005,547	$97,763,013	$106,768,560	26,491,485,933	51.60099%	70,327,546	1.52	-	-	-
OS2	0.00992%	0.00938%	$3,645	$41,350	$44,995	11,006,147	-	-	-	0.00409	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.01218%	9.05274%	$3,679,277	$39,920,448	$43,599,725	10,833,502,128	55.38079%	26,797,044	1.63	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.36122%	1.86315%	$867,702	$8,216,045	$9,083,747	2,574,841,239	66.25224%	5,323,865	1.71	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.15876%	0.12096%	$58,340	$533,423	$591,764	177,940,556	70.94077%	343,602	1.72	-	-	-
SST1T	0.07949%	0.05778%	$29,212	$254,796	$284,008	89,096,934	13.15150%	928,036	-	-	$0.21	$0.10
SST1D1/SST1D2/SST1D3	0.00824%	0.00746%	$3,026	$32,895	$35,922	9,138,135	26.99741%	46,367	-	-	$0.21	$0.10
CILC D/CILC G	2.82826%	2.14740%	$1,039,328	$9,469,543	$10,508,871	3,085,079,885	74.21337%	5,694,576	1.85	-	-	-
CILC T	1.21042%	0.89929%	$444,805	$3,965,656	$4,410,461	1,356,675,191	76.87427%	2,417,531	1.82	-	-	-
MET	0.07461%	0.07104%	$27,418	$313,254	$340,673	82,790,174	65.26192%	173,779	1.96	-	-	-
OL1/SL1/PL1	0.57575%	0.11019%	$211,576	$485,909	$697,484	622,341,281	-	-	-	0.00112	-	-
SL2, GSCU1	0.08592%	0.05899%	$31,575	$260,139	$291,713	92,875,590	-	-	-	0.00314	-	-
TOTAL			$36,748,016	$440,976,193	$477,724,209	108,216,881,595		112,052,346				

[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 2015 through December 2015.

[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
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3
(WITHOUT GAS RESERVES)
ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2014 - Dec 2014 Capacity Recovery Factor				2014 WCEC-3 Capacity Recovery Factor				Total Jan 2014 - Dec 2014 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	-	0.00485	-	-	-	0.00150	-	-	-	0.00635	-	-
GS1/GST1/WIES1	-	0.00434	-	-	-	0.00137	-	-	-	0.00571	-	-
GSD1/GSDT1/HLFT1	1.52	-	-	-	0.47	-	-	-	1.99	-	-	-
OS2	-	0.00409	-	-	-	0.00128	-	-	-	0.00537	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.63	-	-	-	0.55	-	-	-	2.18	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.71	-	-	-	0.52	-	-	-	2.23	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.72	-	-	-	0.64	-	-	-	2.36	-	-	-
SST1T	-	-	$0.21	$0.10	-	-	$0.07	$0.03	-	-	$0.28	$0.13
SST1D1/SST1D2/SST1D3	-	-	$0.21	$0.10	-	-	$0.07	$0.03	-	-	$0.28	$0.13
CILC D/CILC G	1.85	-	-	-	0.58	-	-	-	2.43	-	-	-
CILC T	1.82	-	-	-	0.57	-	-	-	2.39	-	-	-
MET	1.96	-	-	-	0.75	-	-	-	2.71	-	-	-
OL1/SL1/PL1	-	0.00112	-	-	-	0.00038	-	-	-	0.00150	-	-
SL2, GSCU1	-	0.00314	-	-	-	0.00082	-	-	-	0.00396	-	-

[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 VI

2015 REVENUE REQUIREMENT CALCULATION FOR WEST COUNTY ENERGY CENTER UNIT 3

TJK-9
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-2
SEPTEMBER 15, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry J. Keith TJK-9

WCEC UNIT 3
2015 REVENUE REQUIREMENT

Line No.	WCEC3 Revenue Requirement Calculation	2015
1	**Jurisdictional Adjusted Rate Base**	**$668,980,336**
2	**Rate of Return on Rate Base**	**8.701%**
3	**Required Jurisdictional Net Operating Income**	**58,208,380**
4	**Required Net Operating Income**	**58,208,380**
5	**Jurisdictional Adjusted Net Operating Income (Loss)**	**(33,349,631)**
6	**Net Operating Income Deficiency (Excess)**	**91,558,012**
7	**Net Operating Income Multiplier**	**1.63411**
8	**2015 Revenue Requirement**	**$149,615,862**

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	After Tax COC
1	Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.84450%
2	Common Equity	55.800%	10.500%	5.85900%	9.53846%	5.85900%
3	Total	100.000%		8.70106%	12.38052%	7.70350%
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**
15	Production Plant	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
17	Production Reserve	0	(18,765,331)	(32,169,140)	(50,934,471)	(83,103,611)	(115,272,751)	(147,441,890)
18	Transmission Reserve	0	(556,065)	(953,255)	(1,509,320)	(2,462,575)	(3,415,830)	(4,369,084)
19	Deferred Taxes	10,263,153	5,327,263	(117,748)	(5,609,859)	(14,805,540)	(22,398,424)	(28,506,548)
20	Net Plant	852,621,836	828,364,549	809,118,540	784,305,033	741,986,957	701,271,678	662,041,160
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**
24	**Average Rate Base**	840,493,193	830,870,188	806,334,791	818,741,545	763,145,995	721,629,318	681,656,419
25	Juris Factor	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	803,516,227	748,954,532	708,209,899	668,980,336
27								
28	**Juris Interest Expense**	13,675,149	23,174,706	22,490,363	9,515,172	21,285,737	20,127,750	19,012,823
29	**Income Tax - Interest Expense**	(5,275,189)	(8,939,643)	(8,675,658)	(3,670,478)	(8,210,973)	(7,764,280)	(7,334,196)
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**
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
34	Depreciation	19,321,397	33,122,394	33,122,394	13,800,998	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
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
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
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)
40								
41	**Other Income Taxes - Def Taxes**	790,050	1,354,370	1,354,370	564,320	1,354,370	1,354,370	1,354,371
42	**Juris Other Income Taxes**	775,358	1,329,184	1,329,184	553,826	1,329,184	1,329,184	1,329,185
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**
46	Operating Expenses	(38,307,070)	(65,542,755)	(65,469,103)	(27,377,901)	(65,254,414)	(64,654,538)	(64,069,422)
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
48	Income Tax - Interest Expense	5,275,189	8,939,643	8,675,658	3,670,478	8,210,973	7,764,280	7,334,196
49	Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)	(1,329,184)	(1,329,185)
50	**Juris Net Operating Income**	(19,030,287)	(32,649,178)	(32,867,923)	(13,700,224)	(33,200,735)	(33,278,954)	(33,349,631)

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2013

JCB-1
DOCKET NO. 140001-EI
FPL Witness: J. Carine Bullock
Exhibit No.: _____
Pages 1 - 17
March 7, 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 16
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: J. C. Bullock JCB-1

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2013

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 - 6.203.016	GPIF Units Points Tables
6.203.017	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2013

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)			GENERATING PERFORMANCE INCENTIVE FACTOR ($000)		
+ 10		73,938			36,969		
+ 9		66,544			33,272		
+ 8		59,150			29,575		
+ 7		51,757			25,878		
+ 6		44,363			22,181		
+ 5		36,969			18,485		
+ 4		29,575			14,788		
+ 3	<--------- 3.20	22,181	<---------	23,628.477	11,091	<--------	11,814.923
+ 2		14,788			7,394		
+ 1		7,394			3,697		
0		0			0		
- 1		(7,394)			(3,697)		
- 2		(14,788)			(7,394)		
- 3		(22,181)			(11,091)		
- 4		(29,575)			(14,788)		
- 5		(36,969)			(18,485)		
- 6		(44,363)			(22,181)		
- 7		(51,757)			(25,878)		
- 8		(59,150)			(29,575)		
- 9		(66,544)			(33,272)		
- 10		(73,938)			(36,969)		

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2013

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 12,530,193,155	
LINE 2	MONTH OF January	2013	$ 12,643,293,780	
LINE 3	MONTH OF February	2013	$ 12,717,016,420	
LINE 4	MONTH OF March	2013	$ 12,478,105,410	
LINE 5	MONTH OF April	2013	$ 12,561,619,900	
LINE 6	MONTH OF May	2013	$ 12,709,771,110	
LINE 7	MONTH OF June	2013	$ 12,869,343,040	
LINE 8	MONTH OF July	2013	$ 13,052,272,510	
LINE 9	MONTH OF August	2013	$ 13,218,352,450	
LINE 10	MONTH OF September	2013	$ 12,560,870,160	
LINE 11	MONTH OF October	2013	$ 12,650,514,670	
LINE 12	MONTH OF November	2013	$ 13,022,310,370	
LINE 13	MONTH OF December	2013	$ 13,083,708,220	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 12,776,720,861	
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)		$ 52,038,752	
LINE 18	JURISDICTIONAL SALES		102,783,857,000	KWH
LINE 19	TOTAL SALES		104,942,046,340	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		97.94%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 50,966,754	
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$ 36,969,000	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$ 36,969,000	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

JANUARY THROUGH DECEMBER, 2013

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Ft. Myers 2	EAF	3.70	10.00	.3700
Ft. Myers 2	ANOHR	2.25	-10.00	-.2250
Martin 8	EAF	5.46	8.40	.4586
Martin 8	ANOHR	6.27	2.19	.1373
Manatee 3	EAF	5.53	6.80	.3760
Manatee 3	ANOHR	5.65	0.00	.0000
Scherer 4	EAF	2.81	-0.50	-.0141
Scherer 4	ANOHR	4.65	-6.29	-.2925
St. Lucie 1	EAF	10.77	-1.00	-.1077
St. Lucie 1	ANOHR	2.54	10.00	.2540
St. Lucie 2	EAF	12.79	10.00	1.2790
St. Lucie 2	ANOHR	2.57	10.00	.2570
Turkey Point 3	EAF	9.46	-10.00	-.9460
Turkey Point 3	ANOHR	3.29	10.00	.3290
Turkey Point 4	EAF	8.38	9.67	.8103
Turkey Point 4	ANOHR	3.86	0.00	.0000
Turkey Point 5	EAF	5.10	10.00	.5100
Turkey Point 5	ANOHR	4.92	0.00	.0000
GPIF System Total:		100		3.20

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2013

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	0.1	3.0	10.3	86.5	-3.2	83.3	79.9	10.00	09/04/13 - 11/15/13; 10/19/13 - 11/02/13 10/19/13 - 10/25/13; 10/26/13 - 11/01/13 11/02/13 - 11/08/13	9/7/13-11/26/13; 9/7/13-11/16/13 9/7/13-9/27/13; 9/14/13-9/27/13	2,739.0
Martin 8	1.2	3.3	5.5	89.9	3.0	92.9	90.8	8.40	03/09/13 - 03/22/13; 03/23/13 - 04/05/13 10/05/13 - 10/11/13	3/23/13-4/8/13; 3/23/13-4/9/13 3/23/13-4/11/13; 3/23/13-4/13/13 11/1/13-11/9/13	3,388.6
Manatee 3	0.1	4.8	1.8	93.3	-0.1	93.2	91.5	6.80	02/11/13 - 02/15/13; 02/16/13 - 03/01/13 03/02/13 - 03/15/13	5/31/13-6/15/13; 6/16/13-6/28/13	2,779.2
Scherer 4	1.1	3.1	0.0	95.9	0.0	95.9	96.0	-0.50	NONE	NONE	(104.0)
St. Lucie 1	6.3	2.2	11.4	80.2	0.8	81.0	81.3	-1.00	09/05/13 - 10/13/13	8/7/13; 9/29/13-11/15/13; 11/21/13	(796.4)
St. Lucie 2	2.3	0.0	0.0	97.7	0.0	97.7	90.2	10.00	NONE	12/17/13-12/18/13	9,456.0
Turkey Point 3	12.0	0.0	0.3	87.7	-8.8	78.9	83.2	-10.00	10/21/13 - 11/28/13	1/29/13-2/1/13; 6/10/13; 6/25/13 9/1/13, 9/2/13 and 9/23/13; 10/30-31/13	(6,994.0)
Turkey Point 4	3.0	0.0	32.8	64.2	12.3	76.5	73.6	9.67	01/01/13 - 03/15/13	1/1/13-4/19/13, 4/22/13-5/17/13, 5/27-5/30/13 7/15/13, 7/25/13 and 7/31/13 10/17/13	5,992.5
Turkey Point 5	0.1	0.6	2.0	97.4	0.0	97.4	91.4	10.00	07/13/13 - 07/19/13; 07/20/13 - 07/26/13 07/27/13 - 08/02/13; 08/03/13 - 08/09/13	7/27/13-8/4/13; 8/3/13-8/11/13 8/10/13-8/18/13; 8/17/13-8/24/13	3,770.0
											20,230.819

(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, 2013

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Ft. Myers 2	8760	11.9	265.4	903.0	13.6	1188.0	83.3
Martin 8	8760	109.4	293.2	485.0	2.4	210.0	92.9
Manatee 3	8760	9.1	422.4	159.8	1.9	168.0	93.2
Scherer 4	8760	92.2	271.1	0.0	0.0	0.0	95.9
St. Lucie 1	8760	550.7	190.6	995.5	10.4	912.0	81.0
St. Lucie 2	8760	204.5	0.0	0.7	0.0	0.0	97.7
Turkey Point 3	8760	1047.0	0.0	30.0	10.4	912.0	78.9
Turkey Point 4	8760	260.2	0.0	2871.9	20.0	1752.0	76.5
Turkey Point 5	8760	7.6	50.4	173.2	1.9	168.0	97.4

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2013

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=	-8.10	x NOF +	7,917		68.3	7,596	7,364	232	7,130	7,362	-10.00	(1662.0)
Martin 8	ANOHR=	-9.24	x NOF +	7,799		74.8	7,008	7,108	-100	6,955	6,855	2.19	1016.2
Manatee 3	ANOHR=	-2.69	x NOF +	7,175		73.4	7,017	6,978	39	6,921	6,960	0.00	0.0
Scherer 4	ANOHR=	-9.38	x NOF +	10,921		88.1	10,311	10,095	216	10,134	10,350	-6.29	(2162.5)
St. Lucie 1	ANOHR=	-35.29	x NOF +	14,328		100.4	10,332	10,785	-453	10,810	10,357	10.00	1875.0
St. Lucie 2	ANOHR=	-84.84	x NOF +	19,341		102.1	10,195	10,679	-484	10,899	10,415	10.00	1899.0
Turkey Point 3	ANOHR=	-101.81	x NOF +	21,451		97.0	11,092	11,575	-483	11,382	10,899	10.00	2432.0
Turkey Point 4	ANOHR=	-76.69	x NOF +	18,831		102.2	10,994	10,993	1	11,660	11,661	0.00	0.0
Turkey Point 5	ANOHR=	-6.80	x NOF +	7,636		72.1	7,132	7,146	-14	7,000	6,986	0.00	0.0

3,397.658

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, 2013

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	2,739.0	<- Fuel Sav/(Loss) 2,739.0	82.4	<- Adj. Act. EAF= 83.3	+10	1,662.0		7,037	
+9	2,465.1		82.2		+9	1,495.8		7,039	
+8	2,191.2		81.9		+8	1,329.6		7,041	
+7	1,917.3		81.7		+7	1,163.4		7,042	
+6	1,643.4		81.4		+6	997.2		7,044	
+5	1,369.5		81.2		+5	831.0		7,046	
+4	1,095.6		80.9		+4	664.8		7,048	
+3	821.7		80.7		+3	498.6		7,050	
+2	547.8		80.4		+2	332.4		7,051	
+1	273.9		80.2		+1	166.2		7,053	
						0		7,055	
0	0		79.9		0	0		7,130	
						0		7,205	
-1	(273.9)		79.7		-1	(166.2)		7,207	
-2	(547.8)		79.4		-2	(332.4)		7,209	
-3	(821.7)		79.2		-3	(498.6)		7,210	
-4	(1,095.6)		78.9		-4	(664.8)		7,212	
-5	(1,369.5)		78.7		-5	(831.0)		7,214	
-6	(1,643.4)		78.4		-6	(997.2)		7,216	
-7	(1,917.3)		78.2		-7	(1,163.4)		7,218	
-8	(2,191.2)		77.9		-8	(1,329.6)		7,219	
-9	(2,465.1)		77.7		-9	(1,495.8)		7,221	
-10	(2,739.0)		77.4		-10	(1,662.0)	<- Fuel Sav/(Loss) - 1,662.0	7,223	<- Adj. Act. HR=7,362
	WEIGHTING FACTOR =	3.70				WEIGHTING FACTOR =	2.25		

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	4,034.0		93.3		+10	4,640.0		6,766	
+9	3,630.6		93.1		+9	4,176.0		6,777	
+8	3,227.2	<- Fuel Sav/(Loss) 3,388.6	92.8	<- Adj. Act. EAF= 92.9	+8	3,712.0		6,789	
+7	2,823.8		92.6		+7	3,248.0		6,800	
+6	2,420.4		92.3		+6	2,784.0		6,812	
+5	2,017.0		92.1		+5	2,320.0		6,823	
+4	1,613.6		91.8		+4	1,856.0		6,834	
+3	1,210.2		91.6		+3	1,392.0	<- Fuel Sav/(Loss) 1,016.2	6,846	<- Adj. Act. HR=6,855
+2	806.8		91.3		+2	928.0		6,857	
+1	403.4		91.1		+1	464.0		6,869	
						0		6,880	
0	0		90.8		0	0		6,955	
						0		7,030	
-1	(403.4)		90.6		-1	(464.0)		7,041	
-2	(806.8)		90.3		-2	(928.0)		7,053	
-3	(1,210.2)		90.1		-3	(1,392.0)		7,064	
-4	(1,613.6)		89.8		-4	(1,856.0)		7,076	
-5	(2,017.0)		89.6		-5	(2,320.0)		7,087	
-6	(2,420.4)		89.3		-6	(2,784.0)		7,098	
-7	(2,823.8)		89.1		-7	(3,248.0)		7,110	
-8	(3,227.2)		88.8		-8	(3,712.0)		7,121	
-9	(3,630.6)		88.6		-9	(4,176.0)		7,133	
-10	(4,034.0)		88.3		-10	(4,640.0)		7,144	
	WEIGHTING FACTOR =		5.46			WEIGHTING FACTOR =		6.27	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	4,087.0		94.0		+10	4,181.0		6,766	
+9	3,678.3		93.8		+9	3,762.9		6,774	
+8	3,269.6		93.5		+8	3,344.8		6,782	
+7	2,860.9		93.3		+7	2,926.7		6,790	
+6	2,452.2	<- Fuel Sav/(Loss) 2,779.2	93.0	<- Adj. Act. EAF= 93.2	+6	2,508.6		6,798	
+5	2,043.5		92.8		+5	2,090.5		6,806	
+4	1,634.8		92.5		+4	1,672.4		6,814	
+3	1,226.1		92.3		+3	1,254.3		6,822	
+2	817.4		92.0		+2	836.2		6,830	
+1	408.7		91.8		+1	418.1		6,838	
						0		6,846	
0	0		91.5		0	0	<- Fuel Sav/(Loss)	6,921	<- Adj. Act. HR=6.960
						0		6,996	
-1	(408.7)		91.3		-1	(418.1)		7,004	
-2	(817.4)		91.0		-2	(836.2)		7,012	
-3	(1,226.1)		90.8		-3	(1,254.3)		7,020	
-4	(1,634.8)		90.5		-4	(1,672.4)		7,028	
-5	(2,043.5)		90.3		-5	(2,090.5)		7,036	
-6	(2,452.2)		90.0		-6	(2,508.6)		7,044	
-7	(2,860.9)		89.8		-7	(2,926.7)		7,052	
-8	(3,269.6)		89.5		-8	(3,344.8)		7,060	
-9	(3,678.3)		89.3		-9	(3,762.9)		7,068	
-10	(4,087.0)		89.0		-10	(4,181.0)		7,076	
	WEIGHTING FACTOR =		5.53			WEIGHTING FACTOR =		5.65	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	2,080.0		98.0		+10	3,438.0		9,835	
+9	1,872.0		97.8		+9	3,094.2		9,857	
+8	1,664.0		97.6		+8	2,750.4		9,880	
+7	1,456.0		97.4		+7	2,406.6		9,902	
+6	1,248.0		97.2		+6	2,062.8		9,925	
+5	1,040.0		97.0		+5	1,719.0		9,947	
+4	832.0		96.8		+4	1,375.2		9,969	
+3	624.0		96.6		+3	1,031.4		9,992	
+2	416.0		96.4		+2	687.6		10,014	
+1	208.0		96.2		+1	343.8		10,037	
						0		10,059	
0	0		96.0		0	0		10,134	
						0		10,209	
-1	(208.0)	<- Adj. Act. EAF= -104.0	95.8	<- Adj. Act. EAF= 95.9	-1	(343.8)		10,231	
-2	(416.0)		95.6		-2	(687.6)		10,254	
-3	(624.0)		95.4		-3	(1,031.4)		10,276	
-4	(832.0)		95.2		-4	(1,375.2)		10,299	
-5	(1,040.0)		95.0		-5	(1,719.0)		10,321	
-6	(1,248.0)		94.8		-6	(2,062.8)	<- Fuel Sav/(Loss) - 2,162.5	10,343	<- Adj. Act. HR=10,350
-7	(1,456.0)		94.6		-7	(2,406.6)		10,366	
-8	(1,664.0)		94.4		-8	(2,750.4)		10,388	
-9	(1,872.0)		94.2		-9	(3,094.2)		10,411	
-10	(2,080.0)		94.0		-10	(3,438.0)		10,433	
	WEIGHTING FACTOR =		2.81			WEIGHTING FACTOR =		4.65	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	7,964.0	84.3	+10	1,875.0 <- Fuel Sav/(Loss) 1,875.0	10,689 <- Adj. Act. HR=10,357
+9	7,167.6	84.0	+9	1,687.5	10,694
+8	6,371.2	83.7	+8	1,500.0	10,698
+7	5,574.8	83.4	+7	1,312.5	10,703
+6	4,778.4	83.1	+6	1,125.0	10,707
+5	3,982.0	82.8	+5	937.5	10,712
+4	3,185.6	82.5	+4	750.0	10,717
+3	2,389.2	82.2	+3	562.5	10,721
+2	1,592.8	81.9	+2	375.0	10,726
+1	796.4	81.6	+1	187.5	10,730
				0	10,735
0	0	81.3	0	0	10,810
				0	10,885
-1	(796.4) <- Adj. Act. EAF= -796.4	81.0 <- Adj. Act. EAF= 81.0	-1	(187.5)	10,890
-2	(1,592.8)	80.7	-2	(375.0)	10,894
-3	(2,389.2)	80.4	-3	(562.5)	10,899
-4	(3,185.6)	80.1	-4	(750.0)	10,903
-5	(3,982.0)	79.8	-5	(937.5)	10,908
-6	(4,778.4)	79.5	-6	(1,125.0)	10,913
-7	(5,574.8)	79.2	-7	(1,312.5)	10,917
-8	(6,371.2)	78.9	-8	(1,500.0)	10,922
-9	(7,167.6)	78.6	-9	(1,687.5)	10,926
-10	(7,964.0)	78.3	-10	(1,875.0)	10,931
	WEIGHTING FACTOR =	10.77		WEIGHTING FACTOR =	2.54

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	9,456.0	<- Fuel Sav/(Loss) 9,456.0	93.7	<- Adj. Act. EAF= 97.7	+10	1,899.0	<- Fuel Sav/(Loss) 1,899.0	10,795	<- Adj. Act. HR=10,415
+9	8,510.4		93.4		+9	1,709.1		10,798	
+8	7,564.8		93.0		+8	1,519.2		10,801	
+7	6,619.2		92.7		+7	1,329.3		10,804	
+6	5,673.6		92.3		+6	1,139.4		10,807	
+5	4,728.0		92.0		+5	949.5		10,810	
+4	3,782.4		91.6		+4	759.6		10,812	
+3	2,836.8		91.3		+3	569.7		10,815	
+2	1,891.2		90.9		+2	379.8		10,818	
+1	945.6		90.6		+1	189.9		10,821	
						0		10,824	
0	0		90.2		0	0		10,899	
						0		10,974	
-1	(945.6)		89.9		-1	(189.9)		10,977	
-2	(1,891.2)		89.5		-2	(379.8)		10,980	
-3	(2,836.8)		89.2		-3	(569.7)		10,983	
-4	(3,782.4)		88.8		-4	(759.6)		10,986	
-5	(4,728.0)		88.5		-5	(949.5)		10,989	
-6	(5,673.6)		88.1		-6	(1,139.4)		10,991	
-7	(6,619.2)		87.8		-7	(1,329.3)		10,994	
-8	(7,564.8)		87.4		-8	(1,519.2)		10,997	
-9	(8,510.4)		87.1		-9	(1,709.1)		11,000	
-10	(9,456.0)		86.7		-10	(1,899.0)		11,003	
	WEIGHTING FACTOR =		12.79			WEIGHTING FACTOR =		2.57	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	6,994.0	86.2	+10	2,432.0 <- Fuel Sav/(Loss) 2,432.0	11,191 <- Adj. Act. HR=10,899
+9	6,294.6	85.9	+9	2,188.8	11,203
+8	5,595.2	85.6	+8	1,945.6	11,214
+7	4,895.8	85.3	+7	1,702.4	11,226
+6	4,196.4	85.0	+6	1,459.2	11,237
+5	3,497.0	84.7	+5	1,216.0	11,249
+4	2,797.6	84.4	+4	972.8	11,261
+3	2,098.2	84.1	+3	729.6	11,272
+2	1,398.8	83.8	+2	486.4	11,284
+1	699.4	83.5	+1	243.2	11,295
				0	11,307
0	0	83.2	0	0	11,382
				0	11,457
-1	(699.4)	82.9	-1	(243.2)	11,469
-2	(1,398.8)	82.6	-2	(486.4)	11,480
-3	(2,098.2)	82.3	-3	(729.6)	11,492
-4	(2,797.6)	82.0	-4	(972.8)	11,503
-5	(3,497.0)	81.7	-5	(1,216.0)	11,515
-6	(4,196.4)	81.4	-6	(1,459.2)	11,527
-7	(4,895.8)	81.1	-7	(1,702.4)	11,538
-8	(5,595.2)	80.8	-8	(1,945.6)	11,550
-9	(6,294.6)	80.5	-9	(2,188.8)	11,561
-10	(6,994.0) <- Fuel Sav/(Loss) - 6,994.0	80.2 <- Adj. Act. EAF= 78.9	-10	(2,432.0)	11,573
	WEIGHTING FACTOR =	9.46		WEIGHTING FACTOR =	3.29

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	6,197.0		76.6		+10	2,852.0		11,475	
+9	5,577.3	<- Fuel Sav/(Loss) 5,992.5	76.3	<- Adj. Act. EAF= 76.5	+9	2,566.8		11,486	
+8	4,957.6		76.0		+8	2,281.6		11,497	
+7	4,337.9		75.7		+7	1,996.4		11,508	
+6	3,718.2		75.4		+6	1,711.2		11,519	
+5	3,098.5		75.1		+5	1,426.0		11,530	
+4	2,478.8		74.8		+4	1,140.8		11,541	
+3	1,859.1		74.5		+3	855.6		11,552	
+2	1,239.4		74.2		+2	570.4		11,563	
+1	619.7		73.9		+1	285.2		11,574	
						0		11,585	
0	0		73.6		0	0	<- Fuel Sav/(Loss)	11,660	<- Adj. Act. HR=11,661
						0		11,735	
-1	(619.7)		73.3		-1	(285.2)		11,746	
-2	(1,239.4)		73.0		-2	(570.4)		11,757	
-3	(1,859.1)		72.7		-3	(855.6)		11,768	
-4	(2,478.8)		72.4		-4	(1,140.8)		11,779	
-5	(3,098.5)		72.1		-5	(1,426.0)		11,790	
-6	(3,718.2)		71.8		-6	(1,711.2)		11,801	
-7	(4,337.9)		71.5		-7	(1,996.4)		11,812	
-8	(4,957.6)		71.2		-8	(2,281.6)		11,823	
-9	(5,577.3)		70.9		-9	(2,566.8)		11,834	
-10	(6,197.0)		70.6		-10	(2,852.0)		11,845	
	WEIGHTING FACTOR =		8.38			WEIGHTING FACTOR =		3.86	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2013

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	3,770.0	<- Fuel Sav/(Loss) 3,770.0	93.9	<- Adj. Act. EAF= 97.4	+10	3,638.0		6,853	
+9	3,393.0		93.7		+9	3,274.2		6,860	
+8	3,016.0		93.4		+8	2,910.4		6,867	
+7	2,639.0		93.2		+7	2,546.6		6,875	
+6	2,262.0		92.9		+6	2,182.8		6,882	
+5	1,885.0		92.7		+5	1,819.0		6,889	
+4	1,508.0		92.4		+4	1,455.2		6,896	
+3	1,131.0		92.2		+3	1,091.4		6,903	
+2	754.0		91.9		+2	727.6		6,911	
+1	377.0		91.7		+1	363.8		6,918	
						0	<- Fuel Sav/(Loss)	6,925	<- Adj. Act. HR=6,986
0	0		91.4		0	0		7,000	
						0		7,075	
-1	(377.0)		91.2		-1	(363.8)		7,082	
-2	(754.0)		90.9		-2	(727.6)		7,089	
-3	(1,131.0)		90.7		-3	(1,091.4)		7,097	
-4	(1,508.0)		90.4		-4	(1,455.2)		7,104	
-5	(1,885.0)		90.2		-5	(1,819.0)		7,111	
-6	(2,262.0)		89.9		-6	(2,182.8)		7,118	
-7	(2,639.0)		89.7		-7	(2,546.6)		7,125	
-8	(3,016.0)		89.4		-8	(2,910.4)		7,133	
-9	(3,393.0)		89.2		-9	(3,274.2)		7,140	
-10	(3,770.0)		88.9		-10	(3,638.0)		7,147	
	WEIGHTING FACTOR =		5.10			WEIGHTING FACTOR =		4.92	

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2013

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Ft. Myers 2	9/7/13-11/26/13; 9/7/13-11/16/13	Steam turbine #1 outage; Steam turbine #2 outage
	9/7/13-9/27/13; 9/14/13-9/27/13	CT-2C outage; CT-2A, CT-2B, CT-2D, CT-2E and CT-2F outage
Martin 8	3/23/13-4/8/13; 3/23/13-4/9/13	CT-8A and 8B outage; Steam turbine outage
	3/23/13-4/11/13; 3/23/13-4/13/13	CT-8C outage; CT-8D outage
	11/1/13-11/9/13	CT-8B HRSG outage
Manatee 3	5/31/13-6/15/13; 6/16/13-6/28/13	CT-3A Inlet filter replacement; CT-3B Inlet filter replacement
Scherer 4	NONE	
St. Lucie 1	8/7/13; 9/29/13-11/15/13; 11/21/13	Moderator Temperature Coefficient (MTC) testing; Refueling outage; MTC testing
St. Lucie 2	12/17/13-12/18/13	MTC test partial load reduction
Turkey Point 3	1/29/13-2/1/13; 6/10/13; 6/25/13	Turbine Valve Testing; Auxiliary feedwater testing; EPU testing
	9/1/13, 9/2/13 and 9/23/13; 10/30-31/13	Auxiliary Feedwater testing; Turbine Valve Testing
Turkey Point 4	1/1/13-4/19/13, 4/22/13-5/17/13, 5/27-5/30/13	Refueling outage and EPU modifications
	7/15/13, 7/25/13 and 7/31/13	Auxiliary Feedwater testing
	10/17/13	Turbine Valve Testing
Turkey Point 5	7/27/13-8/4/13; 8/3/13-8/11/13	CT-5B HRSG inspection; CT-5D HRSG inspection
	8/10/13-8/18/13; 8/17/13-8/24/13	CT-5C HRSG inspection; CT-5A HRSG inspection

WITNESS: J. CARINE BULLOCK

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2015

SEPTEMBER 15, 2014

JCB-2
DOCKET NO. 140001-EI
FPL Witness: J. Carine Bullock
Exhibit No.: _____
Pages 1 - 32

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 17
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: J. C. Bullock JCB-2

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2015

EXHIBIT	PAGE NUMBER	TITLE
JCB-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 - 7.201.020	Estimated Unit Performance Data
	7.201.021 - 7.201.031	Unit FOF and MOF vs Time Graphs
	7.201.032	Planned Outages Schedule (Estimated)

Projected System Generation
January Through December, 2015

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
PRV5	1,344	8,582	9,969,840	95.9	8.7	8.7	257,000
CCEC	1,355	8,555	9,781,200	94.5	8.5	17.2	260,460
WEST COUNTY 1	1,208	8,392	8,992,830	91.9	7.8	25.0	243,560
WEST COUNTY 3	1,207	7,749	8,056,100	89.2	7.0	32.0	217,890
WEST COUNTY 2	1,202	7,644	7,917,560	89.4	6.9	38.9	214,150
ST. LUCIE 1	1,003	7,968	7,694,320	98.4	6.7	45.6	51,840
MARTIN 8	1,147	7,748	7,445,120	86.5	6.5	52.1	201,690
TURKEY POINT 4	848	8,760	7,107,580	98.8	6.2	58.3	51,380
TURKEY POINT 5	1,166	6,328	6,621,760	92.0	5.8	64.0	133,750
ST. LUCIE 2	860	7,992	6,616,100	98.6	5.8	69.8	43,280
TURKEY POINT 3	839	8,040	6,445,200	98.8	5.6	75.4	48,080
FT. MYERS 2	1,476	5,332	6,209,870	84.2	5.4	80.8	172,790
MANATEE 3	1,134	5,989	6,039,810	93.6	5.3	86.1	165,750
SCHERER 4	646	8,760	5,119,820	91.2	4.5	90.5	133,400
SANFORD 4	990	2,935	2,645,610	96.0	2.3	92.8	76,340
MARTIN 3	454	2,759	1,157,810	95.8	1.0	93.8	34,530
SANFORD 5	994	1,278	1,093,750	90.4	1.0	94.8	30,960
MARTIN 4	453	2,326	936,970	92.2	0.8	95.6	28,120
LAUDERDALE 5	442	1,799	750,100	97.2	0.7	96.3	23,030
ST JOHNS 2O	128	8,760	675,720	60.7	0.6	96.8	23,980
LAUDERDALE 4	442	1,434	596,690	97.0	0.5	97.4	18,470
MARTIN 1	805	951	539,710	71.0	0.5	97.8	32,800
ST JOHNS 1O	128	7,560	496,990	51.8	0.4	98.3	17,910
MARTIN 2	808	1,318	472,670	44.9	0.4	98.7	37,710
MANATEE 1	795	546	352,910	81.9	0.3	99.0	27,280
TURKEY POINT 1	380	1,066	295,200	73.1	0.3	99.2	19,940
MANATEE 2	795	379	253,140	84.7	0.2	99.5	19,150
PUTNAM 2	255	911	218,860	96.1	0.2	99.7	7,830
PUTNAM 1	251	802	188,300	95.1	0.2	99.8	6,870
FORT MYERS 3A_B	314	651	182,180	94.5	0.2	100.0	7,820
FORT MYERS 1-12	690	47	12,750	41.9	0.0	100.0	5,460
LAUDERDALE 1-24	886	29	11,420	46.9	0.0	100.0	980
EVERGLADES 1-12	443	0	0	0.0	0.0	100.0	-
Total	**25,886**		**114,897,890**		**100.0**		**2,614,200**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2015

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, 2015

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	115,905	55,377
+ 9	104,315	49,839
+ 8	92,724	44,301
+ 7	81,134	38,764
+ 6	69,543	33,226
+ 5	57,953	27,688
+ 4	46,362	22,151
+ 3	34,772	16,613
+ 2	23,181	11,075
+ 1	11,591	5,538
0	0	0
- 1	(11,591)	(5,538)
- 2	(23,181)	(11,075)
- 3	(34,772)	(16,613)
- 4	(46,362)	(22,151)
- 5	(57,953)	(27,688)
- 6	(69,543)	(33,226)
- 7	(81,134)	(38,764)
- 8	(92,724)	(44,301)
- 9	(104,315)	(49,839)
- 10	(115,905)	(55,377)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	13,528,240,111	
LINE 2	MONTH OF JANUARY	2015	$	14,078,494,821	
LINE 3	MONTH OF FEBRUARY	2015	$	14,172,840,706	
LINE 4	MONTH OF MARCH	2015	$	14,292,254,762	
LINE 5	MONTH OF APRIL	2015	$	14,390,099,353	
LINE 6	MONTH OF MAY	2015	$	14,562,665,397	
LINE 7	MONTH OF JUNE	2015	$	14,368,682,014	
LINE 8	MONTH OF JULY	2015	$	14,556,993,745	
LINE 9	MONTH OF AUGUST	2015	$	14,194,084,596	
LINE 10	MONTH OF SEPTEMBER	2015	$	14,297,123,292	
LINE 11	MONTH OF OCTOBER	2015	$	14,407,691,042	
LINE 12	MONTH OF NOVEMBER	2015	$	14,527,679,539	
LINE 13	MONTH OF DECEMBER	2015	$	14,618,504,697	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	14,307,334,929	
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)		$	58,272,843	
LINE 18	JURISDICTIONAL SALES			108,216,881,593	KWH
LINE 19	TOTAL SALES			113,871,155,027	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			95.03%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	55,376,683	
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)		$	55,376,683	

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, 2015

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	3.98	84.1	86.6	81.6	4,621	-4,621
Martin 8	4.32	84.7	87.2	82.2	5,003	-5,003
Manatee 3	3.73	90.3	92.8	87.8	4,322	-4,322
St. Lucie 1	8.89	83.5	86.5	80.5	10,302	-10,302
St. Lucie 2	7.32	84.8	87.8	81.8	8,486	-8,486
Turkey Point 3	7.30	83.2	86.2	80.2	8,459	-8,459
Turkey Point 4	8.04	93.6	96.6	90.6	9,317	-9,317
Turkey Point 5	4.77	91.1	93.6	88.6	5,530	-5,530
West County 1	4.61	89.8	92.3	87.3	5,343	-5,343
West County 2	4.91	78.8	81.8	75.8	5,692	-5,692
West County 3	3.41	90.0	92.0	88.0	3,955	-3,955
	61.28				71,030	-71,030

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	2.75	7,197	84.2	7,064	7,330	3,193	-3,193
Martin 8	3.34	6,922	86.5	6,789	7,055	3,875	-3,875
Manatee 3	2.42	6,921	93.6	6,804	7,038	2,802	-2,802
St. Lucie 1	3.73	10,405	98.4	10,277	10,533	4,324	-4,324
St. Lucie 2	3.47	10,288	98.6	10,142	10,434	4,019	-4,019
Turkey Point 3	3.89	11,143	98.8	10,972	11,314	4,506	-4,506
Turkey Point 4	4.58	11,002	98.8	10,821	11,183	5,305	-5,305
Turkey Point 5	2.47	7,011	92.0	6,861	7,161	2,862	-2,862
West County 1	4.52	6,794	91.9	6,648	6,940	5,234	-5,234
West County 2	3.77	6,866	89.4	6,726	7,006	4,367	-4,367
West County 3	3.78	6,703	89.2	6,568	6,838	4,388	-4,388
	38.72					44,875	-44,875

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
#REF!

Plant/Unit	ANOHR	NOF	MW	ANOHR Equation a coef.	b coef.	Bounds	First	Last	Exclusions
Ft. Myers 2	7,197	84.2	1476	8459	-14.99	133	07-11	06-14	12/11, 9/13-11/13
Martin 8	6,922	86.5	1147	7304	-4.42	133	07-11	06-14	12/11, 2/13
Manatee 3	6,921	93.6	1134	7287	-3.91	117	07-11	06-14	8/11-9/11, 11/11, 6/13, 6/14
St. Lucie 1	10,405	98.4	1003	12884	-25.19	128	07-11	06-14	7/11-5/12, 10/13
St. Lucie 2	10,288	98.6	860	11463	-11.92	146	07-11	06-14	8/11-9/11, 4/12-12/12
Turkey Point 3	11,143	98.8	839	12226	-10.96	171	07-11	06-14	10/11-1/12, 3/12-10/12, 12/12, 5/13, 4/14, 6/14
Turkey Point 4	11,002	98.8	848	11666	-6.72	181	07-11	06-14	7/11, 7/12-9/12, 11/12-5/13, 5/14-6/14
Turkey Point 5	7,011	92.0	1166	7573	-6.11	150	07-11	06-14	2/14
West County 1	6,794	91.9	1208	7287	-5.36	146	07-11	06-14	7/13, 12/13-1/14
West County 2	6,866	89.4	1202	7275	-4.58	140	07-11	06-14	7/11, 6/13-7/13, 12/13-1/14
West County 3	6,703	89.2	1207	7421	-8.05	135	07-11	06-14	6/13-7/13, 12/13-2/14

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Ft. Myers 2	EAF	2,614,200	2,609,579	4,621	3.98
Ft. Myers 2	ANOHR	2,614,200	2,611,007	3,193	2.75
Martin 8	EAF	2,614,200	2,609,197	5,003	4.32
Martin 8	ANOHR	2,614,200	2,610,325	3,875	3.34
Manatee 3	EAF	2,614,200	2,609,878	4,322	3.73
Manatee 3	ANOHR	2,614,200	2,611,398	2,802	2.42
St. Lucie 1	EAF	2,614,200	2,603,898	10,302	8.89
St. Lucie 1	ANOHR	2,614,200	2,609,876	4,324	3.73
St. Lucie 2	EAF	2,614,200	2,605,714	8,486	7.32
St. Lucie 2	ANOHR	2,614,200	2,610,181	4,019	3.47
Turkey Point 3	EAF	2,614,200	2,605,741	8,459	7.30
Turkey Point 3	ANOHR	2,614,200	2,609,694	4,506	3.89
Turkey Point 4	EAF	2,614,200	2,604,883	9,317	8.04
Turkey Point 4	ANOHR	2,614,200	2,608,895	5,305	4.58
Turkey Point 5	EAF	2,614,200	2,608,670	5,530	4.77
Turkey Point 5	ANOHR	2,614,200	2,611,338	2,862	2.47
West County 1	EAF	2,614,200	2,608,857	5,343	4.61
West County 1	ANOHR	2,614,200	2,608,966	5,234	4.52
West County 2	EAF	2,614,200	2,608,508	5,692	4.91
West County 2	ANOHR	2,614,200	2,609,833	4,367	3.77
West County 3	EAF	2,614,200	2,610,245	3,955	3.41
West County 3	ANOHR	2,614,200	2,609,812	4,388	3.78
	TOTAL			115,905	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, 2015

	Ft. Myers 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	94.1	94.1	94.1	62.2	65.3	49.7
2	EPOF (%)	0.0	0.0	0.0	33.9	30.6	47.2
3	EUOF (%)	5.9	5.9	5.9	3.9	4.1	3.1
4	EUOR (%)	19.6	17.2	8.2	7.3	8.1	4.9
5	PH	744	672	744	720	744	720
6	SH	225	232	535	388	377	456
7	RSH	519	440	209	164	367	264
8	UH	0	0	0	168	0	0
9	POH	0	0	0	168	0	0
10	FOH & EFOH	17	15	17	11	12	9
11	MOH & EMOH	27	25	27	18	19	14
12	Oper Mbtu	1,952,178	1,923,447	4,779,071	3,108,695	2,492,724	2,442,423
13	Net Gen (MWH)	273,376	266,664	673,583	428,018	332,186	316,992
14	ANOHR (Btu/KWH)	7,141	7,213	7,095	7,263	7,504	7,705
15	NOF (%)	87.9	83.1	91.0	79.8	63.7	50.3
16	NSC (MW)	1,383	1,383	1,383	1,383	1,383	1,383
17	ANOHR Equation	-14.99 x NOF + 8459					

	Ft. Myers 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	79.4	94.1	94.1	94.1	94.1	94.1	84.1
2	EPOF (%)	15.6	0.0	0.0	0.0	0.0	0.0	10.6
3	EUOF (%)	5.0	5.9	5.9	5.9	5.9	5.9	5.3
4	EUOR (%)	6.1	7.9	7.6	7.3	8.5	15.7	8.7
5	PH	744	744	720	744	720	744	8,760
6	SH	611	557	565	604	501	281	5,332
7	RSH	133	187	155	140	219	463	3260
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	14	17	16	17	16	17	175
11	MOH & EMOH	23	27	27	27	27	27	289
12	Oper Mbtu	4,870,689	5,169,202	5,225,744	5,500,804	4,545,523	2,479,058	44,692,384
13	Net Gen (MWH)	669,971	735,620	743,032	778,930	643,113	348,378	6,209,863
14	ANOHR (Btu/KWH)	7,270	7,027	7,033	7,062	7,068	7,116	7,197
15	NOF (%)	79.3	95.5	95.1	93.2	92.8	89.6	84.2
16	NSC (MW)	1,383	1,383	1,383	1,383	1,383	1,383	1,383
17	ANOHR Equation	-14.99 x NOF + 8459						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Manatee 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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 (%)	15.3	11.3	8.5	9.2	10.8	8.5
5	PH	744	672	744	720	744	720
6	SH	341	415	611	549	481	592
7	RSH	403	257	133	171	263	128
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	37	33	37	36	37	36
12	Oper Mbtu	2,444,924	2,792,933	4,227,165	3,829,036	3,461,858	4,164,491
13	Net Gen (MWH)	353,824	402,730	610,421	553,249	501,065	601,979
14	ANOHR (Btu/KWH)	6,910	6,935	6,925	6,921	6,909	6,918
15	NOF (%)	96.3	90.0	92.7	93.5	96.6	94.3
16	NSC (MW)	1,078	1,078	1,078	1,078	1,078	1,078
17	ANOHR Equation	-3.91 x NOF + 7287					

	Manatee 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	63.0	91.5	93.0	93.0	93.0	93.0	90.3
2	EPOF (%)	32.3	1.6	0.0	0.0	0.0	0.0	2.9
3	EUOF (%)	4.7	6.9	7.0	7.0	7.0	7.0	6.8
4	EUOR (%)	16.3	8.9	8.0	9.0	9.0	11.9	9.9
5	PH	744	744	720	744	720	744	8,760
6	SH	217	579	629	580	558	437	5,989
7	RSH	359	165	91	164	162	307	2603
8	UH	168	0	0	0	0	0	168
9	POH	168	0	0	0	0	0	168
10	FOH & EFOH	10	15	15	15	15	15	175
11	MOH & EMOH	25	36	36	37	36	37	420
12	Oper Mbtu	1,263,398	4,071,838	4,467,066	4,097,617	3,930,358	3,048,375	41,801,477
13	Net Gen (MWH)	180,873	588,586	646,090	592,398	568,135	440,453	6,039,803
14	ANOHR (Btu/KWH)	6,985	6,918	6,914	6,917	6,918	6,921	6,921
15	NOF (%)	77.3	94.3	95.3	94.7	94.4	93.5	93.6
16	NSC (MW)	1,078	1,078	1,078	1,078	1,078	1,078	1,078
17	ANOHR Equation	-3.91 x NOF + 7287						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Martin 8	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	75.9	29.6	75.9	92.3	92.3	92.3
2	EPOF (%)	17.7	67.9	17.7	0.0	0.0	0.0
3	EUOF (%)	6.4	2.5	6.4	7.7	7.7	7.7
4	EUOR (%)	10.2	10.6	7.6	7.7	7.7	7.7
5	PH	744	672	744	720	744	720
6	SH	464	158	624	720	744	720
7	RSH	280	130	120	0	0	0
8	UH	0	384	0	0	0	0
9	POH	0	384	0	0	0	0
10	FOH & EFOH	13	5	13	16	16	16
11	MOH & EMOH	34	12	34	40	41	40
12	Oper Mbtu	2,830,024	882,465	3,732,460	4,781,508	5,029,625	4,943,459
13	Net Gen (MWH)	406,905	126,319	536,119	690,670	727,350	715,510
14	ANOHR (Btu/KWH)	6,955	6,986	6,962	6,923	6,915	6,909
15	NOF (%)	78.9	72.0	77.3	86.3	88.0	89.4
16	NSC (MW)	1,111	1,111	1,111	1,111	1,111	1,111
17	ANOHR Equation	-4.42 x NOF + 7304					

	Martin 8	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	92.3	92.3	92.3	92.3	92.3	92.3	84.7
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3	EUOF (%)	7.7	7.7	7.7	7.7	7.7	7.7	7.1
4	EUOR (%)	7.7	7.7	7.7	7.7	8.0	8.6	8.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	700	666	7,748
7	RSH	0	0	0	0	20	78	628
8	UH	0	0	0	0	0	0	384
9	POH	0	0	0	0	0	0	384
10	FOH & EFOH	16	16	16	16	16	16	175
11	MOH & EMOH	41	41	40	41	40	41	447
12	Oper Mbtu	5,143,244	5,134,705	5,006,518	5,114,428	4,704,821	4,222,682	51,535,058
13	Net Gen (MWH)	744,750	743,406	725,267	740,363	680,084	608,368	7,445,111
14	ANOHR (Btu/KWH)	6,906	6,907	6,903	6,908	6,918	6,941	6,922
15	NOF (%)	90.1	89.9	90.7	89.6	87.4	82.2	86.5
16	NSC (MW)	1,111	1,111	1,111	1,111	1,111	1,111	1,111
17	ANOHR Equation	-4.42 x NOF + 7304						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	St. Lucie 1	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	91.8	91.8	65.1	18.4	91.8	91.8
2	EPOF (%)	0.0	0.0	29.0	80.0	0.0	0.0
3	EUOF (%)	8.2	8.2	5.9	1.6	8.2	8.2
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	672	744	720	744	720
6	SH	744	672	528	144	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	216	576	0	0
9	POH	0	0	216	576	0	0
10	FOH & EFOH	35	32	25	7	35	34
11	MOH & EMOH	26	24	19	5	26	25
12	Oper Mbtu	7,547,125	6,816,773	5,356,057	1,436,269	7,420,784	7,181,399
13	Net Gen (MWH)	727,574	657,165	516,346	137,732	711,621	688,665
14	ANOHR (Btu/KWH)	10,373	10,373	10,373	10,428	10,428	10,428
15	NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16	NSC (MW)	981	981	981	981	981	981
17	ANOHR Equation	-25.19 x NOF + 12884					

	St. Lucie 1	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	91.8	91.8	91.8	91.8	91.8	91.8	83.5
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.0
3	EUOF (%)	8.2	8.2	8.2	8.2	8.2	8.2	7.5
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,968
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	792
9	POH	0	0	0	0	0	0	792
10	FOH & EFOH	35	35	34	35	34	35	377
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	7,420,784	7,420,784	7,181,399	7,420,784	7,303,671	7,547,125	80,059,285
13	Net Gen (MWH)	711,621	711,621	688,665	711,621	704,104	727,574	7,694,309
14	ANOHR (Btu/KWH)	10,428	10,428	10,428	10,428	10,373	10,373	10,405
15	NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.4
16	NSC (MW)	981	981	981	981	981	981	981
17	ANOHR Equation	-25.19 x NOF + 12884						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	St. Lucie 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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	24	26	25	26	25
11	MOH & EMOH	26	24	26	25	26	25
12	Oper Mbtu	6,408,749	5,788,548	6,408,749	6,074,263	6,276,729	6,074,263
13	Net Gen (MWH)	623,844	563,472	623,844	589,677	609,332	589,677
14	ANOHR (Btu/KWH)	10,273	10,273	10,273	10,301	10,301	10,301
15	NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16	NSC (MW)	840	840	840	840	840	840
17	ANOHR Equation	-11.92 x NOF + 11463					

	St. Lucie 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	93.0	93.0	18.6	69.0	93.0	93.0	84.8
2	EPOF (%)	0.0	0.0	80.0	25.8	0.0	0.0	8.8
3	EUOF (%)	7.0	7.0	1.4	5.2	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	144	552	720	744	7,992
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	576	192	0	0	768
9	POH	0	0	576	192	0	0	768
10	FOH & EFOH	26	26	5	19	25	26	280
11	MOH & EMOH	26	26	5	19	25	26	280
12	Oper Mbtu	6,276,729	6,276,729	1,214,859	4,656,958	6,202,016	6,408,749	68,066,416
13	Net Gen (MWH)	609,332	609,332	117,936	452,088	603,720	623,844	6,616,098
14	ANOHR (Btu/KWH)	10,301	10,301	10,301	10,301	10,273	10,273	10,288
15	NOF (%)	97.5	97.5	97.5	97.5	99.8	99.8	98.6
16	NSC (MW)	840	840	840	840	840	840	840
17	ANOHR Equation	-11.92 x NOF + 11463						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	90.6	90.6	90.6	90.6	90.6	90.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	9.4	9.4	9.4	9.4	9.4	9.4
4	EUOR (%)	9.4	9.4	9.4	9.4	9.4	9.4
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	44	40	44	42	44	42
11	MOH & EMOH	26	23	26	25	26	25
12	Oper Mbtu	6,767,777	6,112,809	6,767,777	6,351,859	6,563,585	6,351,859
13	Net Gen (MWH)	608,613	549,713	608,613	569,316	588,293	569,316
14	ANOHR (Btu/KWH)	11,120	11,120	11,120	11,157	11,157	11,157
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	-10.96 x NOF + 12226					

	Turkey Point 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	90.6	90.6	90.6	52.7	39.2	90.6	83.2
2	EPOF (%)	0.0	0.0	0.0	41.9	56.7	0.0	8.2
3	EUOF (%)	9.4	9.4	9.4	5.4	4.1	9.4	8.6
4	EUOR (%)	9.4	9.4	9.4	9.4	9.4	9.4	9.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	432	312	744	8,040
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	312	408	0	720
9	POH	0	0	0	312	408	0	720
10	FOH & EFOH	44	44	42	25	18	44	473
11	MOH & EMOH	26	26	25	15	11	26	280
12	Oper Mbtu	6,563,585	6,563,585	6,351,859	3,811,131	2,838,080	6,767,777	71,818,786
13	Net Gen (MWH)	588,293	588,293	569,316	341,591	255,223	608,613	6,445,193
14	ANOHR (Btu/KWH)	11,157	11,157	11,157	11,157	11,120	11,120	11,143
15	NOF (%)	97.5	97.5	97.5	97.5	100.9	100.9	98.8
16	NSC (MW)	811	811	811	811	811	811	811
17	ANOHR Equation	-10.96 x NOF + 12226						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 4	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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	6,759,773	6,105,620	6,759,773	6,346,102	6,557,645	6,346,102
13	Net Gen (MWH)	615,140	555,612	615,140	576,342	595,554	576,342
14	ANOHR (Btu/KWH)	10,989	10,989	10,989	11,011	11,011	11,011
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	-6.72 x NOF + 11666					

	Turkey Point 4	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	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	6,557,645	6,557,645	6,346,102	6,557,645	6,541,719	6,759,773	78,197,496
13	Net Gen (MWH)	595,554	595,554	576,342	595,554	595,297	615,140	7,107,571
14	ANOHR (Btu/KWH)	11,011	11,011	11,011	11,011	10,989	10,989	11,002
15	NOF (%)	97.5	97.5	97.5	97.5	100.7	100.7	98.8
16	NSC (MW)	821	821	821	821	821	821	821
17	ANOHR Equation	-6.72 x NOF + 11666						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 5	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	93.3	93.3	93.3	93.3	93.3	66.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	29.2
3	EUOF (%)	6.7	6.7	6.7	6.7	6.7	4.7
4	EUOR (%)	14.6	11.7	10.1	7.2	8.1	7.1
5	PH	744	672	744	720	744	720
6	SH	340	381	492	666	608	477
7	RSH	404	291	252	54	136	243
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	10
11	MOH & EMOH	34	31	34	33	34	24
12	Oper Mbtu	2,473,940	2,600,767	3,673,628	4,762,971	4,516,620	3,327,112
13	Net Gen (MWH)	352,614	368,694	524,804	677,810	644,863	472,534
14	ANOHR (Btu/KWH)	7,016	7,054	7,000	7,027	7,004	7,041
15	NOF (%)	91.1	85.0	93.7	89.4	93.2	87.1
16	NSC (MW)	1,138	1,138	1,138	1,138	1,138	1,138
17	ANOHR Equation	-6.11 x NOF + 7573					

	Turkey Point 5	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	93.3	93.3	93.3	93.3	93.3	93.3	91.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.4
3	EUOF (%)	6.7	6.7	6.7	6.7	6.7	6.7	6.5
4	EUOR (%)	7.2	6.7	6.9	6.9	35.0	12.9	9.0
5	PH	744	744	720	744	720	744	8,760
6	SH	692	744	692	716	137	383	6,328
7	RSH	52	0	28	28	583	361	2432
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	15	15	175
11	MOH & EMOH	34	34	33	34	33	34	394
12	Oper Mbtu	5,183,431	5,566,851	5,204,527	5,307,696	995,782	2,810,850	46,425,110
13	Net Gen (MWH)	740,596	795,378	743,929	757,701	141,910	400,920	6,621,753
14	ANOHR (Btu/KWH)	6,999	6,999	6,996	7,005	7,017	7,011	7,011
15	NOF (%)	94.0	93.9	94.5	93.0	91.0	92.0	92.0
16	NSC (MW)	1,138	1,138	1,138	1,138	1,138	1,138	1,138
17	ANOHR Equation	-6.11 x NOF + 7573						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	West County 1	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	92.3	92.3	62.5	92.3	92.3	92.3
2	EPOF (%)	0.0	0.0	32.3	0.0	0.0	0.0
3	EUOF (%)	7.7	7.7	5.2	7.7	7.7	7.7
4	EUOR (%)	8.4	7.7	8.4	7.7	7.7	7.7
5	PH	744	672	744	720	744	720
6	SH	684	672	462	720	744	720
7	RSH	60	0	42	0	0	0
8	UH	0	0	240	0	0	0
9	POH	0	0	240	0	0	0
10	FOH & EFOH	15	14	10	15	15	15
11	MOH & EMOH	42	38	29	41	42	41
12	Oper Mbtu	5,073,075	4,845,150	3,352,066	5,193,858	5,422,733	5,346,124
13	Net Gen (MWH)	747,800	712,522	493,241	763,915	798,165	788,049
14	ANOHR (Btu/KWH)	6,784	6,800	6,796	6,799	6,794	6,784
15	NOF (%)	93.8	90.9	91.6	91.0	92.0	93.9
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-5.36 x NOF + 7287					

	West County 1	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	92.3	92.3	92.3	92.3	92.3	92.3	89.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	EUOF (%)	7.7	7.7	7.7	7.7	7.7	7.7	7.5
4	EUOR (%)	7.7	7.7	7.7	7.7	7.9	7.8	7.8
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	702	736	8,392
7	RSH	0	0	0	0	18	8	128
8	UH	0	0	0	0	0	0	240
9	POH	0	0	0	0	0	0	240
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	42	42	41	42	41	42	482
12	Oper Mbtu	5,434,414	5,449,635	5,270,875	5,383,404	5,125,060	5,203,637	61,097,205
13	Net Gen (MWH)	800,002	802,479	776,156	791,910	754,462	764,117	8,992,818
14	ANOHR (Btu/KWH)	6,793	6,791	6,791	6,798	6,793	6,810	6,794
15	NOF (%)	92.2	92.5	92.5	91.3	92.2	89.0	91.9
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-5.36 x NOF + 7287						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	West County 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	90.5	90.5	70.0	90.5	90.5	90.5
2	EPOF (%)	0.0	0.0	22.6	0.0	0.0	0.0
3	EUOF (%)	9.5	9.5	7.4	9.5	9.5	9.5
4	EUOR (%)	9.7	9.6	9.6	9.5	9.6	9.5
5	PH	744	672	744	720	744	720
6	SH	728	664	569	720	736	720
7	RSH	16	8	7	0	8	0
8	UH	0	0	168	0	0	0
9	POH	0	0	168	0	0	0
10	FOH & EFOH	17	15	13	17	17	17
11	MOH & EMOH	54	49	42	52	54	52
12	Oper Mbtu	5,287,587	4,683,648	4,039,309	5,237,634	5,411,057	5,362,462
13	Net Gen (MWH)	771,235	681,853	588,306	763,949	789,820	783,413
14	ANOHR (Btu/KWH)	6,856	6,869	6,866	6,856	6,851	6,845
15	NOF (%)	91.4	88.6	89.2	91.5	92.6	93.9
16	NSC (MW)	1,159	1,159	1,159	1,159	1,159	1,159
17	ANOHR Equation	-4.58 x NOF + 7275					

	West County 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	90.5	90.5	90.5	25.3	37.2	90.5	78.8
2	EPOF (%)	0.0	0.0	0.0	72.0	58.9	0.0	12.9
3	EUOF (%)	9.5	9.5	9.5	2.7	3.9	9.5	8.3
4	EUOR (%)	9.5	9.5	9.5	7.5	9.7	9.5	9.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	263	292	744	7,644
7	RSH	0	0	0	97	164	0	300
8	UH	0	0	0	384	264	0	816
9	POH	0	0	0	384	264	0	816
10	FOH & EFOH	17	17	17	5	7	17	175
11	MOH & EMOH	54	54	52	15	21	54	552
12	Oper Mbtu	5,593,147	5,452,513	5,275,601	1,273,202	1,581,109	5,137,543	54,361,939
13	Net Gen (MWH)	817,592	795,755	769,936	181,834	226,910	746,953	7,917,556
14	ANOHR (Btu/KWH)	6,841	6,852	6,852	7,002	6,968	6,878	6,866
15	NOF (%)	94.8	92.3	92.3	59.7	67.0	86.6	89.4
16	NSC (MW)	1,159	1,159	1,159	1,159	1,159	1,159	1,159
17	ANOHR Equation	-4.58 x NOF + 7275						

ESTIMATED UNIT PERFORMANCE DATA

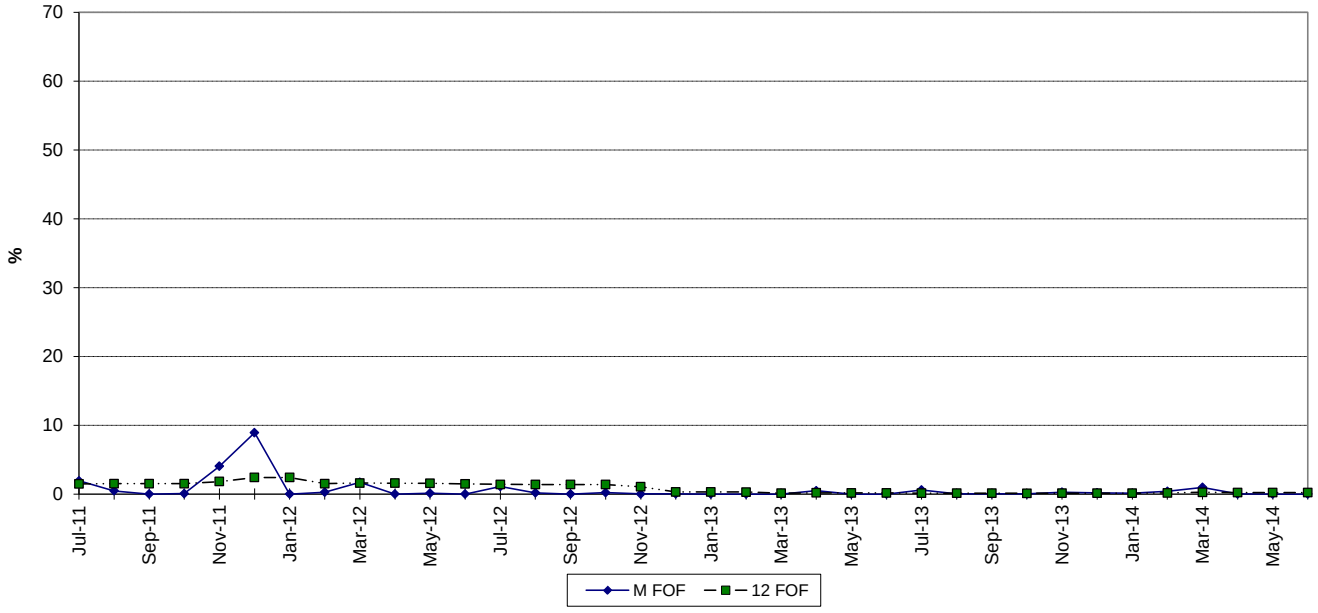
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

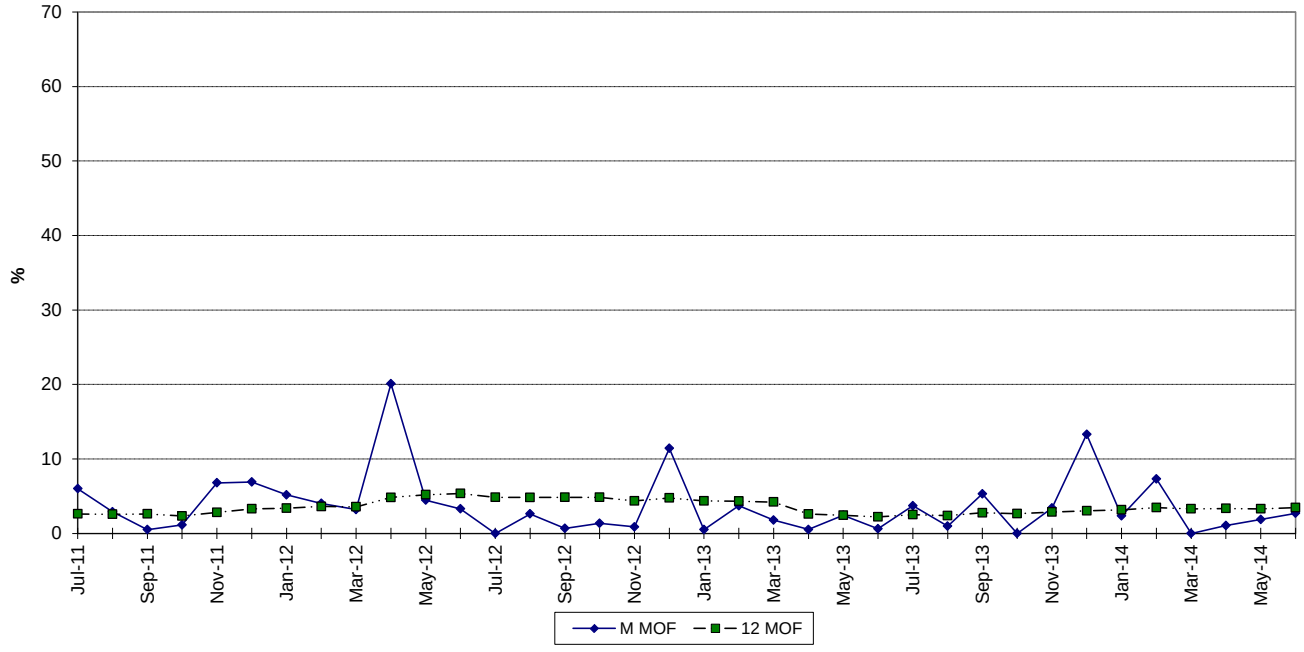
	West County 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	94.8	94.8	66.3	94.8	94.8	94.8
2	EPOF (%)	0.0	0.0	30.1	0.0	0.0	0.0
3	EUOF (%)	5.2	5.2	3.6	5.2	5.2	5.2
4	EUOR (%)	7.7	6.1	5.6	5.2	5.2	5.2
5	PH	744	672	744	720	744	720
6	SH	496	566	478	712	744	720
7	RSH	248	106	98	8	0	0
8	UH	0	0	168	0	0	0
9	POH	0	0	168	0	0	0
10	FOH & EFOH	16	14	11	15	16	15
11	MOH & EMOH	23	21	16	22	23	22
12	Oper Mbtu	3,646,835	3,972,647	3,187,377	4,947,760	5,236,600	5,167,701
13	Net Gen (MWH)	547,655	593,198	473,045	737,921	782,049	773,608
14	ANOHR (Btu/KWH)	6,659	6,697	6,738	6,705	6,696	6,680
15	NOF (%)	94.7	89.9	84.9	88.9	90.1	92.1
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-8.05 x NOF + 7421					

	West County 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	94.8	94.8	67.4	92.7	94.8	94.8	90.0
2	EPOF (%)	0.0	0.0	28.9	2.2	0.0	0.0	5.1
3	EUOF (%)	5.2	5.2	3.7	5.1	5.2	5.2	4.9
4	EUOR (%)	5.2	5.2	4.3	5.2	5.9	6.6	5.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	612	720	632	581	7,749
7	RSH	0	0	108	24	88	163	843
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	16	16	11	15	15	16	175
11	MOH & EMOH	23	23	16	22	22	23	254
12	Oper Mbtu	5,407,535	5,413,062	3,395,950	5,123,609	4,448,968	4,026,108	54,000,011
13	Net Gen (MWH)	810,968	811,797	494,820	766,319	664,521	600,195	8,056,096
14	ANOHR (Btu/KWH)	6,668	6,668	6,863	6,686	6,695	6,708	6,703
15	NOF (%)	93.5	93.6	69.3	91.3	90.2	88.6	89.2
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-8.05 x NOF + 7421						

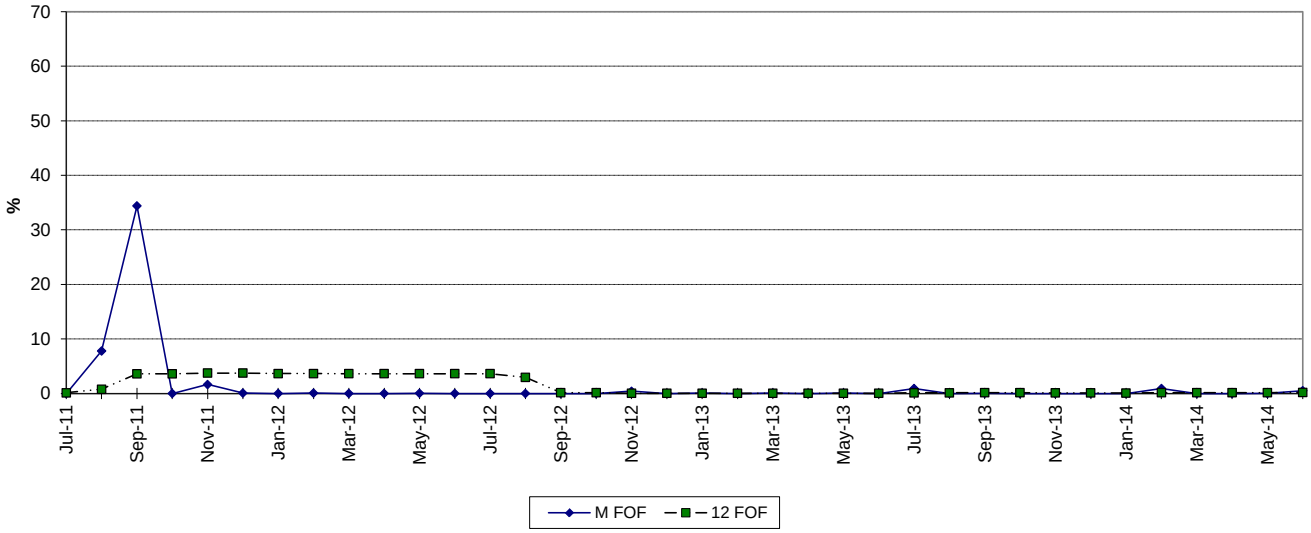
FT. MYERS 2
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



MANATEE 3
FORCED OUTAGE FACTOR



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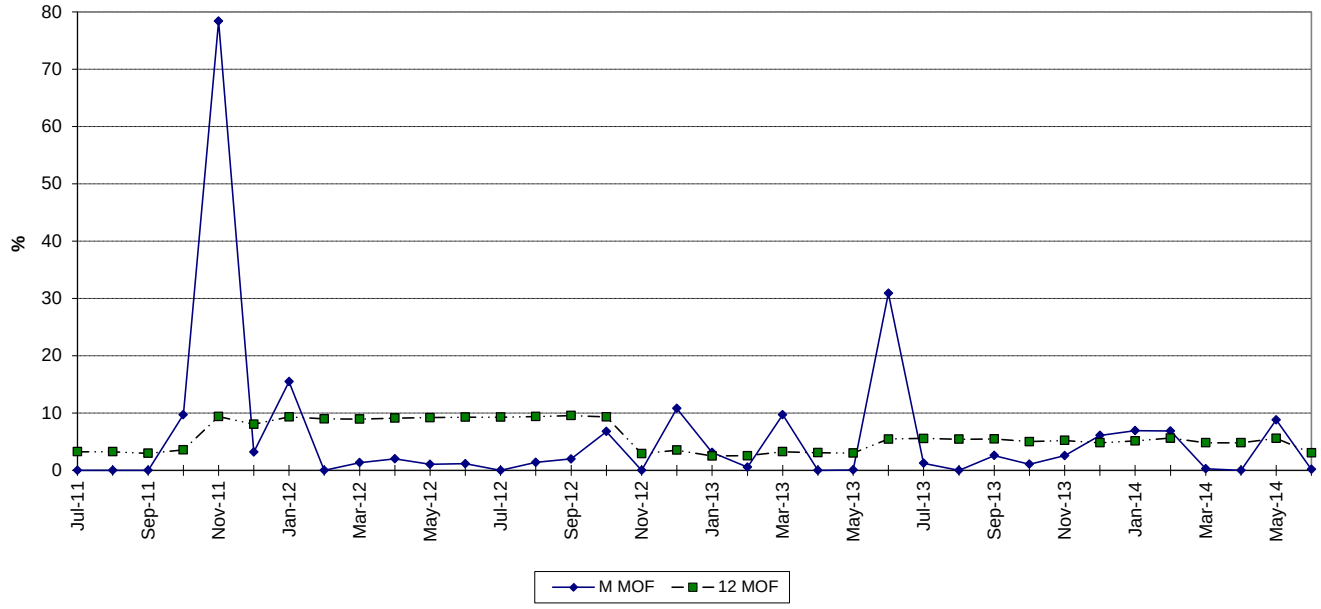

MARTIN 8
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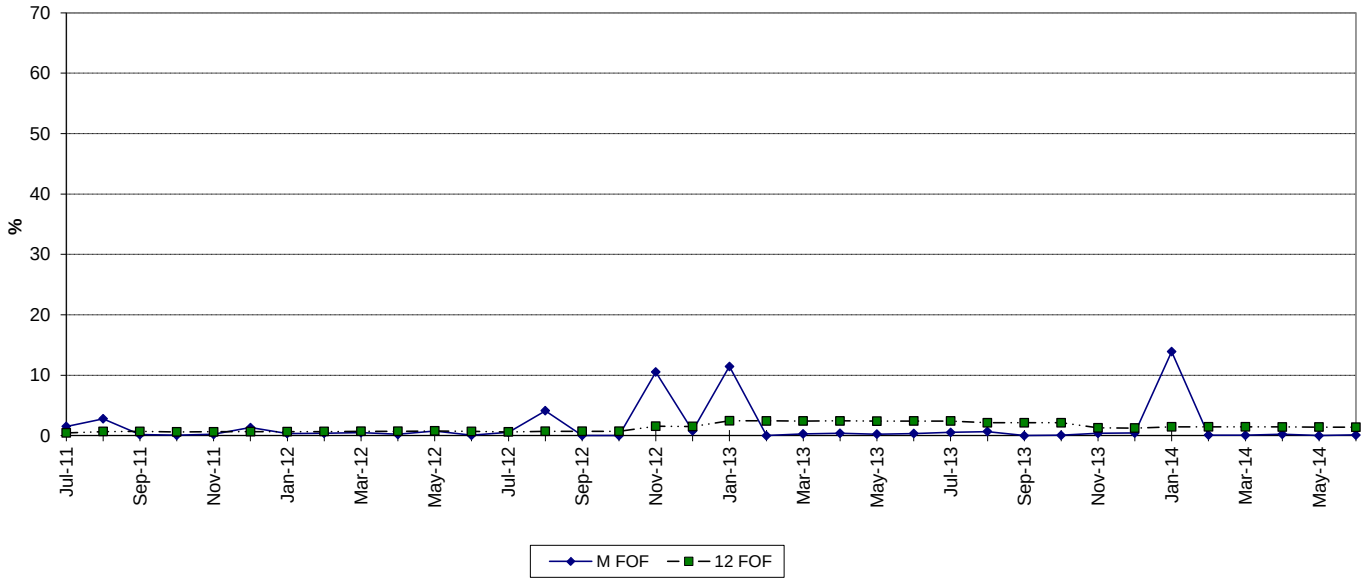

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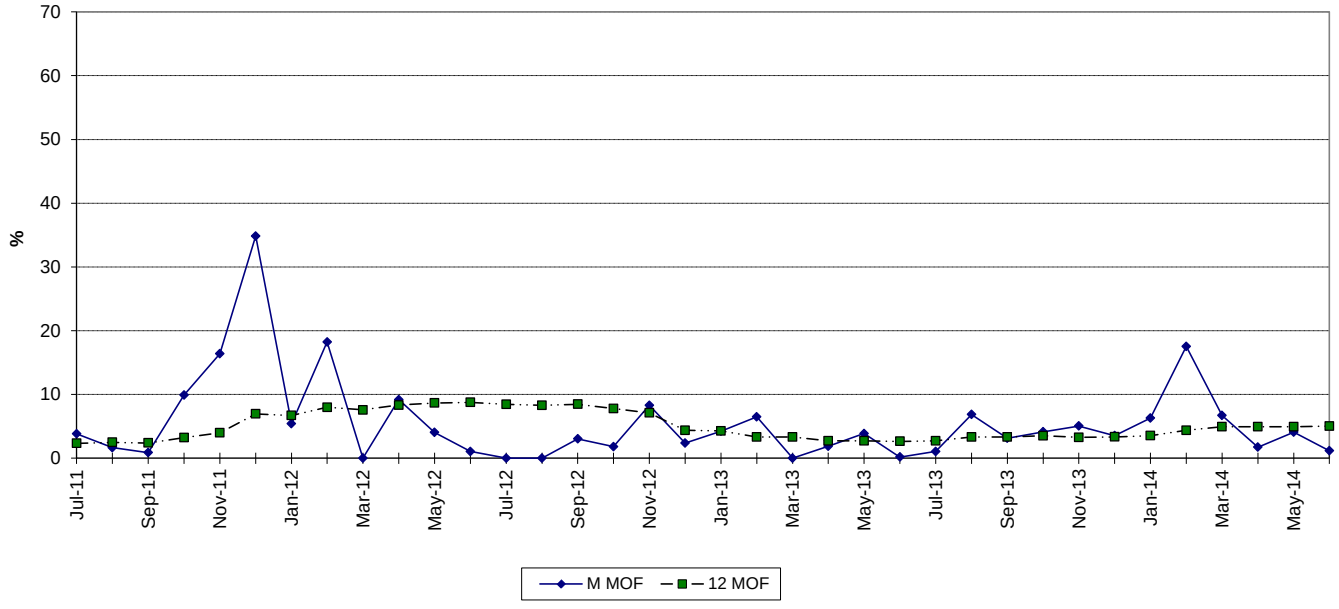

ST. LUCIE 1
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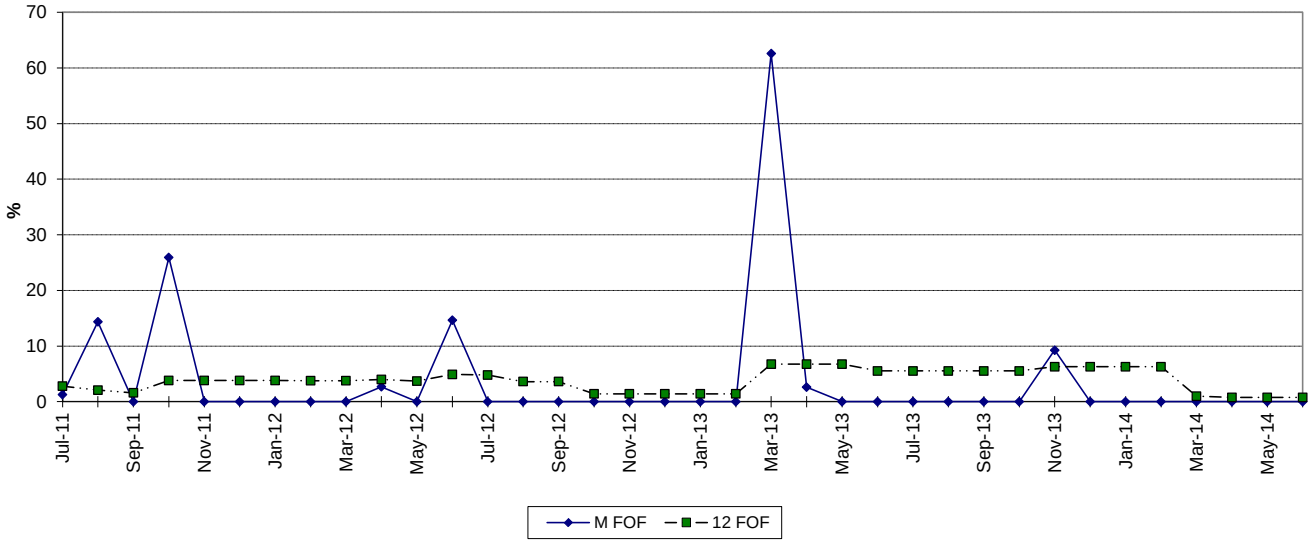
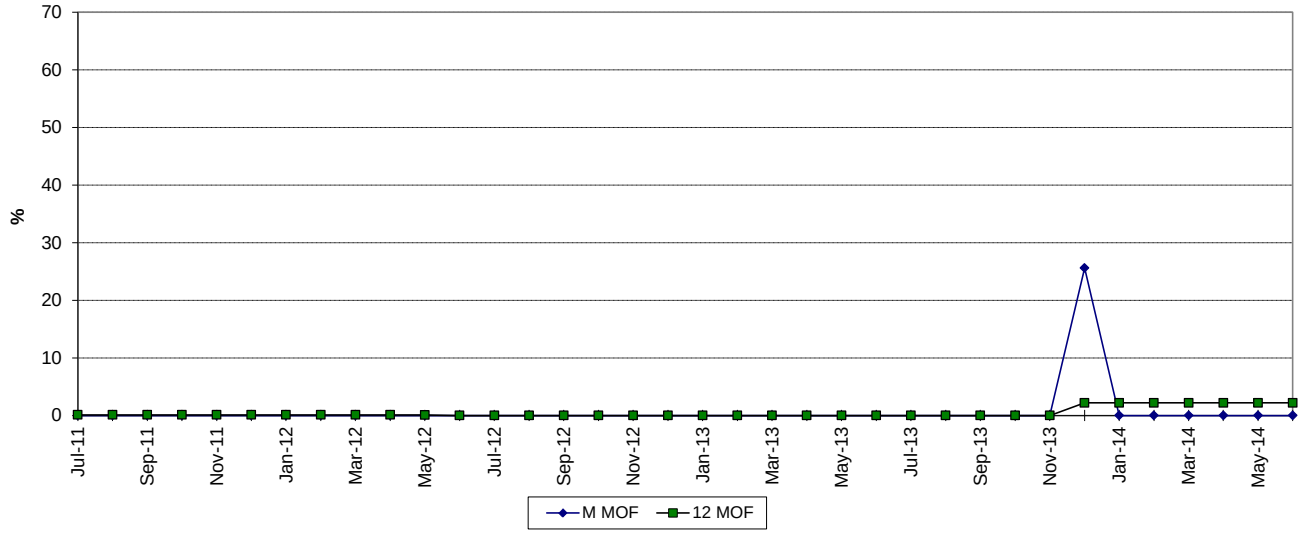


MAINTENANCE OUTAGE FACTOR



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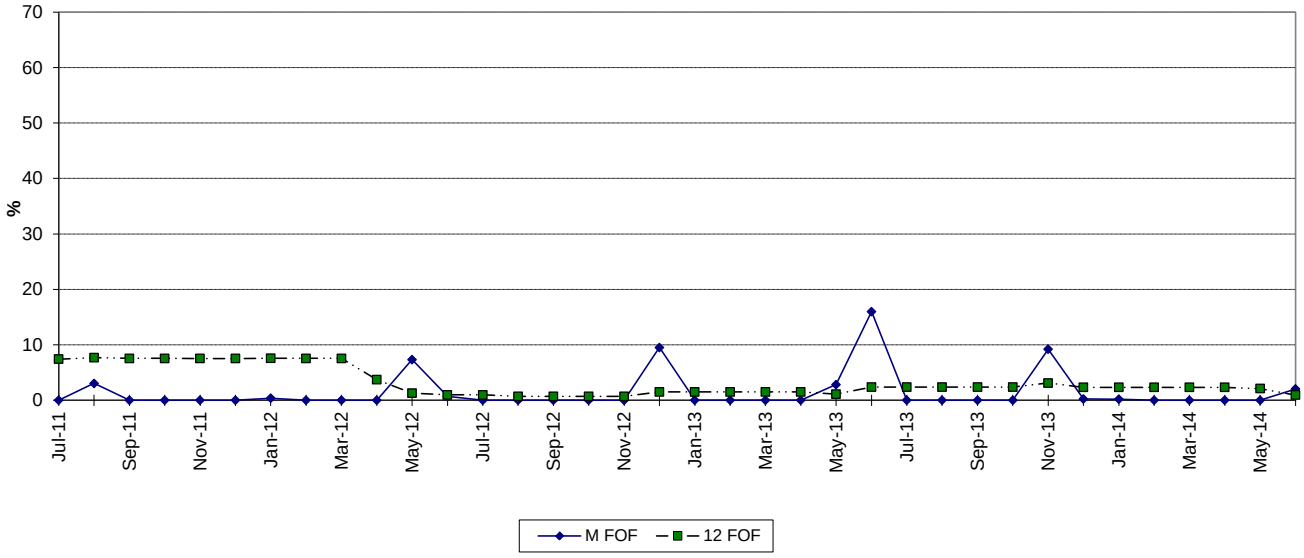

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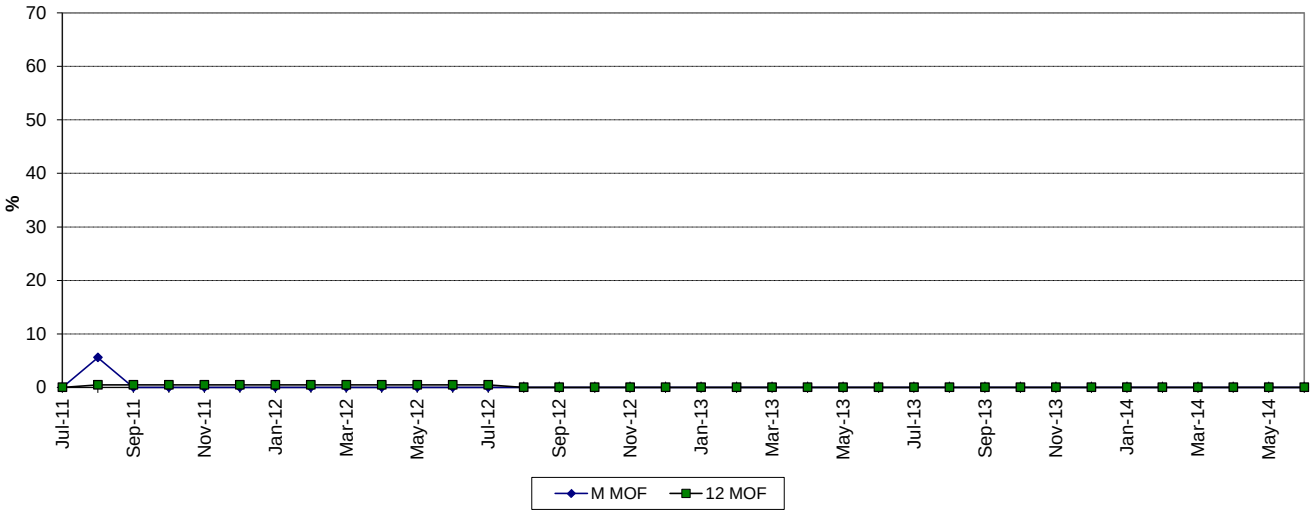
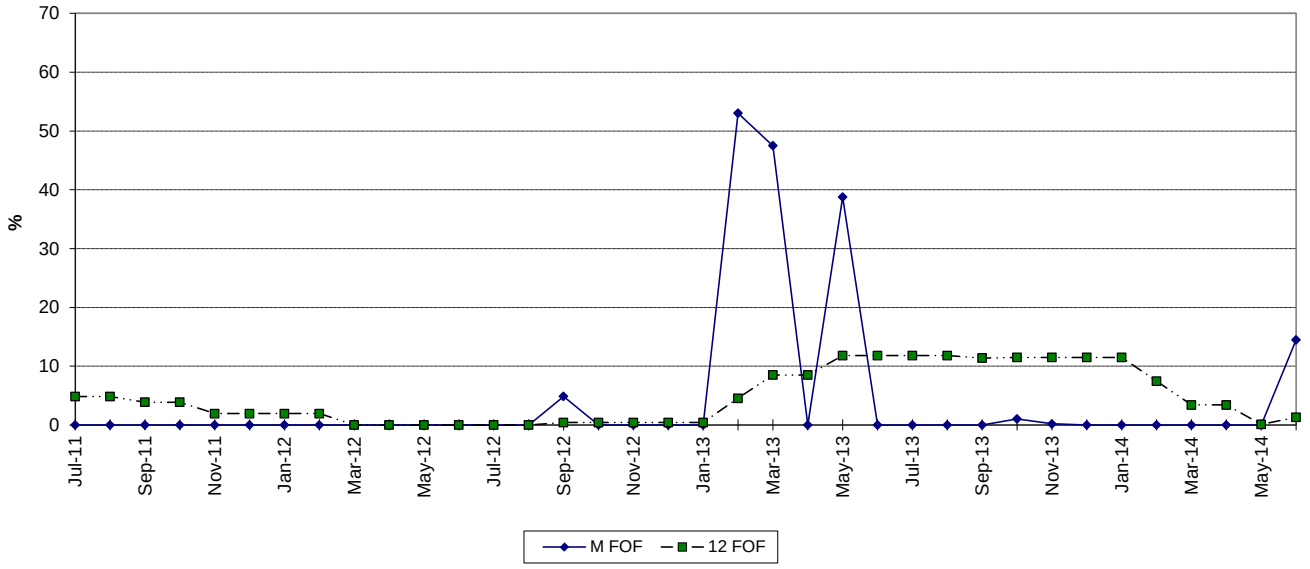


TURKEY POINT 3
FORCED OUTAGE FACTOR



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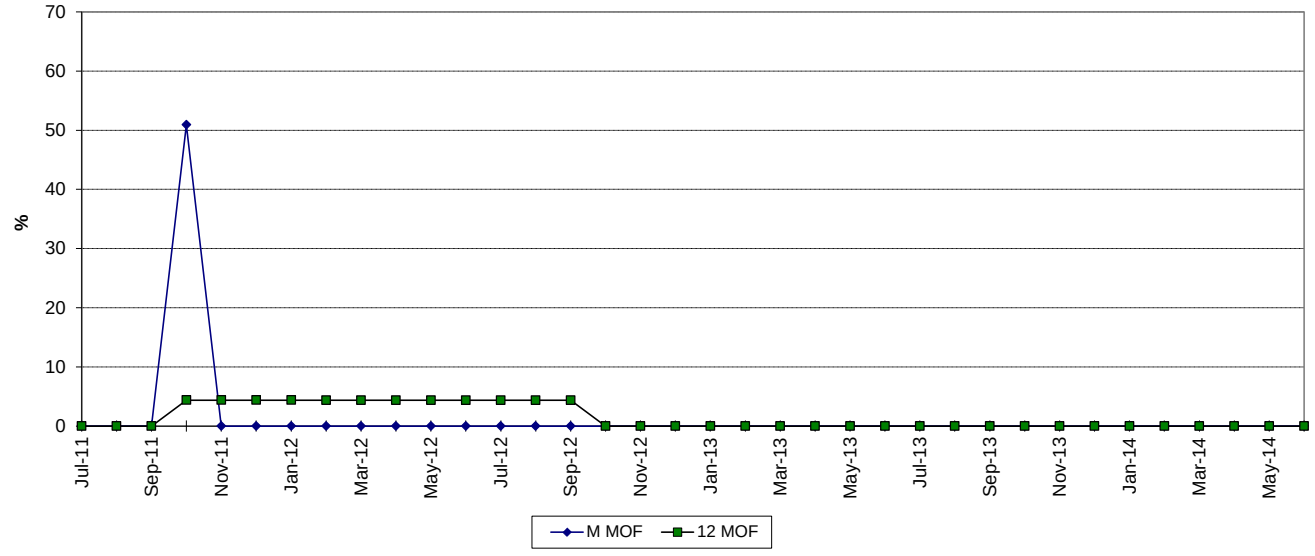

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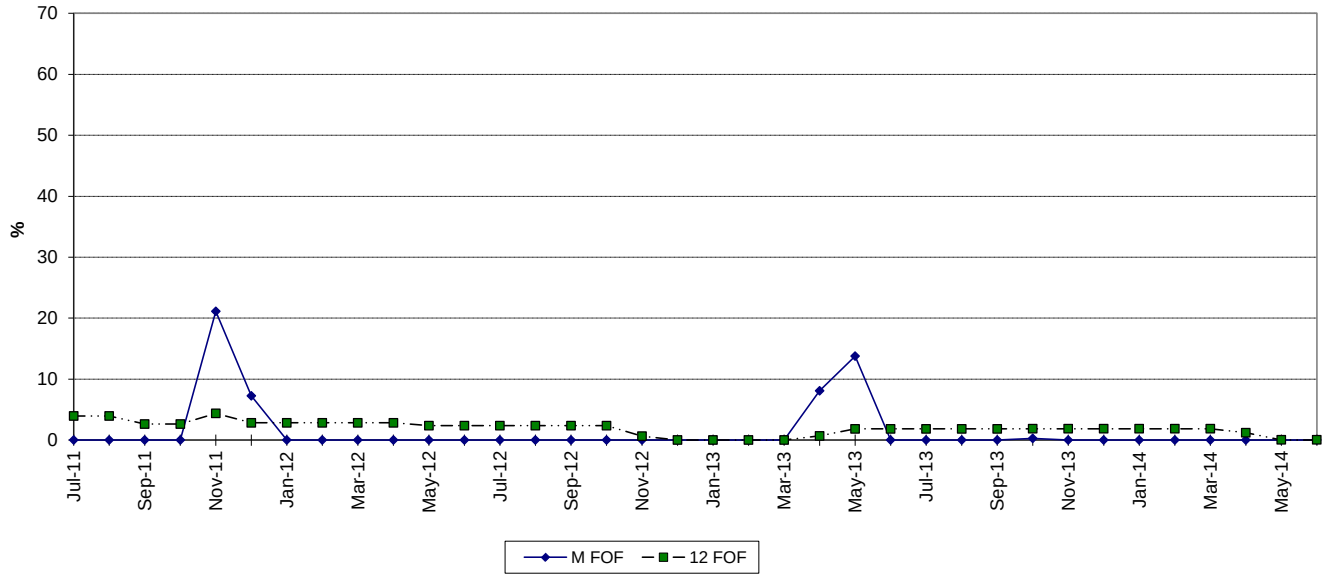
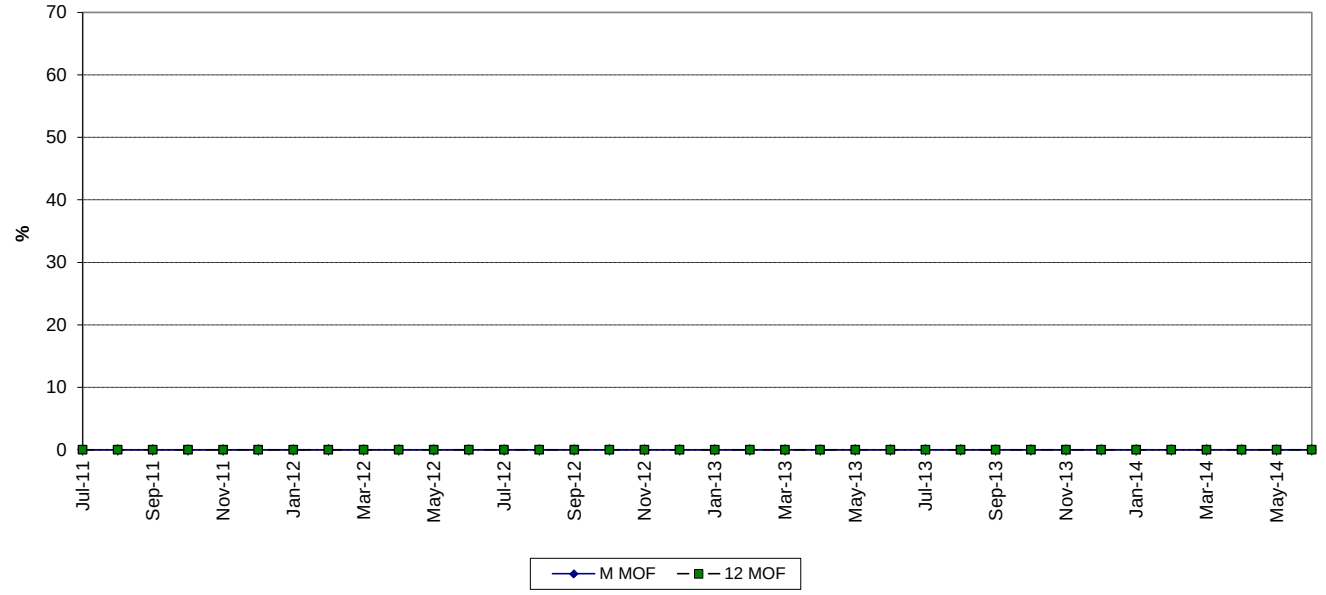
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



TURKEY POINT 5
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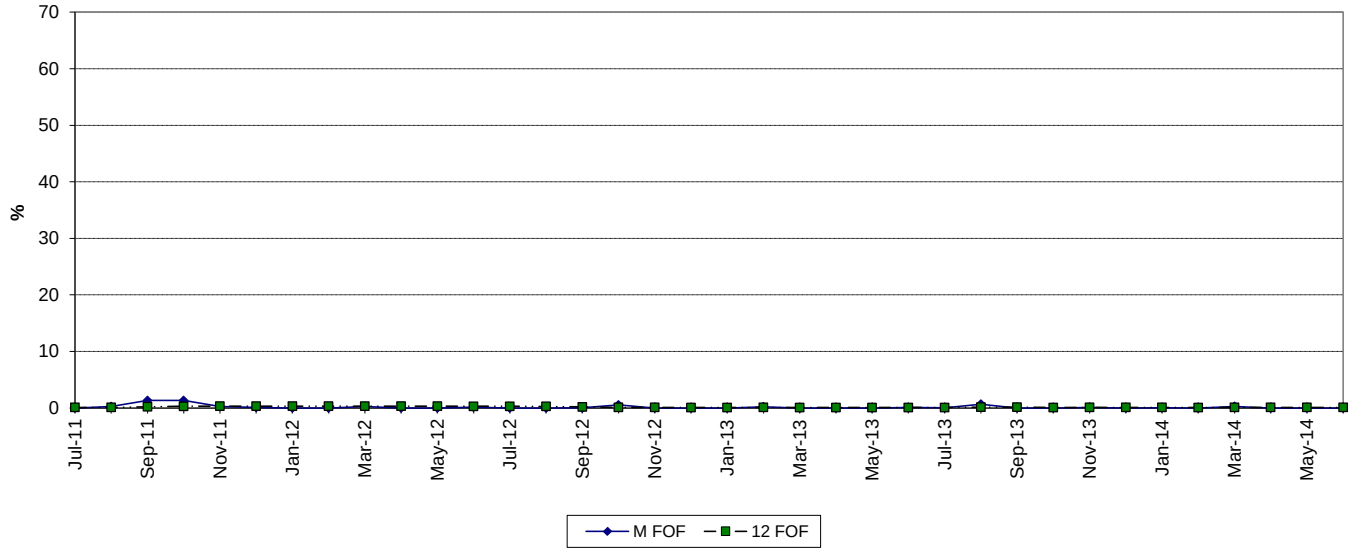
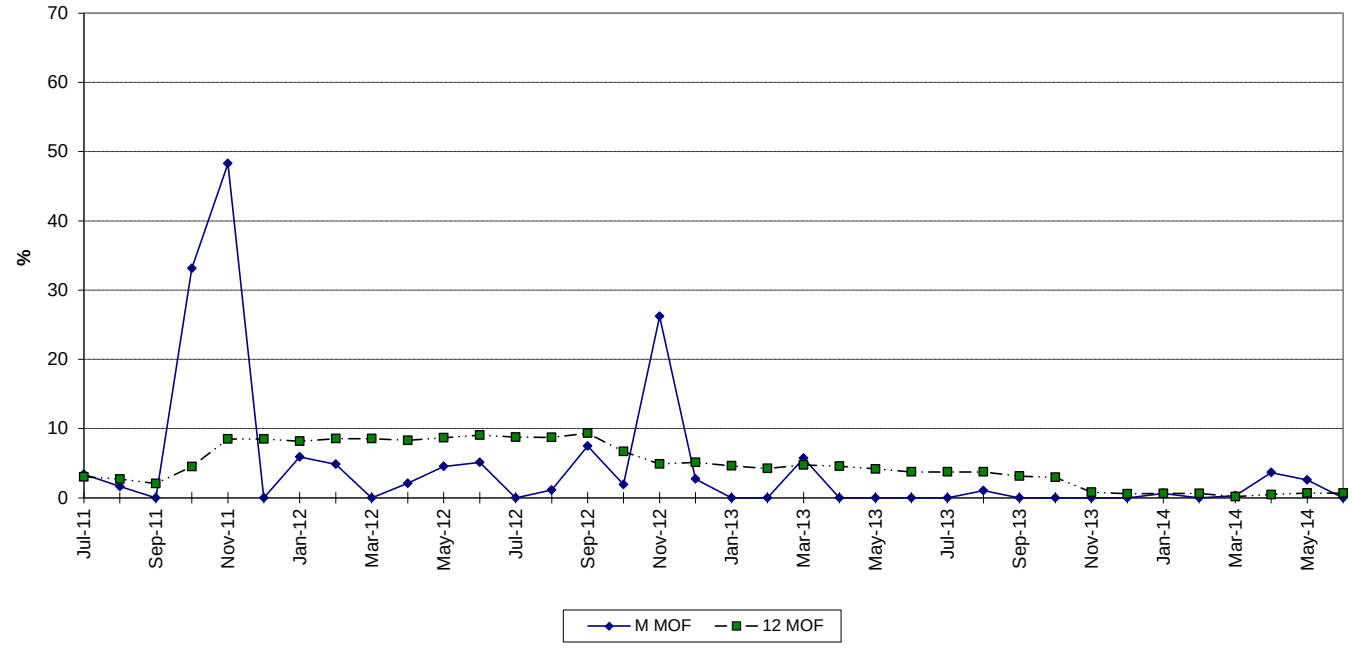
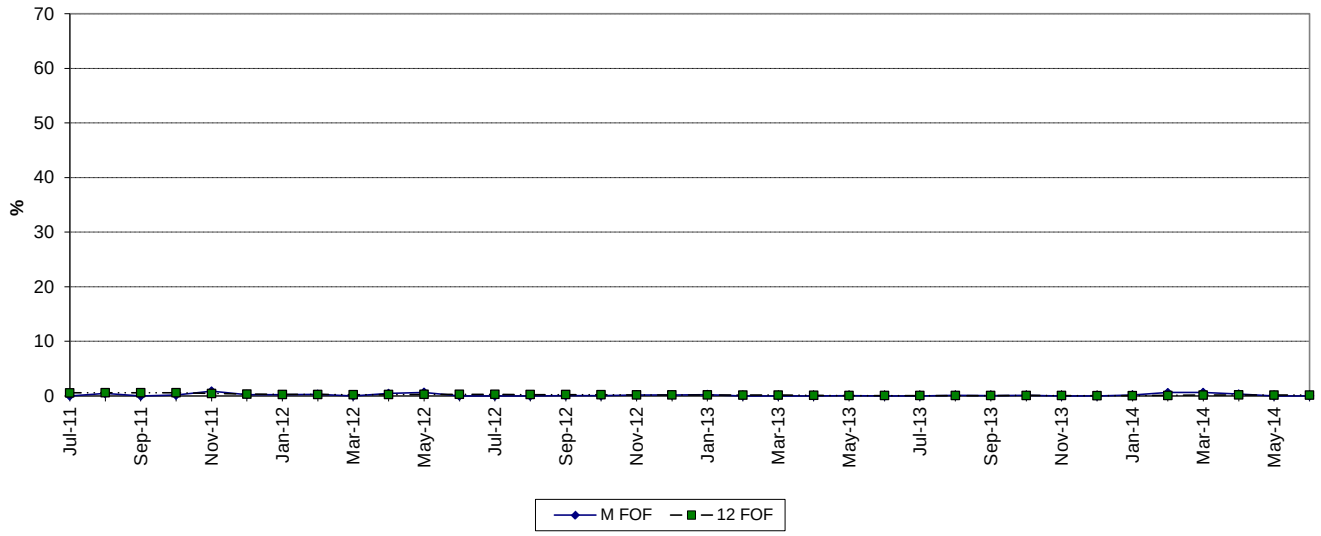


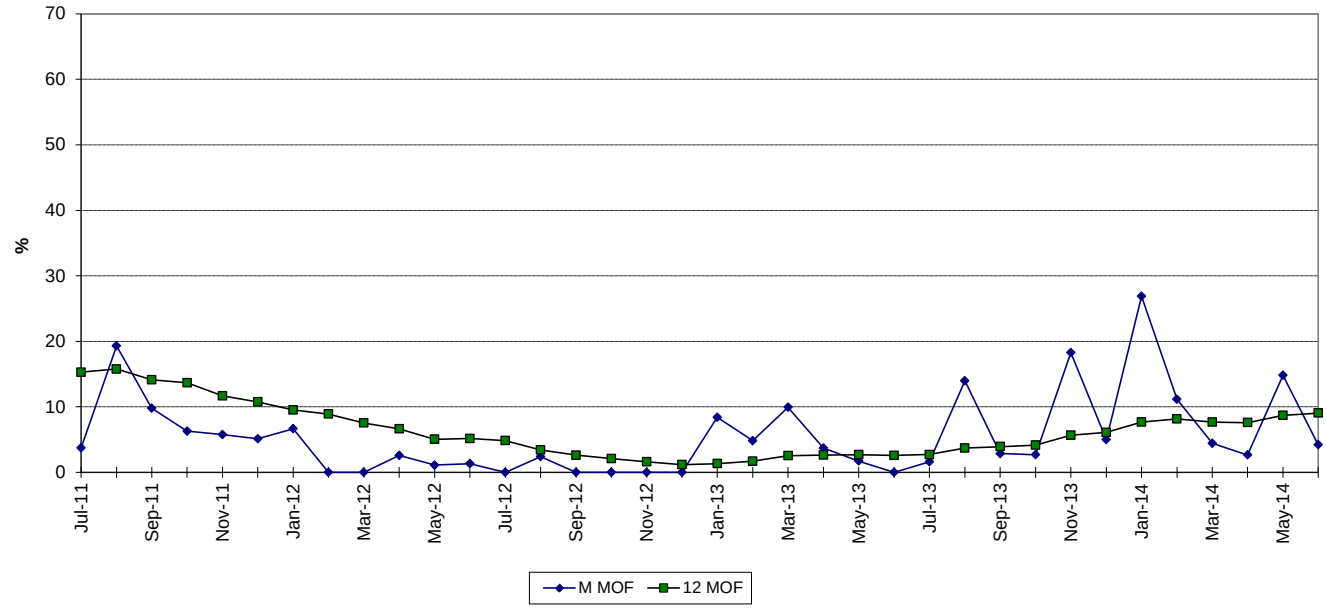
MAINTENANCE OUTAGE FACTOR



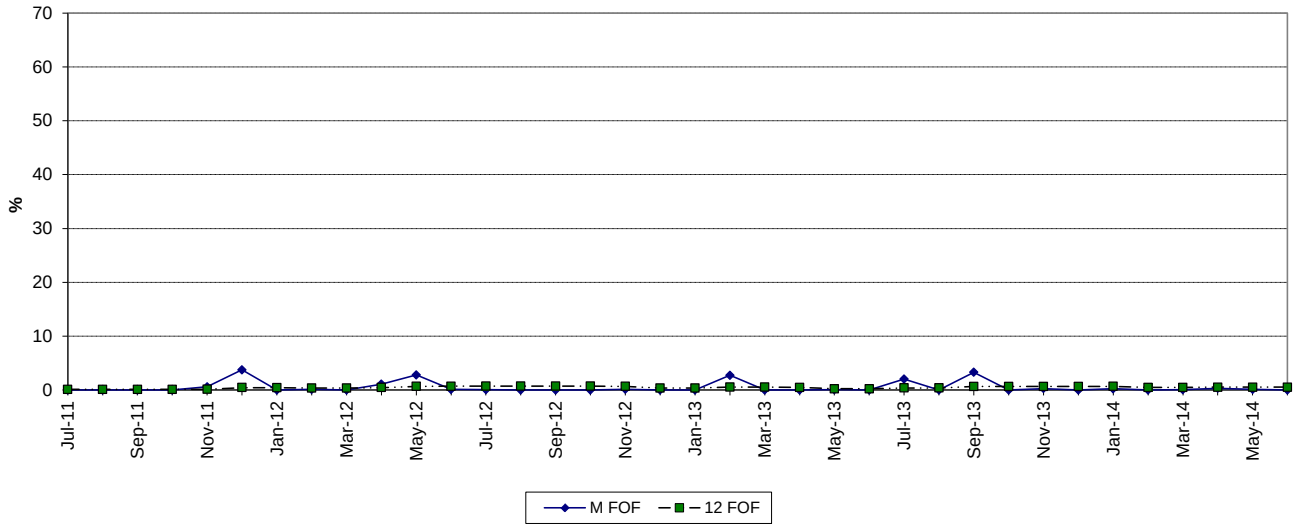
WEST COUNTY 1
FORCED OUTAGE FACTOR



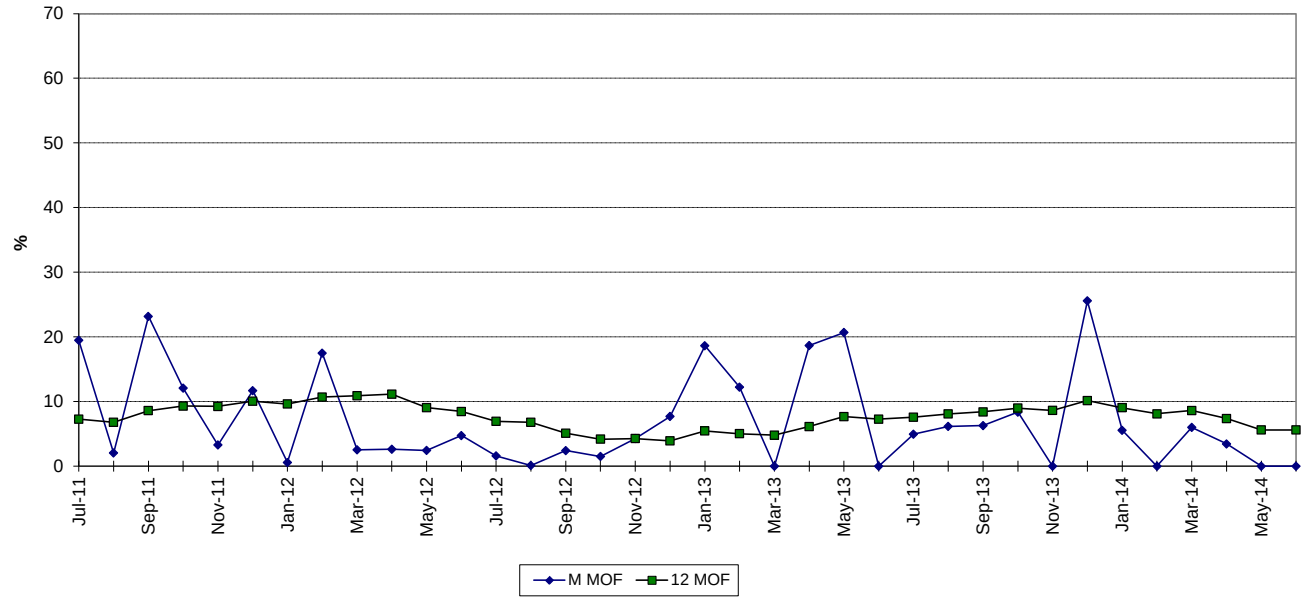
MAINTENANCE OUTAGE FACTOR



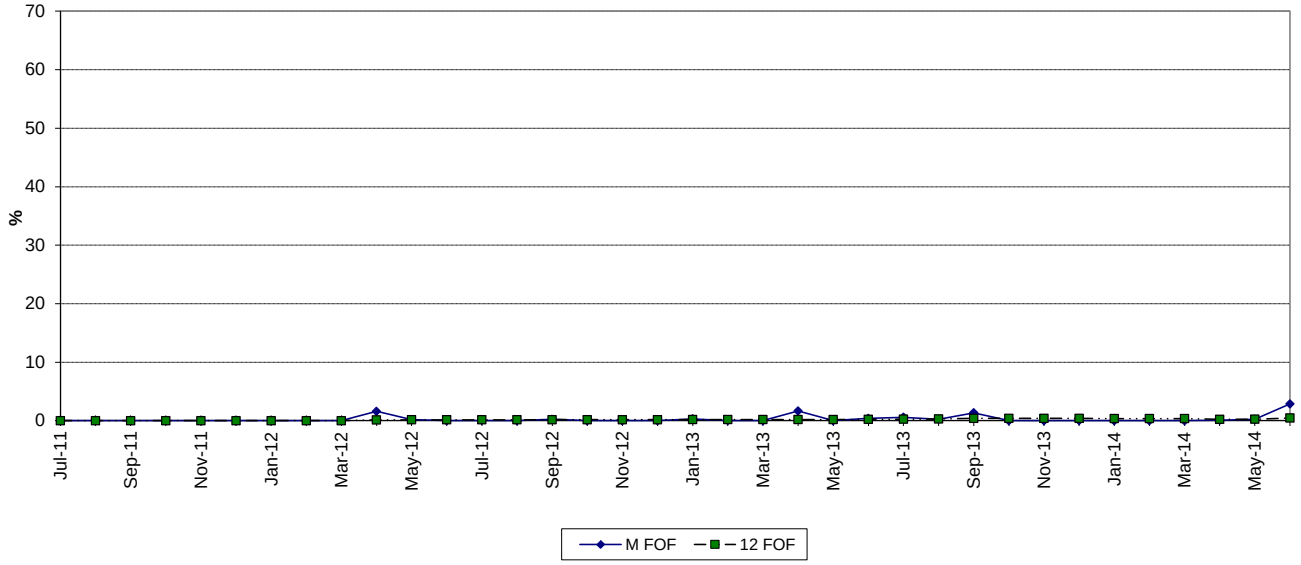
WEST COUNTY 2
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3
FORCED OUTAGE FACTOR



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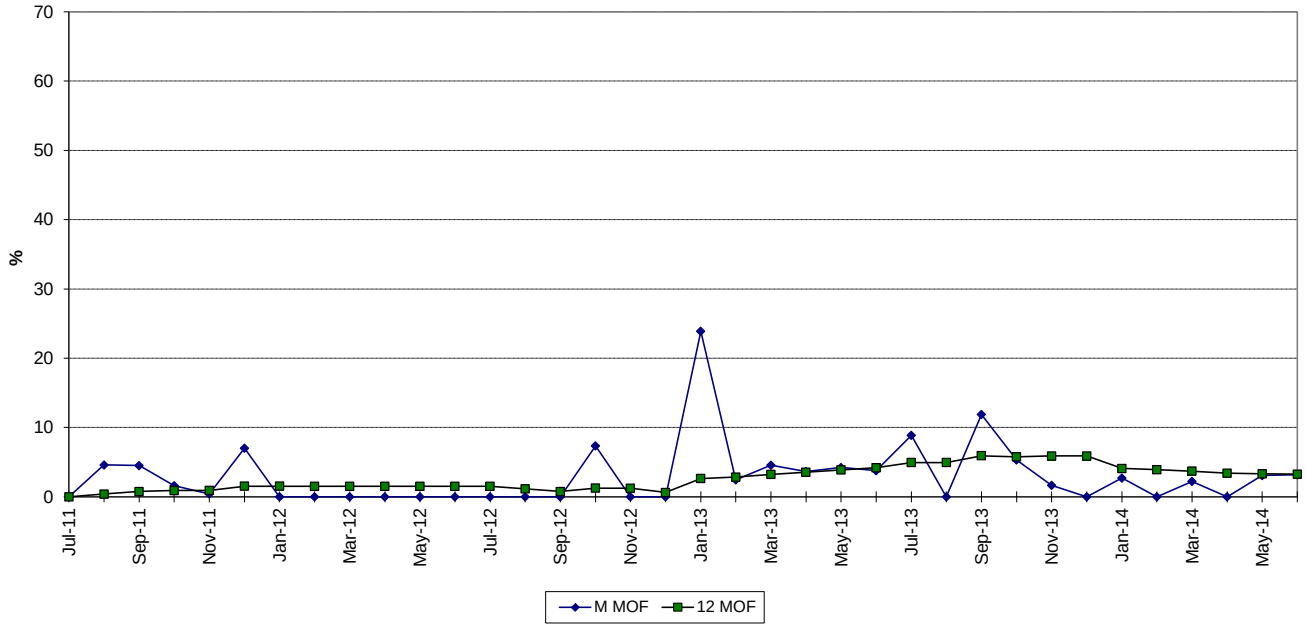


PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Ft. Myers 2	04/11/2015 - 05/24/2015	CT 2A .04 / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	04/18/2015 - 04/24/2015	BOP INSP -100% CURT	1,366
Ft. Myers 2	04/18/2015 - 05/31/2015	CT 2E .04 / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	05/30/2015 - 07/05/2015	CT 2C .04 / CT MAJ / PKG3 / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	06/06/2015 - 07/19/2015	CT 2F .04 / RTR / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	235
Manatee 3	07/13/2015 - 07/19/2015	BOP INSPECTION- 100% CURT	1,078
Manatee 3	07/20/2015 - 07/26/2015	CT 3B HRSG INSP - 25% CURT	270
Manatee 3	07/27/2015 - 08/02/2015	CT 3C HRSG INSP - 25% CURT	270
Martin 8	01/10/2015 - 02/22/2015	CT 8A GENERATOR MAJOR - 25% CURT	287
Martin 8	02/07/2015 - 02/22/2015	BOP - 100% CURT, CT 8C&D MOD CI / HRSG	1,147
Martin 8	02/07/2015 - 03/22/2015	CT 8B GENERATOR MAJOR - 25% CURT	287
St. Lucie 1	03/23/2015 - 04/25/2015	REFUELING	1,003
St. Lucie 2	09/07/2015 - 10/09/2015	REFUELING	840
Turkey Point 3	10/19/2015 - 11/18/2015	REFUELING	811
Turkey Point 4	NONE		
Turkey Point 5	06/06/2015 - 06/10/2015	BOP - 25% CURT	285
Turkey Point 5	06/06/2015 - 06/12/2015	CT 5A, B & C HRSG INSP - 25% CURT	285
Turkey Point 5	06/13/2015 - 06/19/2015	CT 5D HRSG INSP - 25% CURT	285
West County 1	03/14/2015 - 03/23/2015	BLOCK OUTAGE / CONTROLS UPGRADE - 100% CURT	1,208
West County 2	03/14/2015 - 03/20/2015	BLOCK OUTAGE / CONTROLS UPGRADE - 100% CURT	1,202
West County 2	10/03/2015 - 11/11/2015	CT 2A MAJOR / 24K - 33% CURT	382
West County 2	10/10/2015 - 11/18/2015	CT 2C MAJOR / 24K - 33% CURT	382
West County 2	10/16/2015 - 11/11/2015	ST VALVES / GEN MINOR - 100% CURT	1,159
West County 2	10/16/2015 - 11/24/2015	CT 2B MAJOR / 24K - 33% CURT	382
West County 3	03/07/2015 - 03/20/2015	CT 3B COMB INSP - 33% CURT	398
West County 3	03/14/2015 - 03/20/2015	BLOCK OUTAGE / CONTROLS UPGRADE / BOP - 100% CURT	1,207
West County 3	09/05/2015 - 09/19/2015	CT 3A COMB INSP - 33% CURT	385
West County 3	09/19/2015 - 10/02/2015	CT 3C COMB INSP - 33% CURT	385

*Approximate load reduction MW are based on the unit's estimated MW rating during the outage period

WITNESS: J. CARINE BULLOCK

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2015

WITHOUT GAS RESERVES

SEPTEMBER 15, 2014

JCB-3
DOCKET NO. 140001-EI
FPL Witness: J. Carine Bullock
Exhibit No.: _____
Pages 1 - 32

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: J. C. Bullock JCB-3

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2015

EXHIBIT	PAGE NUMBER	TITLE
JCB-3	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 - 7.201.020	Estimated Unit Performance Data
	7.201.021 - 7.201.031	Unit FOF and MOF vs Time Graphs
	7.201.032	Planned Outages Schedule (Estimated)

Projected System Generation
January Through December, 2015

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
PRV5	1,344	8,582	9,967,890	95.8	8.7	8.7	263,720
CCEC	1,355	8,555	9,781,200	94.5	8.5	17.2	259,910
WEST COUNTY 1	1,208	8,392	8,983,720	91.8	7.8	25.0	243,620
WEST COUNTY 3	1,207	7,749	8,047,490	89.1	7.0	32.0	218,110
WEST COUNTY 2	1,202	7,644	7,915,020	89.3	6.9	38.9	213,690
ST. LUCIE 1	1,003	7,968	7,694,320	98.4	6.7	45.6	51,840
MARTIN 8	1,147	7,748	7,443,130	86.5	6.5	52.1	201,680
TURKEY POINT 4	848	8,760	7,107,580	98.8	6.2	58.3	51,380
TURKEY POINT 5	1,166	6,328	6,619,870	91.9	5.8	64.0	179,380
ST. LUCIE 2	860	7,992	6,616,100	98.6	5.8	69.8	43,280
TURKEY POINT 3	839	8,040	6,445,200	98.8	5.6	75.4	48,080
FT. MYERS 2	1,476	5,332	6,206,730	84.2	5.4	80.8	176,910
MANATEE 3	1,134	5,989	6,038,480	93.5	5.3	86.1	166,130
SCHERER 4	646	8,760	5,126,820	91.3	4.5	90.5	133,580
SANFORD 4	990	2,935	2,645,610	96.0	2.3	92.8	76,930
MARTIN 3	454	2,759	1,157,650	95.8	1.0	93.8	34,610
SANFORD 5	994	1,278	1,093,600	90.4	1.0	94.8	32,440
MARTIN 4	453	2,326	936,970	92.2	0.8	95.6	28,190
LAUDERDALE 5	442	1,799	750,100	97.2	0.7	96.3	23,030
ST JOHNS 2O	128	8,760	677,430	60.9	0.6	96.8	24,030
LAUDERDALE 4	442	1,434	596,270	96.9	0.5	97.4	18,450
MARTIN 1	805	951	539,710	71.0	0.5	97.8	32,800
ST JOHNS 1O	128	7,560	497,620	51.8	0.4	98.3	17,930
MARTIN 2	808	1,318	472,670	44.9	0.4	98.7	37,710
MANATEE 1	795	546	352,910	81.9	0.3	99.0	27,250
TURKEY POINT 1	380	1,066	295,200	73.1	0.3	99.2	19,900
MANATEE 2	795	379	253,140	84.7	0.2	99.5	19,150
PUTNAM 2	255	911	218,050	95.7	0.2	99.7	7,810
PUTNAM 1	251	802	187,570	94.7	0.2	99.8	6,840
FORT MYERS 3A_B	314	651	182,180	94.5	0.2	100.0	7,820
FORT MYERS 1-12	690	47	12,750	41.9	0.0	100.0	5,460
LAUDERDALE 1-24	886	29	11,420	46.9	0.0	100.0	980
EVERGLADES 1-12	443	0	0	0.0	0.0	100.0	-
Total	**25,886**		**114,874,400**	**100.0**			**2,672,640**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2015

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, 2015

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	118,434	55,377
+ 9	106,591	49,839
+ 8	94,747	44,301
+ 7	82,904	38,764
+ 6	71,060	33,226
+ 5	59,217	27,688
+ 4	47,374	22,151
+ 3	35,530	16,613
+ 2	23,687	11,075
+ 1	11,843	5,538
0	0	0
- 1	(11,843)	(5,538)
- 2	(23,687)	(11,075)
- 3	(35,530)	(16,613)
- 4	(47,374)	(22,151)
- 5	(59,217)	(27,688)
- 6	(71,060)	(33,226)
- 7	(82,904)	(38,764)
- 8	(94,747)	(44,301)
- 9	(106,591)	(49,839)
- 10	(118,434)	(55,377)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	13,528,240,111	
LINE 2	MONTH OF JANUARY	2015	$	14,078,494,821	
LINE 3	MONTH OF FEBRUARY	2015	$	14,172,840,706	
LINE 4	MONTH OF MARCH	2015	$	14,292,254,762	
LINE 5	MONTH OF APRIL	2015	$	14,390,099,353	
LINE 6	MONTH OF MAY	2015	$	14,562,665,397	
LINE 7	MONTH OF JUNE	2015	$	14,368,682,014	
LINE 8	MONTH OF JULY	2015	$	14,556,993,745	
LINE 9	MONTH OF AUGUST	2015	$	14,194,084,596	
LINE 10	MONTH OF SEPTEMBER	2015	$	14,297,123,292	
LINE 11	MONTH OF OCTOBER	2015	$	14,407,691,042	
LINE 12	MONTH OF NOVEMBER	2015	$	14,527,679,539	
LINE 13	MONTH OF DECEMBER	2015	$	14,618,504,697	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	14,307,334,929	
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)		$	58,272,843	
LINE 18	JURISDICTIONAL SALES			108,216,881,593	KWH
LINE 19	TOTAL SALES			113,871,155,027	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			95.03%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	55,376,683	
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$	59,217,000	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$	55,376,683	

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, 2015

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	3.91	84.1	86.6	81.6	4,632	-4,632
Martin 8	4.24	84.7	87.2	82.2	5,016	-5,016
Manatee 3	3.66	90.3	92.8	87.8	4,334	-4,334
St. Lucie 1	8.72	83.5	86.5	80.5	10,330	-10,330
St. Lucie 2	7.19	84.8	87.8	81.8	8,509	-8,509
Turkey Point 3	7.16	83.2	86.2	80.2	8,483	-8,483
Turkey Point 4	7.89	93.6	96.6	90.6	9,342	-9,342
Turkey Point 5	4.68	91.1	93.6	88.6	5,545	-5,545
West County 1	4.52	89.8	92.3	87.3	5,358	-5,358
West County 2	4.82	78.8	81.8	75.8	5,709	-5,709
West County 3	3.35	90.0	92.0	88.0	3,965	-3,965
	60.14				71,223	-71,223

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

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)
Ft. Myers 2	2.76	7,197	84.2	7,064	7,330	3,269	-3,269
Martin 8	3.27	6,922	86.5	6,789	7,055	3,875	-3,875
Manatee 3	2.37	6,921	93.5	6,804	7,038	2,808	-2,808
St. Lucie 1	3.92	10,405	98.4	10,277	10,533	4,648	-4,648
St. Lucie 2	3.59	10,288	98.6	10,142	10,434	4,249	-4,249
Turkey Point 3	4.09	11,143	98.8	10,972	11,314	4,845	-4,845
Turkey Point 4	4.81	11,002	98.8	10,821	11,183	5,695	-5,695
Turkey Point 5	3.24	7,011	91.9	6,861	7,161	3,838	-3,838
West County 1	4.42	6,795	91.8	6,649	6,941	5,235	-5,235
West County 2	3.68	6,866	89.3	6,726	7,006	4,357	-4,357
West County 3	3.71	6,704	89.1	6,569	6,839	4,392	-4,392
	39.86					47,211	-47,211

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

				ANOHR Equation					
Plant/Unit	**ANOHR**	**NOF**	**MW**	**a coef.**	**b coef.**	**Bounds**	**First**	**Last**	**Exclusions**
Ft. Myers 2	7,197	84.2	1476	8459	-14.99	133	07-11	06-14	12/11, 9/13-11/13
Martin 8	6,922	86.5	1147	7304	-4.42	133	07-11	06-14	12/11, 2/13
Manatee 3	6,921	93.5	1134	7287	-3.91	117	07-11	06-14	8/11-9/11, 11/11, 6/13, 6/14
St. Lucie 1	10,405	98.4	1003	12884	-25.19	128	07-11	06-14	7/11-5/12, 10/13
St. Lucie 2	10,288	98.6	860	11463	-11.92	146	07-11	06-14	8/11-9/11, 4/12-12/12
Turkey Point 3	11,143	98.8	839	12226	-10.96	171	07-11	06-14	10/11-1/12, 3/12-10/12, 12/12, 5/13, 4/14, 6/14
Turkey Point 4	11,002	98.8	848	11666	-6.72	181	07-11	06-14	7/11, 7/12-9/12, 11/12-5/13, 5/14-6/14
Turkey Point 5	7,011	91.9	1166	7573	-6.11	150	07-11	06-14	2/14
West County 1	6,795	91.8	1208	7287	-5.36	146	07-11	06-14	7/13, 12/13-1/14
West County 2	6,866	89.3	1202	7275	-4.58	140	07-11	06-14	7/11, 6/13-7/13, 12/13-1/14
West County 3	6,704	89.1	1207	7421	-8.05	135	07-11	06-14	6/13-7/13, 12/13-2/14

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2015

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Ft. Myers 2	EAF	2,672,640	2,668,008	4,632	3.91
Ft. Myers 2	ANOHR	2,672,640	2,669,371	3,269	2.76
Martin 8	EAF	2,672,640	2,667,624	5,016	4.24
Martin 8	ANOHR	2,672,640	2,668,765	3,875	3.27
Manatee 3	EAF	2,672,640	2,668,306	4,334	3.66
Manatee 3	ANOHR	2,672,640	2,669,832	2,808	2.37
St. Lucie 1	EAF	2,672,640	2,662,310	10,330	8.72
St. Lucie 1	ANOHR	2,672,640	2,667,992	4,648	3.92
St. Lucie 2	EAF	2,672,640	2,664,131	8,509	7.19
St. Lucie 2	ANOHR	2,672,640	2,668,391	4,249	3.59
Turkey Point 3	EAF	2,672,640	2,664,157	8,483	7.16
Turkey Point 3	ANOHR	2,672,640	2,667,795	4,845	4.09
Turkey Point 4	EAF	2,672,640	2,663,298	9,342	7.89
Turkey Point 4	ANOHR	2,672,640	2,666,945	5,695	4.81
Turkey Point 5	EAF	2,672,640	2,667,095	5,545	4.68
Turkey Point 5	ANOHR	2,672,640	2,668,802	3,838	3.24
West County 1	EAF	2,672,640	2,667,282	5,358	4.52
West County 1	ANOHR	2,672,640	2,667,405	5,235	4.42
West County 2	EAF	2,672,640	2,666,931	5,709	4.82
West County 2	ANOHR	2,672,640	2,668,283	4,357	3.68
West County 3	EAF	2,672,640	2,668,675	3,965	3.35
West County 3	ANOHR	2,672,640	2,668,248	4,392	3.71
	TOTAL			118,434	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, 2015

	Ft. Myers 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	94.1	94.1	94.1	62.2	65.3	49.7
2	EPOF (%)	0.0	0.0	0.0	33.9	30.6	47.2
3	EUOF (%)	5.9	5.9	5.9	3.9	4.1	3.1
4	EUOR (%)	19.6	17.2	8.2	7.3	8.1	4.9
5	PH	744	672	744	720	744	720
6	SH	225	232	535	388	377	456
7	RSH	519	440	209	164	367	264
8	UH	0	0	0	168	0	0
9	POH	0	0	0	168	0	0
10	FOH & EFOH	17	15	17	11	12	9
11	MOH & EMOH	27	25	27	18	19	14
12	Oper Mbtu	1,952,178	1,923,455	4,770,594	3,108,695	2,492,724	2,442,423
13	Net Gen (MWH)	273,376	266,665	672,104	428,018	332,186	316,992
14	ANOHR (Btu/KWH)	7,141	7,213	7,098	7,263	7,504	7,705
15	NOF (%)	87.9	83.1	90.8	79.8	63.7	50.3
16	NSC (MW)	1,383	1,383	1,383	1,383	1,383	1,383
17	ANOHR Equation	-14.99 x NOF + 8459					

	Ft. Myers 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	79.4	94.1	94.1	94.1	94.1	94.1	84.1
2	EPOF (%)	15.6	0.0	0.0	0.0	0.0	0.0	10.6
3	EUOF (%)	5.0	5.9	5.9	5.9	5.9	5.9	5.3
4	EUOR (%)	6.1	7.9	7.6	7.3	8.5	15.7	8.7
5	PH	744	744	720	744	720	744	8,760
6	SH	611	557	565	604	501	281	5,332
7	RSH	133	187	155	140	219	463	3260
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	14	17	16	17	16	17	175
11	MOH & EMOH	23	27	27	27	27	27	289
12	Oper Mbtu	4,868,189	5,169,202	5,220,030	5,500,804	4,545,523	2,479,058	44,669,821
13	Net Gen (MWH)	669,443	735,620	741,903	778,930	643,113	348,378	6,206,728
14	ANOHR (Btu/KWH)	7,272	7,027	7,036	7,062	7,068	7,116	7,197
15	NOF (%)	79.2	95.5	94.9	93.2	92.8	89.6	84.2
16	NSC (MW)	1,383	1,383	1,383	1,383	1,383	1,383	1,383
17	ANOHR Equation	-14.99 x NOF + 8459						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Manatee 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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 (%)	15.3	11.3	8.5	9.2	10.8	8.5
5	PH	744	672	744	720	744	720
6	SH	341	415	611	549	481	592
7	RSH	403	257	133	171	263	128
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	37	33	37	36	37	36
12	Oper Mbtu	2,444,924	2,784,145	4,227,165	3,829,036	3,461,858	4,164,491
13	Net Gen (MWH)	353,824	401,405	610,421	553,249	501,065	601,979
14	ANOHR (Btu/KWH)	6,910	6,936	6,925	6,921	6,909	6,918
15	NOF (%)	96.3	89.7	92.7	93.5	96.6	94.3
16	NSC (MW)	1,078	1,078	1,078	1,078	1,078	1,078
17	ANOHR Equation	-3.91 x NOF + 7287					

	Manatee 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	63.0	91.5	93.0	93.0	93.0	93.0	90.3
2	EPOF (%)	32.3	1.6	0.0	0.0	0.0	0.0	2.9
3	EUOF (%)	4.7	6.9	7.0	7.0	7.0	7.0	6.8
4	EUOR (%)	16.3	8.9	8.0	9.0	9.0	11.9	9.9
5	PH	744	744	720	744	720	744	8,760
6	SH	217	579	629	580	558	437	5,989
7	RSH	359	165	91	164	162	307	2603
8	UH	168	0	0	0	0	0	168
9	POH	168	0	0	0	0	0	168
10	FOH & EFOH	10	15	15	15	15	15	175
11	MOH & EMOH	25	36	36	37	36	37	420
12	Oper Mbtu	1,263,398	4,071,838	4,467,066	4,097,617	3,930,358	3,048,375	41,792,306
13	Net Gen (MWH)	180,873	588,586	646,090	592,398	568,135	440,453	6,038,478
14	ANOHR (Btu/KWH)	6,985	6,918	6,914	6,917	6,918	6,921	6,921
15	NOF (%)	77.3	94.3	95.3	94.7	94.4	93.5	93.5
16	NSC (MW)	1,078	1,078	1,078	1,078	1,078	1,078	1,078
17	ANOHR Equation	-3.91 x NOF + 7287						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Martin 8	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	75.9	29.6	75.9	92.3	92.3	92.3
2	EPOF (%)	17.7	67.9	17.7	0.0	0.0	0.0
3	EUOF (%)	6.4	2.5	6.4	7.7	7.7	7.7
4	EUOR (%)	10.2	10.6	7.6	7.7	7.7	7.7
5	PH	744	672	744	720	744	720
6	SH	464	158	624	720	744	720
7	RSH	280	130	120	0	0	0
8	UH	0	384	0	0	0	0
9	POH	0	384	0	0	0	0
10	FOH & EFOH	13	5	13	16	16	16
11	MOH & EMOH	34	12	34	40	41	40
12	Oper Mbtu	2,830,024	882,465	3,732,460	4,781,508	5,029,625	4,943,459
13	Net Gen (MWH)	406,905	126,319	536,119	690,670	727,350	715,510
14	ANOHR (Btu/KWH)	6,955	6,986	6,962	6,923	6,915	6,909
15	NOF (%)	78.9	72.0	77.3	86.3	88.0	89.4
16	NSC (MW)	1,111	1,111	1,111	1,111	1,111	1,111
17	ANOHR Equation	-4.42 x NOF + 7304					

	Martin 8	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	92.3	92.3	92.3	92.3	92.3	92.3	84.7
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3	EUOF (%)	7.7	7.7	7.7	7.7	7.7	7.7	7.1
4	EUOR (%)	7.7	7.7	7.7	7.7	8.0	8.6	8.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	700	666	7,748
7	RSH	0	0	0	0	20	78	628
8	UH	0	0	0	0	0	0	384
9	POH	0	0	0	0	0	0	384
10	FOH & EFOH	16	16	16	16	16	16	175
11	MOH & EMOH	41	41	40	41	40	41	447
12	Oper Mbtu	5,143,244	5,134,705	5,006,518	5,114,428	4,691,760	4,222,682	51,521,311
13	Net Gen (MWH)	744,750	743,406	725,267	740,363	678,098	608,368	7,443,125
14	ANOHR (Btu/KWH)	6,906	6,907	6,903	6,908	6,919	6,941	6,922
15	NOF (%)	90.1	89.9	90.7	89.6	87.2	82.2	86.5
16	NSC (MW)	1,111	1,111	1,111	1,111	1,111	1,111	1,111
17	ANOHR Equation	-4.42 x NOF + 7304						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	St. Lucie 1	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	91.8	91.8	65.1	18.4	91.8	91.8
2	EPOF (%)	0.0	0.0	29.0	80.0	0.0	0.0
3	EUOF (%)	8.2	8.2	5.9	1.6	8.2	8.2
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	672	744	720	744	720
6	SH	744	672	528	144	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	216	576	0	0
9	POH	0	0	216	576	0	0
10	FOH & EFOH	35	32	25	7	35	34
11	MOH & EMOH	26	24	19	5	26	25
12	Oper Mbtu	7,547,125	6,816,773	5,356,057	1,436,269	7,420,784	7,181,399
13	Net Gen (MWH)	727,574	657,165	516,346	137,732	711,621	688,665
14	ANOHR (Btu/KWH)	10,373	10,373	10,373	10,428	10,428	10,428
15	NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16	NSC (MW)	981	981	981	981	981	981
17	ANOHR Equation	-25.19 x NOF + 12884					

	St. Lucie 1	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	91.8	91.8	91.8	91.8	91.8	91.8	83.5
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.0
3	EUOF (%)	8.2	8.2	8.2	8.2	8.2	8.2	7.5
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,968
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	792
9	POH	0	0	0	0	0	0	792
10	FOH & EFOH	35	35	34	35	34	35	377
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	7,420,784	7,420,784	7,181,399	7,420,784	7,303,671	7,547,125	80,059,285
13	Net Gen (MWH)	711,621	711,621	688,665	711,621	704,104	727,574	7,694,309
14	ANOHR (Btu/KWH)	10,428	10,428	10,428	10,428	10,373	10,373	10,405
15	NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.4
16	NSC (MW)	981	981	981	981	981	981	981
17	ANOHR Equation	-25.19 x NOF + 12884						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	St. Lucie 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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	24	26	25	26	25
11	MOH & EMOH	26	24	26	25	26	25
12	Oper Mbtu	6,408,749	5,788,548	6,408,749	6,074,263	6,276,729	6,074,263
13	Net Gen (MWH)	623,844	563,472	623,844	589,677	609,332	589,677
14	ANOHR (Btu/KWH)	10,273	10,273	10,273	10,301	10,301	10,301
15	NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16	NSC (MW)	840	840	840	840	840	840
17	ANOHR Equation	-11.92 x NOF + 11463					

	St. Lucie 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	93.0	93.0	18.6	69.0	93.0	93.0	84.8
2	EPOF (%)	0.0	0.0	80.0	25.8	0.0	0.0	8.8
3	EUOF (%)	7.0	7.0	1.4	5.2	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	144	552	720	744	7,992
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	576	192	0	0	768
9	POH	0	0	576	192	0	0	768
10	FOH & EFOH	26	26	5	19	25	26	280
11	MOH & EMOH	26	26	5	19	25	26	280
12	Oper Mbtu	6,276,729	6,276,729	1,214,859	4,656,958	6,202,016	6,408,749	68,066,416
13	Net Gen (MWH)	609,332	609,332	117,936	452,088	603,720	623,844	6,616,098
14	ANOHR (Btu/KWH)	10,301	10,301	10,301	10,301	10,273	10,273	10,288
15	NOF (%)	97.5	97.5	97.5	97.5	99.8	99.8	98.6
16	NSC (MW)	840	840	840	840	840	840	840
17	ANOHR Equation	-11.92 x NOF + 11463						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	90.6	90.6	90.6	90.6	90.6	90.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	9.4	9.4	9.4	9.4	9.4	9.4
4	EUOR (%)	9.4	9.4	9.4	9.4	9.4	9.4
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	44	40	44	42	44	42
11	MOH & EMOH	26	23	26	25	26	25
12	Oper Mbtu	6,767,777	6,112,809	6,767,777	6,351,859	6,563,585	6,351,859
13	Net Gen (MWH)	608,613	549,713	608,613	569,316	588,293	569,316
14	ANOHR (Btu/KWH)	11,120	11,120	11,120	11,157	11,157	11,157
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	-10.96 x NOF + 12226					

	Turkey Point 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	90.6	90.6	90.6	52.7	39.2	90.6	83.2
2	EPOF (%)	0.0	0.0	0.0	41.9	56.7	0.0	8.2
3	EUOF (%)	9.4	9.4	9.4	5.4	4.1	9.4	8.6
4	EUOR (%)	9.4	9.4	9.4	9.4	9.4	9.4	9.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	432	312	744	8,040
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	312	408	0	720
9	POH	0	0	0	312	408	0	720
10	FOH & EFOH	44	44	42	25	18	44	473
11	MOH & EMOH	26	26	25	15	11	26	280
12	Oper Mbtu	6,563,585	6,563,585	6,351,859	3,811,131	2,838,080	6,767,777	71,818,786
13	Net Gen (MWH)	588,293	588,293	569,316	341,591	255,223	608,613	6,445,193
14	ANOHR (Btu/KWH)	11,157	11,157	11,157	11,157	11,120	11,120	11,143
15	NOF (%)	97.5	97.5	97.5	97.5	100.9	100.9	98.8
16	NSC (MW)	811	811	811	811	811	811	811
17	ANOHR Equation	-10.96 x NOF + 12226						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 4	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
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	6,759,773	6,105,620	6,759,773	6,346,102	6,557,645	6,346,102
13	Net Gen (MWH)	615,140	555,612	615,140	576,342	595,554	576,342
14	ANOHR (Btu/KWH)	10,989	10,989	10,989	11,011	11,011	11,011
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	-6.72 x NOF + 11666					

	Turkey Point 4	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	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	6,557,645	6,557,645	6,346,102	6,557,645	6,541,719	6,759,773	78,197,496
13	Net Gen (MWH)	595,554	595,554	576,342	595,554	595,297	615,140	7,107,571
14	ANOHR (Btu/KWH)	11,011	11,011	11,011	11,011	10,989	10,989	11,002
15	NOF (%)	97.5	97.5	97.5	97.5	100.7	100.7	98.8
16	NSC (MW)	821	821	821	821	821	821	821
17	ANOHR Equation	-6.72 x NOF + 11666						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	Turkey Point 5	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	93.3	93.3	93.3	93.3	93.3	66.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	29.2
3	EUOF (%)	6.7	6.7	6.7	6.7	6.7	4.7
4	EUOR (%)	14.6	11.7	10.1	7.2	8.1	7.1
5	PH	744	672	744	720	744	720
6	SH	340	381	492	666	608	477
7	RSH	404	291	252	54	136	243
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	10
11	MOH & EMOH	34	31	34	33	34	24
12	Oper Mbtu	2,473,940	2,600,767	3,673,628	4,762,971	4,516,620	3,325,359
13	Net Gen (MWH)	352,614	368,694	524,804	677,810	644,863	472,285
14	ANOHR (Btu/KWH)	7,016	7,054	7,000	7,027	7,004	7,041
15	NOF (%)	91.1	85.0	93.7	89.4	93.2	87.0
16	NSC (MW)	1,138	1,138	1,138	1,138	1,138	1,138
17	ANOHR Equation	-6.11 x NOF + 7573					

	Turkey Point 5	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	93.3	93.3	93.3	93.3	93.3	93.3	91.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.4
3	EUOF (%)	6.7	6.7	6.7	6.7	6.7	6.7	6.5
4	EUOR (%)	7.2	6.7	6.9	6.9	35.0	12.9	9.0
5	PH	744	744	720	744	720	744	8,760
6	SH	692	744	692	716	137	383	6,328
7	RSH	52	0	28	28	583	361	2432
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	15	15	175
11	MOH & EMOH	34	34	33	34	33	34	394
12	Oper Mbtu	5,172,720	5,566,851	5,204,527	5,307,696	995,782	2,810,850	46,411,895
13	Net Gen (MWH)	738,960	795,378	743,929	757,701	141,910	400,920	6,619,868
14	ANOHR (Btu/KWH)	7,000	6,999	6,996	7,005	7,017	7,011	7,011
15	NOF (%)	93.8	93.9	94.5	93.0	91.0	92.0	91.9
16	NSC (MW)	1,138	1,138	1,138	1,138	1,138	1,138	1,138
17	ANOHR Equation	-6.11 x NOF + 7573						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	West County 1	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	92.3	92.3	62.5	92.3	92.3	92.3
2	EPOF (%)	0.0	0.0	32.3	0.0	0.0	0.0
3	EUOF (%)	7.7	7.7	5.2	7.7	7.7	7.7
4	EUOR (%)	8.4	7.7	8.4	7.7	7.7	7.7
5	PH	744	672	744	720	744	720
6	SH	684	672	462	720	744	720
7	RSH	60	0	42	0	0	0
8	UH	0	0	240	0	0	0
9	POH	0	0	240	0	0	0
10	FOH & EFOH	15	14	10	15	15	15
11	MOH & EMOH	42	38	29	41	42	41
12	Oper Mbtu	5,073,075	4,835,130	3,352,066	5,173,902	5,422,733	5,346,124
13	Net Gen (MWH)	747,800	710,944	493,241	760,756	798,165	788,049
14	ANOHR (Btu/KWH)	6,784	6,801	6,796	6,801	6,794	6,784
15	NOF (%)	93.8	90.7	91.6	90.6	92.0	93.9
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-5.36 x NOF + 7287					

	West County 1	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	92.3	92.3	92.3	92.3	92.3	92.3	89.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	EUOF (%)	7.7	7.7	7.7	7.7	7.7	7.7	7.5
4	EUOR (%)	7.7	7.7	7.7	7.7	7.9	7.8	7.8
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	702	736	8,392
7	RSH	0	0	0	0	18	8	128
8	UH	0	0	0	0	0	0	240
9	POH	0	0	0	0	0	0	240
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	42	42	41	42	41	42	482
12	Oper Mbtu	5,434,414	5,449,635	5,270,875	5,377,796	5,125,060	5,181,010	61,044,309
13	Net Gen (MWH)	800,002	802,479	776,156	791,085	754,462	760,571	8,983,710
14	ANOHR (Btu/KWH)	6,793	6,791	6,791	6,798	6,793	6,812	6,795
15	NOF (%)	92.2	92.5	92.5	91.2	92.2	88.6	91.8
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-5.36 x NOF + 7287						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

	West County 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	90.5	90.5	70.0	90.5	90.5	90.5
2	EPOF (%)	0.0	0.0	22.6	0.0	0.0	0.0
3	EUOF (%)	9.5	9.5	7.4	9.5	9.5	9.5
4	EUOR (%)	9.7	9.6	9.6	9.5	9.6	9.5
5	PH	744	672	744	720	744	720
6	SH	728	664	569	720	736	720
7	RSH	16	8	7	0	8	0
8	UH	0	0	168	0	0	0
9	POH	0	0	168	0	0	0
10	FOH & EFOH	17	15	13	17	17	17
11	MOH & EMOH	54	49	42	52	54	52
12	Oper Mbtu	5,287,587	4,672,397	4,039,309	5,237,634	5,411,057	5,362,462
13	Net Gen (MWH)	771,235	680,116	588,306	763,949	789,820	783,413
14	ANOHR (Btu/KWH)	6,856	6,870	6,866	6,856	6,851	6,845
15	NOF (%)	91.4	88.4	89.2	91.5	92.6	93.9
16	NSC (MW)	1,159	1,159	1,159	1,159	1,159	1,159
17	ANOHR Equation	-4.58 x NOF + 7275					

	West County 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	90.5	90.5	90.5	25.3	37.2	90.5	78.8
2	EPOF (%)	0.0	0.0	0.0	72.0	58.9	0.0	12.9
3	EUOF (%)	9.5	9.5	9.5	2.7	3.9	9.5	8.3
4	EUOR (%)	9.5	9.5	9.5	7.5	9.7	9.5	9.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	263	292	744	7,644
7	RSH	0	0	0	97	164	0	300
8	UH	0	0	0	384	264	0	816
9	POH	0	0	0	384	264	0	816
10	FOH & EFOH	17	17	17	5	7	17	175
11	MOH & EMOH	54	54	52	15	21	54	552
12	Oper Mbtu	5,593,147	5,447,806	5,275,601	1,273,202	1,581,109	5,137,543	54,344,500
13	Net Gen (MWH)	817,592	794,952	769,936	181,834	226,910	746,953	7,915,016
14	ANOHR (Btu/KWH)	6,841	6,853	6,852	7,002	6,968	6,878	6,866
15	NOF (%)	94.8	92.2	92.3	59.7	67.0	86.6	89.3
16	NSC (MW)	1,159	1,159	1,159	1,159	1,159	1,159	1,159
17	ANOHR Equation	-4.58 x NOF + 7275						

ESTIMATED UNIT PERFORMANCE DATA

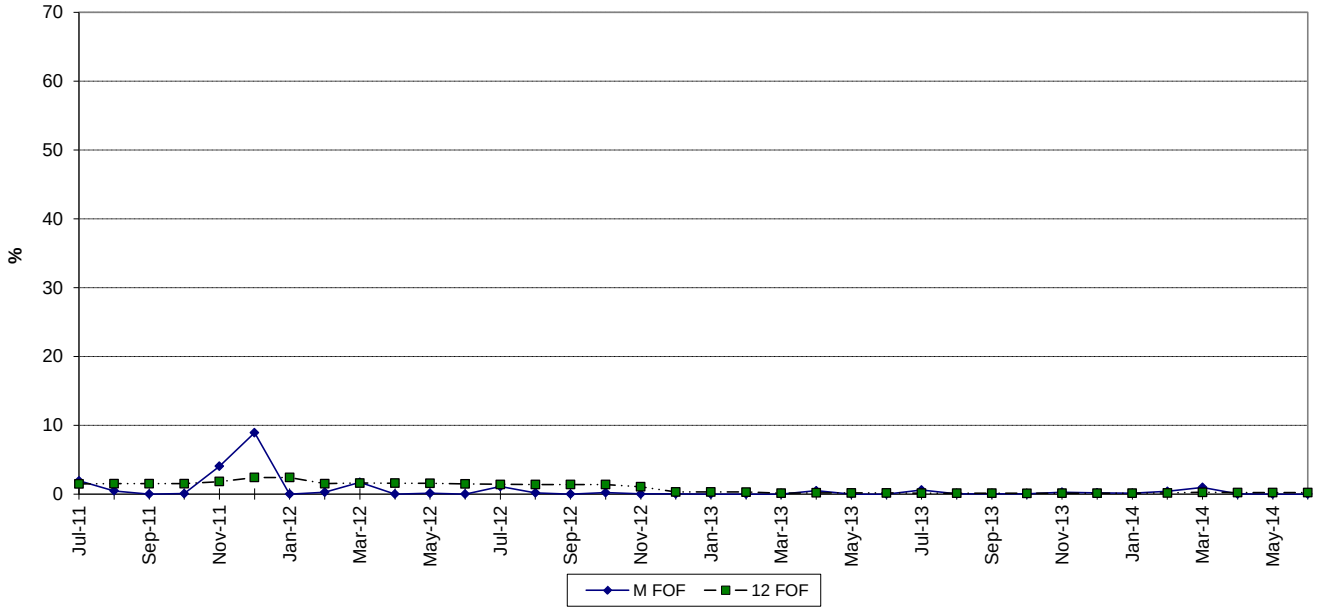
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

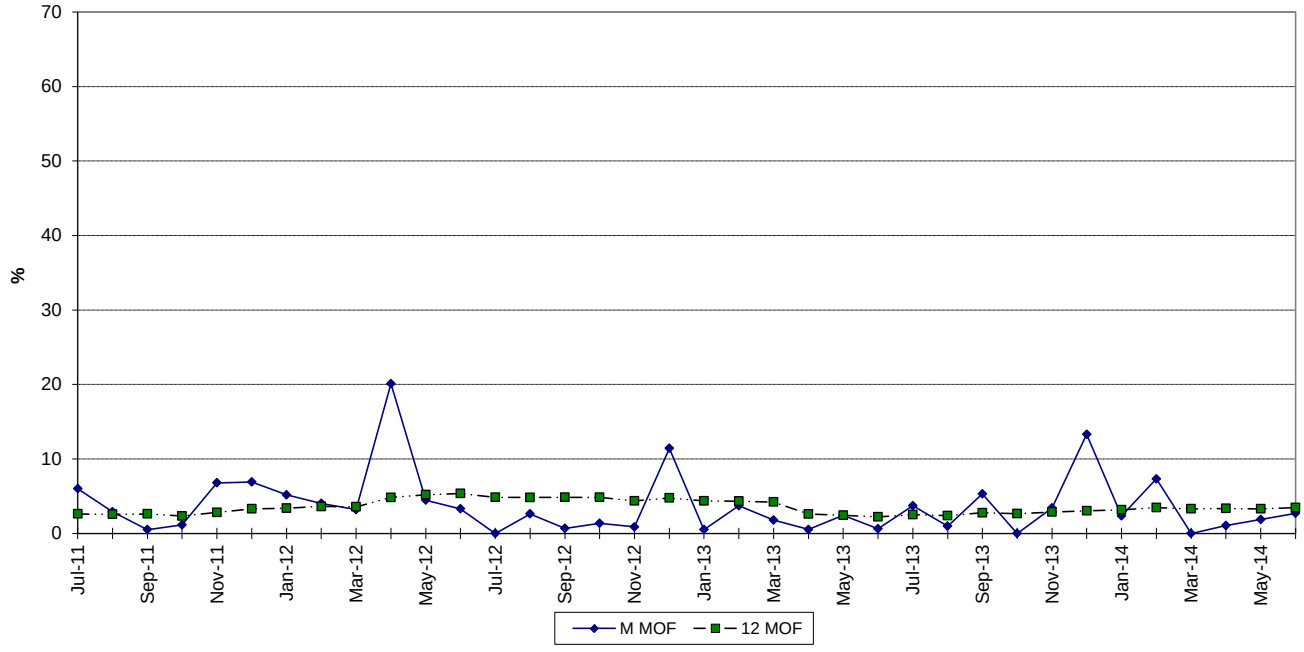
	West County 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15
1	EAF (%)	94.8	94.8	66.3	94.8	94.8	94.8
2	EPOF (%)	0.0	0.0	30.1	0.0	0.0	0.0
3	EUOF (%)	5.2	5.2	3.6	5.2	5.2	5.2
4	EUOR (%)	7.7	6.1	5.6	5.2	5.2	5.2
5	PH	744	672	744	720	744	720
6	SH	496	566	478	712	744	720
7	RSH	248	106	98	8	0	0
8	UH	0	0	168	0	0	0
9	POH	0	0	168	0	0	0
10	FOH & EFOH	16	14	11	15	16	15
11	MOH & EMOH	23	21	16	22	23	22
12	Oper Mbtu	3,646,835	3,944,038	3,168,167	4,947,760	5,236,600	5,167,701
13	Net Gen (MWH)	547,655	588,399	469,915	737,921	782,049	773,608
14	ANOHR (Btu/KWH)	6,659	6,703	6,742	6,705	6,696	6,680
15	NOF (%)	94.7	89.2	84.3	88.9	90.1	92.1
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-8.05 x NOF + 7421					

	West County 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1	EAF (%)	94.8	94.8	67.4	92.7	94.8	94.8	90.0
2	EPOF (%)	0.0	0.0	28.9	2.2	0.0	0.0	5.1
3	EUOF (%)	5.2	5.2	3.7	5.1	5.2	5.2	4.9
4	EUOR (%)	5.2	5.2	4.3	5.2	5.9	6.6	5.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	612	720	632	581	7,749
7	RSH	0	0	108	24	88	163	843
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	16	16	11	15	15	16	175
11	MOH & EMOH	23	23	16	22	22	23	254
12	Oper Mbtu	5,407,535	5,413,062	3,395,950	5,123,609	4,448,968	4,022,113	53,950,319
13	Net Gen (MWH)	810,968	811,797	494,820	766,319	664,521	599,510	8,047,482
14	ANOHR (Btu/KWH)	6,668	6,668	6,863	6,686	6,695	6,709	6,704
15	NOF (%)	93.5	93.6	69.3	91.3	90.2	88.5	89.1
16	NSC (MW)	1,166	1,166	1,166	1,166	1,166	1,166	1,166
17	ANOHR Equation	-8.05 x NOF + 7421						

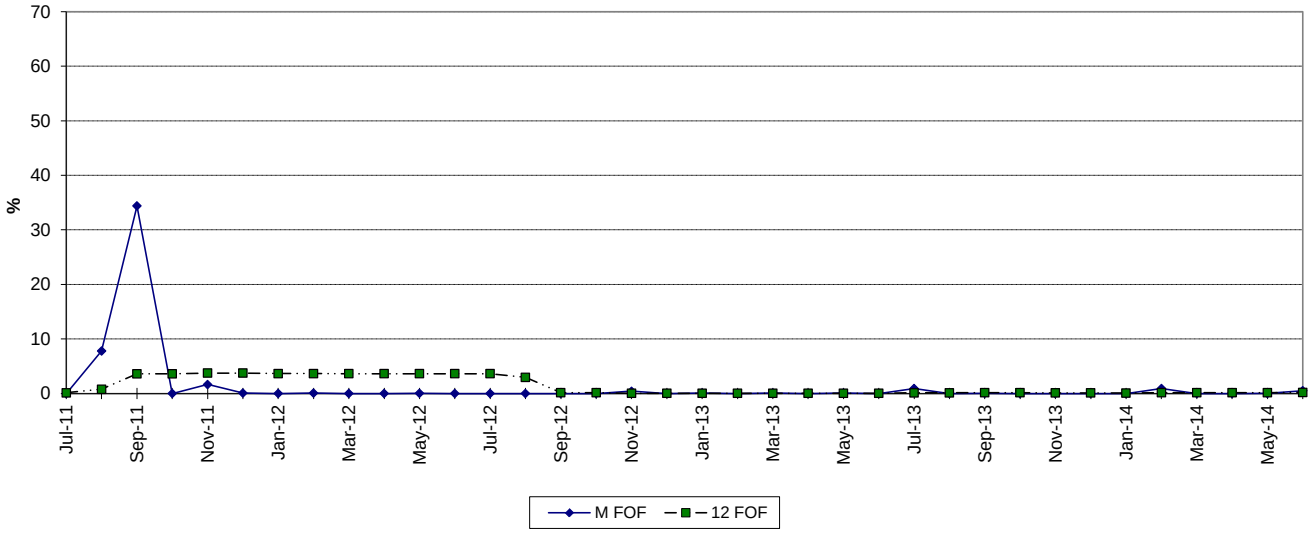
FT. MYERS 2
FORCED OUTAGE FACTOR



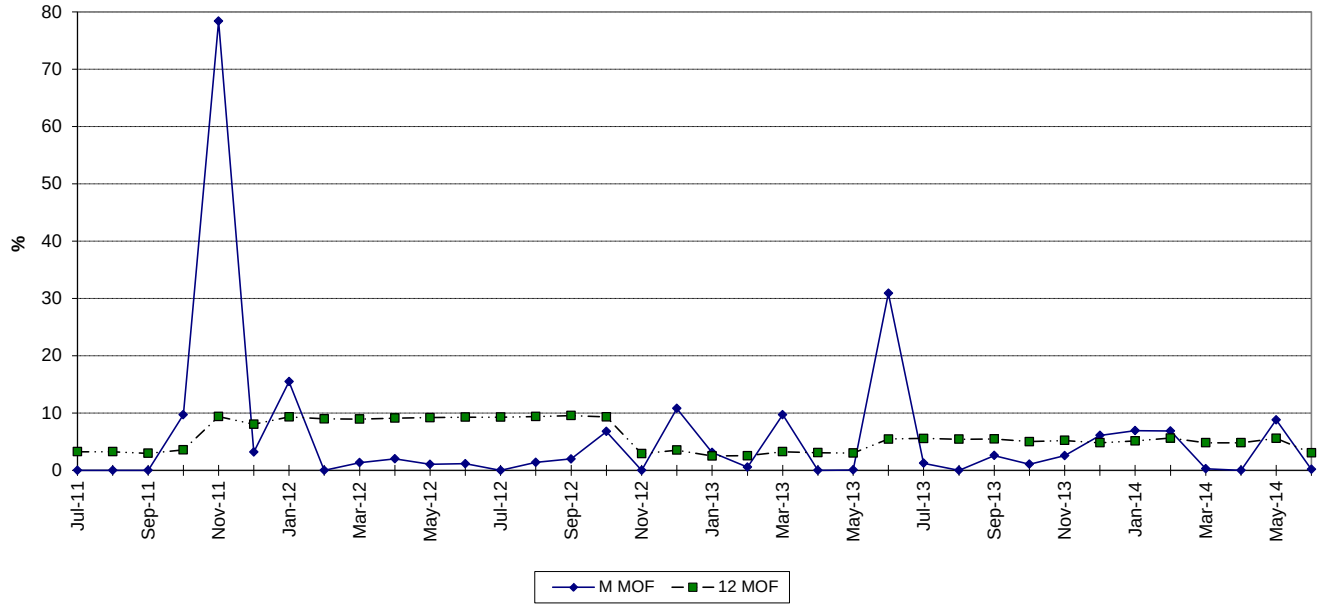
MAINTENANCE OUTAGE FACTOR



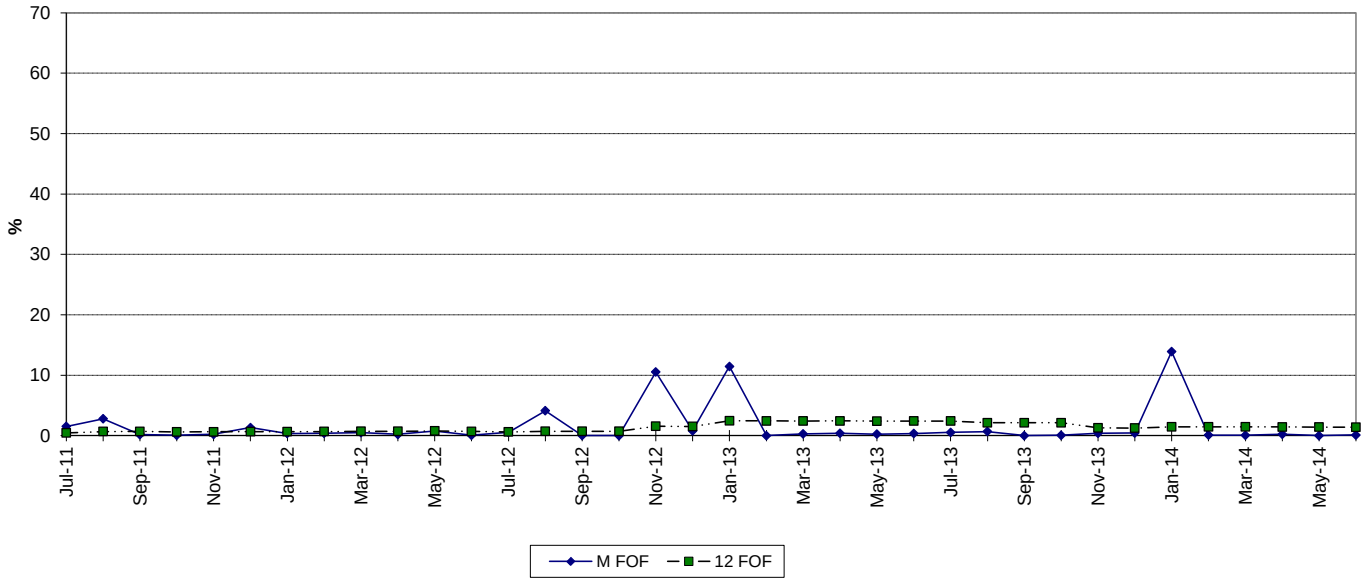
MANATEE 3
FORCED OUTAGE FACTOR



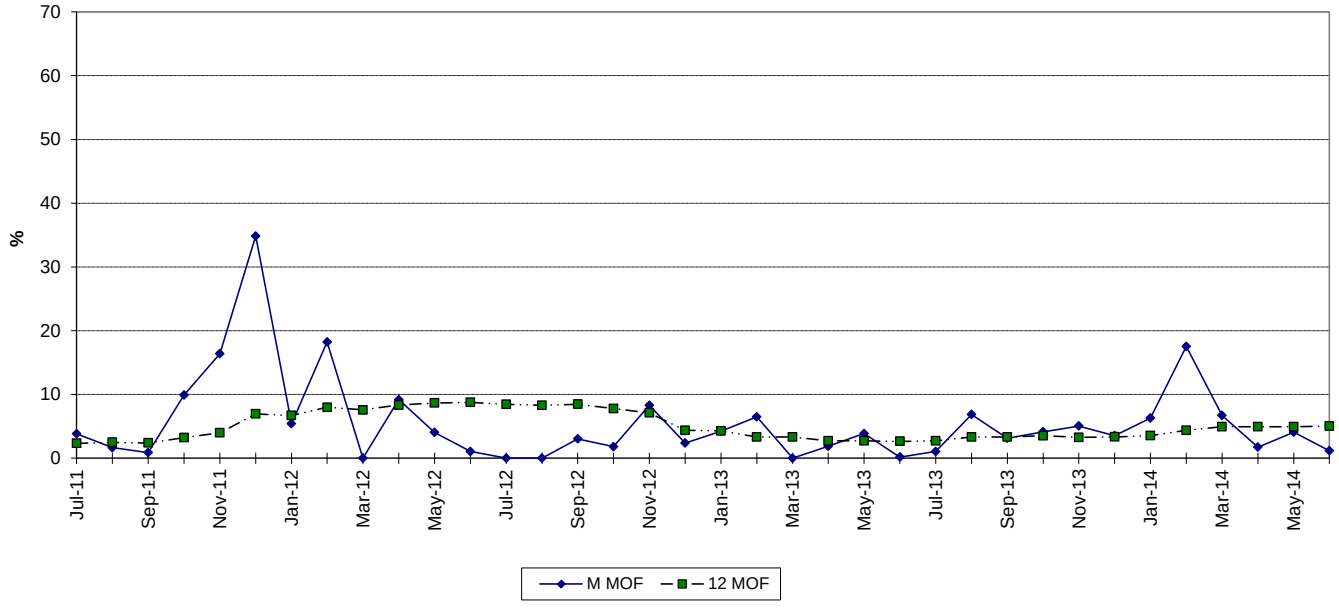
MAINTENANCE OUTAGE FACTOR



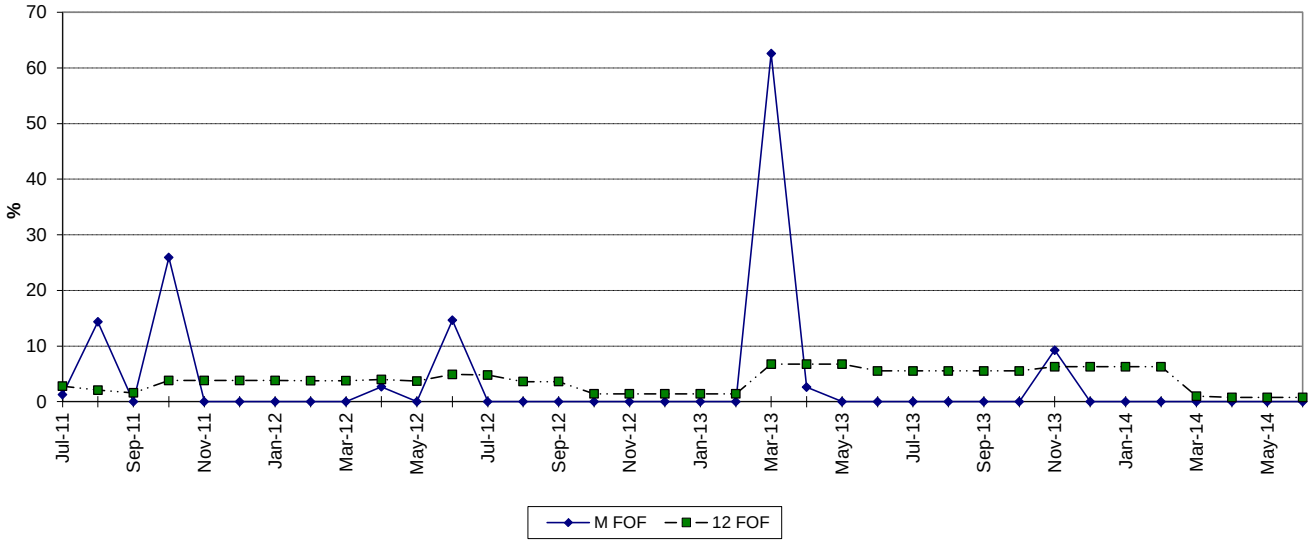
MARTIN 8
FORCED OUTAGE FACTOR



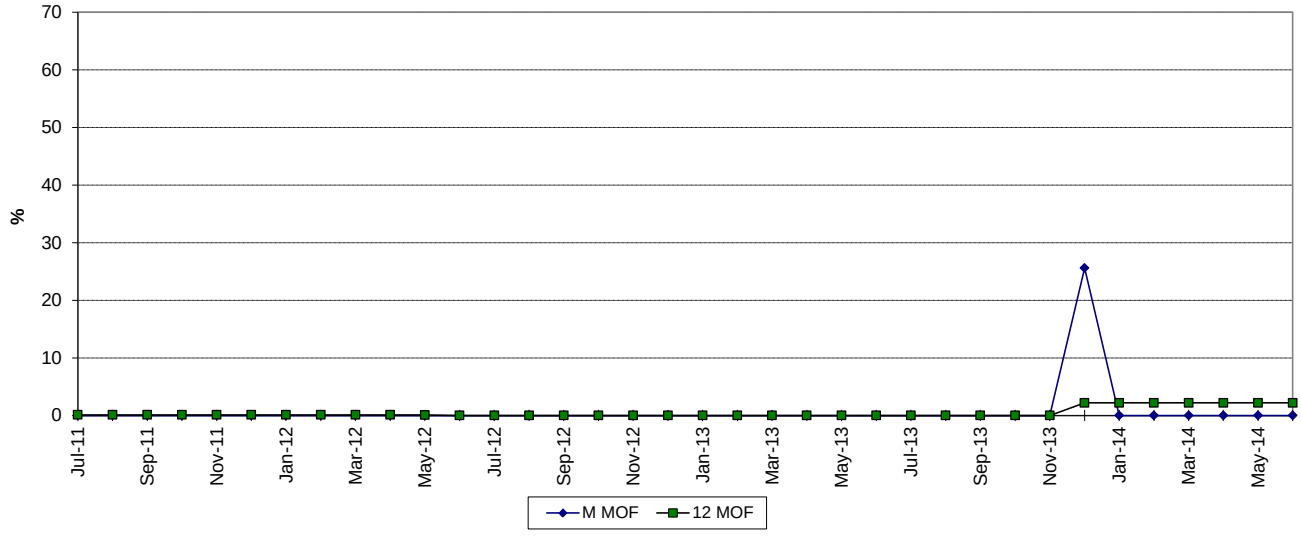
MAINTENANCE OUTAGE FACTOR



ST. LUCIE 1
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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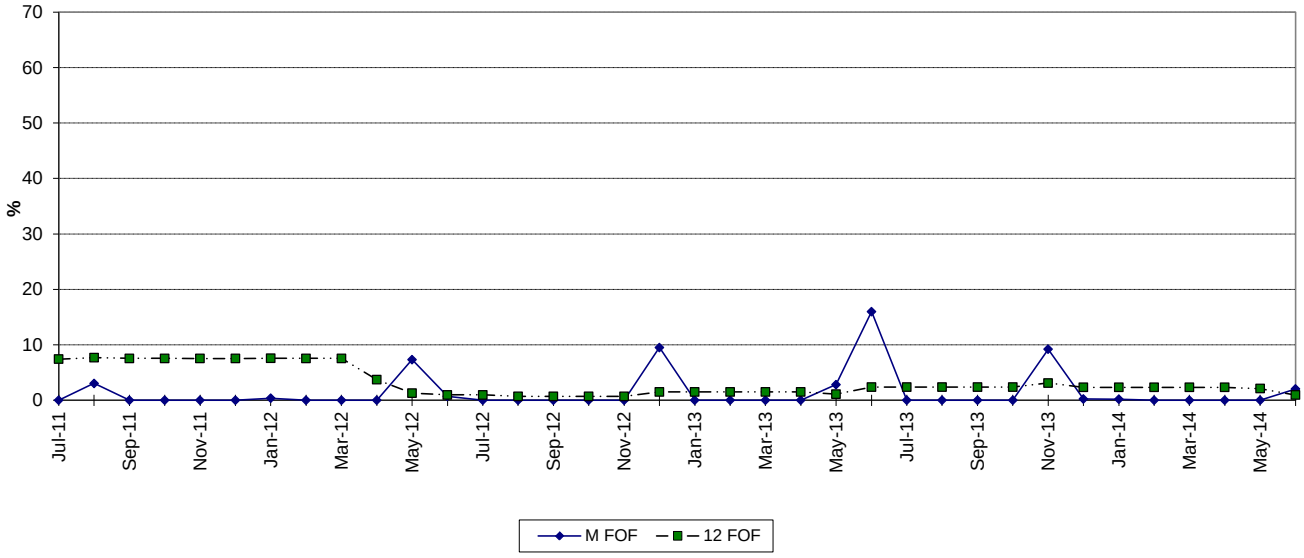
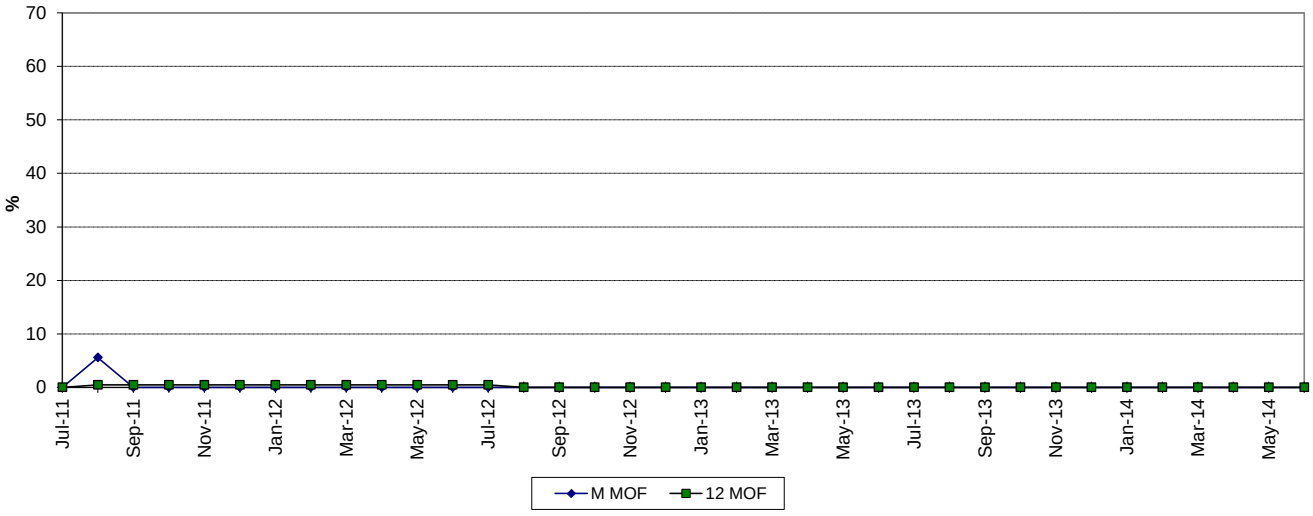
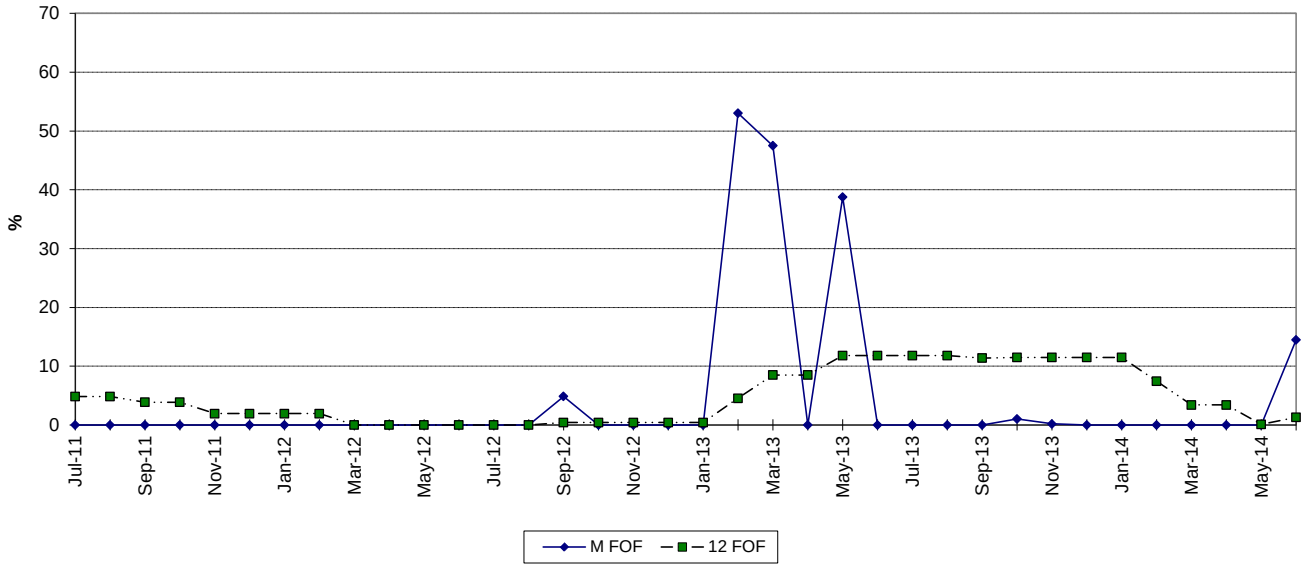
FORCED OUTAGE FACTOR



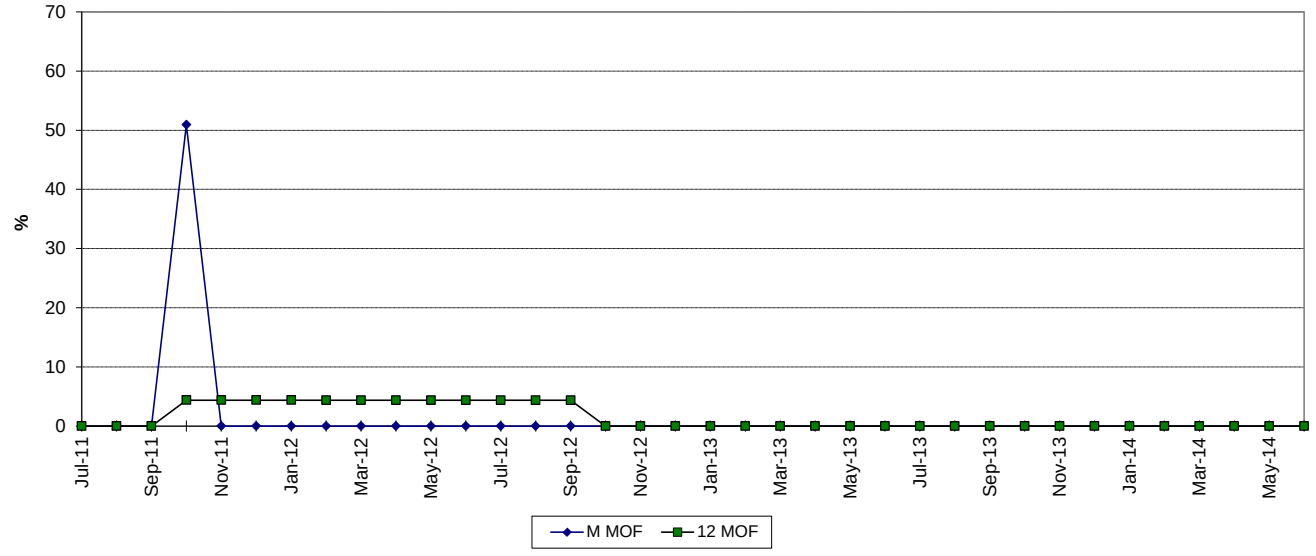
MAINTENANCE OUTAGE FACTOR



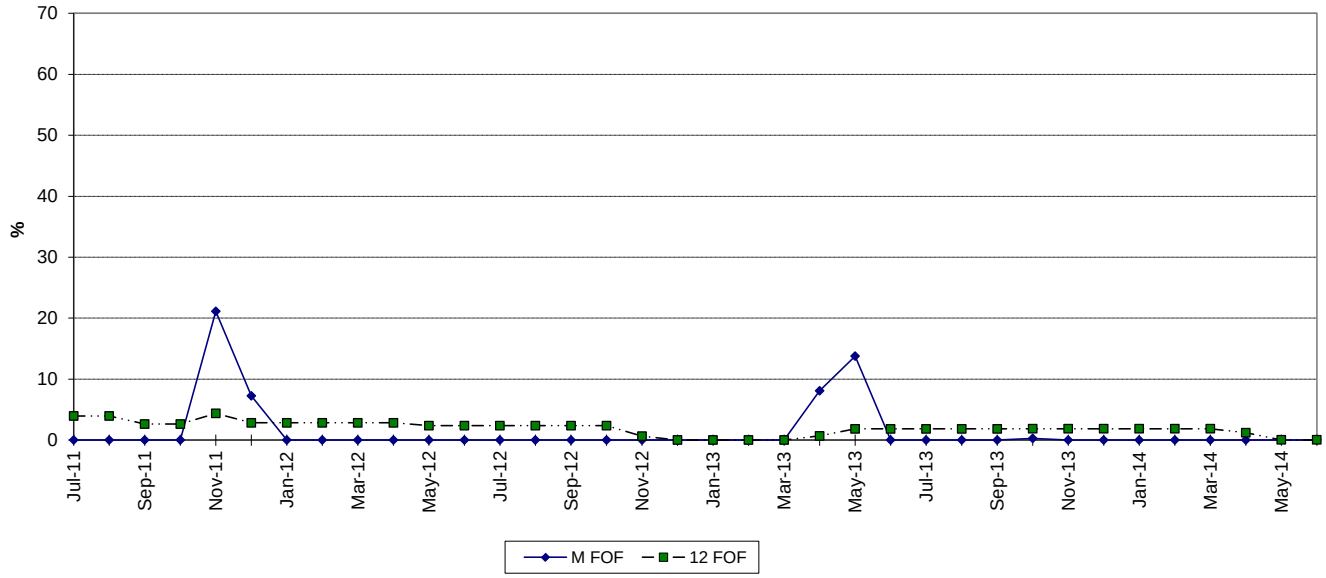
TURKEY POINT 3
FORCED OUTAGE FACTOR



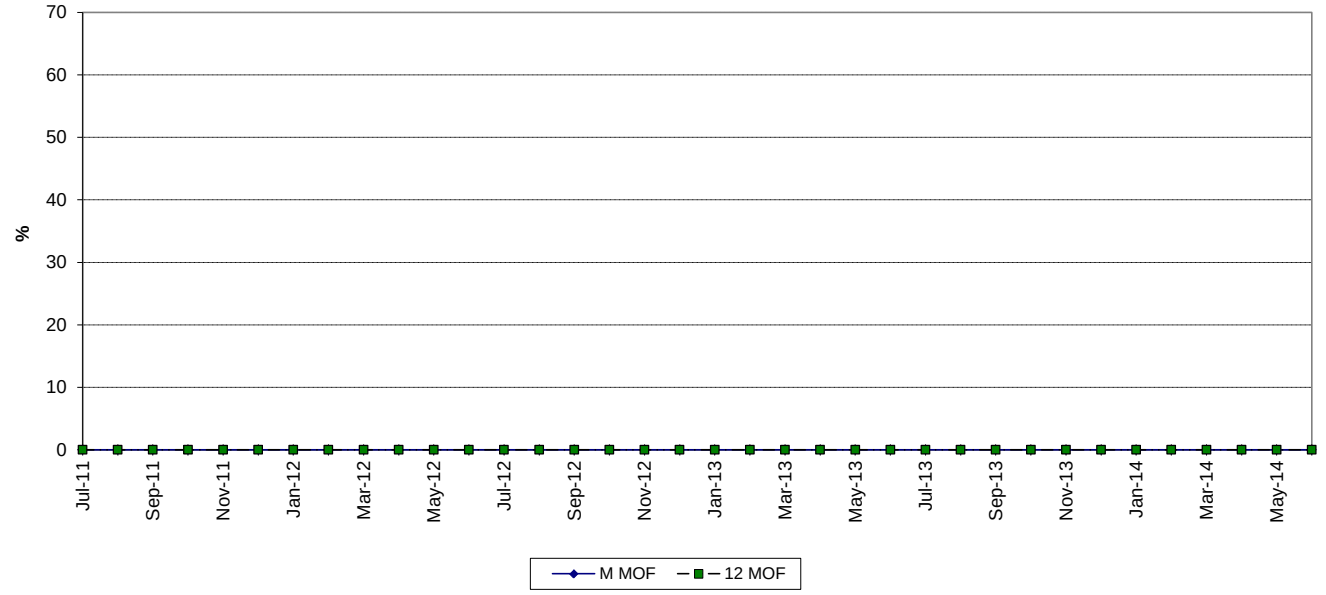
MAINTENANCE OUTAGE FACTOR



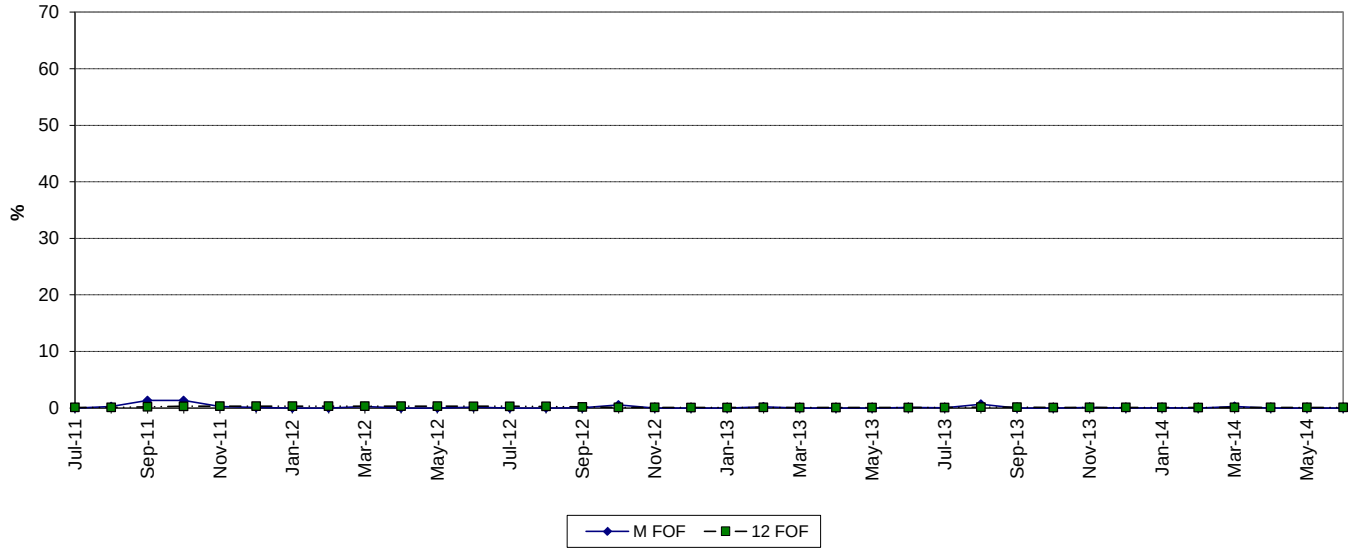
TURKEY POINT 4
FORCED OUTAGE FACTOR



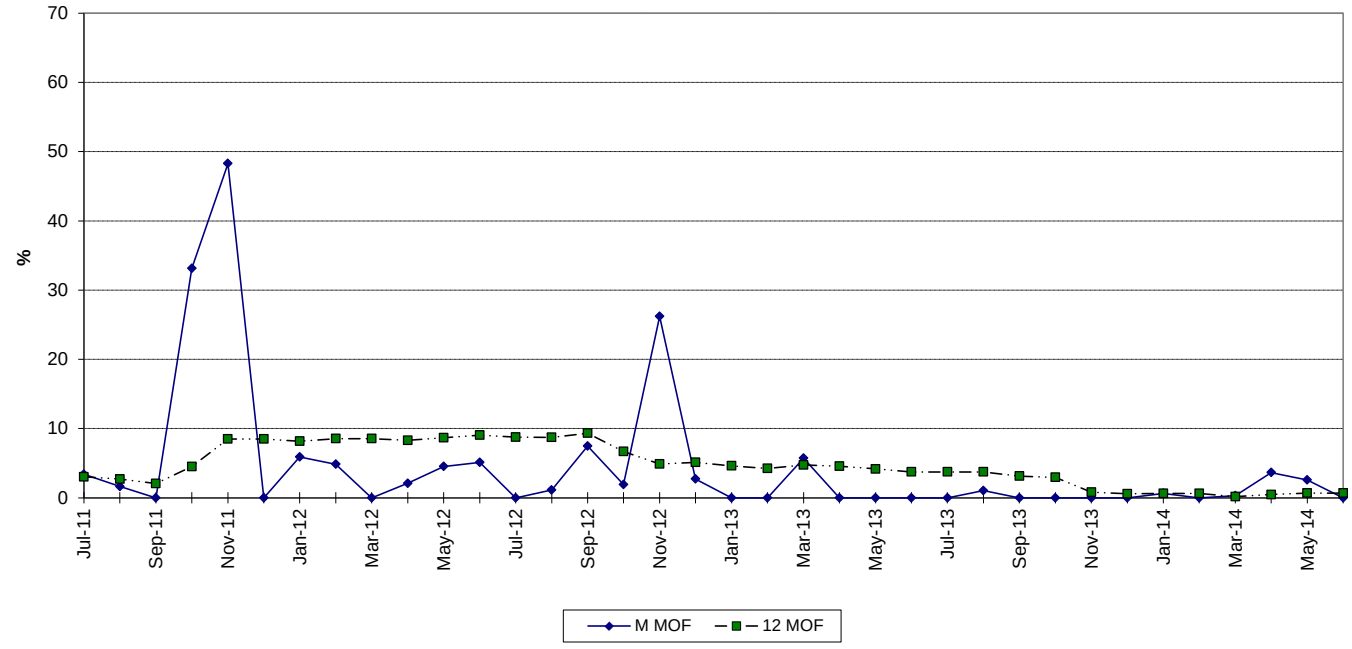
MAINTENANCE OUTAGE FACTOR



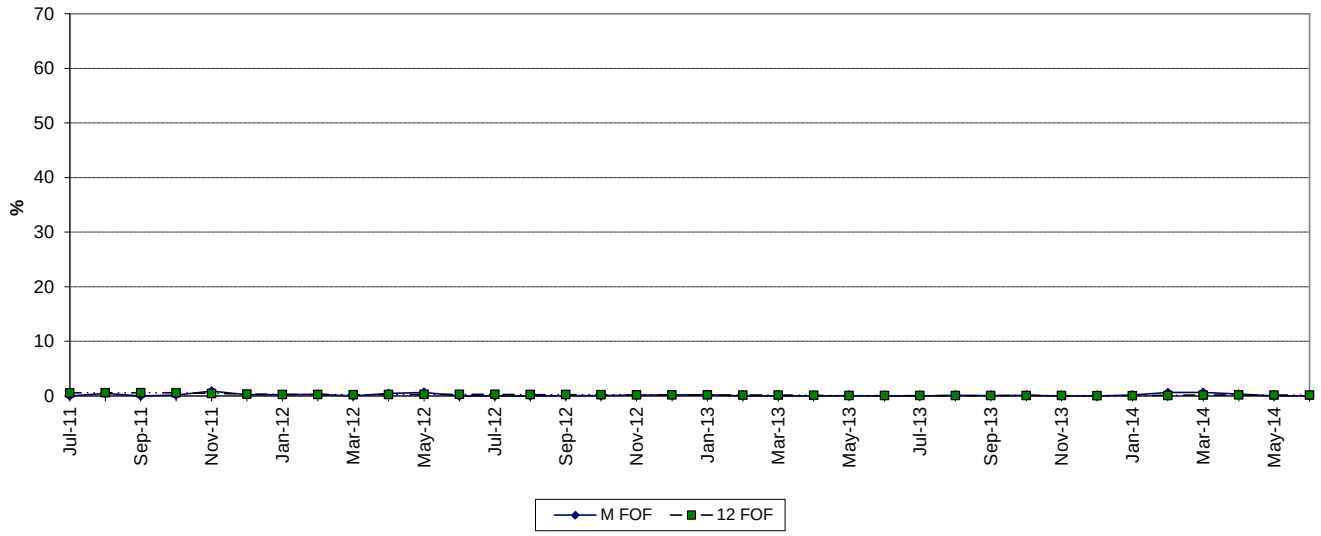
TURKEY POINT 5
FORCED OUTAGE FACTOR



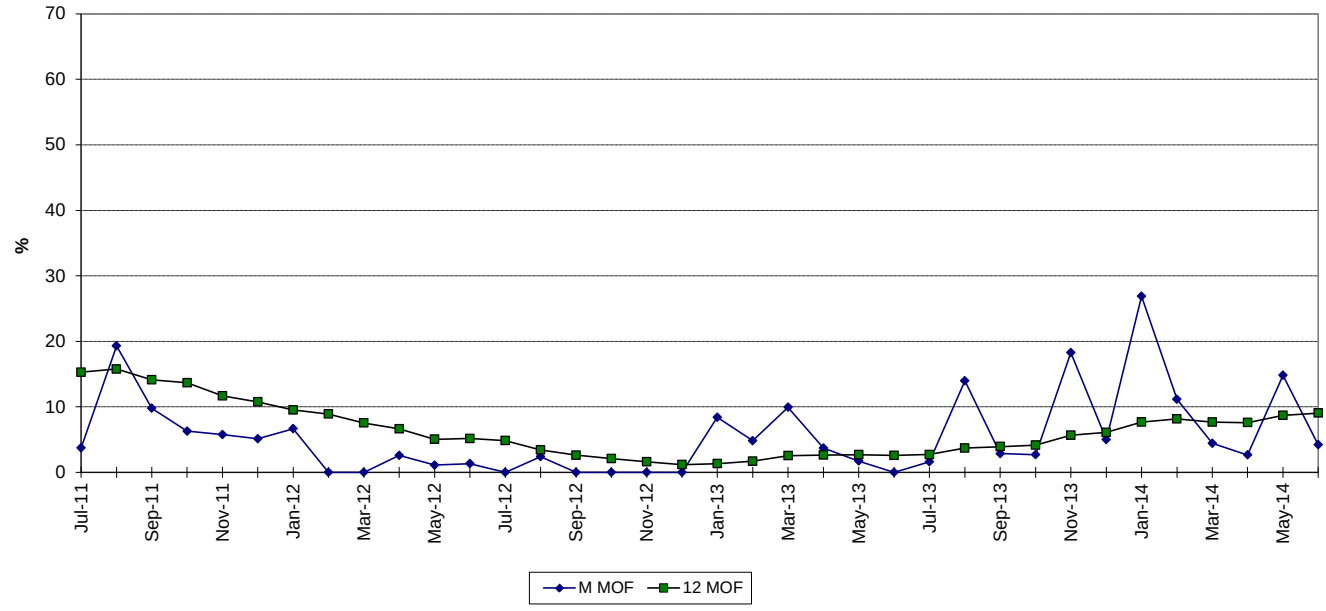
MAINTENANCE OUTAGE FACTOR



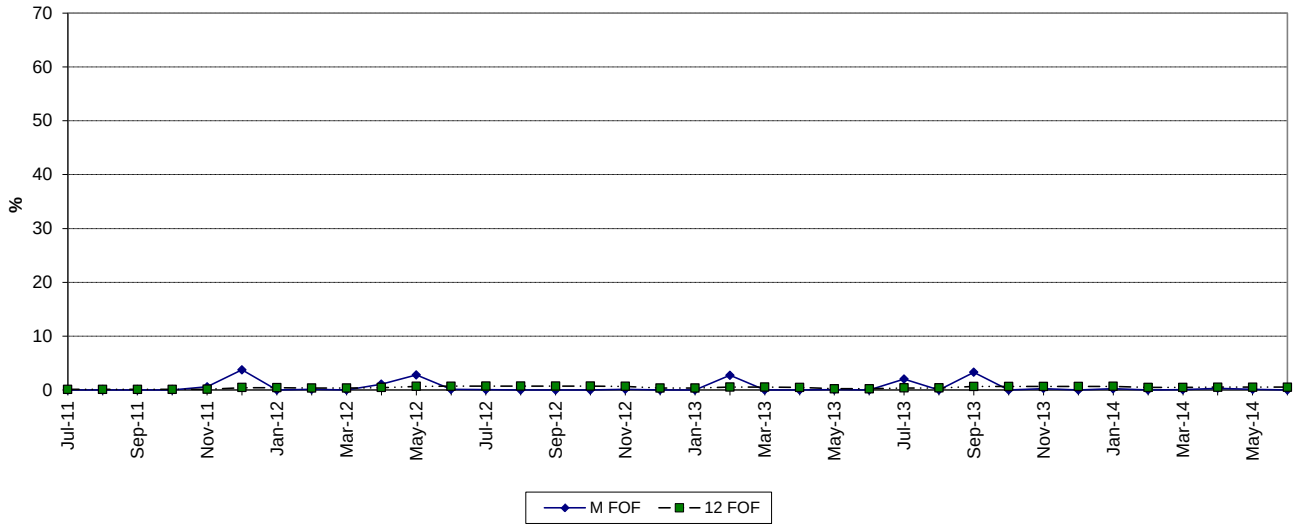
WEST COUNTY 1
FORCED OUTAGE FACTOR



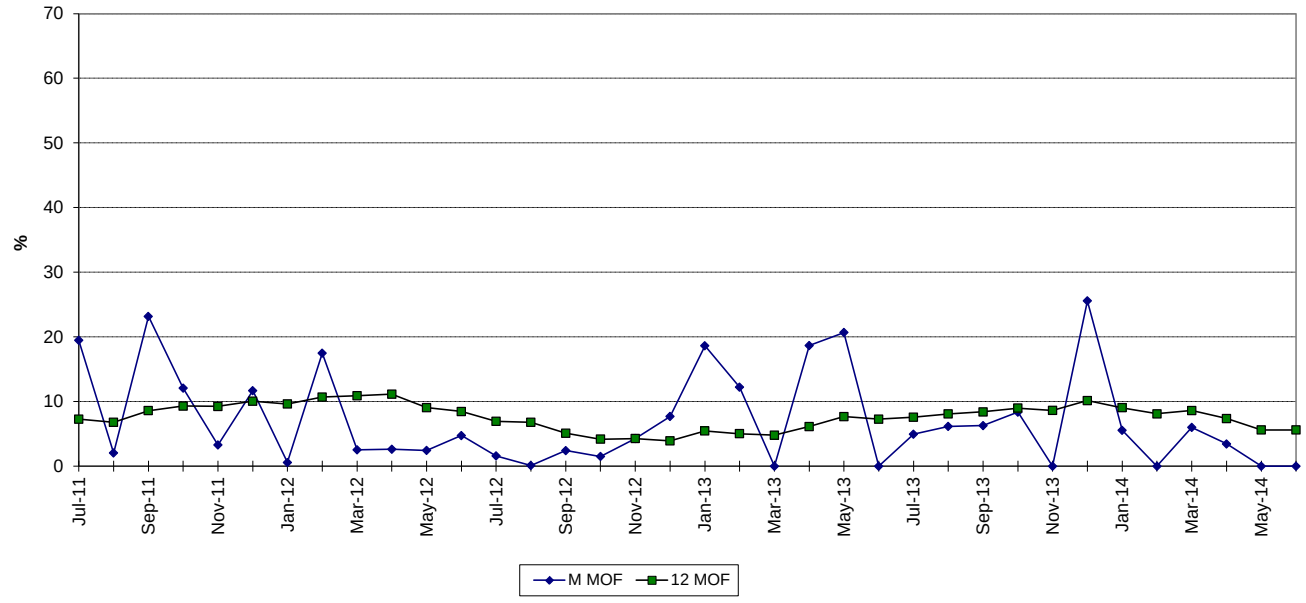
MAINTENANCE OUTAGE FACTOR



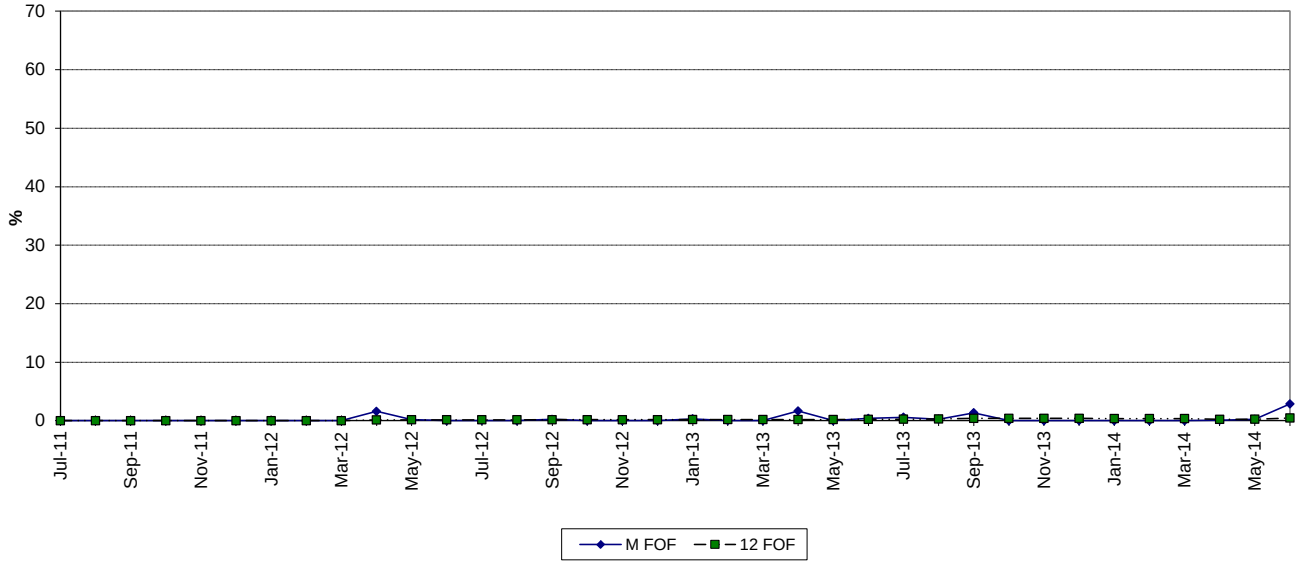
WEST COUNTY 2
FORCED OUTAGE FACTOR



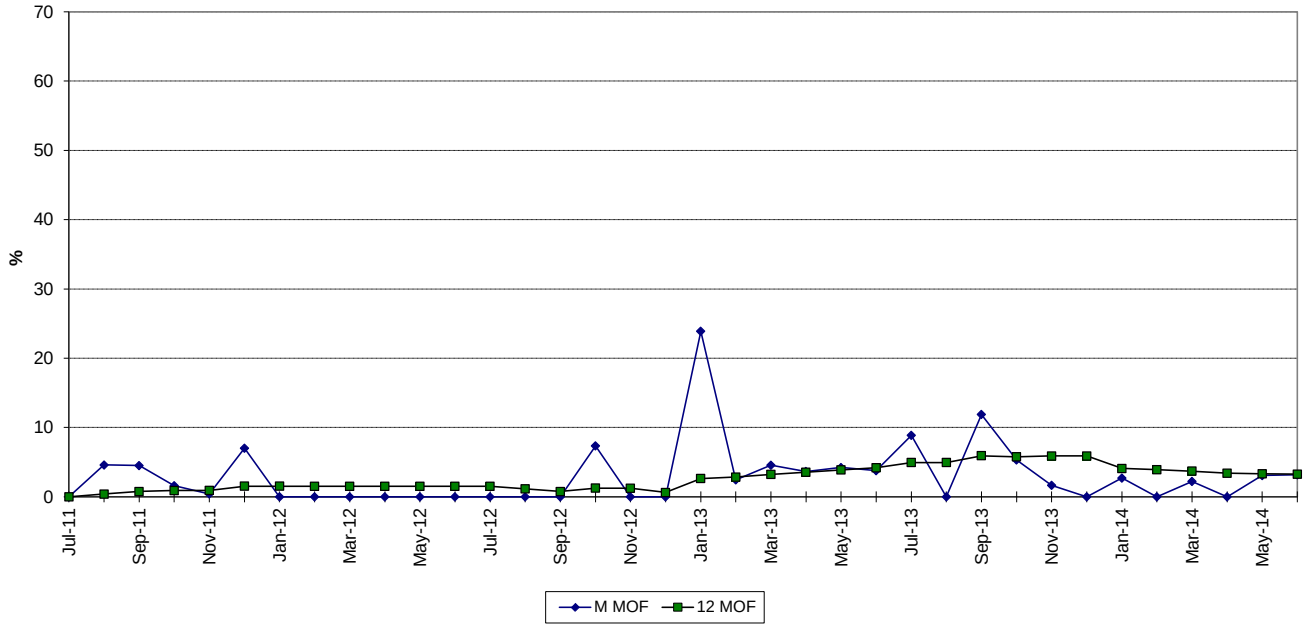
MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2015

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Ft. Myers 2	04/11/2015 - 05/24/2015	CT 2A .04 / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	04/18/2015 - 04/24/2015	BOP INSP -100% CURT	1,366
Ft. Myers 2	04/18/2015 - 05/31/2015	CT 2E .04 / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	05/30/2015 - 07/05/2015	CT 2C .04 / CT MAJ / PKG3 / LPEV / HRSG - 17% CURT	232
Ft. Myers 2	06/06/2015 - 07/19/2015	CT 2F .04 / RTR / CT MAJ / PKG3 / GEN MAJ (REWEDGE) / LPEV / HRSG - 17% CURT	235
Manatee 3	07/13/2015 - 07/19/2015	BOP INSPECTION- 100% CURT	1,078
Manatee 3	07/20/2015 - 07/26/2015	CT 3B HRSG INSP - 25% CURT	270
Manatee 3	07/27/2015 - 08/02/2015	CT 3C HRSG INSP - 25% CURT	270
Martin 8	01/10/2015 - 02/22/2015	CT 8A GENERATOR MAJOR - 25% CURT	287
Martin 8	02/07/2015 - 02/22/2015	BOP - 100% CURT, CT 8C&D MOD CI / HRSG	1,147
Martin 8	02/07/2015 - 03/22/2015	CT 8B GENERATOR MAJOR - 25% CURT	287
St. Lucie 1	03/23/2015 - 04/25/2015	REFUELING	981
St. Lucie 2	09/07/2015 - 10/09/2015	REFUELING	840
Turkey Point 3	10/19/2015 - 11/18/2015	REFUELING	811
Turkey Point 4	NONE		
Turkey Point 5	06/06/2015 - 06/10/2015	BOP - 25% CURT	285
Turkey Point 5	06/06/2015 - 06/12/2015	CT 5A, B & C HRSG INSP - 25% CURT	285
Turkey Point 5	06/13/2015 - 06/19/2015	CT 5D HRSG INSP - 25% CURT	285
West County 1	03/14/2015 - 03/23/2015	BLOCK OUTAGE / CONTROLS UPGRADE - 100% CURT	1,208
West County 2	03/14/2015 - 03/20/2015	BLOCK OUTAGE / CONTROLS UPGRADE - 100% CURT	1,202
West County 2	10/03/2015 - 11/11/2015	CT 2A MAJOR / 24K - 33% CURT	382
West County 2	10/10/2015 - 11/18/2015	CT 2C MAJOR / 24K - 33% CURT	382
West County 2	10/16/2015 - 11/11/2015	ST VALVES / GEN MINOR - 100% CURT	1,159
West County 2	10/16/2015 - 11/24/2015	CT 2B MAJOR / 24K - 33% CURT	382
West County 3	03/07/2015 - 03/20/2015	CT 3B COMB INSP - 33% CURT	398
West County 3	03/14/2015 - 03/20/2015	BLOCK OUTAGE / CONTROLS UPGRADE / BOP - 100% CURT	1,207
West County 3	09/05/2015 - 09/19/2015	CT 3A COMB INSP - 33% CURT	385
West County 3	09/19/2015 - 10/02/2015	CT 3C COMB INSP - 33% CURT	385

*Approximate load reduction MW are based on the unit's estimated MW rating during the outage period

Duke Energy Florida
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January through December 2013

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional Kwh sales - difference	(767,385,169)
2	Non-Jurisdictional Kwh sales - difference	136,131,039
3	Total System Kwh sales - difference Schedule A2, pg 1 of 2, line B3	(631,254,130)
	System:	
4	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C4	$ 22,072,214
	Jurisdictional:	
5	Fuel Revenues - difference Schedule A2, page 2 of 2, line C3	$ 82,636,701
6	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C6 - C12 - C7	16,322,163
7	True Up amount for the period	66,314,538
8	True Up for the prior period Schedule A2, page 2 of 2, lines C9 + C10	(72,210,688)
9	Interest Provision Schedule A2, page 2 of 2, line C8	(64,940)
10	Actual True Up ending balance for the period January 2013 through December 2013 Schedule A2, page 2 of 2, line C13	(5,961,090)
11	Estimated True Up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2013, Docket No. 130001-EI.	(33,195,183)
12	Total True Up for the period January 2013 through December 2013	$ 27,234,093

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 19
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-1T

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2013

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,976)	(2,326,177)	(2,554,581)	(3,037,856)	(5,011,053)	(4,283,713)	(20,261,357)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	19,749,624	16,442,524	18,086,280	16,205,598	18,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(3,726,853)	(980,950)	(1,208,363)	(1,693,142)	(497,107,752)	(1,180,522)	(505,897,583)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	123,947,956	117,806,426	133,320,665	141,650,431	(344,979,200)	184,125,923	355,872,202
B	1	Jurisdictional KWH Sales	2,608,843	2,578,190	2,542,534	2,678,410	3,007,039	3,332,396	16,747,412
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,465
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,898,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	RRSSA Refunds	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,456)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(747,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	91,801,834	90,634,172	89,410,047	94,647,634	107,915,157	120,813,711	595,222,557
	4	Fuel & Net Power Transactions (Line A6)	123,947,956	117,806,426	133,320,665	141,650,431	(344,979,200)	184,125,923	355,872,202
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	123,193,249	117,239,842	132,759,579	140,940,798	(343,976,484)	183,295,699	353,452,683
	6	Over/(Under) Recovery (Line 3 - Line 5)	(31,391,415)	(26,605,670)	(43,349,531)	(46,293,164)	451,891,641	(62,481,988)	241,769,874
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,089	(74,541)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,048)	(26,625,199)	(43,370,900)	(46,314,161)	451,886,539	(62,475,899)	241,695,332
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,819	36,341,728	48,455,637	60,569,547	72,683,456	72,683,456
	11	Subtotal Prior Period True-up	(205,463,690)	(193,349,781)	(181,235,872)	(169,121,962)	(157,008,053)	(144,894,144)	(144,894,144)
	12	Regulatory Accounting Adjustment	0	0	(229,070)	0	37,080	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	(251,380,027)	($282,866,088)	($317,066,340)	$146,971,189	$96,609,198	$96,609,198

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2013

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 140,787,849	$ 156,764,431	$ 144,016,453	$ 123,843,275	$ 105,810,373	$ 113,426,007	$ 1,489,345,986
	2	Fuel Cost of Power Sold	(5,791,581)	(4,126,083)	(4,498,837)	(4,754,695)	(3,820,361)	(2,661,402)	(45,914,316)
	3	Fuel Cost of Purchased Power	12,925,771	13,825,220	11,043,093	8,927,041	4,362,905	6,219,268	118,627,580
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	19,484,721	14,922,235	13,518,916	12,409,944	13,395,961	12,520,463	194,768,082
	4	Energy Cost of Economy Purchases	2,341,535	1,452,499	2,198,163	1,870,099	767,375	631,034	16,754,127
	5	Adjustments to Fuel Cost	(957,291)	(6,906,504)	(554,753)	(993,701)	(1,063,908)	926,244	(515,447,495)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	168,791,004	175,931,800	165,723,035	141,301,964	119,452,345	131,061,614	1,258,133,963
B	1	Jurisdictional KWH Sales	3,558,686	3,478,835	3,700,720	3,384,393	2,942,773	2,803,169	36,615,988
	2	Non-Jurisdictional KWH Sales	22,964	25,100	28,730	26,959	24,277	20,351	249,433
	3	TOTAL SALES (Lines B1 + B2)	3,581,650	3,503,935	3,729,450	3,411,352	2,967,050	2,823,520	36,865,421
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.36%	99.28%	99.23%	99.21%	99.18%	99.28%	99.32%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	131,542,415	128,793,108	137,289,690	124,618,095	106,490,443	102,320,188	1,335,207,737
	1a	RRSSA Refunds	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	130,053,875	127,304,568	135,801,150	123,129,554	105,001,902	100,831,648	1,317,345,253
	4	Fuel & Net Power Transactions (Line A6)	168,791,004	175,931,800	165,723,035	141,301,964	119,452,345	131,061,614	1,258,133,963
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	167,962,308	174,927,088	164,693,638	140,395,957	118,650,545	130,313,147	1,250,395,366
	6	Over/(Under) Recovery (Line 3 - Line 5)	(37,908,433)	(47,622,521)	(28,892,488)	(17,266,402)	(13,648,643)	(29,481,500)	66,949,886
	7	Interest Provision	4,186	2,653	1,346	638	631	147	(64,939)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(37,904,247)	(47,619,868)	(28,891,142)	(17,265,764)	(13,648,012)	(29,481,352)	66,884,947
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,365	96,911,275	109,025,184	121,139,093	133,253,003	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,234)	(120,666,325)	(108,552,416)	(96,438,506)	(84,324,597)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	(443,360)	(635,349)
	13	TOTAL TRUE-UP BALANCE	$70,818,861	$35,312,902	$18,535,670	$13,383,815	$11,849,712	($5,961,090)	(5,961,090)

Duke Energy Florida
Calculation of 2013 Estimated/Actual True-up
For the Period of January through December 2013 (Filed August 2, 2013)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,976)	(2,326,177)	(2,554,581)	(3,037,857)	(5,011,053)	(4,283,713)	(20,261,358)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	19,749,624	16,442,524	18,086,280	16,205,598	18,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(14,542,710)	(11,782,902)	(12,003,796)	(12,497,267)	(507,889,089)	(11,979,214)	(570,694,978)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
B	1	Jurisdictional KWH Sales	2,608,843	2,578,190	2,542,535	2,678,410	3,007,039	3,332,396	16,747,413
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,466
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,898,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,454)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(747,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	81,051,835	79,884,173	78,660,048	83,897,634	97,165,158	110,063,712	530,722,559
	4	Fuel & Net Power Transactions (Line A6)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	112,443,249	106,489,842	122,009,579	130,190,797	(354,726,484)	172,545,699	288,952,682
	6	Over/(Under) Recovery (Line 3 - Line 5)	(31,391,414)	(26,605,669)	(43,349,531)	(46,293,163)	451,891,642	(62,481,988)	241,769,874
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,088	(74,541)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,047)	(26,625,199)	(43,370,900)	(46,314,160)	451,886,539	(62,475,899)	241,695,332
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,818	36,341,727	48,455,636	60,569,545	72,683,454	72,683,454
	11	Subtotal Prior Period True-up	(205,463,691)	(193,349,782)	(181,235,873)	(169,121,964)	(157,008,055)	(144,894,146)	(144,894,146)
	12	Regulatory Accounting Adjustment	0	0	(229,070)	0	37,080	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	($251,380,027)	($282,866,088)	($317,066,339)	$146,971,190	$96,609,198	96,609,196

Duke Energy Florida
Calculation of 2013 Estimated/Actual True-up
For the Period of January through December 2013 (Filed August 2, 2013)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 145,250,812	$ 150,607,717	$ 136,985,940	$ 114,538,238	$ 107,075,208	$ 108,923,607	$ 1,468,079,120
	2	Fuel Cost of Power Sold	(5,569,460)	(5,527,090)	(5,386,128)	(4,969,913)	(3,255,666)	(2,375,290)	(47,344,905)
	3	Fuel Cost of Purchased Power	23,957,592	25,094,990	21,710,075	18,555,272	9,554,987	6,499,016	166,696,213
	3a	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0
	3b	Energy Payments to Qualified Facilities	18,004,359	13,089,077	12,644,871	11,903,930	12,657,284	15,760,883	192,576,244
	4	Energy Cost of Economy Purchases	1,756,060	1,775,447	1,776,669	1,742,573	915,791	706,536	16,166,498
	5	Adjustments to Fuel Cost	(10,817,565)	(10,821,916)	(10,826,271)	(10,828,450)	(10,827,360)	(10,816,477)	(635,633,018)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
B	1	Jurisdictional KWH Sales	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,683,127
	2	Non-Jurisdictional KWH Sales	18,864	21,241	22,661	20,547	17,439	14,034	215,839
	3	TOTAL SALES (Lines B1 + B2)	3,602,269	3,770,211	3,774,900	3,298,134	2,858,604	2,746,382	36,898,966
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.48%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	132,431,293	138,550,051	138,670,863	121,129,229	105,000,455	100,978,923	1,340,914,612
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,913)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	120,192,753	126,311,511	126,432,323	108,890,689	92,761,915	88,740,380	1,194,052,129
	4	Fuel & Net Power Transactions (Line A6)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
	6	Over/(Under) Recovery (Line 3 - Line 5)	(51,749,146)	(47,190,956)	(29,765,347)	(21,434,318)	(22,823,112)	(29,529,673)	39,277,324
	7	Interest Provision	3,842	1,974	656	(18)	(519)	(1,222)	(69,829)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(51,745,304)	(47,188,981)	(29,764,691)	(21,434,336)	(22,823,632)	(29,530,896)	39,207,494
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,363	96,911,272	109,025,181	121,139,090	133,252,999	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,237)	(120,666,328)	(108,552,419)	(96,438,510)	(84,324,601)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	$56,977,803	$21,902,730	$4,251,948	($5,068,478)	($15,778,201)	($33,195,184)	(33,195,183)

Duke Energy Florida
Fuel and Net Power Cost Variance Analysis
January through December 2013

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	2,216,309	(1,558,362)	2,755,764	3,413,711
2	Light Oil	18,957,474	(21,625,917)	(1,306,955)	(3,975,398)
3	Coal	22,277,893	3,117,476	29,567,156	54,962,525
4	Gas	(20,755,302)	22,720,535	71,375,628	73,340,861
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	22,696,374	2,653,732	102,391,593	127,741,699
8	Firm Purchases	(71,978,016)	0	(7,151,352)	(79,129,368)
9	Economy Purchases	9,836,545	0	(4,179,174)	5,657,371
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	23,475,347	0	9,344,448	32,819,795
12	Total Purchases	(38,666,124)	0	(1,986,078)	(40,652,202)
13	Economy Sales	0	0	0	0
14	Other Power Sales	760,020	0	97,312	857,332
15	Supplemental Sales	(875,163)	0	(6,542,399)	(7,417,562)
16	Total Sales	(115,143)	0	(6,445,087)	(6,560,230)
17	Nuclear Fuel Disposal Cost	0	0	0	0
18	Nuclear Decom & Decon	0	0	0	0
	Other Jurisdictional Adjustments:				
19a	Final NEIL Adjustment	0	0	(164,713,428)	(164,713,428)
19b	Sch A2 Page 1 of 2 Line 6b, excl NEIL	0	0	106,256,374	106,256,374
20	Total Fuel and Net Power Cost Variance	(16,084,893)	2,653,732	35,503,374	22,072,213

Docket: 140001-EI
Witness: Foster
Exhibit: TGF-1T (Sheet 7 of 7)

Duke Energy Florida
Summary of Revised and Restated Settlement Agreement (RRSSA) Adjustments
For the Period of January through December 2013

System:	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	12 Month Period	Schedule Reference	RRSSA Paragraph
1 Final NEIL Reimbursement	-	-	-	-	(492,313,428)	-	-	-	-	-	-	-	(492,313,428)		7.c. / 7.d.
2 Other Adjustments to Fuel Cost	(3,726,853)	(980,950)	(1,208,363)	(1,693,142)	(4,794,324)	(1,180,522)	(957,291)	(6,906,504)	(554,753)	(993,701)	(1,063,908)	926,244	(23,134,067)		
3 Total 2013 Adjustments to Fuel Cost (Lines 1 + 2)	(3,726,853)	(980,950)	(1,208,363)	(1,693,142)	(497,107,752)	(1,180,522)	(957,291)	(6,906,504)	(554,753)	(993,701)	(1,063,908)	926,244	(515,447,495)	E1-B, line A5	
4 Jurisdictional % of Total Sales	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.36%	99.28%	99.23%	99.21%	99.18%	99.28%			

Retail:	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	12 Month Period	Schedule Reference	RRSSA Paragraph
5 Final NEIL Reimbursement (Line 1 * 4)	-	-	-	-	(490,147,249)	-	-	-	-	-	-	-	(490,147,249)		7.c. / 7.d.
6 Other Adjustments to Fuel Cost (Line 2 * 4)	(3,699,647)	(974,770)	(1,201,475)	(1,682,136)	(4,773,229)	(1,173,439)	(951,164)	(6,856,777)	(550,481)	(985,851)	(1,055,184)	919,575	(22,984,580)		
7 Total 2013 Adjustments to Fuel Cost (Lines 5 +6)	(3,699,647)	(974,770)	(1,201,475)	(1,682,136)	(494,920,478)	(1,173,439)	(951,164)	(6,856,777)	(550,481)	(985,851)	(1,055,184)	919,575	(513,131,829)		
8 RRSSA Refund (1st 50% of $258 million)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(129,000,000)	E1-B, line C1a	6.a.
9 Total 2013 RRSSA Adjustments & Refunds (Lines 5 + 8)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(500,897,249)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(619,147,249)		

Duke Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2013

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 46	$ 518,070,756	$ 527,802,715	$ (9,731,959)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 42	539,122,320	$ 527,802,715	$ 11,319,605
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 49	(30,138)	0	(30,138)
4	Sub Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 50	$ (21,081,701)	$ -	$ (21,081,701)
5	Prior Period True-up - January through December 2013- Over/(Under) Recovery Sheet 2 of 3, Line 51	(20,253,873)	(10,485,623)	(9,768,250)
6	Prior Period True-up - January through December 2013 - (Refunded)/Collected Sheet 2 of 3, Line 52	10,485,623	10,485,623	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2013 Sheet 2 of 3, Line 55	$ (30,849,951)	$ -	$ (30,849,951)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2013 Docket No. 130001-EI. (Sheet 3 of 3, Line 54)	(24,360,251)		
9	Total Over/(Under) Recovery for the period January through December 2013 (Line 7 - Line 8)	$ (6,489,700)		

Duke Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2013

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 46	$ 518,070,756	$ 527,802,715	$ (9,731,959)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 42	539,122,320	$ 527,802,715	$ 11,319,605
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 49	(30,138)	0	(30,138)
4	Sub Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 50	$ (21,081,701)	$ -	$ (21,081,701)
5	Prior Period True-up - January through December 2013- Over/(Under) Recovery Sheet 2 of 3, Line 51	(20,253,873)	(10,485,623)	(9,768,250)
6	Prior Period True-up - January through December 2013 - (Refunded)/Collected Sheet 2 of 3, Line 52	10,485,623	10,485,623	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2013 Sheet 2 of 3, Line 55	$ (30,849,951)	$ -	$ (30,849,951)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2013 Docket No. 130001-EI. (Sheet 3 of 3, Line 54)	(24,360,251)		
9	Total Over/(Under) Recovery for the period January through December 2013 (Line 7 - Line 8)	$ (6,489,700)		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 20
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-2T

Duke Energy Florida
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January Through December 2013

		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	Auburndale Power Partners, L.P. (AUBRDLFC)	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	9,896,040
3	Auburndale Power Partners, L.P. (AUBSET)	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,107
4	Lake County (LAKCOUNT)	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
5	Lake Cogen Limited (LAKORDER)	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	(3,735,759)	0	0	0	26,150,313
6	Metro-Dade County (METRDADE)	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	0	15,424,530
7	Orange Cogen (ORANGECO)	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,864,442	35,397,001
8	Orlando Cogen Limited (ORLACOGL)	2,951,657	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,625,197
9	Pasco County Resource Recovery (PASCOUNT)	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
10	Pinellas County Resource Recovery (PINCOUNT)	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
11	Polk Power Partners, L.P. (MULBERRY)	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,530
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	797,588	800,946	777,222	794,026	799,869	794,685	775,904	766,360	757,005	748,432	747,065	738,019	9,297,120
13	Southern - Scherer	1,716,577	1,716,976	1,717,736	1,740,639	2,398,835	1,599,329	1,719,821	1,719,994	1,719,962	1,719,652	1,719,207	1,718,003	21,206,729
14	Subtotal - Base Level Capacity Charges	29,193,876	29,125,389	29,102,424	29,142,132	29,806,171	29,001,481	29,103,191	29,093,820	21,612,916	25,339,792	25,337,979	23,832,437	329,691,607
15	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%	
16	Base Level Jurisdictional Capacity Charges	27,116,731	27,053,117	27,031,787	27,068,669	27,685,462	26,938,026	27,032,499	27,023,795	20,075,157	23,536,866	23,535,182	22,136,759	306,234,049
17	**Intermediate Production Level Capacity Charges:**													
18	Southern - Franklin	3,053,631	3,057,021	3,056,255	3,541,434	3,052,407	2,469,707	3,057,990	3,058,836	3,347,787	2,987,604	3,054,763	3,049,115	36,786,551
19	Schedule H Capacity Sales-NSB	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
20	Subtotal - Intermediate Level Capacity Charges	3,038,839	3,042,229	3,041,463	3,526,642	3,037,615	2,454,915	3,043,198	3,044,044	3,332,995	2,972,812	3,039,971	3,034,323	36,609,047
21	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%	
22	Intermediate Level Jurisdict. Capacity Charges	2,209,327	2,211,792	2,211,235	2,563,975	2,208,437	1,784,797	2,212,497	2,213,111	2,423,188	2,161,323	2,210,150	2,206,044	26,615,875
23	**Peaking Production Level Capacity Charges:**													
24	Chattahoochee Capacity Purchase	12,500	11,290	13,710	12,231	12,769	12,231	12,769	12,231	12,769	12,500	12,097	12,903	150,000
25	Vandolah Capacity - Northern Star	0	0	0	0	0	0	0	0	0	0	0	0	-
26	Reliant - Vandolah Capacity Purchase	2,925,728	2,887,475	1,965,866	1,940,723	2,792,514	5,785,174	5,804,782	5,741,880	2,742,123	1,930,080	2,026,347	2,961,032	39,503,724
27	Shady Hills Power Company LLC	1,965,615	1,973,145	1,406,700	1,363,500	1,908,900	3,840,480	3,855,600	3,855,600	1,799,280	1,352,700	1,352,700	1,954,260	26,628,480
28	Subtotal -Peaking Level Capacity Charges	4,903,844	4,871,910	3,386,276	3,316,454	4,714,183	9,637,884.90	9,673,152	9,609,711	4,554,172	3,295,280	3,391,144	4,928,196	66,282,204
29	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%	
30	Peaking Level Jurisdictional Capacity Charges	4,703,963	4,673,331	3,248,251	3,181,275	4,522,033	9,245,045	9,278,874	9,218,019	4,368,544	3,160,964	3,252,921	4,727,322	63,580,542
31	**Other Capacity Charges:**													
32	Retail Wheeling	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(1,284)	0	0	(2,080)	(3,730)	(3,519)	(38,728)
33	Total Other Capacity Charges	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(1,284)	0	0	(2,080)	(3,730)	(3,519)	(38,728)
34														
35	**Subtotal Jurisdictional Capacity Charges (lines 16+22+30+33)**	34,028,038	33,936,646	32,474,900	32,806,333	34,415,695	37,967,523	38,522,586	38,454,925	26,866,888	28,857,074	28,994,523	29,066,606	396,391,738
36														
37	**Nuclear Cost Recovery Clause Charges:**													
38	Levy Costs	8,475,072	11,483,103	8,258,947	8,021,598	8,162,758	8,305,060	8,248,615	8,312,931	8,330,438	8,271,575	8,179,250	8,647,553	102,696,902
39	CR-3 Uprate Costs	3,358,869	3,354,735	3,350,601	3,346,468	3,342,335	3,338,203	3,334,071	3,329,940	3,325,809	3,321,678	3,317,548	3,313,419	40,033,676
40	**Total NCRC Costs - Order No. PSC-12-0650-FOF-EI**	11,833,942	14,837,838	11,609,549	11,368,066	11,505,094	11,643,262	11,582,686	11,642,871	11,656,247	11,593,253	11,496,798	11,960,972	142,730,578
41														
42	**Total Jurisdictional Capacity Charges (Lines 35 + 40)**	45,861,980	48,774,485	44,084,449	44,174,399	45,920,790	49,610,786	50,105,272	50,097,797	38,523,135	40,450,328	40,491,322	41,027,578	539,122,320
43	**Capacity Revenues:**													
44	Capacity Cost Recovery Revenues (net of tax)	37,233,908	36,928,525	36,311,578	38,376,446	43,163,088	48,265,348	52,139,032	50,676,040	54,221,432	49,358,824	42,051,129	39,831,029	528,556,379
45	Prior Period True-Up Provision	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(10,485,623)
46	Current Period CCR Revenues (net of tax)	36,360,106	36,054,723	35,437,776	37,502,644	42,289,286	47,391,546	51,265,231	49,802,238	53,347,630	48,485,022	41,177,327	38,957,227	518,070,756
47	**True-Up Provision - Current Year (Acct 1823203/2543203)**													
48	True-Up Provision - Over/(Under) Recov (line 46-line 42)	(9,501,873)	(12,719,761)	(8,646,672)	(6,671,755)	(3,631,504)	(2,219,239)	1,159,958	(295,558)	14,824,495	8,034,695	686,005	(2,070,351)	(21,051,564)
49	Interest Provision for the Month	(1,425)	(2,785)	(3,569)	(3,599)	(3,341)	(2,887)	(2,870)	(2,805)	(2,398)	(1,427)	(1,522)	(1,512)	(30,138)
50	Total current month over/(under) recovery (Acct 4560097,5572001)	(9,503,298)	(22,225,843)	(30,876,085)	(37,551,438)	(41,186,284)	(43,408,410)	(42,251,322)	(42,549,685)	(27,727,588)	(19,694,320)	(19,009,836)	(21,081,699)	(21,081,702)
51	Prior Year True-Up & Interest Prov. (Begin Bal)-Over/(Under)	(20,253,873)	(19,380,071)	(18,506,269)	(17,632,467)	(16,758,665)	(15,884,863)	(15,011,062)	(14,137,260)	(13,263,458)	(12,389,656)	(11,515,854)	(10,642,052)	(20,253,873)
52	Prior YearTrue-Up Collected/(Refunded)	873,802	873,802	873,802	873,802	873,802	873,802	873,802	873,802	873,802	873,802	873,802	873,802	10,485,623
53	Prior Year True-Up & Interest Provision End Bal - (DR)/CR	(19,380,071)	(18,506,269)	(17,632,467)	(16,758,665)	(15,884,863)	(15,011,062)	(14,137,260)	(13,263,458)	(12,389,656)	(11,515,854)	(10,642,052)	(9,768,251)	(9,768,250)
54														
55	**Net Capacity True-up Over/(Under) (lines 50+53)**	($28,883,369)	($40,732,112)	($48,508,552)	($54,310,104)	($57,071,147)	($58,419,472)	($56,388,582)	($55,813,143)	($40,117,244)	($31,210,174)	($29,651,889)	($30,849,949)	($30,849,951)

Duke Energy Florida
Capacity Cost Recovery Clause
Calculation of Estimated/Actual True-Up
January- December 2013 (Filed 08/02/2013)

		ACT Jan-13	ACT Feb-13	ACT Mar-13	ACT Apr-13	ACT May-13	ACT Jun-13	EST Jul-13	EST Aug-13	EST Sep-13	EST Oct-13	EST Nov-13	EST Dec-13	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$9,896,040
3	Auburndale Power Partners, L.P. (AUBSET)	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,107
4	Lake County (LAKCOUNT)	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
5	Lake Cogen Limited (LAKORDER)	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	-	-	-	-	-	26,150,313
6	Metro-Dade County (METRDADE)	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	-	15,424,530
7	Orange Cogen (ORANGECO)	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	35,490,064
8	Orlando Cogen Limited (ORLACOGL)	2,951,657	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,625,199
9	Pasco County Resource Recovery (PASCOUNT)	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
10	Pinellas County Resource Recovery (PINCOUNT)	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,529
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	797,588	800,946	777,222	794,026	799,869	794,685	800,946	800,946	800,946	800,946	800,946	800,946	9,570,012
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Southern - Scherer	1,716,577	1,716,976	1,717,736	1,740,639	2,398,835	1,599,329	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	20,061,811
15	Subtotal - Base Level Capacity Costs	29,193,876	29,125,389	29,102,424	29,142,132	29,806,171	29,001,481	28,937,033	25,201,274	25,201,274	25,201,274	25,201,274	23,799,044	328,912,645
16	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%	
17	Base Level Jurisdictional Capacity Costs	27,116,731	27,053,117	27,031,787	27,068,669	27,685,462	26,938,026	26,878,163	23,408,203	23,408,203	23,408,203	23,408,203	22,105,742	305,510,510
18	**Intermediate Production Level Capacity Costs**													
19	Southern - Franklin	3,053,631	3,057,021	3,056,255	3,541,434	3,052,407	2,469,707	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	31,208,455
20	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Intermediate Level Capacity Costs	3,038,839	3,042,229	3,041,463	3,526,642	3,037,615	2,454,915	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	31,030,951
23	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%	
24	Intermediate Level Jurisdictional Capacity Costs	2,209,327	2,211,792	2,211,235	2,563,975	2,208,437	1,784,797	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	22,560,432
25	**Peaking Production Level Capacity Costs**													
26	Chattahoochee	12,500	11,290	13,710	12,231	12,769	12,231	12,231	12,231	12,231	12,231	12,231	12,231	148,115
27	Vandolah (RRI)	2,925,728	2,887,475	1,965,866	1,940,723	2,792,514	5,785,174	-	-	-	-	-	-	18,297,480
28	Shady Hills Power Company LLC	1,965,615	1,973,145	1,406,700	1,363,500	1,908,900	3,840,480	3,881,947	3,881,947	1,811,575	1,363,927	1,363,927	1,968,252	26,729,915
29	Vandolah (NSG)	-	-	-	-	-	-	5,471,609	5,427,124	2,561,202	1,868,354	1,912,839	2,719,493	19,960,621
30	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal - Peaking Level Capacity Costs	4,903,844	4,871,910	3,386,276	3,316,454	4,714,183	9,637,885	9,365,786	9,321,302	4,385,008	3,244,512	3,288,997	4,699,976	65,136,132
32	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%	
33	Peaking Level Jurisdictional Capacity Costs	4,703,963	4,673,331	3,248,251	3,181,275	4,522,033	9,245,045	8,984,037	8,941,365	4,206,275	3,112,266	3,154,937	4,508,405	62,481,183
34	**Other Capacity Costs**													
35	Retail Wheeling	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
36	Other Jurisdictional Capacity Costs	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
37	**Subtotal Jurisd Capacity Costs (Line 17+24+33+36)**	34,028,038	33,936,646	32,474,900	32,806,333	34,415,695	37,967,523	37,404,972	33,901,635	29,174,072	28,070,933	28,122,434	28,174,418	390,477,600
38	**Nuclear Cost Recovery Clause Costs**													
39	Levy Costs	8,475,072	11,483,103	8,258,947	8,021,598	8,162,758	8,305,060	8,248,615	8,312,931	8,330,438	8,271,575	8,179,250	8,647,553	102,696,902
40	CR3 Uprate Costs	3,358,869	3,354,735	3,350,601	3,346,468	3,342,335	3,338,203	3,334,071	3,329,940	3,325,809	3,321,678	3,317,548	3,313,419	40,033,676
41	**Total NCRC Costs - Order No. PSC-12-0650-FOF-EI**	11,833,942	14,837,838	11,609,549	11,368,066	11,505,094	11,643,262	11,582,686	11,642,871	11,656,247	11,593,253	11,496,798	11,960,972	142,730,579
42	**Total Jurisdictional Capacity Costs (Line 37+41)**	45,861,980	48,774,484	44,084,448	44,174,399	45,920,789	49,610,786	48,987,658	45,544,506	40,830,319	39,664,187	39,619,232	40,135,390	533,208,179
43	**Capacity Revenues**													
44	Capacity Cost Recovery Revenues (net of tax)	37,233,908	36,928,525	36,311,578	38,376,446	43,163,088	48,265,348	51,923,538	54,322,575	54,369,943	47,492,236	41,168,481	39,591,723	529,147,389
45	Prior Period True-Up Provision Over/(Under) Recovery	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(10,485,622)
46	**Current Period Revenues (net of tax)**	36,360,106	36,054,723	35,437,776	37,502,644	42,289,286	47,391,546	51,049,737	53,448,773	53,496,141	46,618,434	40,294,679	38,717,921	518,661,767
47	**True-Up Provision**													
48	True-Up Provision - Over/(Under) Recov (Line 46-42)	(9,501,874)	(12,719,761)	(8,646,672)	(6,671,755)	(3,631,503)	(2,219,239)	2,062,079	7,904,267	12,665,822	6,954,247	675,447	(1,417,469)	(14,546,411)
49	Interest Provision for the Month	(1,425)	(2,785)	(3,569)	(3,599)	(3,341)	(2,887)	(3,211)	(3,791)	(4,374)	(4,955)	(5,533)	(6,120)	(45,590)
50	Current Cycle Balance - Over/(Under)	(9,503,299)	(22,225,844)	(30,876,086)	(37,551,439)	(41,186,284)	(43,408,410)	(41,349,542)	(33,449,066)	(20,787,618)	(13,838,326)	(13,168,412)	(14,592,001)	(14,592,001)
51	Prior Period Balance - Over/(Under) Recovered	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)
52	Prior Period Cumulative True-Up Collected/(Refunded)	873,802	1,747,604	2,621,405	3,495,207	4,369,009	5,242,811	6,116,613	6,990,415	7,864,216	8,738,018	9,611,820	10,485,622	10,485,622
53	Prior Period True-up Balance - Over/(Under)	(19,380,070)	(18,506,268)	(17,632,466)	(16,758,664)	(15,884,862)	(15,011,061)	(14,137,259)	(13,263,457)	(12,389,655)	(11,515,853)	(10,642,051)	(9,768,250)	(9,768,250)
54	**Net Capacity True-up Over/(Under) (Line 50+53)**	($28,883,369)	($40,732,112)	($48,508,552)	($54,310,104)	($57,071,146)	($58,419,471)	($55,486,800)	($46,712,523)	($33,177,273)	($25,354,180)	($23,810,464)	($24,360,251)	($24,360,251)

DUKE ENERGY FLORIDA
FUEL AND PURCHASED POWER

DECEMBER 2013

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	113,426,007	103,110,800	10,315,206	10.0	2,556,055	2,636,103	(80,048)	(3.0)	4.4375	3.9115	0.5260	13.5
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	926,244	(10,780,185)	11,706,428	(108.6)	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	114,352,250	92,330,616	22,021,635	23.9	2,556,055	2,636,103	(80,048)	(3.0)	4.4738	3.5025	0.9713	27.7
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	6,219,268	7,381,670	(1,162,402)	(15.7)	112,946	113,482	(536)	(0.5)	5.5064	6.5047	(0.9983)	(15.4)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	20,247	0	20,247	0.0	460	0	460	0.0	4.4016	0.0000	4.4016	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	610,787	554,460	56,327	10.2	19,466	7,574	11,892	157.0	3.1376	7.3206	(4.1830)	(57.1)
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)	12,520,463	13,470,256	(949,793)	(7.1)	266,774	305,135	(38,361)	(12.6)	4.6933	4.4145	0.2788	6.3
12	TOTAL COST OF PURCHASED POWER	19,370,765	21,406,386	(2,035,621)	(9.5)	399,647	426,191	(26,544)	(6.2)	4.8470	5.0227	(0.1757)	(3.5)
13	TOTAL AVAILABLE MWH					2,955,702	3,062,294	(106,592)	(3.5)				
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)	(203,987)	0	(203,987)	(100.0)	(5,633)	0	(5,633)	(100.0)	3.6213	0.0000	3.6213	100.0
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(29,094)	0	(29,094)	(100.0)	(5,633)	0	(5,633)	(100.0)	0.5165	0.0000	0.5165	0.0
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
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	(2,428,321)	(2,135,633)	(292,688)	13.7	(81,820)	(65,226)	(16,594)	25.4	2.9679	3.2742	(0.3063)	(9.4)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(2,661,402)	(2,135,633)	(525,769)	24.6	(87,453)	(65,226)	(22,227)	34.1	3.0432	3.2742	(0.2310)	(7.1)
19	NET INADVERTENT AND WHEELED INTERCHANGE					17,357	0	17,357					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	131,061,614	111,601,368	19,460,246	17.4	2,885,606	2,997,068	(111,462)	(3.7)	4.5419	3.7237	0.8182	22.0
21	NET UNBILLED	(6,298,674)	3,570,334	(9,869,008)	(276.4)	138,679	(95,882)	234,561	(244.6)	(0.2231)	0.1311	(0.3542)	(270.2)
22	COMPANY USE	977,810	446,842	530,968	118.8	(21,529)	(12,000)	(9,529)	79.4	0.0346	0.0164	0.0182	111.0
23	T & D LOSSES	8,140,781	6,149,600	1,991,181	32.4	(179,237)	(165,148)	(14,089)	8.5	0.2883	0.2258	0.0625	27.7
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	131,061,614	111,601,368	19,460,246	17.4	2,823,520	2,724,038	99,482	3.7	4.6418	4.0969	0.5449	13.3
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(943,644)	(312,484)	(631,160)	202.0	(20,351)	(7,654)	(12,697)	165.9	4.6369	4.0826	0.5543	13.6
26	JURISDICTIONAL KWH SALES	130,117,970	111,288,885	18,829,086	16.9	2,803,169	2,716,384	86,785	3.2	4.6418	4.0969	0.5449	13.3
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00150	130,313,147	111,424,657	18,888,490	17.0	2,803,169	2,716,384	86,785	3.2	4.6488	4.1019	0.5469	13.3
28	PRIOR PERIOD TRUE-UP	12,113,909	12,113,913	(3)	0.0	2,803,169	2,716,384	86,785	3.2	0.4322	0.4460	(0.0138)	(3.1)
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	2,803,169	2,716,384	86,785	3.2	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	2,803,169	2,716,384	86,785	3.2	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	142,427,057	123,538,570	18,888,487	15.3	2,803,169	2,716,384	86,785	3.2	5.0810	4.5479	0.5331	11.7
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									5.0847	4.5512	0.5335	11.7
32	GPIF	124,631	124,631			2,803,169	2,716,384			0.0044	0.0046	(0.0002)	(4.4)
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.089	4.556	0.533	11.7

*Line 15a. MWH Data for Infomational Purposes Only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI
EXHIBIT: 21
PARTY: DUKE ENERGY FLORIDA
(DEF)(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-3T

DUKE ENERGY FLORIDA
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2013

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,489,345,986	1,361,604,286	127,741,699	9.4	33,858,739	33,752,262	106,477	0.3	4.3987	4.0341	0.3646	9.0
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	(515,447,495)	(456,990,441)	(58,457,054)	12.8	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	973,898,490	904,613,845	69,284,645	7.7	33,858,739	33,752,262	106,477	0.3	2.8764	2.6802	0.1962	7.3
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	118,627,580	197,756,948	(79,129,368)	(40.0)	2,390,451	3,758,406	(1,367,955)	(36.4)	4.9626	5.2617	(0.2991)	(5.7)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	48,279	0	48,279	0.0	1,221	0	1,221	0.0	3.9541	0.0000	3.9541	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	16,705,848	11,096,755	5,609,093	50.6	342,625	182,273	160,352	88.0	4.8758	6.0880	(1.2122)	(19.9)
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)	194,768,082	161,948,287	32,819,795	20.3	3,984,423	3,479,980	504,443	14.5	4.8882	4.6537	0.2345	5.0
12	TOTAL COST OF PURCHASED POWER	330,149,788	370,801,990	(40,652,201)	(11.0)	6,718,720	7,420,659	(701,939)	(9.5)	4.9139	4.9969	(0.0830)	(1.7)
13	TOTAL AVAILABLE MWH					40,577,459	41,172,921	(595,462)	(1.5)				
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)	(1,894,276)	(2,813,022)	918,746	(32.7)	(59,667)	(78,416)	18,749	(23.9)	3.1747	3.5873	(0.4126)	(11.5)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(427,107)	(365,693)	(61,414)	16.8	(59,667)	(78,416)	18,749	(23.9)	0.7158	0.4663	0.2495	53.5
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
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	(43,592,932)	(36,175,371)	(7,417,562)	20.5	(1,239,063)	(1,209,795)	(29,268)	2.4	3.5182	2.9902	0.5280	17.7
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(45,914,316)	(39,354,086)	(6,560,230)	16.7	(1,298,730)	(1,288,211)	(10,519)	0.8	3.5353	3.0549	0.4804	15.7
19	NET INADVERTENT AND WHEELED INTERCHANGE					246,335	0	246,335					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	1,258,133,963	1,236,061,749	22,072,214	1.8	39,525,065	39,884,710	(359,645)	(0.9)	3.1831	3.0991	0.0840	2.7
21	NET UNBILLED	(6,052,816)	1,543,233	(7,596,049)	(492.2)	190,153	(35,330)	225,483	(638.2)	(0.0164)	0.0041	(0.0205)	(500.0)
22	COMPANY USE	5,145,630	4,331,439	814,191	18.8	(161,653)	(144,000)	(17,653)	12.3	0.0140	0.0116	0.0024	20.7
23	T & D LOSSES	85,567,039	68,533,431	17,033,608	24.9	(2,688,142)	(2,208,703)	(479,439)	21.7	0.2321	0.1828	0.0493	27.0
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,258,133,963	1,236,061,749	22,072,214	1.8	36,865,422	37,496,677	(631,255)	(1.7)	3.4128	3.2965	0.1163	3.5
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(9,576,980)	(2,856,631)	(6,720,350)	235.3	(249,434)	(113,303)	(136,131)	120.2	3.8395	2.5212	1.3183	52.3
26	JURISDICTIONAL KWH SALES	1,248,556,983	1,233,205,119	15,351,864	1.2	36,615,988	37,383,374	(767,386)	(2.1)	3.4099	3.2988	0.1111	3.4
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00150	1,250,395,366	1,234,709,629	15,685,737	1.3	36,615,988	37,383,374	(767,386)	(2.1)	3.4149	3.3028	0.1121	3.4
28	PRIOR PERIOD TRUE-UP	145,366,912	145,366,912	0	0.0	36,615,988	37,383,374	(767,386)	(2.1)	0.3970	0.3889	0.0081	2.1
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	36,615,988	37,383,374	(767,386)	(2.1)	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	36,615,988	37,383,374	(767,386)	(2.1)	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	1,395,762,278	1,380,076,540	15,685,738	1.1	36,615,988	37,383,374	(767,386)	(2.1)	3.8119	3.6917	0.1202	3.3
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									3.8146	3.6944	0.1203	3.3
32	GPIF	1,495,572	1,495,572			36,615,988	37,383,374			0.0041	0.0040	0.0001	97.6
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									3.819	3.698	0.120	3.3

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2013

		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	$113,426,007	103,110,800	$10,315,206	10.0	$1,489,345,986	$1,361,604,286	$127,741,699	9.4
1a.	NUCLEAR FUEL DISPOSAL COST	-	0	0	0.0	0	0	0	0.0
1b.	NUCLEAR DECOM & DECON	-	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	(203,987)	0	(203,987)	0.0	(1,894,276)	(2,813,022)	918,746	(32.7)
2a.	GAIN ON POWER SALES	(29,094)	0	(29,094)	0.0	(427,107)	(365,693)	(61,414)	16.8
3 .	FUEL COST OF PURCHASED POWER	6,219,268	7,381,670	(1,162,402)	(15.7)	118,627,580	197,756,948	(79,129,368)	(40.0)
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	12,520,463	13,470,256	(949,793)	(7.1)	194,768,082	161,948,287	32,819,795	20.3
3b.	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	631,034	554,460	76,574	13.8	16,754,127	11,096,755	5,657,372	51.0
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	132,563,691	124,517,186	8,046,505	6.5	1,817,174,391	1,729,227,561	87,946,830	5.1
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(2,428,321)	(2,135,633)	(292,688)	13.7	(43,592,932)	(36,175,371)	(7,417,562)	20.5
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	926,244	(10,780,185)	11,706,428	(108.6)	(515,447,495)	(456,990,441)	(58,457,054)	12.8
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$131,061,614	$111,601,368	$19,460,246	17.4	$1,258,133,963	$1,236,061,749	$22,072,214	1.8

FOOTNOTE: DETAIL OF LINE 6b ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	($32)	$0	($32)		$224	$0	$224
INEFFICIENT USE OF BARTOW CC	0	0	0		0	0	0
UNIV.OF FL STEAM REVENUE ALLOCATION {Wholesale Portion}	720	0	720		8,080	0	8,080
ADJUSTMENT FOR NUCLEAR DECOM & DECON	0	0	0		0	0	0
TANK BOTTOM ADJUSTMENT	1,052,858	0	1,052,858		(1,654,342)	0	(1,654,342)
AERIAL SURVEY ADJUSTMENT (Coal Pile)	0	0	0		(7,822,235)	0	(7,822,235)
NEIL Replacement Power Reimbursement	0	(10,780,185)	10,780,185		(492,313,428)	(456,990,441)	(35,322,987)
Interest Amortized for Fuel Refund	(24,737)	0	(24,737)		(296,696)	0	(296,696)
Gain/Loss on Disposition of Oil	0	0	0		(2,272,533)	0	(2,272,533)
Prior Period Retail/Wholesale Allocation Correction for NEIL Refund	0	0	0		0	0	0
NET METER SETTLEMENT	0	0	0		29,447	0	29,447
Other - Sims Crane (Tiger Bay Replacement Power)	0	0	0		0	0	0
Derivative Collateral Interest	418	0	418		11,055	0	11,055
Joint Owner CR3 Replacement Power (Capacity Factor Agreement)	(102,984)	0	(102,984)		(11,137,067)	0	(11,137,067)
SUBTOTAL LINE 6b SHOWN ABOVE	$926,244	($10,780,185)	$11,706,428		($515,447,495)	($456,990,441)	($58,457,054)

B.	KWH SALES							
1 .	JURISDICTIONAL SALES	2,803,168,900	2,716,384,000	86,784,900	3.2	36,615,988,831	37,383,374,000	(767,385,169)	(2.1)
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	20,350,864	7,654,000	12,696,864	165.9	249,434,039	113,303,000	136,131,039	120.2
3 .	TOTAL SALES	2,823,519,764	2,724,038,000	99,481,764	3.7	36,865,422,870	37,496,677,000	(631,254,130)	(1.7)
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.28	99.72	(0.44)	(0.4)	99.32	99.70	(0.38)	(0.4)

DUKE ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2013

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$102,320,188	$100,388,945	$1,931,244	1.9	$1,335,207,737	$1,381,571,036	($46,363,299)	(3.4)
2 .	ADJUSTMENTS:	10,750,000	0	10,750,000	0.0	129,000,000	0	129,000,000	0.0
2a.	TRUE UP PROVISION	(12,113,909)	(12,113,913)	3	0.0	(145,366,912)	(145,366,912)	(0)	0.0
2b.	INCENTIVE PROVISION	(124,631)	(124,631)	0	0.0	(1,495,572)	(1,495,572)	0	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	100,831,648	88,150,401	12,681,247	14.4	1,317,345,253	1,234,708,553	82,636,701	6.7
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	131,061,614	111,601,368	19,460,246	17.4	1,258,133,963	1,236,061,749	22,072,214	1.8
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.28	99.72	(0.44)	(0.4)	99.32	99.70	(0.38)	(0.4)
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00150 LOSS MULTIPLIER)	130,313,147	111,424,657	18,888,490	17.0	1,250,395,366	1,234,709,629	15,685,737	1.3
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(29,481,500)	(23,274,256)	(6,207,243)	26.7	66,949,887	(1,076)	66,950,963	(6,221,994.0)
8 .	INTEREST PROVISION FOR THE MONTH (LINE D10)	147	571	(423)	(74.2)	(64,940)	92,202	(157,142)	(170.4)
9 .	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	11,849,713	11,250,899	598,814	5.3	(217,577,600)	(145,366,912)	(72,210,688)	49.7
10.	TRUE UP COLLECTED (REFUNDED)	12,113,909	12,113,913	(3)	0.0	145,366,912	145,366,912	0	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(5,517,730)	91,126	(5,608,856)	(6,155.1)	(5,325,740)	91,126	(5,416,866)	(5,944.4)
12.	OTHER:	(443,360)				(635,349)		(635,349)	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	($5,961,090)	91,126	(6,052,216)	(6,641.6)	($5,961,090)	91,126	(6,052,216)	(6,641.6)

D.	INTEREST PROVISION				
1 .	BEGINNING TRUE UP (LINE C9)	$11,849,713	N/A	--	--
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(5,961,237)	N/A	--	--
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	5,888,476	N/A	--	--
4 .	AVERAGE TRUE UP (50% OF LINE D3)	2,944,238	N/A	--	--
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	0.060	N/A	--	--
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	0.060	N/A	--	--
7 .	TOTAL (LINE D5 + LINE D6)	0.120	N/A		
8 .	AVERAGE INTEREST RATE (50% OF LINE D7)	0.060	N/A	--	--
9 .	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.005	N/A	--	--
10.	INTEREST PROVISION (LINE D4 * LINE D9)	$147	N/A	--	--

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 140001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule: A3-1

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	19,773,117	16,359,405	3,413,712	20.9%
2 - LIGHT OIL	16,141,228	20,116,626	(3,975,398)	(19.8%)
3 - COAL	439,925,452	384,962,927	54,962,525	14.3%
4 - GAS	1,013,506,189	940,165,328	73,340,861	7.8%
5 - NUCLEAR	0	0	0	0.0%
6	0	0	0	0.0%
7	0	0	0	0.0%
8 - TOTAL ($)	1,489,345,986	1,361,604,286	127,741,700	9.4%
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	123,377	117,429	5,948	5.1%
10 - LIGHT OIL	35,150	32,768	2,382	7.3%
11 - COAL	10,633,975	10,025,409	608,566	6.1%
12 - GAS	23,066,236	23,576,656	(510,420)	-2.2%
13 - NUCLEAR	0	0	0	0.0%
14	0	0	0	0.0%
15	0	0	0	0.0%
16 - TOTAL (MWH)	33,858,739	33,752,262	106,477	0.3%
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	250,994	215,986	35,008	16.2%
18 - LIGHT OIL (BBL)	132,000	151,894	(19,894)	(13.1%)
19 - COAL (TON)	4,792,094	4,423,757	368,337	8.3%
20 - GAS (MCF)	177,503,510	179,664,328	(2,160,818)	(1.2%)
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	1,529,500	1,415,146	114,354	8.1%
25 - LIGHT OIL	764,007	880,437	(116,430)	-13.2%
26 - COAL	111,597,504	104,691,198	6,906,306	6.6%
27 - GAS	180,039,881	179,664,328	375,553	0.2%
28 - NUCLEAR	0	0	0	0.0%
29	0	0	0	0.0%
30	0	0	0	0.0%
31 - TOTAL (MILLION BTU)	293,930,892	286,651,109	7,279,783	2.5%

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 140001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule: A3-2

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.4	0.35	0.0	4.7%
33 - LIGHT OIL	0.1	0.10	0.0	6.9%
34 - COAL	31.4	29.70	1.7	5.7%
35 - GAS	68.1	69.85	(1.7)	-2.5%
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)	78.78	75.74	3.04	4.0%
41 - LIGHT OIL ($/BBL)	122.29	132.44	(10.15)	(7.7%)
42 - COAL ($/TON)	91.80	87.02	4.78	5.5%
43 - GAS ($/MCF)	5.71	5.23	0.48	9.1%
44 - NUCLEAR ($/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 ($/MILLION BTU)				
47 - HEAVY OIL	12.93	11.56	1.37	11.8%
48 - LIGHT OIL	21.13	22.85	(1.72)	-7.5%
49 - COAL	3.94	3.68	0.26	7.2%
50 - GAS	5.63	5.23	0.40	7.6%
51 - NUCLEAR	0.00	0.00	0.00	0.0%
52	0.00	0.00	0.00	0.0%
53	0.00	0.00	0.00	0.0%
54 - SYSTEM ($/MBTU)	5.07	4.75	0.32	6.7%
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	12,397	12,051	346	2.9%
56 - LIGHT OIL	21,735	26,869	(5,133)	-19.1%
57 - COAL	10,494	10,443	52	0.0%
58 - GAS	7,805	7,620	185	0.0%
59 - NUCLEAR	0	0	0	0.0%
60	0	0	0	0.0%
61	0	0	0	0.0%
62 - SYSTEM (BTU/KWH)	8,681	8,493	188	2.2%

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 140001-EI
Witness: Foster
Exhibit No. (TGF-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	16.03	13.93	2.10	15.0%
64 - LIGHT OIL	45.92	61.39	(15.47)	-25.2%
65 - COAL	4.14	3.84	0.30	7.7%
66 - GAS	4.39	3.99	0.41	10.2%
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)	4.40	4.03	0.41	10.1%

Duke Energy Florida
Schedule A6
Power Sold for the Month of
December 2013

Docket No. 140001-EI
Witness: Foster
Exhibit No. (TGF-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		0		0	0.000	0.000	0.00	0.00	0.00
ACTUAL									
City of New Smyma Beach, FL	CR-1	3,720		3,720	3.424	3.912	127,360.80	145,524.00	18,163.20
City of New Smyma Beach, FL	Schedule H	0		0	0.000	0.000	0.00	0.00	0.00
City of New Smyma Beach, FL	Schedule I	0		0	0.000	0.000	14,371.05	14,371.05	0.00
City of Tallahassee, FL	CR-1	275		275	3.277	4.587	9,011.08	12,613.10	3,602.02
Exelon Generation Company, LLC	InternationalSwapsDerivativesAssoc	75		75	3.191	3.616	2,393.16	2,712.02	318.86
Oglethorpe Power Corp.	EEI	510		510	3.080	3.647	15,708.90	18,600.00	2,891.10
Reedy Creek Improvement District	CR-1	265		265	3.053	3.207	8,091.70	8,499.40	407.70
Tampa Electric Company	CR-1	300		300	3.509	3.840	10,527.93	11,519.18	991.25
The Energy Authority, Inc.	Schedule OS	488		488	3.386	3.943	16,522.19	19,242.03	2,719.84
Subtotal - Gain on Other Power Sales		**5,633**		**5,633**	**3.621**	**4.138**	**203,986.81**	**233,080.78**	**29,093.97**
CURRENT MONTH TOTAL		5,633		5,633	3.621	4.138	203,986.81	233,080.78	29,093.97
DIFFERENCE		5,633		5,633	3.621	4.138	203,986.81	233,080.78	29,093.97
DIFFERENCE %		100.00		100.00	100.00	100.00	100.00	100.00	100.00
CUMULATIVE ACTUAL		59,667		59,667	3.175	3.891	1,894,275.64	2,321,383.05	427,107.41
CUMULATIVE ESTIMATED		78,416		78,416	3.587	4.054	2,813,021.00	3,178,714.00	365,693.00
DIFFERENCE		(18,749)		(18,749)	(0.412)	(0.163)	(918,745.36)	(857,330.95)	61,414.41
DIFFERENCE %		(23.91)		(23.91)	(11.49)	(4.02)	(32.66)	(26.97)	16.79

REDACTED

DUKE ENERGY FLORIDA
SCHEDULE A12 - CAPACITY COSTS
FOR THE PERIOD JAN - DEC 2013

	Counterparty	Type	MW	Start Date - End Date	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YTD
1	Auburndale Power Partners, L.P. (AUBRDLFC)	QF	17.00	1/1/95 - 12/31/13	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	9,896,040
2	Auburndale Power Partners, L.P. (AUBSET)	QF	114.18	8/1/94 - 12/31/13	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,107
3	Lake County (LAKCOUNT)	QF	12.75	1/1/95 - 6/30/14	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
4	Lake Cogen Limited (LAKORDER)	QF	110.00	7/1/93 - 7/31/13	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	(3,735,759)	0	0	0	26,150,313
5	Metro-Dade County (METRDADE)	QF	43.00	11/1/91 - 11/30/13	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	0	15,424,530
6	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,864,442	35,397,001
7	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	2,951,657	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,625,197
8	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
9	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
10	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,530
11	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	797,588	800,946	777,222	794,026	799,869	794,685	775,904	766,360	757,005	748,432	747,065	738,019	9,297,120
12	Southern purchase - Scherer	Other	74	6/1/10 - 5/31/16	1,716,577	1,716,976	1,717,736	1,740,639	2,398,835	1,599,329	1,719,821	1,719,994	1,719,962	1,719,652	1,719,207	1,718,003	21,206,729
13	Southern purchase - Franklin	Other	350	6/1/10 - 5/31/16	3,053,631	3,057,021	3,056,255	3,541,434	3,052,407	2,469,707	3,057,990	3,058,836	3,347,787	2,987,604	3,054,763	3,049,115	36,786,551
14	Retail Wheeling				(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(1,284)	0	0	(2,080)	(3,730)	(3,519)	(38,728)
15	Levy Projected Expense				8,475,072	11,483,103	8,258,947	8,021,598	8,162,758	8,305,060	8,248,615	8,312,931	8,330,438	8,271,575	8,179,250	8,647,553	102,696,902
16	CR-3 Projected Expense				3,358,869	3,354,735	3,350,601	3,346,468	3,342,335	3,338,203	3,334,071	3,329,940	3,325,809	3,321,678	3,317,548	3,313,419	40,033,676
	SUBTOTAL				44,079,465	47,018,654	43,751,855	44,044,046	44,363,435	43,114,106	43,742,584	43,795,527	36,616,950	39,918,570	39,885,811	38,839,005	509,170,008

Confidential Capacity Contracts (Aggregated):

Purchases/Sales (Net)	Other	MW	Contracts												
Chattahoochee Capacity Purchase	1	[redacted]	01/2003 - 01/2017	12,500	11,290	13,710	12,231	12,769	12,231	12,769	12,231	12,769	12,500	12,097	12,903	150,000
Vandolah - NSG	1		06/2012 - 05/2027	2,925,728	2,887,475	1,965,866	1,940,723	2,792,514	5,785,174	5,804,782	5,741,880	2,742,123	1,930,080	2,026,347	2,961,032	39,503,724
Schedule H Capacity Sales-NSB	1		on-going no term date	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
Shady Hills Tolling	1		04/2007 - 04/2024	1,965,615	1,973,145	1,406,700	1,363,500	1,908,900	3,840,480	3,855,600	3,855,600	1,799,280	1,352,700	1,352,700	1,954,260	26,628,480
Total		1176.25	4	4,889,052	4,857,118	3,371,484	3,301,662	4,699,391	9,623,093	9,658,360	9,594,919	4,539,380	3,280,488	3,376,352	4,913,404	66,104,700

TOTAL	48,968,517	51,875,772	47,123,338	47,345,708	49,062,825	52,737,199	53,400,944	53,390,446	41,156,330	43,199,058	43,262,163	43,752,408	575,274,708

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2013

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 3,384,964	45.48%	10.50%	4.78%
Preferred Stock	23,017	0.31%	4.51%	0.01%
Long Term Debt	3,010,543	40.45%	5.73%	2.32%
Short Term Debt	20,229	0.27%	0.65%	0.00%
Customer Deposits - Active	168,807	2.27%	6.27%	0.14%
Customer Deposits - Inactive	882	0.01%	0.00%	0.00%
Deferred Tax	976,720	13.12%	0.00%	0.00%
Deferred Tax (FAS 109)	(145,373)	-1.95%	0.00%	0.00%
ITC	2,887	0.04%	8.36%	0.00%
	7,442,678	100.00%		7.25%

Total Debt	2.46%
Total Equity	4.79%

* May 2012 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 2013 Actual True-up Filing does not currently include a capital return component

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 22
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-4T

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : July through December 2013

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 3,951,603	47.50%	10.50%	4.99%
Preferred Stock	17,874	0.21%	4.49%	0.01%
Long Term Debt	3,223,164	38.75%	5.61%	2.17%
Short Term Debt	35,074	0.42%	1.22%	0.01%
Customer Deposits - Active	182,636	2.20%	3.21%	0.07%
Customer Deposits - Inactive	1,162	0.01%	0.00%	0.00%
Deferred Tax	1,059,780	12.74%	0.00%	0.00%
Deferred Tax (FAS 109)	(155,042)	-1.86%	0.00%	0.00%
ITC	2,091	0.03%	8.22%	0.00%
	8,318,342	100.00%		7.25%

Total Debt	2.25%
Total Equity	5.00%

* May 2013 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 2013 Actual True-up Filing does not currently include a capital return component

Docket 140001-EI
Exhibit No. ____(TGF-2)
Part 1

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2014

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: 140001-EI EXHIBIT: 23
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-2

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 129,009,047	$ 113,289,617	$ 117,896,602	$ 123,707,993	$ 148,849,928	$ 150,044,426	$ 782,797,613
	2	Fuel Cost of Power Sold	(8,399,700)	(4,874,697)	(4,172,032)	(4,006,945)	(2,404,449)	(3,611,616)	(27,469,439)
	3	Fuel Cost of Purchased Power	6,995,460	6,886,472	4,137,281	9,618,764	15,941,968	14,635,873	58,215,817
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	9,787,721	8,788,027	10,717,751	5,483,300	9,437,326	11,822,064	56,036,188
	4	Energy Cost of Economy Purchases	1,126,552	1,984,275	902,144	1,910,682	2,797,492	2,205,474	10,926,619
	5	Adjustments to Fuel Cost	(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(12,913,643)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
B	1	Jurisdictional MWH Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	17,013,292
	2	Non-Jurisdictional MWH Sales	22,565	44,021	16,238	32,556	33,247	28,733	177,361
	3	TOTAL SALES (Lines B1 + B2)	2,645,518	2,960,084	2,583,858	2,594,512	2,990,919	3,415,762	17,190,653
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	98.97%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	112,142,525	125,857,590	109,339,746	109,372,799	128,046,715	147,816,093	732,575,469
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	1b	RRSSA Fuel Adjustment	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(17,013,292)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	118,064,769	131,486,725	115,317,323	115,356,040	133,634,241	152,974,262	766,833,361
	4	Fuel & Net Power Transactions (Line A6)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	137,533,195	124,365,581	128,880,719	135,188,666	172,922,325	161,095,355	859,985,842
	6	Over/(Under) Recovery (Line C3 - Line C5)	(19,468,426)	7,121,144	(13,563,396)	(19,832,626)	(39,288,084)	(8,121,092)	(93,152,480)
	7	Interest Provision	(716)	(1,063)	(1,108)	(1,962)	(3,570)	(4,021)	(12,439)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,469,142)	7,120,081	(13,564,504)	(19,834,588)	(39,291,654)	(8,125,113)	(93,164,920)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(3,194,825)	(428,560)	2,337,705	5,103,970	7,870,235	10,636,500	10,636,500
	12	Regulatory Accounting Adjustment	-	-	(588,930)	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($22,663,966)	(12,777,621)	($24,164,790)	($41,233,113)	($77,758,502)	($83,117,350)	($83,117,350)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 152,197,049	$ 153,089,439	$ 143,724,982	$ 125,028,239	$ 105,592,127	$ 113,199,782	$ 1,575,629,231
	2	Fuel Cost of Power Sold	(3,454,453)	(3,933,202)	(2,804,929)	(2,273,796)	(1,720,555)	(984,793)	(42,641,167)
	3	Fuel Cost of Purchased Power	13,422,539	14,076,449	12,104,080	11,244,071	5,443,096	5,926,210	120,432,262
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	12,830,242	12,768,252	12,331,692	12,332,063	11,620,155	13,174,893	131,093,485
	4	Energy Cost of Economy Purchases	1,387,310	1,538,315	3,090,433	2,406,094	813,273	1,003,572	21,165,616
	5	Adjustments to Fuel Cost	(19,486)	(19,498)	(19,508)	(19,502)	(19,488)	(19,461)	(13,030,585)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
B	1	Jurisdictional MWH Sales	3,578,550	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665
	2	Non-Jurisdictional MWH Sales	24,537	27,901	29,414	26,399	20,273	15,121	321,006
	3	TOTAL SALES (Lines B1 + B2)	3,603,087	3,780,718	3,746,740	3,460,117	2,941,281	2,764,075	37,486,671
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.32%	99.26%	99.21%	99.24%	99.31%	99.45%	99.14%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	156,609,389	164,276,459	162,714,963	150,237,348	127,680,111	120,110,401	1,614,204,140
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	1b	RRSSA Fuel Adjustment	(3,578,550)	(3,752,817)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,165,665)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,268)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	161,576,036	169,068,839	167,542,835	155,348,827	133,304,301	125,906,647	1,679,580,845
	4	Fuel & Net Power Transactions (Line A6)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	175,423,175	176,466,894	167,343,481	147,805,348	121,067,595	131,767,280	1,779,859,614
	6	Over/(Under) Recovery (Line C3 - Line C5)	(13,847,139)	(7,398,056)	199,354	7,543,480	12,236,705	(5,860,633)	(100,278,769)
	7	Interest Provision	(4,430)	(4,823)	(4,865)	(4,533)	(3,901)	(3,604)	(38,596)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(13,851,569)	(7,402,879)	194,489	7,538,946	12,232,804	(5,864,237)	(100,317,366)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	13,402,765	16,169,030	18,935,295	21,701,560	24,467,825	27,234,094	27,234,093
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($94,202,654)	($98,839,267)	($95,878,514)	($85,573,302)	($70,574,233)	($73,672,202)	($73,672,203)

Docket No. 140001-EI
Exhibit TGF-2, Part 1
Schedule E1-B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2014

		DOLLARS				MWH				c/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %
1	Fuel Cost of System Net Generation (E3)	1,575,629,231	1,415,304,375	160,324,856	11%	35,450,615	34,832,378	618,237	2%	4.445	4.063	0.381	9%
2	Spent Nuclear Fuel Disposal Cost	0	0	-	0%	0	0	-	0%	0.000	0.000	0.000	0%
3	Coal Car Investment	0	0	-	0%			-		0.000	0.000	0.000	
4	Adjustment to Fuel Cost [1]	(13,030,585)	(128,673,569)	115,642,984	0%			-		0.000	0.000	0.000	
5	TOTAL COST OF GENERATED POWER	1,562,598,647	1,286,630,806	275,967,840	21%	35,450,615	34,832,378	618,237	2%	4.408	3.694	0.714	19%
6	Energy Cost of Purchased Power	120,432,262	193,909,321	(73,477,059)	-38%	2,184,819	3,301,834	(1,117,015)	-34%	5.512	5.873	-0.361	-6%
	(Excl. Econ & Cogens) (E7)			-				-		0.000	0.000	0.000	
7	Energy Cost of Economy Purchases (E9)	21,165,616	13,558,753	7,606,863	56%	380,889	201,860	179,029	89%	5.557	6.717	-1.160	
8	Payments to Qualifying Facilities (E8)	131,093,485	137,578,568	(6,485,083)	-5%	2,828,107	3,019,852	(191,745)	-6%	4.635	4.556	0.080	2%
9	TOTAL COST OF PURCHASED POWER	272,691,363	345,046,642	(72,355,279)	-21%	5,393,815	6,523,546	(1,129,731)	-17%	5.056	5.289	-0.234	-4%
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)			-		40,844,430	41,355,924	(511,494)	-1%	0.000	0.000	0.000	
11	Fuel Cost of Economy Sales (E6)	(6,463,505)	(3,510,887)	(2,952,618)	84%	(138,922)	(91,711)	(47,211)	51%	4.653	3.828	0.824	22%
11a	Gain on Economy Sales (E6)	(5,887,982)	(667,252)	(5,220,730)	782%	(138,922)	(91,711)	(47,211)	51%	4.238	0.728	3.511	483%
11b	Gain on Economy Sales -20% (E6)	1,105,692	0	1,105,692	0%								
12	Fuel Cost of Stratified Sales (E6)	(31,395,371)	(37,314,237)	5,918,866	-16%	(748,283)	(975,861)	227,578	-23%	4.196	3.824	0.372	10%
13	TOTAL FUEL COST AND GAINS OF POWER SALES	(42,641,167)	(41,492,376)	(1,148,791)	3%	(887,205)	(1,067,572)	180,367	-17%	4.806	3.887	0.920	24%
	(LINES 11 + 11a + 12)												
14	Net Inadvertent Interchange					105,789		105,789					
15	TOTAL FUEL & NET POWER TRANSACTIONS	1,792,648,843	1,590,185,072	202,463,771	13%	40,063,014	40,288,352	(225,338)	-1%	4.475	3.947	0.528	13%
	(LINES 5 + 9 + 13 + 14)												
16	Net Unbilled					(139,190)	(24,268)	(114,922)	474%	0.000	0.000	0.000	
17	Company Use					(153,585)	(144,000)	(9,585)	7%	0.000	0.000	0.000	
18	T & D Losses					(2,283,568)	(2,224,817)	(58,751)	3%	0.000	0.000	0.000	
19	SYSTEM MWH SALES	1,792,648,843	1,590,185,072	202,463,771	13%	37,486,671	37,895,267	(408,596)	-1%	4.782	4.196	0.586	14%
20	Wholesale MWH Sales	(15,422,270)	(9,546,966)	(5,875,304)	62%	(321,006)	(230,488)	(90,518)	39%	4.804	4.142	0.662	16%
21	Jurisdictional MWH Sales	1,777,226,573	1,580,638,106	196,588,466	12%	37,165,665	37,664,779	(499,114)	-1%	4.782	4.197	0.585	14%
21a	Jurisdictional Loss Multiplier	1.00148	1.0015	(0)	0%	1.00148	1.0015	(0)	0%				
22	Jurisdictional Sales Adjusted for Line Losses	1,779,859,614	1,583,009,063	196,850,552	12%	37,165,665	37,664,779	(499,114)	-1%	4.789	4.203	0.586	14%
23	TRUE-UP **	5,961,090	33,195,183	(27,234,094)	-82%	37,165,665	37,664,779	(499,114)	-1%	0.016	0.088	-0.072	-82%
24	TOTAL JURISDICTIONAL FUEL COST	1,785,820,703	1,616,204,246	169,616,457	10%	37,165,665	37,664,779	(499,114)	-1%	4.805	4.291	0.514	12%
25	Revenue Tax Factor	1,285,791	1,163,667	122,124	10%								
26	Fuel Factor Adjusted for Taxes	1,787,106,494	1,617,367,913	169,738,581	10%	37,165,665	37,664,779	(499,114)	-1%	4.808	4.294	0.514	12%
27	GPIF **	3,262,447	3,262,447	-	0%	37,165,665	37,664,779	(499,114)	-1%	0.009	0.009	0.000	1%
28	Fuel Factor Adjusted for Taxes Including GPIF	1,790,368,941	1,620,630,360	169,738,581	10%	37,165,665	37,664,779	(499,114)	-1%	4.817	4.303	0.514	12%
29	FUEL FACTOR ROUNDED TO NEAREST .001 c/KWH									4.817	4.303	0.514	12%

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional MWH Sales

[1] The $129 million retail refund required per RRSSA paragraph 6.a was treated as a reduction to fuel expense in the 2014 Original Projection. In the 2014 Estimated/Actual filing, the refund is treated as an adjustment to revenue, as shown on line C.1a of Schedule E1-B (Sheets 1&2). The difference in treatment is the primary cause of the difference amount on line 4 and 28 of the above schedule. In both filings, retail ratepayers are receiving a refund of $129 million.

Docket: 140001-EI
Exhibit: TGF-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 2014

	Retail:	Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	12 Month Period	Schedule Reference	RRSSA Paragraph
1	Final NEIL Reimbursement [1]	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(164,349,049)		7.c. / 7.d.
2	RRSSA Refund (2nd 50% of $258 million)	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000	E1-B, line C1a	6.a.
3	RRSSA Refund ($10 million)	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000	E1-B, line C1c	6.a.
4	Total RRSSA Refunds (Lines 2 + 3)	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	139,000,000		
5	Retail mWh Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	3,578,550	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665	E1-B, line B1	
6	RRSSA Fuel Adjustment ($/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)
7	Total RRSSA Fuel Adjustment to Revenue (Line 5 * 6)	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(3,578,550)	(3,752,817)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,165,665)	E1-B, line C1b	

Notes:
[1] - Final NEIL Reimbursement is included in the 2013 True-up provision, which applies to retail only

Docket No. 140001-EI
Exhibit TGF-2, Part 1
Schedule E2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2014

			Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	TOTAL
1	Fuel Cost of System Net Generation		$129,009,047	$113,289,617	$117,896,602	$123,707,993	$148,849,928	$150,044,426	$152,197,049	$153,089,439	$143,724,982	$125,028,239	$105,592,127	$113,199,782	$1,575,629,231
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(19,486)	(19,498)	(19,508)	(19,502)	(19,488)	(19,461)	(13,030,585)
2	Fuel Cost of Power Sold		(2,033,703)	(999,742)	(732,117)	(259,845)	(87,422)	(177,909)	(925,989)	(1,243,464)	0	(300)	(1,300)	(1,715)	(6,463,505)
2a	Gains on Power Sales		(3,871,141)	(207,731)	(269,066)	(25,456)	(6,217)	(25,788)	(157,457)	(218,850)	0	(54)	(229)	(302)	(4,782,290)
2b	Fuel Cost of Stratified Sales		(2,494,856)	(3,667,224)	(3,170,850)	(3,721,643)	(2,310,810)	(3,407,919)	(2,371,007)	(2,470,887)	(2,804,929)	(2,273,442)	(1,719,026)	(982,776)	(31,395,371)
3	Fuel Cost of Purchased Power (Excl Economy)		6,995,460	6,886,472	4,137,281	9,618,764	15,941,968	14,635,873	13,422,539	14,076,449	12,104,080	11,244,071	5,443,096	5,926,210	120,432,262
3a	Energy Payments to Qualifying Facilities		9,787,721	8,788,027	10,717,751	5,483,300	9,437,326	11,822,064	12,830,242	12,768,252	12,331,692	12,332,063	11,620,155	13,174,893	131,093,485
4	Energy Cost of Economy Purchases		1,126,552	1,984,275	902,144	1,910,682	2,797,492	2,205,474	1,387,310	1,538,315	3,090,433	2,406,094	813,273	1,003,572	21,165,616
5	Total System Fuel & Net Power Transactions		$138,504,493	$126,060,088	$129,506,146	$136,697,603	$174,604,893	$162,219,933	$176,363,202	$177,519,755	$168,426,750	$148,717,170	$121,728,608	$132,300,204	$1,792,648,843
6	Jurisdictional MWH Sold		2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	3,578,550	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665
7	Jurisdictional % of Total Sales		99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	99.32%	99.26%	99.21%	99.24%	99.31%	99.45%	99.14%
8	Jurisdicitonal Fuel & Net Power Transactions		137,327,204	124,181,792	128,690,258	134,988,883	172,666,778	160,857,286	175,163,932	176,206,109	167,096,179	147,586,919	120,888,680	131,572,553	1,777,226,573
9	Jurisdictional Loss Multiplier		1.00150	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
10	Jurisdictional Fuel & Net Power Transactions		137,533,195	124,365,581	128,880,719	135,188,666	172,922,325	161,095,355	175,423,175	176,466,894	167,343,481	147,805,348	121,067,595	131,767,280	1,779,859,614
11	Adjusted System Sales	MWH	2,645,518	2,960,084	2,583,858	2,594,512	2,990,919	3,415,762	3,603,087	3,780,718	3,746,740	3,460,117	2,941,281	2,764,075	37,486,671
12	System Cost per MWH Sold	c/kwh	5.2354	4.2587	5.0122	5.2687	5.8379	4.7491	4.8948	4.6954	4.4953	4.2980	4.1386	4.7864	4.7821
13	Jurisdictional Loss Multiplier	x	1.0015	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
14	Jurisdictional Cost per MWH Sold	c/kwh	5.2434	4.2648	5.0195	5.2768	5.8466	4.7562	4.9021	4.7023	4.5017	4.3045	4.1447	4.7934	4.7890
15	Prior Period True-Up	+	0.0189	0.0170	0.0194	0.0194	0.0168	0.0147	0.0139	0.0132	0.0134	0.0145	0.0170	0.0181	0.0160
16	Total Jurisdictional Fuel Expense	c/kwh	5.2624	4.2819	5.0388	5.2962	5.8634	4.7709	4.9160	4.7155	4.5151	4.3190	4.1617	4.8114	4.8050
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	5.2662	4.2850	5.0424	5.3000	5.8676	4.7743	4.9195	4.7189	4.5183	4.3221	4.1647	4.8149	4.8085
19	GPIF	+	0.0104	0.0093	0.0106	0.0106	0.0092	0.0080	0.0076	0.0072	0.0073	0.0079	0.0093	0.0099	0.0088
20	Total Recovery Factor (rounded .001)	c/kwh	5.277	4.294	5.053	5.311	5.877	4.782	4.927	4.726	4.526	4.330	4.174	4.825	4.817

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2014

			Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		1,640,709	1,164,654	1,401,862	3,642,367	2,304,232	1,746,521	11,900,346
3	COAL		41,965,217	40,207,180	38,152,248	43,412,779	45,303,730	42,359,673	251,400,826
4	GAS		85,403,122	71,917,783	78,342,492	76,652,847	101,241,966	105,938,232	519,496,441
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	129,009,047	113,289,617	117,896,602	123,707,993	148,849,928	150,044,426	782,797,613
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		6,083	4,632	5,144	12,308	8,102	5,944	42,214
10	COAL		967,441	907,147	864,818	1,069,182	1,123,772	1,013,384	5,945,743
11	GAS		2,091,817	1,374,000	1,787,006	1,614,278	1,919,317	2,293,985	11,080,402
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,065,341	2,285,778	2,656,968	2,695,768	3,051,191	3,313,313	17,068,360
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	13,326	9,290	10,116	29,179	17,592	13,258	92,761
17	COAL	TON	419,953	391,043	382,186	464,073	482,406	448,064	2,587,725
18	GAS	MCF	15,823,804	11,385,135	12,785,402	13,055,887	16,220,510	18,195,694	87,466,432
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		76,820	53,532	58,517	166,903	100,234	75,300	531,307
23	COAL		9,736,339	9,106,025	8,905,990	10,709,988	11,318,936	10,493,302	60,270,580
24	GAS		16,074,997	11,559,784	12,992,143	13,296,639	16,529,033	18,537,487	88,990,084
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	25,888,157	20,719,342	21,956,650	24,173,530	27,948,203	29,106,089	149,791,971
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.20%	0.20%	0.19%	0.46%	0.27%	0.18%	0.25%
30	COAL		31.56%	39.69%	32.55%	39.66%	36.83%	30.59%	34.84%
31	GAS		68.24%	60.11%	67.26%	59.88%	62.90%	69.24%	64.92%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	123.12	125.37	138.58	124.83	130.98	131.73	128.29
37	COAL	$/TON	99.93	102.82	99.83	93.55	93.91	94.54	97.15
38	GAS	$/MCF	5.40	6.32	6.13	5.87	6.24	5.82	5.94
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		21.36	21.76	23.96	21.82	22.99	23.19	22.40
43	COAL		4.31	4.42	4.28	4.05	4.00	4.04	4.17
44	GAS		5.31	6.22	6.03	5.77	6.13	5.72	5.84
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	4.98	5.47	5.37	5.12	5.33	5.16	5.23
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		12,628	11,557	11,376	13,560	12,371	12,668	12,586
50	COAL		10,064	10,038	10,298	10,017	10,072	10,355	10,137
51	GAS		7,685	8,413	7,270	8,237	8,612	8,081	8,031
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,445	9,064	8,264	8,967	9,160	8,785	8,776
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		26.97	25.14	27.25	29.59	28.44	29.38	28.19
57	COAL		4.34	4.43	4.41	4.06	4.03	4.18	4.23
58	GAS		4.08	5.23	4.38	4.75	5.27	4.62	4.69
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	C/KWH	4.21	4.96	4.44	4.59	4.88	4.53	4.59

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2014

			Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		262,715	288,612	189,811	421,719	310,222	370,555	13,743,980
3	COAL		53,385,855	52,662,285	51,877,280	45,069,456	37,662,254	42,927,845	534,985,801
4	GAS		98,548,479	100,138,542	91,657,891	79,537,064	67,619,651	69,901,382	1,026,899,450
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	152,197,049	153,089,439	143,724,982	125,028,239	105,592,127	113,199,782	1,575,629,231
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		308	26	213	152	4	22	42,939
10	COAL		1,369,770	1,350,741	1,332,502	1,181,009	959,481	1,139,412	13,278,658
11	GAS		2,139,959	2,199,170	1,977,396	1,725,631	1,477,539	1,528,920	22,129,017
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,510,037	3,549,937	3,310,111	2,906,792	2,437,024	2,668,354	35,450,615
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	2,001	2,228	1,423	3,274	2,411	2,889	106,987
17	COAL	TON	608,982	600,007	592,194	526,340	418,724	498,880	5,832,852
18	GAS	MCF	16,757,351	17,110,365	15,361,774	13,353,987	11,195,699	11,627,304	172,872,912
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		11,621	12,908	8,245	18,981	13,972	16,745	613,779
23	COAL		14,290,833	14,087,072	13,902,821	12,283,360	9,849,472	11,662,324	136,346,462
24	GAS		16,757,351	17,110,365	15,361,774	13,353,987	11,195,699	11,627,304	174,396,564
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	31,059,805	31,210,345	29,272,840	25,656,328	21,059,143	23,306,373	311,356,805
	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%	0.00%	0.01%	0.01%	0.00%	0.00%	0.12%
30	COAL		39.02%	38.05%	40.26%	40.63%	39.37%	42.70%	37.46%
31	GAS		60.97%	61.95%	59.74%	59.37%	60.63%	57.30%	62.42%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	131.29	129.54	133.39	128.81	128.67	128.26	128.46
37	COAL	$/TON	87.66	87.77	87.60	85.63	89.95	86.05	91.72
38	GAS	$/MCF	5.88	5.85	5.97	5.96	6.04	6.01	5.94
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		22.61	22.36	23.02	22.22	22.20	22.13	22.39
43	COAL		3.74	3.74	3.73	3.67	3.82	3.68	3.92
44	GAS		5.88	5.85	5.97	5.96	6.04	6.01	5.89
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	4.90	4.91	4.91	4.87	5.01	4.86	5.06
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		37,731	496,462	38,709	124,875	3,493,000	761,136	14,294
50	COAL		10,433	10,429	10,434	10,401	10,265	10,235	10,268
51	GAS		7,831	7,780	7,769	7,739	7,577	7,605	7,881
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,849	8,792	8,843	8,826	8,641	8,734	8,783
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		85.30	1110.05	89.11	277.45	7,755.55	1,684.34	32.01
57	COAL		3.90	3.90	3.89	3.82	3.93	3.77	4.03
58	GAS		4.61	4.55	4.64	4.61	4.58	4.57	4.64
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	C/KWH	4.34	4.31	4.34	4.30	4.33	4.24	4.44

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-14

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	150,366	53.9	93.40	58.0	10,560	COAL	64,311	TONS	24.69	1,587,895	7,149,734	4.75
3 CRYSTAL RIVER	2	494	206,263	56.1	96.81	57.2	10,740	COAL	89,721	TONS	24.69	2,215,308	9,914,623	4.81
4 CRYSTAL RIVER	4	722	502,255	93.5	95.75	96.9	10,328	COAL	225,026	TONS	23.05	5,187,361	17,971,909	3.58
5 CRYSTAL RIVER	5	700	510,886	98.1	98.60	99.0	10,375	COAL	229,924	TONS	23.05	5,300,269	18,349,589	3.59
6 ANCLOTE	1	501	0	0.0	93.15	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7 ANCLOTE	2	510	0	0.0	96.75	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	98.06	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	99.03	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11 ANCLOTE	1	501	98,984	26.6	0.00	45.3	10,740	GAS	1,063,135	MCF	1.00	1,063,135	6,429,826	6.50
12 ANCLOTE	2	510	129,454	34.1	0.00	34.8	10,797	GAS	1,397,675	MCF	1.00	1,397,675	8,028,593	6.20
13 AVON PARK	1-2	49	22	0.1	81.94	55.1	15,818	GAS	348	MCF	1.00	348	2,005	9.11
14 BARTOW	1-4	177	60	0.1	68.55	48.6	14,100	GAS	846	MCF	1.00	846	4,775	7.96
15 BARTOW CC	1	1,159	587,745	68.2	97.10	70.2	7,528	GAS	4,424,567	MCF	1.00	4,424,567	26,030,984	4.43
16 DEBARY	1-10	645	2,263	0.5	96.68	13.0	12,915	GAS	29,226	MCF	1.00	29,226	172,467	7.62
17 HIGGINS	1-4	113	79	0.1	91.69	17.5	15,899	GAS	1,256	MCF	1.00	1,256	7,376	9.34
18 HINES CC	1-4	1,912	1,153,727	81.1	96.63	22.3	7,210	GAS	8,318,209	MCF	1.00	8,318,209	48,935,323	4.24
19 INT CITY	1-14	987	17,176	2.3	88.27	7.8	12,858	GAS	220,854	MCF	1.00	220,854	1,301,169	7.58
20 SUWANNEE	1	52	215	0.6	96.13	413.5	13,405	GAS	2,882	MCF	1.00	2,882	137,512	63.96
21 SUWANNEE	2	50	69	0.2	99.03	34.5	16,246	GAS	1,121	MCF	1.00	1,121	123,811	179.44
22 SUWANNEE	3	51	26,348	69.4	98.39	69.4	12,291	GAS	323,855	MCF	1.00	323,855	1,670,674	6.34
23 TIGER BAY CC	1	204	91,309	60.2	91.61	96.5	7,303	GAS	666,851	MCF	1.00	666,851	3,900,840	4.27
24 UNIV OF FLA. CC	1	46	32,508	95.0	97.10	97.9	9,429	GAS	306,526	MCF	1.00	306,526	1,803,124	5.55
25 AVON PARK	1-2	49	5	0.1	81.94	0.0	15,400	LIGHT OIL	13	BBLS	5.92	77	1,776	35.52
26 BARTOW	1-4	177	26	0.1	68.55	0.0	13,500	LIGHT OIL	60	BBLS	5.85	351	8,538	32.84
27 BAYBORO	1-4	174	0	0.0	95.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 DEBARY	1-10	645	171	0.5	96.68	125.8	12,865	LIGHT OIL	377	BBLS	5.84	2,200	56,186	32.86
29 HIGGINS	1-4	113	0	0.0	91.69	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	96.63	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31 INT CITY	1-14	987	37	2.3	88.27	3.7	13,405	LIGHT OIL	85	BBLS	5.84	496	11,548	31.21
32 RIO PINAR	1	12	5	2.5	96.13	0.0	16,600	LIGHT OIL	14	BBLS	5.93	83	1,917	38.34
33 SUWANNEE	1-3	153	37	0.0	97.85	2.4	13,622	LIGHT OIL	87	BBLS	5.79	504	12,653	34.20
34 TURNER	1-4	149	27	0.0	95.65	0.0	16,444	LIGHT OIL	77	BBLS	5.77	444	10,661	39.49
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,288	BBLS	5.80	7,466	159,436	0.00
36 TOTAL			3,510,037									31,059,805	152,197,049	4.34

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-14

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	154,527	55.4	95.34	58.1	10,559	COAL	66,092	TONS	24.69	1,631,591	7,300,739	4.72
3 CRYSTAL RIVER	2	494	203,038	55.2	95.16	58.1	10,725	COAL	88,211	TONS	24.69	2,177,641	9,693,169	4.77
4 CRYSTAL RIVER	4	722	486,934	90.6	92.03	98.3	10,325	COAL	218,018	TONS	23.06	5,027,456	17,460,811	3.59
5 CRYSTAL RIVER	5	700	506,242	97.2	96.23	100.2	10,371	COAL	227,686	TONS	23.06	5,250,384	18,207,566	3.60
6 ANCLOTE	1	501	0	0.0	93.63	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7 ANCLOTE	2	510	0	0.0	96.11	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	98.06	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.19	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11 ANCLOTE	1	501	138,507	37.2	0.00	39.0	10,688	GAS	1,480,370	MCF	1.00	1,480,370	8,406,929	6.07
12 ANCLOTE	2	510	92,667	24.4	0.00	41.0	10,696	GAS	991,178	MCF	1.00	991,178	6,071,037	6.55
13 AVON PARK	1-2	49	5	0.0	77.26	0.0	15,800	GAS	79	MCF	1.00	79	509	10.18
14 BARTOW	1-4	177	321	0.2	93.37	25.9	13,832	GAS	4,440	MCF	1.00	4,440	25,943	8.08
15 BARTOW CC	1	1,159	598,947	69.5	96.45	72.0	7,501	GAS	4,492,850	MCF	1.00	4,492,850	26,283,964	4.39
16 DEBARY	1-10	645	2,177	0.5	95.90	12.5	12,887	GAS	28,056	MCF	1.00	28,056	165,690	7.61
17 HIGGINS	1-4	113	84	0.1	91.77	24.8	15,488	GAS	1,301	MCF	1.00	1,301	7,340	8.74
18 HINES CC	1-4	1,912	1,200,048	84.4	96.17	22.7	7,164	GAS	8,597,167	MCF	1.00	8,597,167	50,318,941	4.19
19 INT CITY	1-14	987	18,845	2.6	87.86	7.7	12,865	GAS	242,443	MCF	1.00	242,443	1,424,283	7.56
20 SUWANNEE	1	52	270	0.7	96.13	0.0	13,152	GAS	3,551	MCF	1.00	3,551	135,492	50.18
21 SUWANNEE	2	50	55	0.1	99.35	27.5	16,818	GAS	925	MCF	1.00	925	116,931	212.60
22 SUWANNEE	3	51	25,795	68.0	99.35	70.1	12,278	GAS	316,713	MCF	1.00	316,713	1,630,072	6.32
23 TIGER BAY CC	1	204	88,509	58.3	87.10	98.8	7,239	GAS	640,732	MCF	1.00	640,732	3,733,643	4.22
24 UNIV OF FLA. CC	1	46	32,940	96.2	98.39	97.8	9,428	GAS	310,560	MCF	1.00	310,560	1,817,768	5.52
25 AVON PARK	1-2	49	0	0.0	77.26	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26 BARTOW	1-4	177	0	0.0	93.37	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27 BAYBORO	1-4	174	0	0.0	95.24	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 DEBARY	1-10	645	0	0.0	95.90	0.0	0	LIGHT OIL	0	BBLS		0	8,960	0.00
29 HIGGINS	1-4	113	0	0.0	91.77	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31 INT CITY	1-14	987	9	2.6	87.86	0.0	13,111	LIGHT OIL	20	BBLS	5.90	118	3,497	38.86
32 RIO PINAR	1	12	0	0.0	99.68	0.0	0	LIGHT OIL	0	BBLS		0	142	0.00
33 SUWANNEE	1-3	153	17	0.0	98.28	0.9	13,941	LIGHT OIL	41	BBLS	5.78	237	6,816	40.09
34 TURNER	1-4	149	0	0.0	95.97	0.0	0	LIGHT OIL	0	BBLS		0	1,128	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,167	BBLS	5.79	12,553	268,069	0.00
36 TOTAL			3,549,937									31,210,345	153,089,439	4.31

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-14

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	144,563	53.5	92.77	57.8	10,563	COAL	61,862	TONS	24.68	1,527,031	6,821,438	4.72
3 CRYSTAL RIVER	2	494	203,329	57.2	99.35	57.2	10,739	COAL	88,463	TONS	24.68	2,183,650	9,689,198	4.77
4 CRYSTAL RIVER	4	722	499,980	96.2	98.43	96.4	10,329	COAL	223,895	TONS	23.07	5,164,347	17,911,935	3.58
5 CRYSTAL RIVER	5	700	484,630	96.2	96.70	99.2	10,374	COAL	217,974	TONS	23.07	5,027,793	17,454,709	3.60
6 ANCLOTE	1	501	0	0.0	94.67	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7 ANCLOTE	2	510	0	0.0	38.02	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	97.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11 ANCLOTE	1	501	136,297	37.8	0.00	39.0	10,687	GAS	1,456,595	MCF	1.00	1,456,595	8,113,041	5.95
12 ANCLOTE	2	510	44,811	12.2	0.00	39.4	10,727	GAS	480,671	MCF	1.00	480,671	3,467,643	7.74
13 AVON PARK	1-2	49	19	0.1	77.67	38.8	16,474	GAS	313	MCF	1.00	313	1,904	10.02
14 BARTOW	1-4	177	97	0.1	91.83	29.9	13,887	GAS	1,347	MCF	1.00	1,347	8,438	8.70
15 BARTOW CC	1	1,159	547,308	65.6	96.00	68.3	7,549	GAS	4,131,793	MCF	1.00	4,131,793	24,674,470	4.51
16 DEBARY	1-10	645	1,149	0.3	95.97	14.5	12,913	GAS	14,837	MCF	1.00	14,837	89,473	7.79
17 HIGGINS	1-4	113	82	0.1	93.50	24.2	15,671	GAS	1,285	MCF	1.00	1,285	7,720	9.41
18 HINES CC	1-4	1,912	1,091,862	79.3	95.59	22.2	7,213	GAS	7,875,188	MCF	1.00	7,875,188	46,969,790	4.30
19 INT CITY	1-14	987	13,195	1.9	88.29	7.6	12,920	GAS	170,482	MCF	1.00	170,482	1,029,212	7.80
20 SUWANNEE	1	52	193	0.5	96.00	123.7	13,865	GAS	2,676	MCF	1.00	2,676	137,263	71.12
21 SUWANNEE	2	50	87	0.2	99.00	43.5	15,563	GAS	1,354	MCF	1.00	1,354	127,689	146.77
22 SUWANNEE	3	51	24,546	66.8	99.67	69.0	12,275	GAS	301,312	MCF	1.00	301,312	1,558,001	6.35
23 TIGER BAY CC	1	204	86,646	59.0	88.67	96.8	7,277	GAS	630,552	MCF	1.00	630,552	3,723,244	4.30
24 UNIV OF FLA. CC	1	46	31,104	93.9	96.00	97.9	9,432	GAS	293,369	MCF	1.00	293,369	1,750,003	5.63
25 AVON PARK	1-2	49	0	0.0	77.67	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26 BARTOW	1-4	177	9	0.1	91.83	0.0	13,222	LIGHT OIL	21	BBLS	5.67	119	3,025	33.61
27 BAYBORO	1-4	174	0	0.0	94.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 DEBARY	1-10	645	162	0.3	95.97	67.8	12,920	LIGHT OIL	362	BBLS	5.78	2,093	53,889	33.26
29 HIGGINS	1-4	113	0	0.0	93.50	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31 INT CITY	1-14	987	13	1.9	88.29	0.0	13,615	LIGHT OIL	30	BBLS	5.90	177	4,754	36.57
32 RIO PINAR	1	12	0	0.0	99.00	0.0	0	LIGHT OIL	0	BBLS		0	142	0.00
33 SUWANNEE	1-3	153	25	0.0	98.22	2.3	13,720	LIGHT OIL	59	BBLS	5.81	343	9,134	36.54
34 TURNER	1-4	149	4	0.0	96.17	0.0	17,750	LIGHT OIL	12	BBLS	5.92	71	2,653	66.33
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	939	BBLS	5.80	5,442	116,214	0.00
36 TOTAL			3,310,111									29,272,840	143,724,982	4.34

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-14

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	129,390	46.4	96.38	58.3	10,556	COAL	55,438	TONS	24.64	1,365,859	6,261,256	4.84
3 CRYSTAL RIVER	2	494	65,524	17.8	35.48	55.3	10,750	COAL	28,590	TONS	24.64	704,395	3,302,729	5.04
4 CRYSTAL RIVER	4	722	493,318	91.8	94.99	95.8	10,333	COAL	220,752	TONS	23.09	5,097,223	17,721,433	3.59
5 CRYSTAL RIVER	5	700	492,777	94.6	96.37	97.5	10,382	COAL	221,560	TONS	23.09	5,115,883	17,784,038	3.61
6 ANCLOTE	1	501	0	0.0	96.86	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7 ANCLOTE	2	510	0	0.0	0.00	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	98.06	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	51.09	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11 ANCLOTE	1	501	134,352	36.0	0.00	36.4	10,772	GAS	1,447,303	MCF	1.00	1,447,303	7,784,606	5.79
12 ANCLOTE	2	510	0	0.0	0.00	0.0	0	GAS	0	MCF		0	827,421	0.00
13 AVON PARK	1-2	49	10	0.0	82.42	0.0	15,500	GAS	155	MCF	1.00	155	968	9.68
14 BARTOW	1-4	177	182	0.1	92.58	25.7	13,813	GAS	2,514	MCF	1.00	2,514	15,543	8.54
15 BARTOW CC	1	1,159	564,782	65.5	92.26	71.0	7,521	GAS	4,247,540	MCF	1.00	4,247,540	25,263,481	4.47
16 DEBARY	1-10	645	1,690	0.4	93.52	12.6	12,915	GAS	21,827	MCF	1.00	21,827	132,614	7.85
17 HIGGINS	1-4	113	117	0.1	89.76	20.7	15,769	GAS	1,845	MCF	1.00	1,845	10,939	9.35
18 HINES CC	1-4	1,912	961,992	67.6	90.66	22.3	7,190	GAS	6,916,728	MCF	1.00	6,916,728	41,230,863	4.29
19 INT CITY	1-14	987	12,807	1.7	88.11	7.9	12,841	GAS	164,451	MCF	1.00	164,451	983,085	7.68
20 SUWANNEE	1	52	5,591	14.5	96.77	30.2	15,066	GAS	84,236	MCF	1.00	84,236	533,472	9.54
21 SUWANNEE	2	50	5,298	14.2	99.68	30.8	15,215	GAS	80,610	MCF	1.00	80,610	511,164	9.65
22 SUWANNEE	3	51	13,616	35.9	97.42	72.2	12,260	GAS	166,933	MCF	1.00	166,933	930,228	6.83
23 TIGER BAY CC	1	204	8,238	5.4	22.48	96.1	7,262	GAS	59,823	MCF	1.00	59,823	359,817	4.37
24 UNIV OF FLA. CC	1	46	16,956	49.5	52.96	97.8	9,437	GAS	160,022	MCF	1.00	160,022	952,863	5.62
25 AVON PARK	1-2	49	0	0.0	82.42	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26 BARTOW	1-4	177	0	0.0	92.58	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27 BAYBORO	1-4	174	0	0.0	94.60	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 DEBARY	1-10	645	105	0.4	93.52	278.3	13,076	LIGHT OIL	236	BBLS	5.82	1,373	38,655	36.81
29 HIGGINS	1-4	113	0	0.0	89.76	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31 INT CITY	1-14	987	5	1.7	88.11	0.0	13,000	LIGHT OIL	11	BBLS	5.91	65	2,379	47.58
32 RIO PINAR	1	12	0	0.0	97.42	0.0	0	LIGHT OIL	0	BBLS		0	142	0.00
33 SUWANNEE	1-3	153	42	0.0	97.96	2.7	14,476	LIGHT OIL	105	BBLS	5.79	608	15,024	35.77
34 TURNER	1-4	149	0	0.0	95.24	0.0	0	LIGHT OIL	0	BBLS		0	1,128	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,922	BBLS	5.80	16,935	364,391	0.00
36 TOTAL			2,906,792									25,656,328	125,028,239	4.30

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-14

	(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	CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	376	99,391	36.7	95.20	55.7	10,450 COAL	42,201 TONS	24.61	1,038,637	4,768,110	4.80
3	CRYSTAL RIVER	2	500	168,006	46.7	92.57	50.2	10,677 COAL	72,884 TONS	24.61	1,793,806	8,124,241	4.84
4	CRYSTAL RIVER	4	732	210,550	39.9	42.43	92.2	10,212 COAL	93,041 TONS	23.11	2,150,157	7,830,043	3.72
5	CRYSTAL RIVER	5	712	481,534	93.9	94.85	98.9	10,107 COAL	210,598 TONS	23.11	4,866,872	16,939,860	3.52
6	ANCLOTE	1	517	0	0.0	94.43	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
7	ANCLOTE	2	521	0	0.0	6.63	0.0	0 HEAVY OIL	0 BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.00	0.0	0 HEAVY OIL	0 BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	94.00	0.0	0 HEAVY OIL	0 BBLS	0	0	0	0.00
10	SUWANNEE	3	73	0	0.0	51.46	0.0	0 HEAVY OIL	0 BBLS	0	0	0	0.00
11	ANCLOTE	1	517	91,956	24.7	0.00	25.6	10,736 GAS	987,197 MCF	1.00	987,197	5,280,494	5.74
12	ANCLOTE	2	521	1,040	0.3	0.00	66.5	10,952 GAS	11,390 MCF	1.00	11,390	741,040	71.25
13	AVON PARK	1-2	69	0	0.0	80.00	0.0	0 GAS	0 MCF		0	132	0.00
14	BARTOW	1-4	228	0	0.0	92.92	0.0	0 GAS	0 MCF		0	806	0.00
15	BARTOW CC	1	1,279	425,148	46.2	85.19	54.5	7,393 GAS	3,143,165 MCF	1.00	3,143,165	18,996,227	4.47
16	DEBARY	1-10	785	37	0.0	82.88	0.0	12,486 GAS	462 MCF	1.00	462	3,650	9.86
17	HIGGINS	1-4	129	0	0.0	91.42	0.0	0 GAS	0 MCF		0	76	0.00
18	HINES CC	1-4	2,204	885,853	55.8	72.44	22.3	7,096 GAS	6,285,847 MCF	1.00	6,285,847	37,935,784	4.28
19	INT CITY	1-14	1,186	3,319	0.4	88.24	7.2	12,572 GAS	41,727 MCF	1.00	41,727	257,255	7.75
20	SUWANNEE	1	67	5,105	10.6	95.67	22.7	14,850 GAS	75,809 MCF	1.00	75,809	493,902	9.67
21	SUWANNEE	2	66	4,924	10.4	99.33	23.2	14,907 GAS	73,404 MCF	1.00	73,404	481,542	9.78
22	SUWANNEE	3	67	12,678	26.3	99.67	50.2	12,116 GAS	153,611 MCF	1.00	153,611	855,067	6.74
23	TIGER BAY CC	1	225	13,610	8.4	89.33	93.1	7,630 GAS	103,850 MCF	1.00	103,850	644,084	4.73
24	UNIV OF FLA. CC	1	47	33,869	100.1	98.00	102.1	9,426 GAS	319,237 MCF	1.00	319,237	1,929,592	5.70
25	AVON PARK	1-2	69	0	0.0	80.00	0.0	0 LIGHT OIL	0 BBLS		0	0	0.00
26	BARTOW	1-4	228	0	0.0	92.92	0.0	0 LIGHT OIL	0 BBLS		0	0	0.00
27	BAYBORO	1-4	231	0	0.0	96.08	0.0	0 LIGHT OIL	0 BBLS		0	0	0.00
28	DEBARY	1-10	785	0	0.0	82.88	0.0	0 LIGHT OIL	0 BBLS		0	8,960	0.00
29	HIGGINS	1-4	129	0	0.0	91.42	0.0	0 LIGHT OIL	0 BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0 LIGHT OIL	0 BBLS	0	0	0	0.00
31	INT CITY	1-14	1,186	0	0.0	88.24	0.0	0 LIGHT OIL	0 BBLS		0	984	0.00
32	RIO PINAR	1	16	0	0.0	98.00	0.0	0 LIGHT OIL	0 BBLS		0	142	0.00
33	SUWANNEE	1-3	200	4	0.0	98.22	0.0	16,750 LIGHT OIL	12 BBLS	5.58	67	3,096	77.40
34	TURNER	1-4	199	0	0.0	95.42	0.0	0 LIGHT OIL	0 BBLS		0	1,128	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0 LIGHT OIL	2,399 BBLS	5.80	13,905	295,912	0.00
36	TOTAL			2,437,024							21,059,143	105,592,127	4.33

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-14

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	376	31,333	11.2	91.18	69.4	10,309	COAL	13,133	TONS	24.59	323,003	1,586,835	5.06
3 CRYSTAL RIVER	2	500	174,410	46.9	95.00	48.3	10,698	COAL	75,864	TONS	24.59	1,865,806	8,439,346	4.84
4 CRYSTAL RIVER	4	732	428,321	78.6	80.99	95.3	10,196	COAL	188,944	TONS	23.11	4,367,019	15,215,123	3.55
5 CRYSTAL RIVER	5	712	505,348	95.4	95.35	99.3	10,105	COAL	220,939	TONS	23.11	5,106,496	17,686,541	3.50
6 ANCLOTE	1	517	0	0.0	94.71	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7 ANCLOTE	2	521	0	0.0	96.75	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	92.58	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10 SUWANNEE	3	73	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11 ANCLOTE	1	517	96,434	25.1	0.00	25.7	10,733	GAS	1,034,996	MCF	1.00	1,034,996	5,566,785	5.77
12 ANCLOTE	2	521	5,368	1.4	0.00	32.2	10,935	GAS	58,701	MCF	1.00	58,701	1,000,654	18.64
13 AVON PARK	1-2	69	0	0.0	78.23	0.0	0	GAS	0	MCF		0	420	0.00
14 BARTOW	1-4	228	138	0.1	93.06	30.3	13,362	GAS	1,844	MCF	1.00	1,844	11,843	8.58
15 BARTOW CC	1	1279	480,486	50.5	85.14	61.2	7,348	GAS	3,530,756	MCF	1.00	3,530,756	21,213,086	4.41
16 DEBARY	1-10	785	1,688	0.3	96.81	11.9	12,519	GAS	21,132	MCF	1.00	21,132	125,088	7.41
17 HIGGINS	1-4	129	45	0.0	91.21	17.4	16,089	GAS	724	MCF	1.00	724	4,243	9.43
18 HINES CC	1-4	2,204	849,995	51.8	91.20	22.1	7,137	GAS	6,066,369	MCF	1.00	6,066,369	36,527,342	4.30
19 INT CITY	1-14	1,186	5,021	0.6	88.55	7.7	12,496	GAS	62,741	MCF	1.00	62,741	375,829	7.49
20 SUWANNEE	1	67	201	0.4	95.81	0.0	12,458	GAS	2,504	MCF	1.00	2,504	147,077	73.17
21 SUWANNEE	2	66	41	0.1	99.35	31.1	16,366	GAS	671	MCF	1.00	671	133,473	325.54
22 SUWANNEE	3	67	24,753	49.7	99.03	51.2	12,057	GAS	298,454	MCF	1.00	298,454	1,530,467	6.18
23 TIGER BAY CC	1	225	30,075	18.0	90.97	97.6	7,365	GAS	221,500	MCF	1.00	221,500	1,300,856	4.33
24 UNIV OF FLA. CC	1	47	34,675	99.2	97.10	102.2	9,428	GAS	326,912	MCF	1.00	326,912	1,964,219	5.66
25 AVON PARK	1-2	69	0	0.0	78.23	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26 BARTOW	1-4	228	0	0.0	93.06	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27 BAYBORO	1-4	231	0	0.0	96.13	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 DEBARY	1-10	785	0	0.0	96.81	0.0	0	LIGHT OIL	0	BBLS		0	8,960	0.00
29 HIGGINS	1-4	129	0	0.0	91.21	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31 INT CITY	1-14	1,186	4	0.6	88.55	0.0	13,750	LIGHT OIL	9	BBLS	6.11	55	2,155	53.88
32 RIO PINAR	1	16	0	0.0	97.10	0.0	0	LIGHT OIL	0	BBLS		0	142	0.00
33 SUWANNEE	1-3	200	18	0.0	98.06	1.1	13,111	LIGHT OIL	41	BBLS	5.76	236	6,795	37.75
34 TURNER	1-4	199	0	0.0	95.08	0.0	0	LIGHT OIL	0	BBLS		0	1,128	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,839	BBLS	5.80	16,454	351,375	0.00
36 TOTAL			2,668,354									23,306,373	113,199,782	4.24

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2014

			Act Jan-14	Act Feb-14	Act Mar-14	Act Apr-14	Act May-14	Act Jun-14	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	509	0	0	509
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	34,528	34,528	34,528	34,528	34,528	34,528	
11	UNIT COST	$/BBL	54.11	54.11	54.11	54.12	54.12	54.12	
12	AMOUNT	$	1,868,167	1,868,167	1,868,167	1,868,676	1,868,676	1,868,676	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	179	13,652	3,547	62,393	34,431	4,760	118,962
15	UNIT COST	$/BBL	887.79	147.15	177.26	141.81	143.85	168.10	146.24
16	AMOUNT	$	158,915	2,008,896	628,741	8,847,641	4,952,793	800,136	17,397,123
17	BURNED:								
18	UNITS	BBL	13,326	9,290	10,116	29,179	17,592	13,258	92,761
19	UNIT COST	$/BBL	123.12	125.37	138.58	124.83	130.98	131.73	128.29
20	AMOUNT	$	1,640,709	1,164,654	1,401,862	3,642,367	2,304,232	1,746,521	11,900,346
21	ENDING INVENTORY:								
22	UNITS	BBL	1,041,540	1,045,903	1,039,335	1,072,547	1,089,384	1,080,885	
23	UNIT COST	$/BBL	113.53	113.86	113.84	115.17	115.82	115.85	
24	AMOUNT	$	118,247,225	119,091,419	118,318,294	123,523,557	126,172,085	125,225,690	
	COAL								
25	PURCHASES:								
26	UNITS	TON	396,459	399,758	486,266	467,436	466,400	475,232	2,691,551
27	UNIT COST	$/TON	105.45	99.29	91.09	87.54	94.52	91.44	94.46
28	AMOUNT	$	41,807,826	39,690,555	44,295,223	40,920,160	44,083,346	43,455,348	254,252,459
29	BURNED:								
30	UNITS	TON	419,953	391,043	382,186	464,073	482,406	448,064	2,587,725
31	UNIT COST	$/TON	99.93	102.82	99.83	93.55	93.91	94.54	97.15
32	AMOUNT	$	41,965,217	40,207,180	38,152,248	43,412,779	45,303,730	42,359,673	251,400,826
33	ENDING INVENTORY:								
34	UNITS	TON	724,391	733,106	837,186	840,548	824,541	851,709	
35	UNIT COST	$/TON	101.32	99.41	94.39	91.05	91.34	89.71	
36	AMOUNT	$	73,397,285	72,880,686	79,023,666	76,531,051	75,310,670	76,406,346	
	GAS								
37	BURNED:								
38	UNITS	MCF	15,823,804	11,385,135	12,785,402	13,055,887	16,220,510	18,195,694	87,466,432
39	UNIT COST	$/MCF	5.40	6.32	6.13	5.87	6.24	5.82	5.94
40	AMOUNT	$	85,403,122	71,917,783	78,342,492	76,652,847	101,241,966	105,938,232	519,496,441
	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 2014

			Est Jul-14	Est Aug-14	Est Sep-14	Est Oct-14	Est Nov-14	Est Dec-14	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	509
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	34,528	34,528	34,528	34,528	34,528	34,528	
11	UNIT COST	$/BBL	54.12	54.12	54.12	54.12	54.12	54.12	
12	AMOUNT	$	1,868,676	1,868,676	1,868,676	1,868,676	1,868,676	1,868,676	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	2,001	2,228	1,423	3,274	2,411	2,889	133,188
15	UNIT COST	$/BBL	131.29	129.54	133.39	128.81	128.67	128.26	144.46
16	AMOUNT	$	262,715	288,612	189,811	421,719	310,222	370,555	19,240,757
17	BURNED:								
18	UNITS	BBL	2,001	2,228	1,423	3,274	2,411	2,889	106,987
19	UNIT COST	$/BBL	131.29	129.54	133.39	128.81	128.67	128.26	128.46
20	AMOUNT	$	262,715	288,612	189,811	421,719	310,222	370,555	13,743,980
21	ENDING INVENTORY:								
22	UNITS	BBL	1,080,885	1,080,885	1,080,885	1,080,885	1,080,885	1,080,885	
23	UNIT COST	$/BBL	131.29	129.54	133.39	128.81	128.67	128.26	
24	AMOUNT	$	141,909,392	140,017,843	144,179,250	139,228,797	139,077,473	138,634,310	
	COAL								
25	PURCHASES:								
26	UNITS	TON	608,982	600,007	592,194	526,340	418,724	498,880	5,936,678
27	UNIT COST	$/TON	87.66	87.77	87.60	85.63	89.95	86.05	90.60
28	AMOUNT	$	53,385,855	52,662,285	51,877,280	45,069,456	37,662,254	42,927,845	537,837,434
29	BURNED:								
30	UNITS	TON	608,982	600,007	592,194	526,340	418,724	498,880	5,832,852
31	UNIT COST	$/TON	87.66	87.77	87.60	85.63	89.95	86.05	91.72
32	AMOUNT	$	53,385,855	52,662,285	51,877,280	45,069,456	37,662,254	42,927,845	534,985,801
33	ENDING INVENTORY:								
34	UNITS	TON	851,709	851,709	851,709	851,709	851,709	851,709	
35	UNIT COST	$/TON	87.66	87.77	87.60	85.63	89.95	86.05	
36	AMOUNT	$	74,664,303	74,754,073	74,611,241	72,930,138	76,607,222	73,288,197	
	GAS								
37	BURNED:								
38	UNITS	MCF	16,757,351	17,110,365	15,361,774	13,353,987	11,195,699	11,627,304	172,872,912
39	UNIT COST	$/MCF	5.88	5.85	5.97	5.96	6.04	6.01	5.94
40	AMOUNT	$	98,548,479	100,138,542	91,657,891	79,537,064	67,619,651	69,901,382	1,026,899,450
	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 2014

(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-14	ECONSALE	--	53,596		53,596	3.795	12.642	2,033,703	6,775,851	4,742,148
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(871,007)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	70,062		70,062	3.561	3.561	2,494,856	2,494,856	0
	TOTAL		123,658		123,658	3.662	7.497	4,528,559	9,270,707	3,871,141
Feb-14	ECONSALE	--	20,149		20,149	4.962	6.250	999,742	1,259,406	259,664
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(51,933)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,391		84,391	4.346	4.346	3,667,224	3,667,224	0
	TOTAL		104,540		104,540	4.464	4.713	4,666,966	4,926,630	207,731
Mar-14	ECONSALE	--	22,235		22,235	3.293	4.805	732,117	1,068,449	336,332
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(67,266)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	83,883		83,883	3.780	3.780	3,170,850	3,170,850	0
	TOTAL		106,118		106,118	3.678	3.995	3,902,967	4,239,299	269,066
Apr-14	ECONSALE	--	7,492		7,492	3.468	3.893	259,844	291,664	31,820
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(6,364)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	72,281		72,281	5.149	5.149	3,721,643	3,721,643	0
	TOTAL		79,773		79,773	4.991	5.031	3,981,488	4,013,308	25,456
May-14	ECONSALE	--	2,560		2,560	3.415	3.718	87,422	95,193	7,771
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(1,554)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	52,053		52,053	4.439	4.439	2,310,810	2,310,810	0
	TOTAL		54,613		54,613	4.391	4.406	2,398,232	2,406,003	6,217
Jun-14	ECONSALE	--	6,650		6,650	2.675	3.160	177,909	210,144	32,235
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(6,447)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	81,372		81,372	4.188	4.188	3,407,919	3,407,919	0
	TOTAL		88,022		88,022	4.074	4.110	3,585,828	3,618,063	25,788
Jan	ECONSALE	--	112,682		112,682	3.808	8.609	4,290,736	9,700,707	5,409,970
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-14	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(1,004,572)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	444,042		444,042	4.228	4.228	18,773,303	18,773,303	0
	TOTAL		556,724		556,724	4.143	5.115	23,064,040	28,474,010	4,405,399

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2014

(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-14	ECONSALE	--	12,430		12,430	7.450	9.089	925,989	1,129,707	203,718
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(46,261)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	57,431		57,431	4.128	4.128	2,371,007	2,371,007	0
	TOTAL		69,861		69,861	4.719	5.011	3,296,996	3,500,714	157,457
Aug-14	ECONSALE	--	13,710		13,710	9.070	11.065	1,243,464	1,517,027	273,563
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(54,713)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	59,627		59,627	4.144	4.144	2,470,887	2,470,887	0
	TOTAL		73,337		73,337	5.065	5.438	3,714,351	3,987,914	218,850
Sep-14	ECONSALE	--	0		0	0.000	0.000	0	0	0
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	--	67,643		67,643	4.147	4.147	2,804,929	2,804,929	0
	TOTAL		67,643		67,643	4.147	4.147	2,804,929	2,804,929	0
Oct-14	ECONSALE	--	10		10	3.000	3.670	300	367	67
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(13)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	54,990		54,990	4.134	4.134	2,273,442	2,273,442	0
	TOTAL		55,000		55,000	4.134	4.134	2,273,742	2,273,809	54
Nov-14	ECONSALE	--	40		40	3.250	3.965	1,300	1,586	286
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(57)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	41,048		41,048	4.188	4.188	1,719,026	1,719,026	0
	TOTAL		41,088		41,088	4.187	4.188	1,720,326	1,720,612	229
Dec-14	ECONSALE	--	50		50	3.430	4.186	1,715	2,093	378
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(76)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	23,502		23,502	4.182	4.182	982,776	982,776	0
	TOTAL		23,552		23,552	4.180	4.182	984,491	984,869	302
Jan-14	ECONSALE	--	138,922		138,922	4.653	8.891	6,463,504	12,351,487	5,887,982
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-14	EXCESS GAIN	--	0		0	0.000	0.000	0	(1,105,692)	(1,105,692)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	748,283		748,283	4.196	4.196	31,395,371	31,395,371	0
	TOTAL		887,205		887,205	4.267	4.806	37,858,875	42,641,166	4,782,290

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2014

(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-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	32,128			32,128	6.457	6.457	2,074,545
	SOCO Franklin	--	84,600			84,600	4.793	4.793	4,054,549
	SOCO Scherer	--	9,291			9,291	3.171	3.171	294,612
	Vandolah (NSG)	--	5,665			5,665	10.093	10.093	571,754
	TOTAL		131,684	0	0	131,684	5.312	5.312	6,995,460
Feb-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	32,156			32,156	7.004	7.004	2,252,131
	SOCO Franklin	--	39,741			39,741	6.479	6.479	2,574,641
	SOCO Scherer	--	47,169			47,169	3.431	3.431	1,618,210
	Vandolah (NSG)	--	3,873			3,873	11.399	11.399	441,491
	TOTAL		122,939	0	0	122,939	5.602	5.602	6,886,472
Mar-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	17,854			17,854	7.529	7.529	1,344,303
	SOCO Franklin	--	16,950			16,950	7.244	7.244	1,227,926
	SOCO Scherer	--	42,678			42,678	3.254	3.254	1,388,717
	Vandolah (NSG)	--	819			819	21.531	21.531	176,335
	TOTAL		78,301	0	0	78,301	5.284	5.284	4,137,281
Apr-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	41,276			41,276	6.959	6.959	2,872,463
	SOCO Franklin	--	64,348			64,348	5.196	5.196	3,343,678
	SOCO Scherer	--	43,295			43,295	3.765	3.765	1,630,250
	Vandolah (NSG)	--	22,827			22,827	7.764	7.764	1,772,373
	TOTAL		171,746	0	0	171,746	5.601	5.601	9,618,764
May-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	67,954			67,954	7.293	7.293	4,955,655
	SOCO Franklin	--	137,288			137,288	4.578	4.578	6,284,832
	SOCO Scherer	--	44,435			44,435	3.192	3.192	1,418,405
	Vandolah (NSG)	--	39,313			39,313	8.351	8.351	3,283,076
	TOTAL		288,990	0	0	288,990	5.516	5.516	15,941,968
Jun-14	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	62,872			62,872	7.299	7.299	4,588,913
	SOCO Franklin	--	145,433			145,433	4.215	4.215	6,129,582
	SOCO Scherer	--	39,026			39,026	3.454	3.454	1,348,010
	Vandolah (NSG)	--	32,550			32,550	7.894	7.894	2,569,368
	TOTAL		279,881	0	0	279,881	5.229	5.229	14,635,873
Jan-14	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	254,240			254,240	7.115	7.115	18,088,009
Jun-14	SOCO Franklin	--	488,360			488,360	4.836	4.836	23,615,208
	SOCO Scherer	--	225,894			225,894	3.408	3.408	7,698,204
	Vandolah (NSG)	--	105,047			105,047	8.391	8.391	8,814,396
	TOTAL		1,073,541	0	0	1,073,541	5.423	5.423	58,215,817

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2014

(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-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	34,837			34,837	7.604	7.604	2,649,141
	SOCO Franklin	--	115,577			115,577	5.181	5.181	5,987,831
	SOCO Scherer	--	42,887			42,887	3.627	3.627	1,555,614
	Vandolah (NSG)	--	41,663			41,663	7.753	7.753	3,229,953
	TOTAL		234,964	0	0	234,964	5.713	5.713	13,422,539
Aug-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	37,046			37,046	7.584	7.584	2,809,537
	SOCO Franklin	--	122,179			122,179	5.134	5.134	6,272,296
	SOCO Scherer	--	43,587			43,587	3.631	3.631	1,582,504
	Vandolah (NSG)	--	45,059			45,059	7.573	7.573	3,412,112
	TOTAL		247,871	0	0	247,871	5.679	5.679	14,076,449
Sep-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	27,648			27,648	7.719	7.719	2,134,077
	SOCO Franklin	--	102,647			102,647	5.294	5.294	5,434,441
	SOCO Scherer	--	43,543			43,543	3.616	3.616	1,574,379
	Vandolah (NSG)	--	38,214			38,214	7.749	7.749	2,961,183
	TOTAL		212,052	0	0	212,052	5.708	5.708	12,104,080
Oct-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	20,175			20,175	7.563	7.563	1,525,855
	SOCO Franklin	--	111,276			111,276	5.198	5.198	5,783,937
	SOCO Scherer	--	42,714			42,714	3.625	3.625	1,548,553
	Vandolah (NSG)	--	31,615			31,615	7.546	7.546	2,385,726
	TOTAL		205,780	0	0	205,780	5.464	5.464	11,244,071
Nov-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	2,563			2,563	7.804	7.804	200,014
	SOCO Franklin	--	54,195			54,195	6.317	6.317	3,423,527
	SOCO Scherer	--	41,153			41,153	3.626	3.626	1,492,230
	Vandolah (NSG)	--	4,145			4,145	7.897	7.897	327,325
	TOTAL		102,056	0	0	102,056	5.333	5.333	5,443,096
Dec-14	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	4,558			4,558	8.567	8.567	390,495
	SOCO Franklin	--	56,640			56,640	6.347	6.347	3,595,094
	SOCO Scherer	--	42,568			42,568	3.626	3.626	1,543,693
	Vandolah (NSG)	--	4,789			4,789	8.288	8.288	396,928
	TOTAL		108,555	0	0	108,555	5.459	5.459	5,926,210
Jan-14	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	381,067			381,067	7.295	7.295	27,797,128
Dec-14	SOCO Franklin	--	1,050,874			1,050,874	5.149	5.149	54,112,334
	SOCO Scherer	--	482,346			482,346	3.523	3.523	16,995,177
	Vandolah (NSG)	--	270,532			270,532	7.958	7.958	21,527,623
TOTAL			2,184,819	0	0	2,184,819	5.512	5.512	120,432,262

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2014

(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-14 Act	QUAL. FACILITIES	COGEN	228,107			228,107	4.291	12.979	9,787,721
Feb-14 Act	QUAL. FACILITIES	COGEN	210,378			210,378	4.177	13.655	8,788,027
Mar-14 Act	QUAL. FACILITIES	COGEN	226,949			226,949	4.723	13.538	10,717,751
Apr-14 Act	QUAL. FACILITIES	COGEN	136,096			136,096	4.029	18.724	5,483,300
May-14 Act	QUAL. FACILITIES	COGEN	229,402			229,402	4.114	12.828	9,437,326
Jun-14 Act	QUAL. FACILITIES	COGEN	233,779			233,779	5.057	13.481	11,822,064
Jul-14 Est	QUAL. FACILITIES	COGEN	266,573			266,573	4.813	11.639	12,830,242
Aug-14 Est	QUAL. FACILITIES	COGEN	266,562			266,562	4.790	11.616	12,768,252
Sep-14 Est	QUAL. FACILITIES	COGEN	257,978			257,978	4.780	11.834	12,331,692
Oct-14 Est	QUAL. FACILITIES	COGEN	255,211			255,211	4.832	11.962	12,332,063
Nov-14 Est	QUAL. FACILITIES	COGEN	240,094			240,094	4.840	12.419	11,620,155
Dec-14 Est	QUAL. FACILITIES	COGEN	276,977			276,977	4.757	11.326	13,174,893
TOTAL	QUAL. FACILITIES	COGEN	2,828,107			2,828,107	4.635	12.719	131,093,485

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2014

(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-14	ECONPURCH	--	10,256	8.705	8.705	892,807	4.780	490,234	(402,572)
Act	SEPA	--	5,460	4.281	4.281	233,745	4.281	233,745	(0)
	TOTAL		15,716	7.168	7.168	1,126,552	4.607	723,979	(402,572)
Feb-14	ECONPURCH	--	31,889	6.140	6.140	1,958,142	6.970	2,222,813	264,671
Act	SEPA	--	594	4.403	4.403	26,133	4.403	26,133	(0)
	TOTAL		32,483	6.109	6.109	1,984,275	6.924	2,248,946	264,671
Mar-14	ECONPURCH	--	12,821	5.481	5.481	702,672	5.512	706,700	4,027
Act	SEPA	--	4,257	4.686	4.686	199,472	4.686	199,472	0
	TOTAL		17,078	5.283	5.283	902,144	5.306	906,172	4,028
Apr-14	ECONPURCH	--	35,544	5.369	5.369	1,908,250	6.086	2,163,372	255,122
Act	SEPA	--	55	4.387	4.387	2,431	4.387	2,431	(0)
	TOTAL		35,599	5.367	5.367	1,910,682	6.084	2,165,803	255,121
May-14	ECONPURCH	--	53,475	5.231	5.231	2,797,492	6.083	3,252,708	455,217
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		53,475	5.231	5.231	2,797,492	6.083	3,252,708	455,217
Jun-14	ECONPURCH	--	39,844	5.406	5.406	2,153,843	5.520	2,199,377	45,534
Act	SEPA	--	1,082	4.770	4.770	51,631	4.770	51,631	(0)
	TOTAL		40,926	5.389	5.389	2,205,474	5.500	2,251,008	45,534
Jan-14	ECONPURCH	--	183,829	5.665	5.665	10,413,206	6.00	11,035,204	621,998
THRU	SEPA	--	11,448	4.485	4.485	513,412	4.48	513,412	(0)
Jun-14									
	TOTAL		195,277	5.595	5.595	10,926,619	5.914	11,548,616	621,997

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2014

(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-14	ECONPURCH	--	17,885	7.092	7.092	1,268,403	8.264	1,478,004	209,601
Est	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		21,112	6.571	6.571	1,387,310	7.564	1,596,911	209,601
Aug-14	ECONPURCH	--	21,061	6.740	6.740	1,419,408	8.000	1,684,881	265,473
Est	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		24,288	6.334	6.334	1,538,315	7.427	1,803,788	265,473
Sep-14	ECONPURCH	--	57,365	5.187	5.187	2,975,362	6.653	3,816,538	841,176
Est	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		60,488	5.109	5.109	3,090,433	6.500	3,931,609	841,176
Oct-14	ECONPURCH	--	44,032	5.194	5.194	2,287,187	6.526	2,873,738	586,551
Est	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		47,259	5.091	5.091	2,406,094	6.332	2,992,645	586,551
Nov-14	ECONPURCH	--	11,505	6.069	6.069	698,202	6.057	696,829	(1,373)
Est	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		14,628	5.560	5.560	813,273	5.550	811,900	(1,373)
Dec-14	ECONPURCH	--	14,610	6.055	6.055	884,665	6.518	952,283	67,618
Est	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		17,837	5.626	5.626	1,003,572	6.005	1,071,190	67,618
Jan-14	ECONPURCH	--	350,287	5.694	5.694	19,946,433	6.434	22,537,477	2,591,044
THRU	SEPA	--	30,602	3.984	3.984	1,219,182	3.984	1,219,182	(0)
Dec-14									
	TOTAL		380,889	5.557	5.557	21,165,616	6.237	23,756,659	2,591,043

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2014

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 3,951,603	47.50%	10.50%	4.99%
Preferred Stock	17,874	0.21%	4.49%	0.01%
Long Term Debt	3,223,164	38.75%	5.61%	2.17%
Short Term Debt	35,074	0.42%	1.22%	0.01%
Customer Deposits - Active	182,636	2.20%	3.21%	0.07%
Customer Deposits - Inactive	1,162	0.01%	0.00%	0.00%
Deferred Tax	1,059,780	12.74%	0.00%	0.00%
Deferred Tax (FAS 109)	(155,042)	-1.86%	0.00%	0.00%
ITC	2,091	0.03%	8.22%	0.00%
	8,318,342	100.00%		7.25%

Total Debt	2.25%
Total Equity	5.00%

* May 2013 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 2014 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 2014

	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	100.00%		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 2014 Actual/Estimated True-up Filing does not currently include a capital return component

Docket 140001-EI
Exhibit No. ____(TGF-2)
Part 2

DUKE ENERGY FLORIDA

CAPACITY COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2014

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
Calculation of Projected Capacity Costs
For the Year 2014 - As filed on 08/30/13 in Docket 130001-EI

Docket No. 140001-EI
Exhibit__TGF-2, Part 2
Schedule E12-A
Page 1 of 1

		EST Jan-14	EST Feb-14	EST Mar-14	EST Apr-14	EST May-14	EST Jun-14	EST Jul-14	EST Aug-14	EST Sep-14	EST Oct-14	EST Nov-14	EST Dec-14	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Auburndale Power Partners, L.P. (AUBSET)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	822,248	822,248	822,248	822,248	822,248	822,248	-	-	-	-	-	-	4,933,488
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	37,301,840
8	Orlando Cogen Limited (ORLACOGL)	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	52,740,936
9	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	17,799,240
10	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	42,369,936
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	71,991,105
12	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
13	Southern Scherer	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	18,343,440
14	Subtotal - Base Level Capacity Costs	21,668,735	21,668,735	21,668,735	21,668,735	21,668,735	21,668,735	20,846,487	20,846,487	20,846,487	20,846,487	20,846,487	20,846,487	255,091,337
15	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%	
16	Base Level Jurisdictional Capacity Costs	20,127,005	20,127,004	20,127,004	20,127,004	20,127,004	20,127,005	19,363,260	19,363,260	19,363,260	19,363,260	19,363,260	19,363,260	236,941,585
17	**Intermediate Production Level Capacity Costs**													
18	Southern Franklin	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	25,956,000
19	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
20	Subtotal - Intermediate Level Capacity Costs	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	25,778,496
21	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%	
22	Intermediate Level Jurisdictional Capacity Costs	1,561,812	1,561,812	1,561,812	1,561,812	1,561,813	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	18,741,742
23	**Peaking Production Level Capacity Costs**													
24	Chattahoochee	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	146,769
25	Shady Hills Power Company LLC	1,968,252	1,968,252	1,405,894	1,363,927	1,909,498	3,881,947	3,881,947	3,881,947	1,811,575	1,363,927	1,363,927	1,968,252	26,769,345
26	Vandolah (NSG)	2,703,924	2,719,493	1,929,521	1,907,278	2,626,076	5,488,291	5,471,609	5,427,124	2,561,202	1,868,354	1,912,839	2,719,493	37,335,203
27	Subtotal - Peaking Level Capacity Costs	4,684,406	4,699,976	3,347,646	3,283,436	4,547,804	9,382,468	9,365,786	9,321,302	4,385,008	3,244,512	3,288,997	4,699,976	64,251,318
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	4,493,470	4,508,405	3,211,196	3,149,603	4,362,436	9,000,039	8,984,037	8,941,365	4,206,275	3,112,266	3,154,937	4,508,405	61,632,434
30	**Other Capacity Costs**													
31	Retail Wheeling	(14,527)	(26,756)	(1,588)	(2,226)	(46,227)	(439)	(4,904)	(44,262)	(327)	(2,288)	(2,005)	(245)	(145,793)
32	Other Jurisdictional Capacity Costs	(14,527)	(26,756)	(1,588)	(2,226)	(46,227)	(439)	(4,904)	(44,262)	(327)	(2,288)	(2,005)	(245)	(145,793)
33	**Total Capacity Costs (line 16+22+29+32)**	26,167,760	26,170,465	24,898,423	24,836,194	26,005,026	30,688,416	29,904,204	29,822,175	25,131,019	24,035,050	24,078,004	25,433,232	317,169,968
34	Estimated/Actual True-Up Provision - Jan - Dec 2013													24,360,251
35	**Total Capacity Costs w/ True-Up**													341,530,218
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													341,776,120
38	**Nuclear Cost Recovery Clause**													174,226,557
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													174,352,000
41	**Total Recoverable Capacity & Nuclear Costs (line 37+40)**													516,128,120

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2014

Docket No. 140001-EI
Exhibit__TGF-2, Part 2
Schedule E12-B

		ACT Jan-14	ACT Feb-14	ACT Mar-14	ACT Apr-14	ACT May-14	ACT Jun-14	EST Jul-14	EST Aug-14	EST Sep-14	EST Oct-14	EST Nov-14	EST Dec-14	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Auburndale Power Partners, L.P. (AUBSET)	$0	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	$822,248	822,248	822,248	822,248	822,248	822,248	-	-	-	-	-	-	4,933,485
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	2,832,765	3,015,075	3,108,487	3,108,487	3,108,487	3,084,148	2,925,220	2,925,220	2,925,220	2,925,220	2,925,220	2,925,220	35,808,768
8	Orlando Cogen Limited (ORLACOGL)	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,126,910	3,942,200	3,942,200	3,942,200	3,942,200	3,942,200	3,942,200	49,755,500
9	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	17,799,240
10	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	42,369,930
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,532,650	5,532,650	5,532,650	5,532,650	5,532,650	5,532,650	69,191,454
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	755,858	692,447	666,435	659,566	650,875	648,085	782,100	782,100	782,100	782,100	782,100	782,100	8,765,866
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Southern - Scherer	1,718,587	1,749,640	1,733,997	1,733,824	1,766,928	2,445,593	1,729,834	1,729,834	1,729,834	1,729,834	1,729,834	1,729,834	21,527,574
15	Subtotal - Base Level Capacity Costs	21,537,892	21,687,844	21,739,601	21,732,560	21,756,972	22,140,339	19,926,102	19,926,102	19,926,102	19,926,102	19,926,102	19,926,102	250,151,818
16	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%	
17	Base Level Jurisdictional Capacity Costs	20,005,471	20,144,754	20,192,829	20,186,288	20,208,963	20,565,054	18,508,360	18,508,360	18,508,360	18,508,360	18,508,360	18,508,360	232,353,516
18	**Intermediate Production Level Capacity Costs**													
19	Southern - Franklin	3,051,967	3,187,328	3,119,080	3,572,465	3,125,039	3,193,093	3,114,689	3,114,689	3,114,689	3,114,689	3,114,689	3,114,689	37,937,102
20	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Intermediate Level Capacity Costs	3,037,175	3,172,536	3,104,288	3,557,673	3,110,247	3,178,301	3,099,897	3,099,897	3,099,897	3,099,897	3,099,897	3,099,897	37,759,598
23	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%	
24	Intermediate Level Jurisdictional Capacity Costs	2,208,117	2,306,529	2,256,910	2,586,535	2,261,243	2,310,721	2,253,718	2,253,718	2,253,718	2,253,718	2,253,718	2,253,718	27,452,361
25	**Peaking Production Level Capacity Costs**													
26	Chattahoochee	11,636	8,929	-	-	-	-	-	-	-	-	-	-	20,564
27	Vandolah (RRI)	2,941,381	2,907,332	1,976,385	1,954,804	2,812,014	5,817,412	-	-	-	-	-	-	18,409,329
28	Shady Hills Power Company LLC	1,969,380	1,939,140	1,395,900	1,352,700	1,893,780	3,565,111	3,853,393	3,853,393	1,798,250	1,353,895	1,353,895	1,953,774	26,282,610
29	Vandolah (NSG)	-	-	-	-	-	-	5,576,136	5,531,366	2,647,069	1,949,778	1,994,548	2,806,375	20,505,272
30	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal - Peaking Level Capacity Costs	4,922,397	4,855,401	3,372,285	3,307,504	4,705,794	9,382,523	9,429,529	9,384,759	4,445,319	3,303,673	3,348,443	4,760,149	65,217,775
32	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%	
33	Peaking Level Jurisdictional Capacity Costs	4,721,760	4,657,495	3,234,831	3,172,690	4,513,986	9,000,091	9,045,181	9,002,236	4,264,127	3,169,015	3,211,960	4,566,125	62,559,498
34	**Other Capacity Costs**													
35	Retail Wheeling	(183,230)	(122,235)	(76,146)	(6,579)	(327)	(1,578)	(20,315)	(22,407)	-	(16)	(65)	(82)	(432,979)
36	Other Jurisdictional Capacity Costs	(183,230)	(122,235)	(76,146)	(6,579)	(327)	(1,578)	(20,315)	(22,407)	-	(16)	(65)	(82)	(432,979)
37	**Subtotal Jurisd Capacity Costs (Line 17+24+33+36)**	26,752,118	26,986,543	25,608,424	25,938,934	26,983,864	31,874,288	29,786,944	29,741,907	25,026,205	23,931,076	23,973,972	25,328,121	321,932,396
38	**Nuclear Cost Recovery Clause Costs**													
39	Levy Costs	9,297,660	10,346,712	8,857,433	8,809,330	8,761,227	8,713,125	8,246,353	8,616,919	8,568,816	8,520,714	8,472,611	8,424,508	105,635,408
40	CR3 Uprate Costs	5,879,367	5,849,741	5,819,965	5,790,240	5,760,514	5,730,788	5,701,063	5,671,341	5,641,617	5,611,894	5,582,171	5,552,449	68,591,149
41	**Total NCRC Costs - Order No. PSC-13-0665-FOF-EI**	15,177,027	16,196,453	14,677,398	14,599,570	14,521,741	14,443,913	13,947,416	14,288,260	14,210,433	14,132,608	14,054,782	13,976,957	174,226,557
42	**Total Jurisdictional Capacity Costs (Line 37+41)**	41,929,145	43,182,996	40,285,822	40,538,504	41,505,606	46,318,201	43,734,360	44,030,166	39,236,638	38,063,684	38,028,754	39,305,078	496,158,954
43	**Capacity Revenues**													
44	Capacity Cost Recovery Revenues (net of tax)	36,179,776	41,716,964	35,336,479	34,678,831	39,782,265	45,650,073	49,133,494	51,526,182	51,038,881	47,144,950	40,105,437	37,743,132	510,036,463
45	Prior Period True-Up Provision Over/(Under) Recovery	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(24,360,251)
46	**Current Period Revenues (net of tax)**	34,149,755	39,686,943	33,306,458	32,648,810	37,752,244	43,620,052	47,103,473	49,496,161	49,008,860	45,114,929	38,075,416	35,713,111	485,676,212
47	**True-Up Provision**													
48	True-Up Provision - Over/(Under) Recov (Line 46-42)	(7,779,390)	(3,496,053)	(6,979,364)	(7,889,693)	(3,753,362)	(2,698,148)	3,369,113	5,465,995	9,772,223	7,051,245	46,662	(3,591,967)	(10,482,739)
49	Interest Provision for the Month	(1,821)	(2,240)	(2,433)	(2,757)	(2,985)	(2,547)	(1,147)	(960)	(665)	(438)	(386)	(424)	(18,801)
50	Current Cycle Balance - Over/(Under)	(7,781,211)	(11,279,504)	(18,261,301)	(26,153,751)	(29,910,098)	(32,610,793)	(29,242,827)	(23,777,792)	(14,006,233)	(6,955,426)	(6,909,149)	(10,501,540)	(10,501,540)
51	Prior Period Balance - Over/(Under) Recovered	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)
52	Prior Period Cumulative True-Up Collected/(Refunded)	2,030,021	4,060,042	6,090,063	8,120,084	10,150,105	12,180,126	14,210,146	16,240,167	18,270,188	20,300,209	22,330,230	24,360,251	24,360,251
53	Prior Period True-up Balance - Over/(Under)	(28,819,930)	(26,789,909)	(24,759,888)	(22,729,867)	(20,699,846)	(18,669,825)	(16,639,804)	(14,609,783)	(12,579,762)	(10,549,741)	(8,519,721)	(6,489,700)	(6,489,700)
54	**Net Capacity True-up Over/(Under) (Line 50+53)**	($36,601,141)	($38,069,413)	($43,021,189)	($48,883,618)	($50,609,944)	($51,280,618)	($45,882,631)	($38,387,575)	($26,585,996)	($17,505,167)	($15,428,870)	($16,991,240)	($16,991,240)

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Lake County (LAKCOUNT)	Jan-95	Jun-14	QF	Purch	12.75
2	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
3	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	74.00
4	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
5	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
6	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
8	Florida Power Development	May-14	May-34	QF	Purch	60.00
9	Southern - Franklin	Jun-10	May-16	Other	Purch	350.00
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

(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 2014

Docket No. 140001-EI
Exhibit__TGF-2, Part 2
Schedule E12-C

		Re-Projection Total	Original Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$510,036,463	$515,756,775	($5,720,312)
3	Prior Period True-Up Provision Over/(Under) Recovery	(24,360,251)	(24,360,251)	0
4	**Current Period Revenues (net of tax)**	485,676,212	491,396,524	5,720,312
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Auburndale Power Partners, L.P. (AUBRDLFC)	0	0	0
9	Auburndale Power Partners, L.P. (AUBSET)	0	0	0
10	Lake County (LAKCOUNT)	13,833,105	4,933,488	8,899,617
11	Lake Cogen Limited (LAKORDER)	0	0	0
12	Metro-Dade County (METRDADE)	0	0	0
13	Orange Cogen (ORANGECO)	35,808,768	37,301,840	(1,493,071)
14	Orlando Cogen Limited (ORLACOGL)	49,755,500	52,740,936	(2,985,436)
15	Pasco County Resource Recovery (PASCOUNT)	30,084,585	17,799,240	12,285,345
16	Pinellas County Resource Recovery (PINCOUNT)	25,877,565	42,369,936	(16,492,371)
17	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	69,191,454	71,991,105	(2,799,651)
18	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	4,073,266	9,611,352	(5,538,086)
19	Southern - Sherer	21,527,574	18,343,440	3,184,134
20	Subtotal - Base Level Capacity Costs	250,151,818	255,091,337	(4,939,519)
21	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
22	Base Level Jurisdictional Capacity Costs	232,353,516	236,941,585	(4,588,069)
23				
24	**Intermediate Production Level Capacity Costs**			
25	Southern - Franklin	37,937,102	25,956,000	11,981,102
26	Schedule H Capacity Sales - NSB & RCID	(177,504)	(177,504)	0
27	Subtotal - Intermediate Level Capacity Costs	37,759,598	25,778,496	11,981,102
28	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
29	Intermediate Level Jurisdictional Capacity Costs	27,452,361	18,741,742	8,710,619
30				
31	**Peaking Production Level Capacity Costs**			
32	Chattahoochee	20,564	146,769	(126,205)
33	Vandolah (RRI)	18,409,329	0	18,409,329
34	Shady Hills Power Company LLC	26,282,610	26,769,345	(486,735)
35	Vandolah (NSG)	20,505,272	37,335,203	(16,829,931)
36	Subtotal - Peaking Level Capacity Costs	65,217,775	64,251,318	966,457
37	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
38	Peaking Level Jurisdictional Capacity Costs	62,559,498	61,632,434	927,064
39				
40	**Other Capacity Costs**			
41	Retail Wheeling	(432,979)	(145,793)	(287,186)
42	Other Jurisdictional Capacity Costs	(432,979)	(145,793)	(287,186)
43				
44	**Subtotal Jurisdictional Capacity Costs (Line 22+29+38+42)**	321,932,396	317,169,968	4,762,429
45				
46	**Nuclear Cost Recovery Clause Costs**			
47	Levy Costs	105,635,408	105,635,408	0
48	CR3 Uprate Costs	68,591,149	68,591,149	0
49	**Total NCRC Costs - Order No. PSC-13-0665-FOF-EI**	174,226,557	174,226,557	0
50				
51	**Total Jurisdictional Capacity Costs (Line 44+49)**	496,158,954	491,396,525	4,762,429
52				
53	**True-Up Provision**			
54	True-Up Provision - Over/(Under) Recov (Line 4-51)	(10,482,739)	0	(10,482,739)
55	Interest Provision for the Month	(18,801)	0	(18,801)
56	Current Cycle Balance - Over/(Under)	(10,501,540)	0	(10,501,540)
57				
58	Prior Period Balance - Over/(Under) Recovered	(30,849,951)	(24,360,251)	(6,489,700)
59	Prior Period Cumulative True-Up Collected/(Refunded)	24,360,251	24,360,251	0
60	Prior Period True-up Balance - Over/(Under)	(6,489,700)	0	(6,489,700)
61				
62	**Net Capacity True-up Over/(Under) (Line 56+60)**	($16,991,240)	$0	($16,991,240)

Docket 140001-EI
Exhibit No. ____(TGF-3)
Part 1

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2015

PART 1 – 2015 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 24
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-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 2015	112.93	19.48	108.52	4.41	77.03	3.34	4.15
Feb 2015	112.42	19.40	107.01	4.35	76.60	3.32	4.14
Mar 2015	112.98	19.49	105.48	4.29	76.19	3.31	4.07
Apr 2015	112.55	19.42	104.33	4.24	75.92	3.30	3.84
May 2015	112.33	19.38	103.23	4.20	75.73	3.29	3.83
Jun 2015	112.15	19.35	102.32	4.16	75.61	3.29	3.86
Jul 2015	112.08	19.34	101.76	4.14	75.33	3.28	3.89
Aug 2015	112.05	19.33	101.26	4.12	75.08	3.27	3.90
Sep 2015	110.87	19.13	100.98	4.10	74.94	3.26	3.88
Oct 2015	110.81	19.12	100.94	4.10	74.81	3.26	3.90
Nov 2015	110.69	19.10	100.92	4.10	74.88	3.26	3.96
Dec 2015	110.97	19.15	100.89	4.10	74.75	3.25	4.13
Average	111.90	19.31	103.14	4.19	75.57	3.28	3.96

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 140001-EI
Exhibit No. ____(TGF-3)
Part 2

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

JANUARY THROUGH DECEMBER 2015

PART 2 - 2015 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 RRSSA – Summary of RRSSA Adjustments

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. 140001-EI
Schedule E1
Exhibit TGF-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2015

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)		1,450,550,393	35,719,602	4.06094
2.	Spent Nuclear Fuel Disposal Cost		0	0 *	0.00000
3.	Coal Car Investment		0	0	0.00000
4.	Adjustment to Fuel Cost		(40,353,675)	0	0.00000
5.	TOTAL COST OF GENERATED POWER		1,410,196,718	35,719,602	3.94796
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		101,841,738	2,017,470	5.04799
7.	Energy Cost of Economy Purchases (E9)		16,351,874	356,500	4.58678
8.	Payments to Qualifying Facilities (E8)		145,142,688	3,087,667	4.70072
9.	TOTAL COST OF PURCHASED POWER		263,336,300	5,461,637	4.82156
10.	TOTAL AVAILABLE MWH			41,181,239	
11.	Fuel Cost of Economy Sales	(E6)	(4,199,152)	(126,300)	3.32474
11a.	Gain on Economy Sales	(E6)	(923,813)	(126,300) *	0.73144
12.	Fuel Cost of Stratified Sales	(E6)	(21,800,391)	(550,476)	3.96028
13.	TOTAL FUEL COST AND GAINS ON POWER SALES		(26,923,356)	(676,776)	3.97818
14.	Net Inadvertent Interchange				
15.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,646,609,662	40,504,463	4.06525
16.	Net Unbilled		3,781,869 *	(93,029)	0.00995
17.	Company Use		5,853,967 *	(144,000)	0.01540
18.	T & D Losses		91,160,151 *	(2,242,422)	0.23974
19.	Adjusted System Sales		1,646,609,662	38,025,012	4.33033
20.	Wholesale Sales (Excluding Supplemental Sales)		(10,295,985)	(239,422)	4.30035
21.	Jurisdictional Sales		1,636,313,678	37,785,590	4.33052
22.	Jurisdictional Sales Adjusted for Line Losses x	1.00148	1,638,735,421	37,785,590	4.33693
23.	Prior Period True-Up (Sch E1-A)		73,672,203	37,785,590	0.19497
24.	Total Jurisdictional Fuel Cost		1,712,407,624	37,785,590	4.53191
25.	Revenue Tax Factor		1,232,933		1.00072
26.	Fuel Cost Adjusted for Taxes		1,713,640,557	37,785,590	4.53517
27.	GPIF **		2,231,853	37,785,590	0.00591
28.	Fuel Factor Adjusted for taxes including GPIF		1,715,872,410	37,785,590	4.54108
29.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				4.541

* 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 2015

1.	Actual Over/(Under) Recovery January - December 2013. **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '13 **)**	$	(5,961,090)
2.	Projected (Over)/Under Recovery January - December 2013 . (Refunded)/Collected January - December 2013 . **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '13 **)**	$	33,195,183
3.	Estimated Over/(Under) Recovery January - December 2014 **(** Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '14 **)**	$	(100,906,296)
4.	Total Over/(Under) Recovery to be Included in the January - December 2014 Projected Period **(** Lines 1 through 3 **)**	$	(73,672,203)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	37,785,590
6.	True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.195

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 129,009,047	$ 113,289,617	$ 117,896,602	$ 123,707,993	$ 148,849,928	$ 150,044,426	$ 782,797,613
	2	Fuel Cost of Power Sold	(8,399,700)	(4,874,697)	(4,172,032)	(4,006,945)	(2,404,449)	(3,611,616)	(27,469,439)
	3	Fuel Cost of Purchased Power	6,995,460	6,886,472	4,137,281	9,618,764	15,941,968	14,635,873	58,215,817
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	9,787,721	8,788,027	10,717,751	5,483,300	9,437,326	11,822,064	56,036,188
	4	Energy Cost of Economy Purchases	1,126,552	1,984,275	902,144	1,910,682	2,797,492	2,205,474	10,926,619
	5	Adjustments to Fuel Cost	(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(12,913,643)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
B	1	Jurisdictional MWH Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	17,013,292
	2	Non-Jurisdictional MWH Sales	22,565	44,021	16,238	32,556	33,247	28,733	177,361
	3	TOTAL SALES (Lines B1 + B2)	2,645,518	2,960,084	2,583,858	2,594,512	2,990,919	3,415,762	17,190,653
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	98.97%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	112,142,525	125,857,590	109,339,746	109,372,799	128,046,715	147,816,093	732,575,469
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	1b	RRSSA Fuel Adjustment	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(17,013,292)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	118,064,769	131,486,725	115,317,323	115,356,040	133,634,241	152,974,262	766,833,361
	4	Fuel & Net Power Transactions (Line A6)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	137,533,195	124,365,581	128,880,719	135,188,666	172,922,325	161,095,355	859,985,842
	6	Over/(Under) Recovery (Line C3 - Line C5)	(19,468,426)	7,121,144	(13,563,396)	(19,832,626)	(39,288,084)	(8,121,092)	(93,152,480)
	7	Interest Provision	(716)	(1,063)	(1,108)	(1,962)	(3,570)	(4,021)	(12,439)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,469,142)	7,120,081	(13,564,504)	(19,834,588)	(39,291,654)	(8,125,113)	(93,164,920)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(3,194,825)	(428,560)	2,337,705	5,103,970	7,870,235	10,636,500	10,636,500
	12	Regulatory Accounting Adjustment	-	-	(588,930)	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($22,663,966)	(12,777,621)	($24,164,790)	($41,233,113)	($77,758,502)	($83,117,350)	($83,117,350)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 152,197,049	$ 153,089,439	$ 143,724,982	$ 125,028,239	$ 105,592,127	$ 113,199,782	$ 1,575,629,231
	2	Fuel Cost of Power Sold	(3,454,453)	(3,933,202)	(2,804,929)	(2,273,796)	(1,720,555)	(984,793)	(42,641,167)
	3	Fuel Cost of Purchased Power	13,422,539	14,076,449	12,104,080	11,244,071	5,443,096	5,926,210	120,432,262
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	12,830,242	12,768,252	12,331,692	12,332,063	11,620,155	13,174,893	131,093,485
	4	Energy Cost of Economy Purchases	1,387,310	1,538,315	3,090,433	2,406,094	813,273	1,003,572	21,165,616
	5	Adjustments to Fuel Cost	(19,486)	(19,498)	(19,508)	(19,502)	(19,488)	(19,461)	(13,030,585)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
B	1	Jurisdictional MWH Sales	3,578,550	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665
	2	Non-Jurisdictional MWH Sales	24,537	27,901	29,414	26,399	20,273	15,121	321,006
	3	TOTAL SALES (Lines B1 + B2)	3,603,087	3,780,718	3,746,740	3,460,117	2,941,281	2,764,075	37,486,671
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.32%	99.26%	99.21%	99.24%	99.31%	99.45%	99.14%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	156,609,389	164,276,459	162,714,963	150,237,348	127,680,111	120,110,401	1,614,204,140
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	1b	RRSSA Fuel Adjustment	(3,578,550)	(3,752,817)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,165,665)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,268)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	161,576,036	169,068,839	167,542,835	155,348,827	133,304,301	125,906,647	1,679,580,845
	4	Fuel & Net Power Transactions (Line A6)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	175,423,175	176,466,894	167,343,481	147,805,348	121,067,595	131,767,280	1,779,859,614
	6	Over/(Under) Recovery (Line C3 - Line C5)	(13,847,139)	(7,398,056)	199,354	7,543,480	12,236,705	(5,860,633)	(100,278,769)
	7	Interest Provision	(4,430)	(4,823)	(4,865)	(4,533)	(3,901)	(3,604)	(38,596)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(13,851,569)	(7,402,879)	194,489	7,538,946	12,232,804	(5,864,237)	(100,317,366)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	13,402,765	16,169,030	18,935,295	21,701,560	24,467,825	27,234,094	27,234,093
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($94,202,654)	($98,839,267)	($95,878,514)	($85,573,302)	($70,574,233)	($73,672,202)	($73,672,203)

Docket: 140001-EI
Witness: Foster
Exhibit: TGF-3, Part 2
Schedule: RRSSA

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

	System:	Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
1	RRSSA Refund ($40 million)	(3,347,151)	(3,352,208)	(3,345,133)	(3,343,789)	(3,346,142)	(3,345,805)	(3,350,183)	(3,353,897)	(3,354,573)	(3,353,559)	(3,351,533)	(3,346,478)	(40,190,452)		6.b.
2	Other Adjustments to Fuel Cost	(13,594)	(13,614)	(13,585)	(13,580)	(13,589)	(13,588)	(13,606)	(13,621)	(13,624)	(13,620)	(13,611)	(13,591)	(163,223)		
3	Total 2015 Adjustments to Fuel Cost (Lines 1 + 2)	(3,360,745)	(3,365,822)	(3,358,718)	(3,357,369)	(3,359,731)	(3,359,394)	(3,363,789)	(3,367,518)	(3,368,197)	(3,367,179)	(3,365,144)	(3,360,069)	(40,353,675)	E1, line 4	
4	Jurisdictional % of Total Sales	99.44%	99.29%	99.50%	99.54%	99.47%	99.48%	99.35%	99.24%	99.22%	99.25%	99.31%	99.46%			
5	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			

	Retail:	Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
6	RRSSA Refund ($40 million)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(40,000,000)		6.b.
7	Other Adjustments to Fuel Cost	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(162,209)		
8	Total 2015 Adjustments to Fuel Cost (Lines 6 + 7)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(40,162,209)		
9	Retail mWh Sales	3,053,112	2,711,825	2,630,687	2,655,086	2,850,830	3,443,184	3,787,779	3,680,235	3,748,879	3,503,048	2,952,686	2,768,240	37,785,590	E1-D, line 5	
10	RRSSA Fuel Adjustment ($/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		E1-D, line 9	7.a. / 7.a(ii)
11	Total RRSSA Fuel Adjustment to Revenue (Line 9 * 10)	(3,053,112)	(2,711,825)	(2,630,687)	(2,655,086)	(2,850,830)	(3,443,184)	(3,787,779)	(3,680,235)	(3,748,879)	(3,503,048)	(2,952,686)	(2,768,240)	(37,785,590)		

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2015

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	2,231,853
	B. True-Up (Over) / Under Recovery	$	73,672,203
2.	JURISDICTIONAL mWh SALES	mWh	37,785,590
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.006
	B. True-Up Factor	Cents/kWh	0.195

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2015

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$	1,638,735,421	
1a.	Prior Period True-up (E1, Line 23)	$	73,672,203	
2.	Regulatory Assessment Fee (E1, Line 25)	$	1,232,933	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$	2,231,853	
4.	Total amount to be Recovered	$	1,715,872,410	
5.	Jurisdictional Sales (January - December 2015)		37,785,590	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		4.541	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		37,738,631	mWh

LEVELIZED FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):

8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)	4.547	Cents/kWh
9.	Fuel Factor Adjustment pursuant to 2013 Revised and Restated Stipulation and Settlement Agreement	0.100	Cents/kWh
10.	Adjusted Fuel Factor at Secondary Metering (Line 8 + Line 9)	4.647	Cents/kWh
11.	Fuel Factor at Primary Metering	4.601	Cents/kWh
12.	Fuel Factor at Transmission Metering	4.554	Cents/kWh

LEVELIZED FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):

13.	2013 Settlement Agreement Refund (per Order No. PSC-13-0598-FOF-EI)*	$	(9,400,000)	
14.	Interest Amortization on Settlement Agreement Refund*	$	(15,408)	
15.	Applicable Jurisdictional Sales at Secondary Metering**		19,390,957	mWh
16.	Fuel Factor at Secondary Metering Rate Adjustment (Line 13 + Line 14 / Line 15 / 10)		(0.049)	Cents/kWh
17.	Fuel Factor at Secondary Metering (Line 10 + Line 16)		4.598	Cents/kWh

LEVELIZED FUEL FACTORS (only GS-1, GST-1 & GS-2):

18.	2013 Settlement Agreement Refund (per Order No. PSC-13-0598-FOF-EI)*	$	(600,000)	
19.	Interest Amortization on Settlement Agreement Refund*	$	(983)	
20.	Applicable Jurisdictional Sales at Secondary Metering**		1,420,031	mWh
21.	Fuel Factor at Secondary Metering Rate Adjustment (Line 18 + Line 19 / Line 20 / 10)		(0.042)	Cents/kWh
22.	Fuel Factor at Secondary Metering (Line10 + Line 21)		4.605	Cents/kWh
23.	Fuel Factor at Primary Metering		4.559	Cents/kWh
24.	Fuel Factor at Transmission Metering		4.513	Cents/kWh

TIERED FUEL FACTORS:

25.	Fuel Factor - First Tier (0-1000 kWh)	4.323	Cents/kWh
26.	Fuel Factor - Second Tier (Over 1000 kWh)	5.323	Cents/kWh

* The 2013 Settlement Agreement refunds and associated interest included on lines 13-14 and 18-19 are included in paragraph 6 of the 2013 RRSSA

** Applicable Jurisdictional Sales at Secondary Metering utilized in the calculation of the 2013 Settlement Agreement Refund Fuel Factor Adjustment (lines 15 & 20) are a subset of the Effective Jurisdictional Sales reported above on line 7.

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	33,430,835	33,430,835
Distribution Primary	4,013,650	3,973,513
Transmission	341,105	334,283
Total	37,785,590	37,738,631

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2015

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	----------Time of Use---------- On-Peak Multiplier 1.346	Off-Peak Multiplier 0.837
	FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):					
1.	Distribution Secondary	--	--	4.647	6.255	3.890
2.	Distribution Primary	--	--	4.601	6.193	3.851
3.	Transmission	--	--	4.554	6.130	3.812
4.	Lighting Service	--	--	4.332	--	--
	Line 4 calculated at secondary rate of 4.647 * (18.7% * On-Peak Multiplier 1.346 + 81.3% * Off-Peak Multiplier 0.837).					
	FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):					
5.	Distribution Secondary	4.323	5.323	4.598	6.189	3.849
	FUEL FACTORS (only GS-1, GST-1 & GS-2):					
6.	Distribution Secondary	--	--	4.605	6.198	3.854
7.	Distribution Primary	--	--	4.559	6.136	3.816
8.	Transmission	--	--	4.513	6.074	3.777

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-15	848,405	36,773,208	4.334	2,296,121	74,786,984	3.257	3,144,526	111,560,192	3.548
Feb-15	738,227	34,512,286	4.675	2,064,839	71,390,078	3.457	2,803,066	105,902,364	3.778
Mar-15	770,030	32,571,134	4.230	2,153,340	76,932,716	3.573	2,923,370	109,503,849	3.746
Apr-15	1,077,068	63,994,355	5.942	1,968,264	63,780,311	3.240	3,045,332	127,774,666	4.196
May-15	1,243,861	72,794,652	5.852	2,406,613	82,359,441	3.422	3,650,474	155,154,093	4.250
Jun-15	1,405,702	81,752,678	5.816	2,521,153	84,546,503	3.353	3,926,855	166,299,181	4.235
Jul-15	1,471,948	96,339,873	6.545	2,627,310	90,223,688	3.434	4,099,258	186,563,560	4.551
Aug-15	1,364,647	82,629,098	6.055	2,797,685	102,503,512	3.664	4,162,332	185,132,609	4.448
Sep-15	1,426,454	86,673,653	6.076	2,483,906	84,276,951	3.393	3,910,360	170,950,605	4.372
Oct-15	1,213,054	67,123,022	5.533	2,249,444	74,078,928	3.293	3,462,498	141,201,950	4.078
Nov-15	725,131	29,467,100	4.064	2,103,699	75,115,038	3.571	2,828,830	104,582,138	3.697
Dec-15	881,722	37,629,270	4.268	2,216,298	70,667,815	3.189	3,098,020	108,297,085	3.496
TOTAL	13,166,249	722,260,328	5.486	27,888,672	950,661,965	3.409	41,054,921	1,672,922,293	4.075

MARGINAL FUEL COST	ON-PEAK	OFF-PEAK	AVERAGE
WEIGHTING MULTIPLIER	1.346	0.837	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2013
Estimated for the Period of : January through December 2015

		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		344,867	(1,518)	343,349		0.9851266	348,533		
Distribution Primary		3,960,209	(17,395)	3,942,814		0.9751266	4,043,387		
Distribution Secondary		32,310,913	(142,218)	32,168,695		0.9360703	34,365,683		
Total Retail		36,615,989	(161,131)	36,454,858	97.21%	0.9405860	38,757,602	97.36%	1.00148
						5.94%			
Wholesale									
Generation Level		626,100	(22,884)	603,216		1.0000000	603,216		
Transmission		419,322	(2,872)	416,450		0.9851266	422,737		
Distribution Primary		26,079	(1,158)	24,921		0.9751266	25,557		
Distribution Secondary		-	-	-			-		
Total Wholesale		1,071,500	(26,914)	1,044,586	2.79%	0.9934159	1,051,510	2.64%	0.94822
						0.66%			
Subtotal Class		37,687,489	(188,045)	37,499,444	100.00%	0.9419814	39,809,112	100.00%	1.00000
						5.80%			
Non-Class									
SEPA	Transmission	30,736	-	30,736		0.9851266	31,200		
Homestead - Base	Generation	124,539	665	125,204		1.0000000	125,204		
SECI - Base	Generation	89,061	(3,692)	85,369		1.0000000	85,369		
Homestead - Intermediate	Generation	8,459	45	8,504		1.0000000	8,504		
Reedy Creek - Base	Generation	9,965	53	10,018		1.0000000	10,018		
Reedy Creek - Intermediate	Generation	99,225	530	99,755		1.0000000	99,755		
NSB - Peaking	Generation	9,446	50	9,496		1.0000000	9,496		
Tallahassee - Base	Transmission	8,482	45	8,527		0.9851266	8,656		
Gainesville - Base	Generation	37,083	198	37,281		1.0000000	37,281		
Interchange	Generation	426,503	-	426,503		1.0000000	426,503		
Company Use	Secondary	161,653	-	161,653		0.9360703	172,693		
Total Non-Class		1,005,153	(2,106)	1,003,047			1,014,680		
Total System		38,692,642	(190,151)	38,502,491		0.943139	40,823,791		

Docket No. 140001-EI
Schedule E2
Exhibit TGF-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2015

			Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	TOTAL
1	Fuel Cost of System Net Generation		$113,245,954	$100,531,367	$104,243,014	$113,277,405	$132,785,987	$136,880,328	$142,696,460	$144,773,035	$136,530,018	$120,355,860	$97,148,895	$108,082,070	$1,450,550,393
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(3,360,745)	(3,365,822)	(3,358,718)	(3,357,369)	(3,359,731)	(3,359,394)	(3,363,789)	(3,367,518)	(3,368,197)	(3,367,179)	(3,365,144)	(3,360,069)	(40,353,675)
2	Fuel Cost of Power Sold		(1,038,840)	(665,089)	(194,320)	(147,722)	(886,743)	(26,948)	(483,815)	(468,841)	(3,240)	(4,618)	(142,180)	(136,796)	(4,199,152)
2a	Gains on Power Sales		(228,545)	(146,320)	(42,750)	(32,498)	(195,084)	(5,928)	(106,439)	(103,146)	(712)	(1,016)	(31,280)	(30,095)	(923,813)
2b	Fuel Cost of Stratified Sales		(1,215,937)	(1,250,429)	(1,303,070)	(1,572,220)	(1,689,334)	(2,067,519)	(2,357,532)	(2,464,570)	(2,753,161)	(2,297,359)	(1,740,143)	(1,089,118)	(21,800,391)
3	Fuel Cost of Purchased Power (Excl Economy)		4,313,976	6,121,894	5,286,038	4,619,223	9,120,856	12,039,049	14,241,003	14,514,843	11,272,680	10,334,627	6,241,234	3,736,315	101,841,738
3a	Energy Payments to Qualifying Facilities		13,203,009	11,888,505	12,002,597	10,786,174	12,529,047	12,071,397	12,448,464	12,410,731	11,971,496	11,891,761	11,295,964	12,643,543	145,142,688
4	Energy Cost of Economy Purchases		541,062	427,832	1,175,780	1,389,895	1,794,295	2,086,429	1,379,450	1,487,857	2,579,449	1,905,474	939,971	644,380	16,351,874
5	Total System Fuel & Net Power Transactions		$125,459,934	$113,541,938	$117,808,571	$124,962,888	$150,099,293	$157,617,414	$164,453,801	$166,782,391	$156,228,333	$138,817,551	$110,347,317	$120,490,230	$1,646,609,662
6	Jurisdictional mWh Sold		3,053,112	2,711,825	2,630,687	2,655,086	2,850,830	3,443,184	3,787,779	3,680,235	3,748,879	3,503,048	2,952,686	2,768,240	37,785,590
7	Jurisdictional % of Total Sales		99.44%	99.29%	99.50%	99.54%	99.47%	99.48%	99.35%	99.24%	99.22%	99.25%	99.31%	99.46%	99.37%
8	Jurisdicitonal Fuel & Net Power Transactions		124,757,358	112,735,790	117,219,528	124,388,059	149,303,767	156,797,804	163,384,852	165,514,845	155,009,752	137,776,419	109,585,920	119,839,583	1,636,313,678
9	Jurisdictional Loss Multiplier		1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
10	Jurisdictional Fuel & Net Power Transactions		124,941,999	112,902,639	117,393,013	124,572,153	149,524,736	157,029,865	163,626,661	165,759,807	155,239,166	137,980,328	109,748,108	120,016,945	1,638,735,422
11	Adjusted System Sales	mWh	3,070,268	2,731,256	2,643,916	2,667,455	2,866,060	3,461,116	3,812,375	3,708,258	3,778,362	3,529,488	2,973,079	2,783,380	38,025,012
12	System Cost per kWh Sold	c/kWh	4.0863	4.1571	4.4559	4.6847	5.2371	4.5539	4.3137	4.4976	4.1348	3.9331	3.7115	4.3289	4.3303
13	Jurisdictional Loss Multiplier	x	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
14	Jurisdictional Cost per kWh Sold	c/kWh	4.0923	4.1633	4.4624	4.6918	5.2450	4.5606	4.3199	4.5041	4.1409	3.9389	3.7169	4.3355	4.3369
15	Prior Period True-Up	+	0.2011	0.2264	0.2334	0.2312	0.2154	0.1783	0.1621	0.1668	0.1638	0.1753	0.2079	0.2218	0.1950
16	Total Jurisdictional Fuel Expense	c/kWh	4.2934	4.3897	4.6958	4.9231	5.4603	4.7389	4.4819	4.6709	4.3047	4.1141	3.9248	4.5573	4.5319
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	4.2965	4.3929	4.6992	4.9266	5.4642	4.7423	4.4852	4.6742	4.3078	4.1171	3.9276	4.5606	4.5352
19	GPIF	+	0.0061	0.0069	0.0071	0.0070	0.0065	0.0054	0.0049	0.0051	0.0050	0.0053	0.0063	0.0067	0.0059
20	Total Recovery Factor (rounded .001)	c/kWh	4.303	4.400	4.706	4.934	5.471	4.748	4.490	4.679	4.313	4.122	3.934	4.567	4.541

Docket No. 140001-EI
Schedule E3 (Sheet 1)
Exhibit TGF-3, Part 2

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2015

			Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
3	COAL		37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
4	GAS		74,987,317	65,153,020	65,740,975	76,341,745	95,207,574	98,625,108	476,055,739
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	113,245,954	100,531,367	104,243,014	113,277,405	132,785,987	136,880,328	700,964,055
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		565	513	74	21	16	129	1,318
10	COAL		1,028,298	957,458	1,050,974	982,603	993,270	1,014,726	6,027,329
11	GAS		1,778,960	1,483,660	1,502,028	1,735,327	2,229,801	2,359,104	11,088,880
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,807,823	2,441,631	2,553,076	2,717,951	3,223,087	3,373,959	17,117,527
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	3,381	2,924	1,590	1,173	2,011	2,121	13,200
17	COAL	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
18	GAS	MCF	13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
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		19,593	16,943	9,209	6,805	11,668	12,305	76,523
23	COAL		10,584,690	9,838,950	10,815,632	10,375,406	10,491,562	10,694,891	62,801,131
24	GAS		13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	23,993,389	21,093,278	22,190,470	23,823,783	27,943,217	28,932,472	147,976,609
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.02%	0.02%	0.00%	0.00%	0.00%	0.00%	0.01%
30	COAL		36.62%	39.21%	41.17%	36.15%	30.82%	30.08%	35.21%
31	GAS		63.36%	60.77%	58.83%	63.85%	69.18%	69.92%	64.78%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
37	COAL	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
38	GAS	$/MCF	5.60	5.80	5.78	5.68	5.46	5.41	5.59
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		22.00	22.07	22.45	23.20	22.32	22.21	22.26
43	COAL		3.57	3.56	3.54	3.55	3.56	3.55	3.55
44	GAS		5.60	5.80	5.78	5.68	5.46	5.41	5.59
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	4.72	4.77	4.70	4.76	4.75	4.73	4.74
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		34,678	33,027	124,446	324,048	729,250	95,388	58,060
50	COAL		10,293	10,276	10,291	10,559	10,563	10,540	10,419
51	GAS		7,526	7,574	7,567	7,746	7,821	7,726	7,674
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,545	8,639	8,692	8,765	8,670	8,575	8,645
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		76.27	72.88	279.34	751.91	1627.44	211.88	129.22
57	COAL		3.68	3.66	3.64	3.74	3.76	3.74	3.70
58	GAS		4.22	4.39	4.38	4.40	4.27	4.18	4.29
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	C/KWH	4.03	4.12	4.08	4.17	4.12	4.06	4.10

Docket No. 140001-EI
Schedule E3 (Sheet 2)
Exhibit TGF-3, Part 2

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2015

			Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
3	COAL		39,499,890	42,256,051	36,768,990	36,526,293	24,380,598	35,316,613	437,953,621
4	GAS		102,595,281	101,961,226	99,496,778	83,650,884	72,212,697	72,412,214	1,008,384,819
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	142,696,460	144,773,035	136,530,018	120,355,860	97,148,895	108,082,070	1,450,550,393
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		426	1,038	273	17	0	53	3,125
10	COAL		1,059,392	1,133,741	993,536	991,078	658,041	994,938	11,858,055
11	GAS		2,471,106	2,451,475	2,357,042	1,963,298	1,788,654	1,737,967	23,858,422
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,530,924	3,586,254	3,350,851	2,954,393	2,446,695	2,732,958	35,719,602
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	4,801	4,431	2,054	1,367	4,508	2,818	33,179
17	COAL	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
18	GAS	MCF	19,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,938,293
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		27,819	25,668	11,900	7,926	26,132	16,334	192,302
23	COAL		11,141,102	11,922,450	10,481,332	10,456,304	6,842,379	10,242,473	123,887,171
24	GAS		19,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,938,293
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	30,304,564	30,954,557	28,819,270	25,575,052	20,180,624	23,207,090	307,017,766
	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%	0.03%	0.01%	0.00%	0.00%	0.00%	0.01%
30	COAL		30.00%	31.61%	29.65%	33.55%	26.90%	36.41%	33.20%
31	GAS		69.99%	68.36%	70.34%	66.45%	73.11%	63.59%	66.79%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
37	COAL	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
38	GAS	$/MCF	5.36	5.36	5.43	5.54	5.42	5.59	5.51
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		21.61	21.65	22.21	22.54	21.26	21.63	21.90
43	COAL		3.55	3.54	3.51	3.49	3.56	3.45	3.54
44	GAS		5.36	5.37	5.43	5.54	5.43	5.59	5.51
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	4.71	4.68	4.74	4.71	4.81	4.66	4.73
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		65,303	24,728	43,590	466,235	0	308,189	61,537
50	COAL		10,517	10,516	10,550	10,550	10,398	10,295	10,448
51	GAS		7,744	7,753	7,775	7,697	7,443	7,450	7,668
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,583	8,631	8,601	8,657	8,248	8,492	8,595
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		141.15	53.54	96.79	1051.08	0.00	666.50	134.78
57	COAL		3.73	3.73	3.70	3.69	3.71	3.55	3.69
58	GAS		4.15	4.16	4.22	4.26	4.04	4.17	4.23
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	C/KWH	4.04	4.04	4.07	4.07	3.97	3.95	4.06

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Schedule E4
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Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	4,950	1.8	89.72	47.0	10,588	COAL	2,130	TONS	24.61	52,411	374,480	7.57
3	CRYSTAL RIVER	2	500	120,074	32.3	95.48	33.8	11,028	COAL	53,822	TONS	24.60	1,324,210	5,984,111	4.98
4	CRYSTAL RIVER	4	732	437,465	80.3	77.02	85.3	10,250	COAL	194,267	TONS	23.08	4,483,998	15,333,967	3.51
5	CRYSTAL RIVER	5	712	465,809	87.9	96.03	91.5	10,142	COAL	204,668	TONS	23.08	4,724,071	16,135,138	3.46
6	ANCLOTE	1	517	0	0.0	91.64	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	99.01	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	98.71	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	92.90	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.13	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	26,506	6.9	91.64	34.6	10,824	GAS	286,914	MCF	1.00	286,914	2,015,529	7.60
12	ANCLOTE	2	521	90,375	23.3	99.01	23.3	10,847	GAS	980,299	MCF	1.00	980,299	5,099,012	5.64
13	AVON PARK	1-2	69	91	0.2	82.42	44.0	15,440	GAS	1,405	MCF	1.00	1,405	7,405	8.14
14	BARTOW	1-4	228	497	0.3	92.74	24.7	13,280	GAS	6,600	MCF	1.00	6,600	36,296	7.30
15	BARTOW CC	1	1279	690,976	72.6	85.81	76.1	7,160	GAS	4,947,316	MCF	1.00	4,947,316	27,987,679	4.05
16	DEBARY	1-10	785	2,355	0.4	96.74	12.0	12,536	GAS	29,522	MCF	1.00	29,522	166,284	7.06
17	HIGGINS	1-4	129	264	0.3	92.66	22.7	16,451	GAS	4,343	MCF	1.00	4,343	23,562	8.93
18	HINES CC	1-4	2,204	874,407	53.3	93.25	21.6	7,102	GAS	6,210,030	MCF	1.00	6,210,030	34,450,302	3.94
19	INT CITY	1-14	1,186	7,638	0.9	88.39	8.0	12,447	GAS	95,067	MCF	1.00	95,067	547,231	7.16
20	SUWANNEE	1	67	633	1.3	97.10	944.8	12,404	GAS	7,852	MCF	1.00	7,852	168,979	26.69
21	SUWANNEE	2	66	290	0.6	99.35	31.4	15,845	GAS	4,595	MCF	1.00	4,595	144,425	49.80
22	SUWANNEE	3	67	24,629	49.4	99.03	51.4	12,102	GAS	298,065	MCF	1.00	298,065	1,458,995	5.92
23	TIGER BAY CC	1	225	25,624	15.3	88.39	99.9	7,422	GAS	190,186	MCF	1.00	190,186	1,012,605	3.95
24	UNIV OF FLA. CC	1	47	34,675	99.2	97.10	102.2	9,428	GAS	326,912	MCF	1.00	326,912	1,869,013	5.39
25	AVON PARK	1-2	69	0	0.0	82.42	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	9	0.3	92.74	0.0	14,000	LIGHT OIL	22	BBLS	5.73	126	3,197	35.52
27	BAYBORO	1-4	231	6	0.0	96.13	0.0	13,167	LIGHT OIL	14	BBLS	5.64	79	1,853	30.88
28	DEBARY	1-10	785	189	0.4	96.74	162.0	13,048	LIGHT OIL	425	BBLS	5.80	2,466	60,172	31.84
29	HIGGINS	1-4	129	0	0.0	92.66	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	293	0.9	88.39	111.5	13,642	LIGHT OIL	689	BBLS	5.80	3,997	88,141	30.08
32	RIO PINAR	1	16	0	0.0	98.71	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	68	0.0	98.49	1.7	12,882	LIGHT OIL	151	BBLS	5.80	876	20,860	30.68
34	TURNER	1-4	199	0	0.0	72.34	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,080	BBLS	5.79	12,049	256,005	0.00
36	TOTAL			2,807,823									23,993,389	113,245,954	4.03

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Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	0	0.0	94.29	0.0	0	COAL	0	TONS	0.00	0	143,306	0.00
3	CRYSTAL RIVER	2	500	115,192	34.3	90.38	37.6	10,896	COAL	51,013	TONS	24.60	1,255,090	5,602,088	4.86
4	CRYSTAL RIVER	4	732	417,409	84.9	95.71	87.7	10,244	COAL	185,464	TONS	23.05	4,275,777	14,575,878	3.49
5	CRYSTAL RIVER	5	712	424,857	88.8	95.39	92.8	10,140	COAL	186,865	TONS	23.05	4,308,083	14,683,212	3.46
6	ANCLOTE	1	517	0	0.0	94.89	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	98.91	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.14	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.78	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.79	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	22,287	6.4	94.89	52.6	10,275	GAS	228,988	MCF	1.00	228,988	1,873,938	8.41
12	ANCLOTE	2	521	91,842	26.2	98.91	26.2	10,676	GAS	980,525	MCF	1.00	980,525	5,218,277	5.68
13	AVON PARK	1-2	69	63	0.1	77.50	45.7	15,381	GAS	969	MCF	1.00	969	5,314	8.43
14	BARTOW	1-4	228	380	0.3	92.86	24.3	13,205	GAS	5,018	MCF	1.00	5,018	28,363	7.46
15	BARTOW CC	1	1279	422,229	49.1	96.43	50.9	7,334	GAS	3,096,700	MCF	1.00	3,096,700	18,267,920	4.33
16	DEBARY	1-10	785	1,722	0.4	97.04	12.7	12,454	GAS	21,445	MCF	1.00	21,445	126,844	7.37
17	HIGGINS	1-4	129	192	0.2	91.79	24.8	16,188	GAS	3,108	MCF	1.00	3,108	18,476	9.62
18	HINES CC	1-4	2,204	861,264	58.2	95.89	23.2	7,062	GAS	6,082,310	MCF	1.00	6,082,310	34,723,781	4.03
19	INT CITY	1-14	1,186	5,564	0.7	88.39	8.2	12,387	GAS	68,920	MCF	1.00	68,920	422,076	7.59
20	SUWANNEE	1	67	469	1.0	95.71	0.0	12,264	GAS	5,752	MCF	1.00	5,752	163,510	34.86
21	SUWANNEE	2	66	251	0.6	99.29	31.7	15,590	GAS	3,913	MCF	1.00	3,913	147,425	58.74
22	SUWANNEE	3	67	22,353	49.6	99.29	51.3	12,064	GAS	269,664	MCF	1.00	269,664	1,337,357	5.98
23	TIGER BAY CC	1	225	23,825	15.8	89.64	101.8	7,377	GAS	175,767	MCF	1.00	175,767	1,079,233	4.53
24	UNIV OF FLA. CC	1	47	31,219	98.8	96.79	102.2	9,427	GAS	294,306	MCF	1.00	294,306	1,740,506	5.58
25	AVON PARK	1-2	69	0	0.0	77.50	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	8	0.3	92.86	0.0	13,500	LIGHT OIL	19	BBLS	5.68	108	2,795	34.94
27	BAYBORO	1-4	231	6	0.0	94.82	0.0	13,167	LIGHT OIL	14	BBLS	5.64	79	1,847	30.78
28	DEBARY	1-10	785	165	0.4	97.04	21.0	12,345	LIGHT OIL	351	BBLS	5.80	2,037	50,867	30.83
29	HIGGINS	1-4	129	0	0.0	91.79	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	284	0.7	88.39	82.2	13,183	LIGHT OIL	647	BBLS	5.79	3,744	83,090	29.26
32	RIO PINAR	1	16	0	0.0	98.57	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	50	0.0	98.10	1.6	13,120	LIGHT OIL	113	BBLS	5.81	656	16,026	32.05
34	TURNER	1-4	199	0	0.0	72.68	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,780	BBLS	5.80	10,319	218,525	0.00
36	TOTAL			2,441,631									21,093,278	100,531,367	4.12

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-15

	(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	CRYS RIV NUC 3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER 1	376	2,514	0.9	52.72	51.4	10,493	COAL	1,072 TONS	24.61	26,380	256,410	10.20
3	CRYSTAL RIVER 2	500	137,494	37.0	94.24	38.5	10,889	COAL	60,856 TONS	24.60	1,497,226	6,562,609	4.77
4	CRYSTAL RIVER 4	732	432,150	79.4	92.57	85.1	10,260	COAL	192,497 TONS	23.03	4,433,805	15,036,210	3.48
5	CRYSTAL RIVER 5	712	478,816	90.4	98.60	91.2	10,146	COAL	210,923 TONS	23.03	4,858,221	16,440,101	3.43
6	ANCLOTE 1	517	0	0.0	94.38	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE 2	521	0	0.0	94.48	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE 1	30	0	0.0	33.55	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE 2	30	0	0.0	92.73	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE 3	73	0	0.0	95.19	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE 1	517	1,283	0.3	94.38	49.6	10,469	GAS	13,432 MCF	1.00	13,432	865,117	67.43
12	ANCLOTE 2	521	110,263	28.4	94.48	29.6	10,548	GAS	1,162,999 MCF	1.00	1,162,999	5,963,447	5.41
13	AVON PARK 1-2	69	7	0.0	79.35	0.0	15,429	GAS	108 MCF	1.00	108	537	7.67
14	BARTOW 1-4	228	176	0.1	93.47	25.7	13,227	GAS	2,328 MCF	1.00	2,328	12,779	7.26
15	BARTOW CC 1	1279	377,082	39.6	62.58	41.8	7,441	GAS	2,806,054 MCF	1.00	2,806,054	16,517,888	4.38
16	DEBARY 1-10	785	624	0.1	96.42	11.4	12,447	GAS	7,767 MCF	1.00	7,767	45,391	7.27
17	HIGGINS 1-4	129	71	0.1	90.73	27.5	16,183	GAS	1,149 MCF	1.00	1,149	5,248	7.39
18	HINES CC 1-4	2,204	928,004	56.6	79.11	22.9	7,051	GAS	6,543,362 MCF	1.00	6,543,362	37,502,013	4.04
19	INT CITY 1-14	1,186	6,385	0.7	94.17	7.4	12,380	GAS	79,044 MCF	1.00	79,044	439,875	6.89
20	SUWANNEE 1	67	2,044	4.1	96.13	34.3	14,312	GAS	29,254 MCF	1.00	29,254	277,154	13.56
21	SUWANNEE 2	66	1,606	3.3	99.68	29.0	14,865	GAS	23,873 MCF	1.00	23,873	248,426	15.47
22	SUWANNEE 3	67	21,048	42.2	99.03	50.9	12,077	GAS	254,201 MCF	1.00	254,201	1,274,233	6.05
23	TIGER BAY CC 1	225	30,395	18.2	88.71	100.8	7,400	GAS	224,923 MCF	1.00	224,923	1,308,539	4.31
24	UNIV OF FLA. CC 1	47	23,040	65.9	100.00	102.1	9,424	GAS	217,135 MCF	1.00	217,135	1,280,328	5.56
25	AVON PARK 1-2	69	0	0.0	79.35	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW 1-4	228	0	0.0	93.47	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO 1-4	231	3	0.0	95.16	0.0	18,667	LIGHT OIL	10 BBLS	5.60	56	1,339	44.63
28	DEBARY 1-10	785	0	0.0	96.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29	HIGGINS 1-4	129	0	0.0	90.73	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY 1-14	1,186	51	0.7	94.17	542.7	14,255	LIGHT OIL	126 BBLS	5.77	727	19,309	37.86
32	RIO PINAR 1	16	0	0.0	98.39	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE 1-3	200	20	0.0	98.28	0.8	14,900	LIGHT OIL	51 BBLS	5.84	298	6,439	32.20
34	TURNER 1-4	199	0	0.0	72.82	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP	-	0	-	0.00	0.0	0	LIGHT OIL	1,403 BBLS	5.79	8,128	171,419	0.00
36	TOTAL		2,553,076								22,190,470	104,243,014	4.08

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	8,723	3.2	68.51	59.5	10,542	COAL	3,738	TONS	24.60	91,961	533,303	6.11
3	CRYSTAL RIVER	2	500	138,561	38.5	97.70	38.9	11,051	COAL	62,242	TONS	24.60	1,531,274	6,637,269	4.79
4	CRYSTAL RIVER	4	732	429,741	81.5	98.44	82.3	10,445	COAL	195,013	TONS	23.02	4,488,681	15,174,966	3.53
5	CRYSTAL RIVER	5	712	405,578	79.1	96.70	81.6	10,512	COAL	185,229	TONS	23.02	4,263,490	14,432,221	3.56
6	ANCLOTE	1	517	0	0.0	64.99	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	95.31	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	31.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	81.54	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	70,619	19.0	64.99	54.2	10,437	GAS	737,056	MCF	1.00	737,056	4,609,589	6.53
12	ANCLOTE	2	521	143,123	38.2	95.31	39.5	10,627	GAS	1,520,923	MCF	1.00	1,520,923	8,162,074	5.70
13	AVON PARK	1-2	69	0	0.0	79.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
14	BARTOW	1-4	228	0	0.0	92.00	0.0	0	GAS	0	MCF	0.00	0	866	0.00
15	BARTOW CC	1	1279	346,146	37.6	46.33	39.7	7,679	GAS	2,658,155	MCF	1.00	2,658,155	15,218,183	4.40
16	DEBARY	1-10	785	137	0.0	95.63	8.7	13,102	GAS	1,795	MCF	1.00	1,795	9,278	6.77
17	HIGGINS	1-4	129	8	0.0	89.75	0.0	17,125	GAS	137	MCF	1.00	137	677	8.46
18	HINES CC	1-4	2,204	1,016,489	64.1	70.54	22.7	7,005	GAS	7,120,092	MCF	1.00	7,120,092	40,418,979	3.98
19	INT CITY	1-14	1,186	5,855	0.7	94.48	6.3	12,977	GAS	75,983	MCF	1.00	75,983	438,876	7.50
20	SUWANNEE	1	67	7,534	15.6	95.33	28.5	14,794	GAS	111,461	MCF	1.00	111,461	630,727	8.37
21	SUWANNEE	2	66	7,612	16.0	99.33	29.0	14,870	GAS	113,194	MCF	1.00	113,194	637,363	8.37
22	SUWANNEE	3	67	9,804	20.3	99.00	51.2	12,376	GAS	121,334	MCF	1.00	121,334	674,910	6.88
23	TIGER BAY CC	1	225	97,587	60.2	88.33	101.8	7,117	GAS	694,564	MCF	1.00	694,564	3,888,664	3.98
24	UNIV OF FLA. CC	1	47	30,413	89.9	64.44	102.1	9,433	GAS	286,878	MCF	1.00	286,878	1,651,559	5.43
25	AVON PARK	1-2	69	3	0.0	79.00	0.0	19,667	LIGHT OIL	10	BBLS	5.90	59	1,308	43.60
26	BARTOW	1-4	228	0	0.0	92.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	0	0.0	95.25	0.0	0	LIGHT OIL	0	BBLS	0.00	0	120	0.00
28	DEBARY	1-10	785	0	0.0	95.63	0.0	0	LIGHT OIL	0	BBLS	0.00	0	7,490	0.00
29	HIGGINS	1-4	129	0	0.0	89.75	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	3	0.7	94.48	0.0	16,000	LIGHT OIL	8	BBLS	6.00	48	4,458	148.60
32	RIO PINAR	1	16	0	0.0	98.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	15	0.0	97.89	3.8	15,667	LIGHT OIL	40	BBLS	5.88	235	6,894	45.96
34	TURNER	1-4	199	0	0.0	72.17	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,115	BBLS	5.80	6,463	136,918	0.00
36	TOTAL			2,717,951									23,823,783	113,277,405	4.17

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: May-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	19,749	7.1	92.77	56.0	10,593	COAL	8,503	TONS	24.60	209,195	1,021,121	5.17
3	CRYSTAL RIVER	2	494	158,333	43.1	94.92	43.9	10,933	COAL	70,360	TONS	24.60	1,730,984	7,406,780	4.68
4	CRYSTAL RIVER	4	722	418,739	78.0	94.58	81.9	10,454	COAL	190,279	TONS	23.01	4,377,450	14,780,037	3.53
5	CRYSTAL RIVER	5	700	396,449	76.1	93.76	80.8	10,528	COAL	181,432	TONS	23.01	4,173,933	14,110,084	3.56
6	ANCLOTE	1	501	0	0.0	62.10	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	96.43	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	96.13	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	39.35	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	144,485	38.8	62.10	50.9	10,461	GAS	1,511,488	MCF	1.00	1,511,488	8,285,473	5.73
12	ANCLOTE	2	510	167,694	44.2	96.43	45.4	10,482	GAS	1,757,822	MCF	1.00	1,757,822	9,367,372	5.59
13	AVON PARK	1-2	49	59	0.2	78.87	20.1	23,780	GAS	1,403	MCF	1.00	1,403	6,220	10.54
14	BARTOW	1-4	177	146	0.1	92.74	28.1	13,952	GAS	2,037	MCF	1.00	2,037	9,823	6.73
15	BARTOW CC	1	1159	662,747	76.9	48.39	79.4	7,330	GAS	4,858,129	MCF	1.00	4,858,129	26,290,293	3.97
16	DEBARY	1-10	645	2,042	0.4	96.48	9.9	13,359	GAS	27,279	MCF	1.00	27,279	134,126	6.57
17	HIGGINS	1-4	113	96	0.1	91.53	10.6	22,313	GAS	2,142	MCF	1.00	2,142	9,520	9.92
18	HINES CC	1-4	1,912	1,074,738	75.6	72.66	23.2	7,148	GAS	7,682,239	MCF	1.00	7,682,239	42,321,060	3.94
19	INT CITY	1-14	987	19,960	2.7	93.96	7.1	13,016	GAS	259,797	MCF	1.00	259,797	1,369,604	6.86
20	SUWANNEE	1	52	187	0.5	94.52	0.0	13,198	GAS	2,468	MCF	1.00	2,468	127,378	68.12
21	SUWANNEE	2	50	518	1.4	99.68	38.4	15,266	GAS	7,908	MCF	1.00	7,908	149,609	28.88
22	SUWANNEE	3	51	24,048	63.4	98.71	67.3	12,315	GAS	296,158	MCF	1.00	296,158	1,416,703	5.89
23	TIGER BAY CC	1	204	101,221	66.7	87.74	99.8	7,218	GAS	730,585	MCF	1.00	730,585	4,054,263	4.01
24	UNIV OF FLA. CC	1	46	31,860	93.1	85.48	97.8	9,433	GAS	300,532	MCF	1.00	300,532	1,666,130	5.23
25	AVON PARK	1-2	49	0	0.0	78.87	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	177	3	0.1	92.74	0.0	21,667	LIGHT OIL	11	BBLS	5.91	65	1,850	61.67
27	BAYBORO	1-4	174	0	0.0	95.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	4	0.4	96.48	0.0	18,000	LIGHT OIL	12	BBLS	6.00	72	9,019	225.48
29	HIGGINS	1-4	113	0	0.0	91.53	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	6	2.7	93.96	0.0	16,000	LIGHT OIL	16	BBLS	6.00	96	5,464	91.07
32	RIO PINAR	1	12	0	0.0	97.74	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	3	0.0	97.63	0.2	16,333	LIGHT OIL	8	BBLS	6.13	49	2,855	95.17
34	TURNER	1-4	149	0	0.0	73.23	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,964	BBLS	5.80	11,386	240,370	0.00
36	TOTAL			3,223,087									27,943,217	132,785,987	4.12

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	33,029	12.2	94.33	55.0	10,602	COAL	14,234 TONS	24.60	350,163	1,599,669	4.84
3	CRYSTAL RIVER	2	494	156,233	43.9	96.68	45.1	10,907	COAL	69,268 TONS	24.60	1,704,081	7,230,751	4.63
4	CRYSTAL RIVER	4	722	419,603	80.7	95.96	83.3	10,436	COAL	190,425 TONS	23.00	4,379,088	14,768,962	3.52
5	CRYSTAL RIVER	5	700	405,861	80.5	96.55	83.1	10,500	COAL	185,314 TONS	23.00	4,261,559	14,382,513	3.54
6	ANCLOTE	1	501	0	0.0	95.19	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	94.32	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	95.33	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	99.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	128,401	35.6	95.19	52.1	10,387	GAS	1,333,755 MCF	1.00	1,333,755	7,333,109	5.71
12	ANCLOTE	2	510	158,715	43.2	94.32	45.5	10,489	GAS	1,664,776 MCF	1.00	1,664,776	8,783,643	5.53
13	AVON PARK	1-2	49	78	0.2	77.17	33.1	19,692	GAS	1,536 MCF	1.00	1,536	7,075	9.07
14	BARTOW	1-4	177	478	0.4	92.25	19.3	15,151	GAS	7,242 MCF	1.00	7,242	35,139	7.35
15	BARTOW CC	1	1159	689,312	82.6	92.67	84.6	7,302	GAS	5,033,078 MCF	1.00	5,033,078	26,967,457	3.91
16	DEBARY	1-10	645	2,522	0.6	96.87	10.1	13,384	GAS	33,754 MCF	1.00	33,754	174,569	6.92
17	HIGGINS	1-4	113	402	0.5	90.75	12.3	20,386	GAS	8,195 MCF	1.00	8,195	37,741	9.39
18	HINES CC	1-4	1,912	1,209,729	87.9	83.85	23.5	7,123	GAS	8,617,096 MCF	1.00	8,617,096	46,994,294	3.88
19	INT CITY	1-14	987	16,885	2.4	95.10	7.3	12,963	GAS	218,873 MCF	1.00	218,873	1,171,534	6.94
20	SUWANNEE	1	52	608	1.6	94.00	233.8	13,931	GAS	8,470 MCF	1.00	8,470	154,508	25.41
21	SUWANNEE	2	50	892	2.5	99.33	38.8	15,124	GAS	13,491 MCF	1.00	13,491	172,462	19.33
22	SUWANNEE	3	51	24,781	67.5	99.33	67.7	12,311	GAS	305,070 MCF	1.00	305,070	1,453,648	5.87
23	TIGER BAY CC	1	204	94,441	64.3	90.33	100.0	7,196	GAS	679,579 MCF	1.00	679,579	3,693,869	3.91
24	UNIV OF FLA. CC	1	46	31,860	96.2	98.33	97.8	9,428	GAS	300,361 MCF	1.00	300,361	1,646,060	5.17
25	AVON PARK	1-2	49	3	0.2	77.17	0.0	19,667	LIGHT OIL	10 BBLS	5.90	59	1,301	43.37
26	BARTOW	1-4	177	0	0.0	92.25	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	174	0	0.0	96.08	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	95	0.6	96.87	202.9	15,000	LIGHT OIL	245 BBLS	5.82	1,425	37,685	39.67
29	HIGGINS	1-4	113	0	0.0	90.75	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	0	0.0	95.10	0.0	0	LIGHT OIL	0 BBLS	0.00	0	3,444	0.00
32	RIO PINAR	1	12	0	0.0	97.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	31	0.0	97.56	1.0	14,710	LIGHT OIL	78 BBLS	5.85	456	11,640	37.55
34	TURNER	1-4	149	0	0.0	72.92	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,788 BBLS	5.80	10,365	218,422	0.00
36	TOTAL			3,373,959								28,932,472	136,880,328	4.06

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-15

	(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	CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	45,476	16.3	95.91	53.9	10,620	COAL	19,631 TONS	24.60	482,941	2,140,920	4.71
3	CRYSTAL RIVER	2	494	166,276	45.2	97.74	46.3	10,886	COAL	73,575 TONS	24.60	1,810,021	7,630,191	4.59
4	CRYSTAL RIVER	4	722	423,916	78.9	90.68	86.1	10,405	COAL	191,839 TONS	22.99	4,410,646	14,820,409	3.50
5	CRYSTAL RIVER	5	700	423,724	81.4	94.58	85.5	10,473	COAL	193,007 TONS	22.99	4,437,494	14,908,370	3.52
6	ANCLOTE	1	501	0	0.0	94.80	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	96.77	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.10	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.74	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	95.48	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	139,705	37.5	94.80	52.4	10,410	GAS	1,454,262 MCF	1.00	1,454,262	7,880,296	5.64
12	ANCLOTE	2	510	171,114	45.1	96.77	46.5	10,456	GAS	1,789,158 MCF	1.00	1,789,158	9,351,829	5.47
13	AVON PARK	1-2	49	58	0.2	81.61	32.1	19,034	GAS	1,104 MCF	1.00	1,104	5,245	9.04
14	BARTOW	1-4	177	506	0.4	92.82	21.1	14,828	GAS	7,503 MCF	1.00	7,503	36,388	7.19
15	BARTOW CC	1	1,159	716,056	83.0	97.10	85.6	7,300	GAS	5,226,924 MCF	1.00	5,226,924	27,775,043	3.88
16	DEBARY	1-10	645	3,427	0.8	96.68	10.5	13,373	GAS	45,828 MCF	1.00	45,828	240,392	7.01
17	HIGGINS	1-4	113	219	0.3	91.85	16.2	18,155	GAS	3,976 MCF	1.00	3,976	19,695	8.99
18	HINES CC	1-4	1,912	1,261,043	88.6	94.98	23.6	7,117	GAS	8,974,914 MCF	1.00	8,974,914	48,460,832	3.84
19	INT CITY	1-14	987	22,303	3.0	88.89	7.2	12,980	GAS	289,495 MCF	1.00	289,495	1,546,125	6.93
20	SUWANNEE	1	52	932	2.4	94.52	162.9	14,023	GAS	13,069 MCF	1.00	13,069	168,018	18.03
21	SUWANNEE	2	50	699	1.9	99.68	38.8	15,363	GAS	10,739 MCF	1.00	10,739	152,685	21.84
22	SUWANNEE	3	51	24,856	65.5	98.39	68.6	12,314	GAS	306,085 MCF	1.00	306,085	1,454,969	5.85
23	TIGER BAY CC	1	204	97,896	64.5	88.06	99.8	7,233	GAS	708,077 MCF	1.00	708,077	3,854,213	3.94
24	UNIV OF FLA. CC	1	46	32,292	94.4	96.45	97.8	9,430	GAS	304,509 MCF	1.00	304,509	1,649,551	5.11
25	AVON PARK	1-2	49	5	0.2	81.61	0.0	15,400	LIGHT OIL	13 BBLS	5.92	77	1,678	33.56
26	BARTOW	1-4	177	17	0.4	92.82	0.0	13,941	LIGHT OIL	41 BBLS	5.78	237	6,017	35.39
27	BAYBORO	1-4	174	54	0.0	95.97	15.5	14,611	LIGHT OIL	137 BBLS	5.76	789	17,269	31.98
28	DEBARY	1-10	645	215	0.8	96.68	112.9	14,158	LIGHT OIL	525 BBLS	5.80	3,044	71,897	33.44
29	HIGGINS	1-4	113	0	0.0	91.85	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	65	3.0	88.89	2266.3	13,954	LIGHT OIL	156 BBLS	5.81	907	22,476	34.58
32	RIO PINAR	1	12	0	0.0	98.06	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	54	0.0	97.53	1.3	14,056	LIGHT OIL	131 BBLS	5.79	759	18,158	33.63
34	TURNER	1-4	149	16	0.0	72.98	0.0	16,563	LIGHT OIL	46 BBLS	5.76	265	6,259	39.12
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	3,752 BBLS	5.79	21,741	457,474	0.00
36	TOTAL			3,530,924								30,304,564	142,696,460	4.04

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-15

	(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	CRYS RIV NUC	3	0	0	0	0.00	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	91,113	32.7	91.71	51.9	10,655	COAL	39,461 TONS	24.60	970,781	4,138,980	4.54
3	CRYSTAL RIVER	2	494	157,850	42.9	92.65	45.1	10,910	COAL	70,005 TONS	24.60	1,722,164	7,231,625	4.58
4	CRYSTAL RIVER	4	722	445,219	82.9	94.99	86.5	10,400	COAL	201,426 TONS	22.99	4,630,309	15,493,534	3.48
5	CRYSTAL RIVER	5	700	439,559	84.4	97.63	86.0	10,463	COAL	200,072 TONS	22.99	4,599,196	15,391,912	3.50
6	ANCLOTE	1	501	0	0.0	90.18	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	95.54	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	98.06	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	98.06	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	99.03	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	163,239	43.8	90.18	46.3	10,473	GAS	1,709,639 MCF	1.00	1,709,639	8,986,322	5.51
12	ANCLOTE	2	510	137,129	36.1	95.54	48.1	10,500	GAS	1,439,807 MCF	1.00	1,439,807	7,799,601	5.69
13	AVON PARK	1-2	49	167	0.5	78.55	28.4	19,557	GAS	3,266 MCF	1.00	3,266	15,402	9.22
14	BARTOW	1-4	177	895	0.7	92.58	21.3	14,825	GAS	13,268 MCF	1.00	13,268	65,452	7.31
15	BARTOW CC	1	1,159	711,024	82.5	96.77	85.2	7,298	GAS	5,188,842 MCF	1.00	5,188,842	27,545,882	3.87
16	DEBARY	1-10	645	3,485	0.9	96.19	12.3	13,208	GAS	46,029 MCF	1.00	46,029	244,105	7.00
17	HIGGINS	1-4	113	647	0.8	91.37	15.9	18,162	GAS	11,751 MCF	1.00	11,751	57,363	8.87
18	HINES CC	1-4	1,912	1,249,935	87.9	94.99	23.6	7,126	GAS	8,907,342 MCF	1.00	8,907,342	48,105,635	3.85
19	INT CITY	1-14	987	23,896	3.3	88.02	7.3	12,952	GAS	309,506 MCF	1.00	309,506	1,687,839	7.06
20	SUWANNEE	1	52	792	2.0	92.90	126.9	13,855	GAS	10,973 MCF	1.00	10,973	167,308	21.12
21	SUWANNEE	2	50	712	1.9	99.35	39.6	15,277	GAS	10,877 MCF	1.00	10,877	158,590	22.27
22	SUWANNEE	3	51	25,875	68.2	99.68	68.8	12,309	GAS	318,497 MCF	1.00	318,497	1,519,237	5.87
23	TIGER BAY CC	1	204	100,739	66.4	86.77	100.0	7,208	GAS	726,082 MCF	1.00	726,082	3,929,190	3.90
24	UNIV OF FLA. CC	1	46	32,940	96.2	98.39	97.8	9,428	GAS	310,560 MCF	1.00	310,560	1,679,300	5.10
25	AVON PARK	1-2	49	0	0.0	78.55	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	177	9	0.7	92.58	0.0	13,222	LIGHT OIL	21 BBLS	5.67	119	3,018	33.53
27	BAYBORO	1-4	174	0	0.0	96.13	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	724	0.9	96.19	36.3	13,518	LIGHT OIL	1,689 BBLS	5.79	9,787	214,448	29.62
29	HIGGINS	1-4	113	0	0.0	91.37	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	177	3.3	88.02	487.8	14,192	LIGHT OIL	434 BBLS	5.79	2,512	56,127	31.71
32	RIO PINAR	1	12	0	0.0	98.06	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	128	0.1	97.31	3.1	13,438	LIGHT OIL	297 BBLS	5.79	1,720	38,856	30.36
34	TURNER	1-4	149	0	0.0	72.98	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,990 BBLS	5.79	11,530	242,476	0.00
36	TOTAL			3,586,254								30,954,557	144,773,035	4.04

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-15

	(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	CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	14,772	5.5	96.00	54.7	10,604	COAL	6,368 TONS	24.60	156,647	786,291	5.32
3	CRYSTAL RIVER	2	494	156,358	44.0	94.70	45.8	10,894	COAL	69,243 TONS	24.60	1,703,423	7,135,303	4.56
4	CRYSTAL RIVER	4	722	417,571	80.3	96.52	82.9	10,449	COAL	189,834 TONS	22.98	4,363,298	14,595,405	3.50
5	CRYSTAL RIVER	5	700	404,835	80.3	97.45	81.9	10,518	COAL	185,252 TONS	22.98	4,257,964	14,251,991	3.52
6	ANCLOTE	1	501	0	0.0	96.32	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	97.53	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	98.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	97.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	174,096	48.3	96.32	49.2	10,399	GAS	1,810,442 MCF	1.00	1,810,442	9,554,843	5.49
12	ANCLOTE	2	510	152,237	41.5	97.53	46.8	10,453	GAS	1,591,297 MCF	1.00	1,591,297	8,591,701	5.64
13	AVON PARK	1-2	49	37	0.1	79.50	25.2	19,811	GAS	733 MCF	1.00	733	3,499	9.46
14	BARTOW	1-4	177	341	0.3	93.75	19.3	15,413	GAS	5,256 MCF	1.00	5,256	24,904	7.30
15	BARTOW CC	1	1,159	677,261	81.2	96.67	84.0	7,321	GAS	4,957,912 MCF	1.00	4,957,912	26,704,919	3.94
16	DEBARY	1-10	645	1,391	0.4	96.07	11.5	13,487	GAS	18,761 MCF	1.00	18,761	92,238	6.63
17	HIGGINS	1-4	113	209	0.3	91.42	12.3	19,967	GAS	4,173 MCF	1.00	4,173	19,343	9.26
18	HINES CC	1-4	1,912	1,173,790	85.3	94.80	23.0	7,152	GAS	8,395,161 MCF	1.00	8,395,161	46,159,968	3.93
19	INT CITY	1-14	987	15,761	2.2	88.76	7.2	13,047	GAS	205,636 MCF	1.00	205,636	1,025,486	6.51
20	SUWANNEE	1	52	181	0.5	96.00	87.0	14,210	GAS	2,572 MCF	1.00	2,572	125,495	69.33
21	SUWANNEE	2	50	222	0.6	99.33	40.4	15,221	GAS	3,379 MCF	1.00	3,379	127,293	57.34
22	SUWANNEE	3	51	24,352	66.3	98.67	68.4	12,343	GAS	300,587 MCF	1.00	300,587	1,434,710	5.89
23	TIGER BAY CC	1	204	118,480	80.7	92.67	99.8	7,207	GAS	853,877 MCF	1.00	853,877	4,660,313	3.93
24	UNIV OF FLA. CC	1	46	18,684	56.4	96.11	97.9	9,433	GAS	176,252 MCF	1.00	176,252	972,066	5.20
25	AVON PARK	1-2	49	0	0.0	79.50	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	177	0	0.0	93.75	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	174	0	0.0	95.33	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	247	0.4	96.07	36.3	14,462	LIGHT OIL	617 BBLS	5.79	3,572	83,004	33.60
29	HIGGINS	1-4	113	0	0.0	91.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	12	2.2	88.76	0.0	14,417	LIGHT OIL	30 BBLS	5.77	173	7,071	58.93
32	RIO PINAR	1	12	0	0.0	96.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	14	0.0	98.00	0.5	13,571	LIGHT OIL	32 BBLS	5.94	190	5,887	42.05
34	TURNER	1-4	149	0	0.0	72.17	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,375 BBLS	5.79	7,965	167,455	0.00
36	TOTAL			3,350,851								28,819,270	136,530,018	4.07

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-15

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	375	8,968	3.2	94.52	53.1	10,630	COAL	3,875	TONS	24.60	95,332	534,478	5.96
3 CRYSTAL RIVER	2	494	148,636	40.4	94.53	42.5	10,966	COAL	66,259	TONS	24.60	1,630,012	6,831,663	4.60
4 CRYSTAL RIVER	4	722	433,344	80.7	96.67	83.1	10,442	COAL	196,878	TONS	22.98	4,524,765	15,098,565	3.48
5 CRYSTAL RIVER	5	700	400,130	76.8	96.65	81.9	10,512	COAL	183,017	TONS	22.98	4,206,195	14,061,587	3.51
6 ANCLOTE	1	501	0	0.0	96.71	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7 ANCLOTE	2	510	0	0.0	94.90	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.84	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10 SUWANNEE	3	71	0	0.0	96.45	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11 ANCLOTE	1	501	159,483	42.8	96.71	43.6	10,540	GAS	1,680,911	MCF	1.00	1,680,911	8,448,237	5.30
12 ANCLOTE	2	510	2,449	0.6	94.90	43.7	10,752	GAS	26,331	MCF	1.00	26,331	986,081	40.26
13 AVON PARK	1-2	49	0	0.0	83.55	0.0	0	GAS	0	MCF	0.00	0	58	0.00
14 BARTOW	1-4	177	169	0.1	93.79	15.9	15,834	GAS	2,676	MCF	1.00	2,676	13,293	7.87
15 BARTOW CC	1	1,159	705,613	81.8	98.71	82.9	7,308	GAS	5,156,650	MCF	1.00	5,156,650	28,200,059	4.00
16 DEBARY	1-10	645	2,166	0.5	95.97	8.6	13,821	GAS	29,937	MCF	1.00	29,937	145,423	6.71
17 HIGGINS	1-4	113	229	0.3	92.74	11.9	20,607	GAS	4,719	MCF	1.00	4,719	21,336	9.32
18 HINES CC	1-4	1,912	959,357	67.4	95.38	20.5	7,259	GAS	6,964,306	MCF	1.00	6,964,306	38,989,258	4.06
19 INT CITY	1-14	987	14,223	1.9	82.63	7.1	13,090	GAS	186,178	MCF	1.00	186,178	988,171	6.95
20 SUWANNEE	1	52	78	0.2	94.19	0.0	13,244	GAS	1,033	MCF	1.00	1,033	117,262	150.34
21 SUWANNEE	2	50	461	1.2	98.39	38.4	15,295	GAS	7,051	MCF	1.00	7,051	143,051	31.03
22 SUWANNEE	3	51	24,387	64.3	98.71	66.6	12,311	GAS	300,238	MCF	1.00	300,238	1,466,115	6.01
23 TIGER BAY CC	1	204	63,795	42.0	92.17	99.9	7,201	GAS	459,402	MCF	1.00	459,402	2,498,199	3.92
24 UNIV OF FLA. CC	1	46	30,888	90.3	63.14	97.9	9,434	GAS	291,390	MCF	1.00	291,390	1,634,341	5.29
25 AVON PARK	1-2	49	0	0.0	83.55	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26 BARTOW	1-4	177	0	0.0	93.79	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	174	0	0.0	96.05	0.0	0	LIGHT OIL	0	BBLS	0.00	0	120	0.00
28 DEBARY	1-10	645	4	0.5	95.97	0.0	22,500	LIGHT OIL	16	BBLS	5.63	90	9,375	234.38
29 HIGGINS	1-4	113	0	0.0	92.74	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31 INT CITY	1-14	987	3	1.9	82.63	0.0	15,667	LIGHT OIL	8	BBLS	5.88	47	4,420	147.33
32 RIO PINAR	1	12	0	0.0	96.77	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	153	10	0.0	97.10	1.3	15,200	LIGHT OIL	26	BBLS	5.85	152	5,038	50.38
34 TURNER	1-4	149	0	0.0	72.90	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,317	BBLS	5.80	7,637	159,017	0.00
36 TOTAL			2,954,393									25,575,052	120,355,860	4.07

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-15

	(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	CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	7,533	2.8	92.04	27.8	11,167 COAL	3,419 TONS	24.60	84,121	488,403	6.48
3	CRYSTAL RIVER	2	500	106,094	29.5	94.44	34.7	11,021 COAL	47,531 TONS	24.60	1,169,285	4,940,159	4.66
4	CRYSTAL RIVER	4	732	404,287	76.7	93.16	81.6	10,298 COAL	181,172 TONS	22.98	4,163,316	13,936,442	3.45
5	CRYSTAL RIVER	5	712	140,127	27.3	93.55	87.1	10,174 COAL	62,039 TONS	22.98	1,425,657	5,015,594	3.58
6	ANCLOTE	1	517	0	0.0	92.64	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	0.00	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.00	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	94.33	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.67	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	119,123	32.0	92.64	39.1	10,406 GAS	1,239,604 MCF	1.00	1,239,604	5,951,903	5.00
12	ANCLOTE	2	521	0	0.0	0.00	0.0	0 GAS	0 MCF	0.00	0	647,638	0.00
13	AVON PARK	1-2	69	0	0.0	81.33	0.0	0 GAS	0 MCF	0.00	0	58	0.00
14	BARTOW	1-4	228	22	0.0	93.42	0.0	13,273 GAS	292 MCF	1.00	292	2,116	9.62
15	BARTOW CC	1	1,279	762,381	82.8	98.00	84.4	7,113 GAS	5,422,781 MCF	1.00	5,422,781	29,194,661	3.83
16	DEBARY	1-10	785	301	0.1	96.27	116.0	12,379 GAS	3,726 MCF	1.00	3,726	16,752	5.57
17	HIGGINS	1-4	129	4	0.0	92.00	0.0	14,250 GAS	57 MCF	1.00	57	244	6.10
18	HINES CC	1-4	2,204	844,343	53.2	81.38	31.3	7,082 GAS	5,979,289 MCF	1.00	5,979,289	32,766,281	3.88
19	INT CITY	1-14	1,186	5,063	0.6	93.79	32.0	12,385 GAS	62,705 MCF	1.00	62,705	325,683	6.43
20	SUWANNEE	1	67	54	0.1	95.00	0.0	12,074 GAS	652 MCF	1.00	652	117,038	216.74
21	SUWANNEE	2	66	46	0.1	99.00	34.8	14,543 GAS	669 MCF	1.00	669	117,422	255.27
22	SUWANNEE	3	67	23,563	48.8	100.00	50.5	12,059 GAS	284,149 MCF	1.00	284,149	1,329,560	5.64
23	TIGER BAY CC	1	225	0	0.0	76.67	0.0	0 GAS	0 MCF	0.00	0	0	0.00
24	UNIV OF FLA. CC	1	47	33,754	99.7	91.00	100.0	9,427 GAS	318,189 MCF	1.00	318,189	1,743,341	5.16
25	AVON PARK	1-2	69	0	0.0	81.33	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	0	0.0	93.42	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	0	0.0	95.33	0.0	0 LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	785	0	0.0	96.27	0.0	0 LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29	HIGGINS	1-4	129	0	0.0	92.00	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	0	0.0	93.79	0.0	0 LIGHT OIL	0 BBLS	0.00	0	3,444	0.00
32	RIO PINAR	1	16	0	0.0	97.67	0.0	0 LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	0	0.0	98.00	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
34	TURNER	1-4	199	0	0.0	73.08	0.0	0 LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP		0	0	-	0.00	0.0	0 LIGHT OIL	4,508 BBLS	5.80	26,132	543,833	0.00
36	TOTAL			2,446,695							20,180,624	97,148,895	3.97

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-15

	(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	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	52,965	18.9	96.21	33.7	10,911	COAL	23,492	TONS	24.60	577,923	2,513,519	4.75
3	CRYSTAL RIVER	2	500	51,389	13.8	90.55	32.9	11,050	COAL	23,083	TONS	24.60	567,857	2,472,236	4.81
4	CRYSTAL RIVER	4	732	448,098	82.3	97.10	83.9	10,271	COAL	200,285	TONS	22.98	4,602,345	15,341,082	3.42
5	CRYSTAL RIVER	5	712	442,486	83.5	28.10	89.9	10,157	COAL	195,585	TONS	22.98	4,494,348	14,989,776	3.39
6	ANCLOTE	1	517	0	0.0	94.67	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	54.46	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.03	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.42	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	95,008	24.7	94.67	25.3	10,726	GAS	1,019,102	MCF	1.00	1,019,102	5,092,190	5.36
12	ANCLOTE	2	521	3,359	0.9	54.46	35.8	11,351	GAS	38,128	MCF	1.00	38,128	785,714	23.39
13	AVON PARK	1-2	69	7	0.0	78.39	0.0	15,429	GAS	108	MCF	1.00	108	668	9.54
14	BARTOW	1-4	228	66	0.0	92.02	28.9	13,212	GAS	872	MCF	1.00	872	5,289	8.01
15	BARTOW CC	1	1279	725,162	76.2	94.52	80.7	7,148	GAS	5,183,180	MCF	1.00	5,183,180	28,770,773	3.97
16	DEBARY	1-10	785	991	0.2	96.42	11.5	12,506	GAS	12,393	MCF	1.00	12,393	65,627	6.62
17	HIGGINS	1-4	129	30	0.0	90.89	0.0	15,833	GAS	475	MCF	1.00	475	2,357	7.86
18	HINES CC	1-4	2,204	842,230	51.4	79.45	21.1	7,078	GAS	5,961,714	MCF	1.00	5,961,714	33,550,701	3.98
19	INT CITY	1-14	1,186	3,161	0.4	93.46	7.5	12,467	GAS	39,408	MCF	1.00	39,408	227,909	7.21
20	SUWANNEE	1	67	134	0.3	94.19	0.0	12,291	GAS	1,647	MCF	1.00	1,647	135,725	101.29
21	SUWANNEE	2	66	24	0.0	99.35	36.4	15,750	GAS	378	MCF	1.00	378	127,478	531.16
22	SUWANNEE	3	67	25,046	50.2	97.42	50.2	12,061	GAS	302,088	MCF	1.00	302,088	1,454,099	5.81
23	TIGER BAY CC	1	225	7,959	4.8	0.00	98.3	7,643	GAS	60,831	MCF	1.00	60,831	342,403	4.30
24	UNIV OF FLA. CC	1	47	34,790	99.5	97.42	102.1	9,427	GAS	327,959	MCF	1.00	327,959	1,851,281	5.32
25	AVON PARK	1-2	69	0	0.0	78.39	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	0	0.0	92.02	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	0	0.0	93.95	0.0	0	LIGHT OIL	0	BBLS	0.00	0	120	0.00
28	DEBARY	1-10	785	0	0.0	96.42	0.0	0	LIGHT OIL	0	BBLS	0.00	0	7,490	0.00
29	HIGGINS	1-4	129	0	0.0	90.89	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	38	0.4	93.46	0.0	14,316	LIGHT OIL	93	BBLS	5.85	544	14,722	38.74
32	RIO PINAR	1	16	0	0.0	98.39	0.0	0	LIGHT OIL	0	BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	15	0.0	96.99	1.5	14,533	LIGHT OIL	38	BBLS	5.74	218	6,440	42.93
34	TURNER	1-4	199	0	0.0	72.66	0.0	0	LIGHT OIL	0	BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,687	BBLS	5.80	15,572	323,758	0.00
36	TOTAL			2,732,958									23,207,090	108,082,070	3.95

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2015

	HEAVY OIL		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	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	3,381	2,924	1,590	1,173	2,011	2,121	13,200
15	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
16	AMOUNT	$	430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
17	BURNED:								
18	UNITS	BBL	3,381	2,924	1,590	1,173	2,011	2,121	13,200
19	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
20	AMOUNT	$	430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	
24	AMOUNT	$	135,449,787	135,875,394	138,155,497	143,051,620	137,600,349	136,944,458	
	COAL								
25	PURCHASES:								
26	UNITS	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
27	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
28	AMOUNT	$	37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
29	BURNED:								
30	UNITS	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
31	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
32	AMOUNT	$	37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	
36	AMOUNT	$	79,371,200	78,920,410	78,546,167	78,666,715	79,051,361	78,939,212	
	GAS								
37	BURNED:								
38	UNITS	MCF	13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
39	UNIT COST	$/MCF	5.60	5.80	5.78	5.68	5.46	5.41	5.59
40	AMOUNT	$	74,987,317	65,153,020	65,740,975	76,341,745	95,207,574	98,625,108	476,055,739
	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 2015

	HEAVY OIL		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	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	4,801	4,431	2,054	1,367	4,508	2,818	33,179
15	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
16	AMOUNT	$	601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
17	BURNED:								
18	UNITS	BBL	4,801	4,431	2,054	1,367	4,508	2,818	33,179
19	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
20	AMOUNT	$	601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	
24	AMOUNT	$	133,093,596	133,287,642	136,716,299	138,905,861	130,973,746	133,210,491	
	COAL								
25	PURCHASES:								
26	UNITS	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
27	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
28	AMOUNT	$	39,499,890	42,256,051	36,768,990	36,526,293	24,380,598	35,316,613	437,953,621
29	BURNED:								
30	UNITS	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
31	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
32	AMOUNT	$	39,499,890	42,256,051	36,768,990	36,526,293	24,380,598	35,316,613	437,953,621
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	
36	AMOUNT	$	78,863,810	78,932,436	77,867,070	77,467,915	79,107,197	76,186,269	
	GAS								
37	BURNED:								
38	UNITS	MCF	19,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,938,293
39	UNIT COST	$/MCF	5.36	5.36	5.43	5.54	5.42	5.59	5.51
40	AMOUNT	$	102,595,281	101,961,226	99,496,778	83,650,884	72,212,697	72,412,214	1,008,384,819
	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 2015

(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-15	ECONSALE	--	31,940		31,940	3.252	3.968	1,038,840	1,267,385	228,545
	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	--	26,478		26,478	4.592	4.592	1,215,937	1,215,937	0
	TOTAL		58,418		58,418	3.860	4.251	2,254,777	2,483,322	228,545
Feb-15	ECONSALE	--	19,240		19,240	3.457	4.217	665,089	811,409	146,320
	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	--	25,437		25,437	4.916	4.916	1,250,429	1,250,429	0
	TOTAL		44,677		44,677	4.287	4.615	1,915,518	2,061,838	146,320
Mar-15	ECONSALE	--	5,535		5,535	3.511	4.283	194,320	237,070	42,750
	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	--	27,434		27,434	4.750	4.750	1,303,070	1,303,070	0
	TOTAL		32,969		32,969	4.542	4.671	1,497,390	1,540,140	42,750
Apr-15	ECONSALE	--	5,700		5,700	2.592	3.162	147,722	180,220	32,498
	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	--	38,178		38,178	4.118	4.118	1,572,220	1,572,220	0
	TOTAL		43,878		43,878	3.920	3.994	1,719,942	1,752,440	32,498
May-15	ECONSALE	--	32,645		32,645	2.716	3.314	886,743	1,081,827	195,084
	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	--	44,189		44,189	3.823	3.823	1,689,334	1,689,334	0
	TOTAL		76,834		76,834	3.353	3.607	2,576,077	2,771,161	195,084
Jun-15	ECONSALE	--	555		555	4.855	5.924	26,948	32,876	5,928
	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	--	54,378		54,378	3.802	3.802	2,067,519	2,067,519	0
	TOTAL		54,933		54,933	3.813	3.824	2,094,467	2,100,395	5,928

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-15	ECONSALE	--	12,335		12,335	3.922	4.785	483,815	590,254	106,439
	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	--	62,859		62,859	3.751	3.751	2,357,532	2,357,532	0
	TOTAL		75,194		75,194	3.779	3.920	2,841,347	2,947,786	106,439
Aug-15	ECONSALE	--	8,250		8,250	5.683	6.933	468,841	571,987	103,146
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	64,864		64,864	3.800	3.800	2,464,570	2,464,570	0
	TOTAL		73,114		73,114	4.012	4.153	2,933,411	3,036,557	103,146
Sep-15	ECONSALE	--	70		70	4.629	5.646	3,240	3,952	712
	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	--	72,881		72,881	3.778	3.778	2,753,161	2,753,161	0
	TOTAL		72,951		72,951	3.778	3.779	2,756,401	2,757,113	712
Oct-15	ECONSALE	--	165		165	2.799	3.415	4,618	5,634	1,016
	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	--	59,672		59,672	3.850	3.850	2,297,359	2,297,359	0
	TOTAL		59,837		59,837	3.847	3.849	2,301,977	2,302,993	1,016
Nov-15	ECONSALE	--	5,485		5,485	2.592	3.162	142,180	173,460	31,280
	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	--	45,899		45,899	3.791	3.791	1,740,143	1,740,143	0
	TOTAL		51,384		51,384	3.663	3.724	1,882,323	1,913,603	31,280
Dec-15	ECONSALE	--	4,380		4,380	3.123	3.810	136,796	166,891	30,095
	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	--	28,207		28,207	3.861	3.861	1,089,118	1,089,118	0
	TOTAL		32,587		32,587	3.762	3.854	1,225,914	1,256,009	30,095
Jan-15	ECONSALE	--	126,300		126,300	3.325	4.056	4,199,152	5,122,965	923,813
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-15	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	550,476		550,476	3.960	3.960	21,800,391	21,800,391	0
	TOTAL		676,776		676,776	3.842	3.978	25,999,543	26,923,356	923,813

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(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-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	7,017			7,017	8.068	8.068	566,155
	SOCO Franklin	--	31,997			31,997	5.549	5.549	1,775,494
	SOCO Scherer	--	33,548			33,548	3.629	3.629	1,217,298
	Vandolah (NSG)	--	9,340			9,340	8.084	8.084	755,029
	TOTAL		81,902	0	0	81,902	5.267	5.267	4,313,976
Feb-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	14,454			14,454	6.809	6.809	984,151
	SOCO Franklin	--	55,529			55,529	4.787	4.787	2,658,337
	SOCO Scherer	--	34,302			34,302	3.629	3.629	1,244,977
	Vandolah (NSG)	--	18,440			18,440	6.694	6.694	1,234,429
	TOTAL		122,725	0	0	122,725	4.988	4.988	6,121,894
Mar-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	9,527			9,527	6.644	6.644	632,976
	SOCO Franklin	--	63,298			63,298	4.662	4.662	2,951,119
	SOCO Scherer	--	22,208			22,208	3.642	3.642	808,840
	Vandolah (NSG)	--	12,414			12,414	7.194	7.194	893,103
	TOTAL		107,447	0	0	107,447	4.920	4.920	5,286,038
Apr-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	18,389			18,389	6.775	6.775	1,245,876
	SOCO Franklin	--	23,096			23,096	5.695	5.695	1,315,340
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	30,930			30,930	6.654	6.654	2,058,007
	TOTAL		72,415	0	0	72,415	6.379	6.379	4,619,223
May-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	42,443			42,443	6.658	6.658	2,825,975
	SOCO Franklin	--	39,312			39,312	4.822	4.822	1,895,608
	SOCO Scherer	--	15,068			15,068	3.649	3.649	549,817
	Vandolah (NSG)	--	60,165			60,165	6.398	6.398	3,849,456
	TOTAL		156,988	0	0	156,988	5.810	5.810	9,120,856
Jun-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	40,089			40,089	6.639	6.639	2,661,520
	SOCO Franklin	--	124,781			124,781	4.009	4.009	5,002,423
	SOCO Scherer	--	37,161			37,161	3.626	3.626	1,347,551
	Vandolah (NSG)	--	45,539			45,539	6.648	6.648	3,027,555
	TOTAL		247,570	0	0	247,570	4.863	4.863	12,039,049
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	131,919			131,919	6.759	6.759	8,916,653
Jun-15	SOCO Franklin	--	338,013			338,013	4.615	4.615	15,598,321
	SOCO Scherer	--	142,287			142,287	3.632	3.632	5,168,483
	Vandolah (NSG)	--	176,828			176,828	6.683	6.683	11,817,579
	TOTAL		789,047	0	0	789,047	5.260	5.260	41,501,036

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(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-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	48,644			48,644	6.678	6.678	3,248,370
	SOCO Franklin	--	140,177			140,177	3.983	3.983	5,583,673
	SOCO Scherer	--	38,113			38,113	3.634	3.634	1,384,838
	Vandolah (NSG)	--	61,531			61,531	6.540	6.540	4,024,122
	TOTAL		288,465	0	0	288,465	4.937	4.937	14,241,003
Aug-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	51,889			51,889	6.789	6.789	3,522,884
	SOCO Franklin	--	132,711			132,711	4.014	4.014	5,327,505
	SOCO Scherer	--	37,122			37,122	3.634	3.634	1,349,001
	Vandolah (NSG)	--	65,877			65,877	6.551	6.551	4,315,453
	TOTAL		287,599	0	0	287,599	5.047	5.047	14,514,843
Sep-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	26,769			26,769	6.593	6.593	1,764,943
	SOCO Franklin	--	133,209			133,209	3.999	3.999	5,327,546
	SOCO Scherer	--	35,438			35,438	3.642	3.642	1,290,552
	Vandolah (NSG)	--	44,210			44,210	6.536	6.536	2,889,639
	TOTAL		239,626	0	0	239,626	4.704	4.704	11,272,680
Oct-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	30,951			30,951	6.787	6.787	2,100,620
	SOCO Franklin	--	97,459			97,459	4.176	4.176	4,069,677
	SOCO Scherer	--	37,042			37,042	3.631	3.631	1,344,882
	Vandolah (NSG)	--	42,834			42,834	6.582	6.582	2,819,448
	TOTAL		208,286	0	0	208,286	4.962	4.962	10,334,627
Nov-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	15,546			15,546	6.528	6.528	1,014,869
	SOCO Franklin	--	53,983			53,983	4.719	4.719	2,547,294
	SOCO Scherer	--	33,077			33,077	3.630	3.630	1,200,676
	Vandolah (NSG)	--	24,120			24,120	6.129	6.129	1,478,395
	TOTAL		126,726	0	0	126,726	4.925	4.925	6,241,234
Dec-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,495			2,495	8.131	8.131	202,871
	SOCO Franklin	--	38,199			38,199	5.349	5.349	2,043,219
	SOCO Scherer	--	33,777			33,777	3.637	3.637	1,228,442
	Vandolah (NSG)	--	3,250			3,250	8.055	8.055	261,783
	TOTAL		77,721	0	0	77,721	4.807	4.807	3,736,315
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	308,213			308,213	6.739	6.739	20,771,210
Dec-15	SOCO Franklin	--	933,751			933,751	4.337	4.337	40,497,235
	SOCO Scherer	--	356,856			356,856	3.634	3.634	12,966,874
	Vandolah (NSG)	--	418,650			418,650	6.594	6.594	27,606,419
TOTAL			2,017,470	0	0	2,017,470	5.048	5.048	101,841,738

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2015

(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-15	QUAL. FACILITIES	COGEN	276,981			276,981	4.767	11.680	13,203,009
Feb-15	QUAL. FACILITIES	COGEN	250,157			250,157	4.752	12.407	11,888,505
Mar-15	QUAL. FACILITIES	COGEN	241,703			241,703	4.966	12.888	12,002,597
Apr-15	QUAL. FACILITIES	COGEN	230,930			230,930	4.671	12.962	10,786,174
May-15	QUAL. FACILITIES	COGEN	266,574			266,574	4.700	11.883	12,529,047
Jun-15	QUAL. FACILITIES	COGEN	257,962			257,962	4.680	12.102	12,071,397
Jul-15	QUAL. FACILITIES	COGEN	266,562			266,562	4.670	11.853	12,448,464
Aug-15	QUAL. FACILITIES	COGEN	266,582			266,582	4.656	11.838	12,410,731
Sep-15	QUAL. FACILITIES	COGEN	257,962			257,962	4.641	12.064	11,971,496
Oct-15	QUAL. FACILITIES	COGEN	255,185			255,185	4.660	12.164	11,891,761
Nov-15	QUAL. FACILITIES	COGEN	240,086			240,086	4.705	12.680	11,295,964
Dec-15	QUAL. FACILITIES	COGEN	276,983			276,983	4.565	11.478	12,643,543
TOTAL	QUAL. FACILITIES	COGEN	3,087,667			3,087,667	4.701	12.142	145,142,688

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(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-15	ECONPURCH	--	6,536	6.459	6.459	422,155	7.801	509,852	87,697
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		9,763	5.542	5.542	541,062	6.440	628,759	87,697
Feb-15	ECONPURCH	--	4,878	6.569	6.569	320,433	7.595	370,493	50,060
	SEPA	--	2,915	3.684	3.684	107,399	3.684	107,399	0
	TOTAL		7,793	5.490	5.490	427,832	6.132	477,892	50,060
Mar-15	ECONPURCH	--	23,454	4.506	4.506	1,056,873	5.881	1,379,416	322,543
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		26,681	4.407	4.407	1,175,780	5.616	1,498,323	322,543
Apr-15	ECONPURCH	--	26,613	4.790	4.790	1,274,824	6.305	1,678,009	403,185
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		29,736	4.674	4.674	1,389,895	6.030	1,793,080	403,185
May-15	ECONPURCH	--	33,247	5.039	5.039	1,675,388	6.698	2,226,782	551,394
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		36,474	4.919	4.919	1,794,295	6.431	2,345,689	551,394
Jun-15	ECONPURCH	--	44,795	4.401	4.401	1,971,358	5.876	2,632,260	660,902
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		47,918	4.354	4.354	2,086,429	5.733	2,747,331	660,902
Jan-15 THRU Jun-15	ECONPURCH	--	139,523	4.817	4.817	6,721,031	6.30	8,796,812	2,075,781
	SEPA	--	18,842	3.685	3.685	694,262	3.68	694,262	0
	TOTAL		158,365	4.682	4.682	7,415,293	5.993	9,491,074	2,075,781

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(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-15	ECONPURCH	--	22,417	5.623	5.623	1,260,543	7.398	1,658,444	397,901
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		25,644	5.379	5.379	1,379,450	6.931	1,777,351	397,901
Aug-15	ECONPURCH	--	26,921	5.085	5.085	1,368,950	6.712	1,806,962	438,012
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		30,148	4.935	4.935	1,487,857	6.388	1,925,869	438,012
Sep-15	ECONPURCH	--	58,871	4.186	4.186	2,464,378	5.619	3,307,698	843,320
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		61,994	4.161	4.161	2,579,449	5.521	3,422,769	843,320
Oct-15	ECONPURCH	--	41,572	4.298	4.298	1,786,567	5.723	2,379,097	592,530
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		44,799	4.253	4.253	1,905,474	5.576	2,498,004	592,530
Nov-15	ECONPURCH	--	17,688	4.664	4.664	824,900	6.002	1,061,613	236,713
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		20,811	4.517	4.517	939,971	5.654	1,176,684	236,713
Dec-15	ECONPURCH	--	11,512	4.565	4.565	525,473	5.658	651,398	125,925
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		14,739	4.372	4.372	644,380	5.226	770,305	125,925
Jan-15 THRU Dec-15	ECONPURCH	--	318,504	4.694	4.694	14,951,842	6.173	19,662,024	4,710,182
	SEPA	--	37,996	3.685	3.685	1,400,032	3.685	1,400,032	0
	TOTAL		356,500	4.587	4.587	16,351,874	5.908	21,062,056	4,710,182

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January through December 2015

	Approved Jan 14 - Dec 14 ($/1000 KWH)	Requested Jan 15 - Dec 15 ($/1000 KWH)	Difference from Current $	Difference from Current %
Base Rate	$58.50	$58.50	$0.00	0.00%
Fuel Cost Recovery	40.77	43.23	2.46	6.04%
Capacity Cost Recovery (CCR)	10.82	10.74	(0.08)	-0.74%
Energy Conservation Cost Recovery (ECCR) [1]	4.02	2.54	(1.48)	-36.82%
Environmental Cost Recovery (ECRC)	2.43	1.38	(1.05)	-43.21%
Nuclear CR3 Uprate	2.17	2.00	(0.17)	-7.83%
Nuclear Levy	3.45	3.45	0.00	0.00%
Subtotal	122.16	121.84	(0.32)	-0.26%
Gross Receipts Tax	3.13	3.12	(0.01)	-0.32%
Total	$125.29	$124.96	($0.33)	-0.26%

[1] The 2015 ECCR Residential bill impact represents DEF's current estimate and is subject to change. DEF submits the 2015 ECCR Projection Filing in Docket 140002-EI on August 27, 2014.

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	14,061,818	4.598	$ 646,562,413	4.323	$ 607,920,005
Over 1,000 kWh	5,328,545	4.598	245,006,502	5.323	283,648,910
Total	19,390,364		$ 891,568,915		$ 891,568,915
Rate Differential by Tier - Cents per kWh				1.000	

Residential Sales:	
Total	19,390,957
Time of Use	593
Levelized	19,390,364

Docket No. 140001-EI
Schedule H1
Exhibit TGF-3, Part 2

Duke Energy Florida
Generating System Comparative Data by Fuel Type

		2012 Actual	2013 Actual	2014 Actual / Estimated	2015 Projection	2013 vs. 2012	2014 vs. 2013	2015 vs. 2014
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		6,890,407	19,773,117	0	0	187.0%	-100.0%	0.0%
LIGHT OIL		18,829,066	16,141,228	13,743,980	4,211,953	-14.3%	-14.9%	-69.4%
COAL		407,895,600	439,925,452	534,985,801	437,953,621	7.9%	21.6%	-18.1%
GAS		1,054,896,646	1,013,506,189	1,026,899,450	1,008,384,819	-3.9%	1.3%	-1.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,488,511,720	1,489,345,986	1,575,629,231	1,450,550,393	0.1%	5.8%	-7.9%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		45,476	123,377	0	0	171.3%	-100.0%	0.0%
LIGHT OIL		72,093	35,150	42,939	3,125	-51.2%	22.2%	-92.7%
COAL		10,034,864	10,633,975	13,278,658	11,858,055	6.0%	24.9%	-10.7%
GAS		23,997,245	23,066,236	22,129,017	23,858,422	-3.9%	-4.1%	7.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	34,149,677	33,858,739	35,450,615	35,719,602	-0.9%	4.7%	0.8%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	89,246	250,994	0	0	181.2%	-100.0%	0.0%
LIGHT OIL	BBL	163,136	132,000	106,987	33,179	-19.1%	-18.9%	-69.0%
COAL	TON	4,543,203	4,792,094	5,832,852	5,325,962	5.5%	21.7%	-8.7%
GAS	MCF	187,422,970	177,503,510	172,872,912	182,938,293	-5.3%	-2.6%	5.8%
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		568,459	1,529,500	0	0	169.1%	-100.0%	0.0%
LIGHT OIL		925,480	764,007	613,779	192,302	-17.4%	-19.7%	-68.7%
COAL		106,599,484	111,597,504	136,346,462	123,887,171	4.7%	22.2%	-9.1%
GAS		189,832,950	180,039,881	174,396,564	182,938,293	-5.2%	-3.1%	4.9%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	297,926,373	293,930,892	311,356,805	307,017,766	-1.3%	5.9%	-1.4%
GENERATION MIX (% MWH)								
HEAVY OIL		0.13%	0.36%	0.00%	0.00%	150.4%	-109.9%	0.0%
LIGHT OIL		0.21%	0.10%	0.12%	0.01%	-47.4%	0.0%	-82.6%
COAL		29.39%	31.41%	37.46%	33.20%	6.8%	19.4%	-11.5%
GAS		70.27%	68.13%	62.42%	66.79%	-3.0%	-8.4%	7.0%
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	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT								
HEAVY OIL	$/BBL	77.21	78.78	0.00	0.00	2.0%	-100.0%	0.0%
LIGHT OIL	$/BBL	115.42	122.28	128.46	126.95	5.9%	5.1%	-1.2%
COAL	$/TON	89.78	91.80	91.72	82.23	2.3%	-0.1%	-10.3%
GAS	$/MCF	5.63	5.71	5.94	5.51	1.4%	4.0%	-7.2%
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		12.12	12.93	0.00	0.00	6.7%	-100.0%	0.0%
LIGHT OIL		20.35	21.13	22.39	21.90	3.8%	6.0%	-2.2%
COAL		3.83	3.94	3.92	3.54	3.0%	-0.5%	-9.9%
GAS		5.56	5.63	5.89	5.51	1.3%	4.6%	-6.4%
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	5.00	5.07	5.06	4.73	1.4%	-0.1%	-6.6%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		12,500	12,397	0	0	-0.8%	-100.0%	0.0%
LIGHT OIL		12,837	21,735	14,294	61,537	69.3%	-34.2%	330.5%
COAL		10,623	10,494	10,268	10,448	-1.2%	-2.2%	1.7%
GAS		7,911	7,805	7,881	7,668	-1.3%	1.0%	-2.7%
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	8,724	8,681	8,783	8,595	-0.5%	1.2%	-2.1%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		15.15	16.03	0.00	0.00	5.8%	-100.0%	0.0%
LIGHT OIL		26.12	45.92	32.01	134.78	75.8%	-30.3%	321.1%
COAL		4.06	4.14	4.03	3.69	1.8%	-2.6%	-8.3%
GAS		4.40	4.39	4.64	4.23	0.0%	5.6%	-8.9%
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	4.36	4.40	4.44	4.06	0.9%	1.0%	-8.6%

Docket 140001-EI
Exhibit No. ____(TGF-3)
Part 3

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2015

PART 3 – 2015 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 2015

Docket No. 140001-EI
Exhibit__TGF-3, Part 3
Schedule E12-A
Page 1 of 2

		EST Jan-15	EST Feb-15	EST Mar-15	EST Apr-15	EST May-15	EST 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	Auburndale Power Partners, L.P. (AUBRDLFC)	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Auburndale Power Partners, L.P. (AUBSET)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	36,887,520
8	Orlando Cogen Limited (ORLACOGL)	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	49,721,400
9	Pasco County Resource Recovery (PASCOUNT)	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	1,577,570	18,930,840
10	Pinellas County Resource Recovery (PINCOUNT)	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	3,755,303	45,063,630
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	69,786,600
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	9,385,200
13	Southern Scherer	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	20,936,826
14	Subtotal - Base Level Capacity Costs	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	250,712,016
15	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%	
16	Base Level Jurisdictional Capacity Costs	19,406,155	19,406,154	19,406,154	19,406,154	19,406,154	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	232,873,854
17	**Intermediate Production Level Capacity Costs**													
18	Southern Franklin	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	38,222,016
19	Schedule H Capacity Sales - NSB	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
20	Subtotal - Intermediate Level Capacity Costs	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	38,044,512
21	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%	
22	Intermediate Level Jurisdict. Capacity Costs	2,304,958	2,304,958	2,304,958	2,304,958	2,304,959	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	27,659,502
23	**Peaking Production Level Capacity Costs**													
24	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Shady Hills	1,953,774	1,953,774	1,395,553	1,353,895	1,895,453	3,853,393	3,853,393	3,853,393	1,798,250	1,353,895	1,353,895	1,953,774	26,572,441
26	Vandolah (NSG)	2,790,705	2,806,375	2,011,337	1,988,952	2,712,358	5,592,925	5,576,136	5,531,366	2,647,069	1,949,778	1,994,548	2,806,375	38,407,924
27	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Subtotal - Peaking Level Capacity Costs	4,744,480	4,760,149	3,406,890	3,342,847	4,607,811	9,446,318	9,429,529	9,384,759	4,445,319	3,303,673	3,348,443	4,760,149	64,980,364
29	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%	
30	Peaking Level Jurisdictional Capacity Costs	4,551,095	4,566,125	3,268,025	3,206,592	4,419,996	9,061,286	9,045,181	9,002,236	4,264,127	3,169,015	3,211,960	4,566,125	62,331,765
31	**Other Capacity Costs**													
32	Retail Wheeling	(52,200)	(31,444)	(9,046)	(9,316)	(53,353)	(907)	(20,159)	(13,483)	(114)	(270)	(8,964)	(7,158)	(206,415)
33	**Total Capacity Costs (line 16+22+30+32)**	26,210,007	26,245,793	24,970,091	24,908,389	26,077,757	30,771,492	30,736,135	30,699,866	25,975,126	24,879,859	24,914,109	26,270,080	322,658,705
34	Estimated/Actual True-Up Provision - Jan - Dec 2014													16,991,240
35	**Total Capacity Costs w/ True-Up**													339,649,944
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													339,894,492
38	**Nuclear Cost Recovery Clause**													169,131,698
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													169,253,473
41	**Total Recov Capacity & Nuclear Costs (line 37+40)**													509,147,965

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 Wholesale - Scherer 3	Jun-10	May-16	Other	Purch	73.00
10	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
11	Chattahoochee	Jan-03	Dec-17	Other	Purch	5.25
12	Vandolah (NSG)	Jun-12	May-27	Other	Puch	655.00
13	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 2014

Docket No. 140001-EI
Exhibit__TGF-3, Part 2
Schedule E12-B

		ACT Jan-14	ACT Feb-14	ACT Mar-14	ACT Apr-14	ACT May-14	ACT Jun-14	EST Jul-14	EST Aug-14	EST Sep-14	EST Oct-14	EST Nov-14	EST Dec-14	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Auburndale Power Partners, L.P. (AUBSET)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	822,248	822,248	822,248	822,248	822,248	822,248	-	-	-	-	-	-	4,933,485
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	2,832,765	3,015,075	3,108,487	3,108,487	3,108,487	3,084,148	2,925,220	2,925,220	2,925,220	2,925,220	2,925,220	2,925,220	35,808,768
8	Orlando Cogen Limited (ORLACOGL)	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,126,910	3,942,200	3,942,200	3,942,200	3,942,200	3,942,200	3,942,200	49,755,500
9	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	17,799,240
10	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	42,369,930
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,532,650	5,532,650	5,532,650	5,532,650	5,532,650	5,532,650	69,191,454
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	755,858	692,447	666,435	659,566	650,875	648,085	782,100	782,100	782,100	782,100	782,100	782,100	8,765,866
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Southern - Scherer	1,718,587	1,749,640	1,733,997	1,733,824	1,766,928	2,445,593	1,729,834	1,729,834	1,729,834	1,729,834	1,729,834	1,729,834	21,527,574
15	Subtotal - Base Level Capacity Costs	21,537,892	21,687,844	21,739,601	21,732,560	21,756,972	22,140,339	19,926,102	19,926,102	19,926,102	19,926,102	19,926,102	19,926,102	250,151,818
16	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%	
17	Base Level Jurisdictional Capacity Costs	20,005,471	20,144,754	20,192,829	20,186,288	20,208,963	20,565,054	18,508,360	18,508,360	18,508,360	18,508,360	18,508,360	18,508,360	232,353,516
18	**Intermediate Production Level Capacity Costs**													
19	Southern - Franklin	3,051,967	3,187,328	3,119,080	3,572,465	3,125,039	3,193,093	3,114,689	3,114,689	3,114,689	3,114,689	3,114,689	3,114,689	37,937,102
20	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Intermediate Level Capacity Costs	3,037,175	3,172,536	3,104,288	3,557,673	3,110,247	3,178,301	3,099,897	3,099,897	3,099,897	3,099,897	3,099,897	3,099,897	37,759,598
23	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%	
24	Intermediate Level Jurisdictional Capacity Costs	2,208,117	2,306,529	2,256,910	2,586,535	2,261,243	2,310,721	2,253,718	2,253,718	2,253,718	2,253,718	2,253,718	2,253,718	27,452,361
25	**Peaking Production Level Capacity Costs**													
26	Chattahoochee	11,636	8,929	-	-	-	-	-	-	-	-	-	-	20,564
27	Vandolah (RRI)	2,941,381	2,907,332	1,976,385	1,954,804	2,812,014	5,817,412	-	-	-	-	-	-	18,409,329
28	Shady Hills Power Company LLC	1,969,380	1,939,140	1,395,900	1,352,700	1,893,780	3,565,111	3,853,393	3,853,393	1,798,250	1,353,895	1,353,895	1,953,774	26,282,610
29	Vandolah (NSG)	-	-	-	-	-	-	5,576,136	5,531,366	2,647,069	1,949,778	1,994,548	2,806,375	20,505,272
30	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal - Peaking Level Capacity Costs	4,922,397	4,855,401	3,372,285	3,307,504	4,705,794	9,382,523	9,429,529	9,384,759	4,445,319	3,303,673	3,348,443	4,760,149	65,217,775
32	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%	
33	Peaking Level Jurisdictional Capacity Costs	4,721,760	4,657,495	3,234,831	3,172,690	4,513,986	9,000,091	9,045,181	9,002,236	4,264,127	3,169,015	3,211,960	4,566,125	62,559,498
34	**Other Capacity Costs**													
35	Retail Wheeling	(183,230)	(122,235)	(76,146)	(6,579)	(327)	(1,578)	(20,315)	(22,407)	-	(16)	(65)	(82)	(432,979)
36	Other Jurisdictional Capacity Costs	(183,230)	(122,235)	(76,146)	(6,579)	(327)	(1,578)	(20,315)	(22,407)	-	(16)	(65)	(82)	(432,979)
37	**Subtotal Jurisd Capacity Costs (Line 17+24+33+36)**	26,752,118	26,986,543	25,608,424	25,938,934	26,983,864	31,874,288	29,786,944	29,741,907	25,026,205	23,931,076	23,973,972	25,328,121	321,932,396
38	**Nuclear Cost Recovery Clause Costs**													
39	Levy Costs	9,297,660	10,346,712	8,857,433	8,809,330	8,761,227	8,713,125	8,246,353	8,616,919	8,568,816	8,520,714	8,472,611	8,424,508	105,635,408
40	CR3 Uprate Costs	5,879,367	5,849,741	5,819,965	5,790,240	5,760,514	5,730,788	5,701,063	5,671,341	5,641,617	5,611,894	5,582,171	5,552,449	68,591,149
41	**Total NCRC Costs - Order No. PSC-13-0665-FOF-EI**	15,177,027	16,196,453	14,677,398	14,599,570	14,521,741	14,443,913	13,947,416	14,288,260	14,210,433	14,132,608	14,054,782	13,976,957	174,226,557
42	**Total Jurisdictional Capacity Costs (Line 37+41)**	41,929,145	43,182,996	40,285,822	40,538,504	41,505,606	46,318,201	43,734,360	44,030,166	39,236,638	38,063,684	38,028,754	39,305,078	496,158,954
43	**Capacity Revenues**													
44	Capacity Cost Recovery Revenues (net of tax)	36,179,776	41,716,964	35,336,479	34,678,831	39,782,265	45,650,073	49,133,494	51,526,182	51,038,881	47,144,950	40,105,437	37,743,132	510,036,463
45	Prior Period True-Up Provision Over/(Under) Recovery	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(2,030,021)	(24,360,251)
46	**Current Period Revenues (net of tax)**	34,149,755	39,686,943	33,306,458	32,648,810	37,752,244	43,620,052	47,103,473	49,496,161	49,008,860	45,114,929	38,075,416	35,713,111	485,676,212
47	**True-Up Provision**													
48	True-Up Provision - Over/(Under) Recov (Line 46-42)	(7,779,390)	(3,496,053)	(6,979,364)	(7,889,693)	(3,753,362)	(2,698,148)	3,369,113	5,465,995	9,772,223	7,051,245	46,662	(3,591,967)	(10,482,739)
49	Interest Provision for the Month	(1,821)	(2,240)	(2,433)	(2,757)	(2,985)	(2,547)	(1,147)	(960)	(665)	(438)	(386)	(424)	(18,801)
50	Current Cycle Balance - Over/(Under)	(7,781,211)	(11,279,504)	(18,261,301)	(26,153,751)	(29,910,098)	(32,610,793)	(29,242,827)	(23,777,792)	(14,006,233)	(6,955,426)	(6,909,149)	(10,501,540)	(10,501,540)
51	Prior Period Balance - Over/(Under) Recovered	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)	(30,849,951)
52	Prior Period Cumulative True-Up Collected/(Refunded)	2,030,021	4,060,042	6,090,063	8,120,084	10,150,105	12,180,126	14,210,146	16,240,167	18,270,188	20,300,209	22,330,230	24,360,251	24,360,251
53	Prior Period True-up Balance - Over/(Under)	(28,819,930)	(26,789,909)	(24,759,888)	(22,729,867)	(20,699,846)	(18,669,825)	(16,639,804)	(14,609,783)	(12,579,762)	(10,549,741)	(8,519,721)	(6,489,700)	(6,489,700)
54	**Net Capacity True-up Over/(Under) (Line 50+53)**	($36,601,141)	($38,069,413)	($43,021,189)	($48,883,618)	($50,609,944)	($51,280,618)	($45,882,631)	($38,387,575)	($26,585,996)	($17,505,167)	($15,428,870)	($16,991,240)	($16,991,240)

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 2015

Docket No. 140001-EI
Exhibit__TGF-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 (%)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	0.519	19,390,958	4,265.27	0.9360703	20,715,280	4,556.57	2,364.76	51.561%	62.055%	61.248%
General Service Non-Demand										
GS-1, GST-1										
Secondary	0.652	1,264,199	221.31	0.9360703	1,350,539	236.42	154.17	3.362%	3.220%	3.231%
Primary	0.652	4,428	0.78	0.9751266	4,541	0.79	0.52	0.011%	0.011%	0.011%
Transmission	0.652	3,817	0.67	0.9851266	3,875	0.68	0.44	0.010%	0.009%	0.009%
								3.382%	3.240%	3.251%
General Service										
GS-2 Secondary	1.000	147,708	16.86	0.9360703	157,796	18.01	18.01	0.393%	0.245%	0.257%
General Service Demand										
GSD-1, GSDT-1										
Secondary	0.774	12,149,615	1,791.89	0.9360703	12,979,383	1,914.27	1,481.66	32.306%	26.070%	26.550%
Transm Del/ Primary Mtr	0.774	579	0.09	0.9751266	594	0.09	0.07	0.001%	0.001%	0.001%
Sec Del/Primary Mtr	0.774	45,893	6.77	0.9751266	47,064	6.94	5.37	0.117%	0.095%	0.096%
Primary	0.774	2,281,355	336.47	0.9751266	2,339,548	345.05	267.07	5.823%	4.699%	4.786%
SS-1 Primary	1.483	5,483	0.42	0.9751266	5,623	0.43	0.64	0.014%	0.006%	0.007%
Transm Del/ Primary Mtr	1.483	1,964	0.15	0.9751266	2,014	0.16	0.23	0.005%	0.002%	0.002%
Transmission	1.483	5,846	0.45	0.9851266	5,934	0.46	0.68	0.015%	0.006%	0.007%
								38.282%	30.879%	31.449%
Curtailable										
CS-1, CST-1, CS-2, CST-2, SS-3										
Primary	1.186	35,094	3.38	0.9751266	35,989	3.46	4.11	0.090%	0.047%	0.050%
SS-3 Primary	0.814	1,013	0.14	0.9751266	1,039	0.15	0.12	0.003%	0.002%	0.002%
								0.092%	0.049%	0.052%
Interruptible										
IS-1, IST-1, IS-2, IST-2										
Secondary	0.963	89,325	10.59	0.9360703	95,426	11.31	10.89	0.238%	0.154%	0.161%
Sec Del/Primary Mtr	0.963	4,383	0.52	0.9751266	4,495	0.53	0.51	0.011%	0.007%	0.008%
Primary Del / Primary Mtr	0.963	1,257,770	149.13	0.9751266	1,289,853	152.93	147.24	3.210%	2.083%	2.170%
Primary Del / Transm Mtr	0.963	20,318	2.41	0.9851266	20,625	2.45	2.35	0.051%	0.033%	0.035%
Transm Del/ Primary Mtr	0.963	333,314	39.52	0.9751266	341,816	40.53	39.02	0.851%	0.552%	0.575%
Transm Del/ Transm Mtr	0.963	269,380	31.94	0.9851266	273,447	32.42	31.22	0.681%	0.442%	0.460%
SS-2 Primary	0.859	38,315	5.09	0.9751266	39,292	5.22	4.49	0.098%	0.071%	0.073%
Transm Del/ Primary Mtr	0.859	4,059	0.54	0.9751266	4,163	0.55	0.48	0.010%	0.008%	0.008%
Transmission	0.859	41,744	5.55	0.9851266	42,374	5.63	4.84	0.105%	0.077%	0.079%
								5.256%	3.426%	3.567%
Lighting										
LS-1 (Secondary)	6.141	389,030	7.23	0.9360703	415,599	7.73	47.44	1.034%	0.105%	0.177%
Total		37,785,590	6,897.15		40,176,306	7,342.78	4,586.34	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2012 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2015
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2013
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 6 / 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

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2015

Docket No. 140001-EI
Exhibit__TGF-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 ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(7) Capacity CCR Factor (c/kWh)	(8) Levy CCR Factor (c/kWh)	(9) CR3 CCR Factor (c/kWh)	(10) Capacity & Nuclear CCR Factor (c/kWh)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	61.248%	19,390,958	$208,177,843	$66,898,805	$38,739,021	$313,815,669	**1.074**	**0.345**	**0.200**	**1.619**
General Service Non-Demand										
GS-1, GST-1										
Secondary		1,264,199					**0.868**	**0.252**	**0.162**	**1.282**
Primary		4,384					**0.859**	**0.249**	**0.160**	**1.269**
Transmission		3,741					**0.851**	**0.247**	**0.159**	**1.256**
TOTAL GS	3.251%	1,272,323	11,049,420	3,205,956	2,056,144	16,311,521				
General Service										
GS-2 Secondary	0.257%	147,708	872,374	268,829	162,337	1,303,539	**0.591**	**0.182**	**0.110**	**0.883**
General Service Demand										
GSD-1, GSDT-1, SS-1										
Secondary		12,149,615								
Primary		2,311,921								
Transmission		5,729								
TOTAL GSD	31.449%	14,467,265	106,891,929	31,830,333	19,891,111	158,613,373				
Curtailable										
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3										
Secondary		-								
Primary		35,746								
Transmission		-								
TOTAL CS	0.052%	35,746	178,297	86,524	33,179	297,999				
Interruptible										
IS-1, IST-1, IS-2, IST-2, SS-2										
Secondary		89,325								
Primary		1,621,463								
Transmission		324,813								
TOTAL IS	3.567%	2,035,601	12,124,063	3,511,060	2,256,121	17,891,244				
Lighting										
LS-1 Secondary	0.177%	389,030	600,567	202,296	111,757	914,620	**0.154**	**0.052**	**0.029**	**0.235**
Total	100.000%	37,738,631	$339,894,492	$106,003,803	$63,249,670	$509,147,965	**0.901**	**0.282**	**0.168**	**1.351**

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) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10
(9) (Column 5 / Column 2) / 10
(10) Column 7 + Column 8 + Column 9
(11) Class Billing kW Load Factor
(12) Column 2 x 1000 / 8760 / Column 11 x 12
(13) Column 3 / Column 12
(14) Column 4 / Column 12
(15) Column 5 / Column 12
(16) Column 6 / Column 12

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2015

Docket No. 140001-EI
Exhibit__TGF-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 ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(11) Billing KW Load Factor (%)	(12) Projected Effective KW at Meter Level (kW)	(13) Capacity CCR Factor ($/kW-mo)	(14) Levy CCR Factor ($/kW-mo)	(15) CR3 CCR Factor ($/kW-mo)	(16) Capacity & Nuclear CCR Factor ($/kW-mo)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	61.248%	19,390,958	$208,177,843	$66,898,805	$38,739,021	$313,815,669						
General Service Non-Demand												
GS-1, GST-1												
Secondary		1,264,199										
Primary		4,384										
Transmission		3,741										
TOTAL GS	3.251%	1,272,323	11,049,420	3,205,956	2,056,144	16,311,521						
General Service												
GS-2 Secondary	0.257%	147,708	872,374	268,829	162,337	1,303,539						
General Service Demand												
GSD-1, GSDT-1, SS-1												
Secondary		12,149,615							**2.82**	**0.84**	**0.52**	**4.19**
Primary		2,311,921							**2.79**	**0.83**	**0.51**	**4.15**
Transmission		5,729							**2.76**	**0.82**	**0.51**	**4.11**
TOTAL GSD	31.449%	14,467,265	106,891,929	31,830,333	19,891,111	158,613,373	52.30%	37,893,254				
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
Secondary		-							**1.88**	**0.91**	**0.35**	**3.13**
Primary		35,746							**1.86**	**0.90**	**0.35**	**3.10**
Transmission		-							**1.84**	**0.89**	**0.34**	**3.07**
TOTAL CS	0.052%	35,746	178,297	86,524	33,179	297,999	51.50%	95,082				
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary		89,325							**2.38**	**0.69**	**0.44**	**3.52**
Primary		1,621,463							**2.36**	**0.68**	**0.44**	**3.48**
Transmission		324,813							**2.33**	**0.68**	**0.43**	**3.45**
TOTAL IS	3.567%	2,035,601	12,124,063	3,511,060	2,256,121	17,891,244	54.80%	5,088,493				
Lighting												
LS-1 Secondary	0.177%	389,030	600,567	202,296	111,757	914,620						
Total	100.000%	37,738,631	$339,894,492	$106,003,803	$63,249,670	$509,147,965						

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) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10
(9) (Column 5 / Column 2) / 10
(10) Column 7 + Column 8 + Column 9
(11) Class Billing kW Load Factor
(12) Column 2 x 1000 / 8760 / Column 11 x 12
(13) Column 3 / Column 12
(14) Column 4 / Column 12
(15) Column 5 / Column 12
(16) Column 6 / Column 12

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

	Capacity + Nuclear Cost		
	Cost	Effective kW	$/kW
Total GSD, CS, IS	$176,802,616	43,076,828	4.10

SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $4.10/kW * 10%	0.410	0.406	0.402
Daily - $4.10/kW / 21	0.195	0.193	0.191

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 24A
PARTY: DUKE ENERGY FLORIDA (DEF)(DIRECT)
DESCRIPTION: James McClay JM-1T

Duke Energy Florida **REDACTED**
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-13							13,114,500			
Feb-13							11,917,200			
Mar-13							13,740,900			
Apr-13							12,722,600			
May-13							14,957,700			
Jun-13							18,572,900			
Jul-13							19,247,800			
Aug-13							21,038,900			
Sep-13							18,308,300			
Oct-13							16,634,900			
Nov-13							13,699,000			
Dec-13							15,238,200			
YTD	($140,907,108)	$0	($140,907,108)	122,757,500	0	122,757,500	189,192,900	65%	100%	0%

No. 2 Oil

	Savings/(Cost) on Hedges			Hedged Volumes (Barrels)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-13							9,306			
Feb-13							15,500			
Mar-13							8,402			
Apr-13							11,026			
May-13							13,004			
Jun-13							17,314			
Jul-13							14,843			
Aug-13							20,254			
Sep-13							8,504			
Oct-13							6,209			
Nov-13							4,147			
Dec-13							3,491			
YTD	($213,675)	$0	($213,675)	49,000	0	49,000	132,000	37%	100%	0%

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-13							250,000			
YTD	$25,575	$0	$25,575	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-13							521,349			
Feb-13							528,738			
Mar-13							528,738			
Apr-13							528,738			
May-13							528,738			
Jun-13							530,468			
Jul-13							337,958			
Aug-13							431,233			
Sep-13							431,233			
Oct-13							337,162			
Nov-13							337,162			
Dec-13							337,162			
YTD	($141,464)	$0	($141,464)	2,562,000	0	2,562,000	5,378,679	48%	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-13							176,906			
Feb-13							176,477			
Mar-13							176,477			
Apr-13							176,477			
May-13							176,477			
Jun-13							174,082			
Jul-13							174,082			
Aug-13							328,967			
Sep-13							352,465			
Oct-13							352,465			
Nov-13							352,465			
Dec-13							352,465			
YTD	($77,608)	$0	($77,608)	1,470,000	0	1,470,000	2,969,805	49%	100%	0%

As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Docket No. 140001-EI
Witness: McClay
Exhibit No. ___ (JM-1T)
Hedging Details (Jan - Dec 2013)
2 of 17

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3272956	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3272956	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3329706	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3329706	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3369594	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3369594	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3455148	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3455148	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3468181	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3468181	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3491465	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3491465	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3502035	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3502035	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3514713	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3514713	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3571186	BAR#	IFERC	TRNSZ4			$3.3800			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3571186	BAR#	IFERC	TRNSZ4			$3.3800			
Financial	FIXED SWAP		1/1/2013	2209421	DEU#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2244150	MSCG	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2262126	MSCG	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2348805	JPMC#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2372718	JPMC#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3472650	BAR#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3502916	BOM#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3508826	DEU#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3514194	BOM#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3526028	CEH#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3534316	CEH#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2625163	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	2640235	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	2656079	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3202228	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3207066	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3213804	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3217519	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3222399	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3235054	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3231885	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3274074	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3295356	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3298000	MACQ#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3301233	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3309048	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3312394	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3321930	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3329693	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3334010	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3341156	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3347573	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3349580	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3353527	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3355367	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3367374	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3371630	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3371671	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3372243	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3373820	MACQ#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3377742	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3379138	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3383970	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3386626	MACQ#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3395983	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3448436	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3456972	CIT#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3461248	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3478078	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3479924	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3490398	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3522742	SG#	NYMEX	NG			$3.3540			
												13,114,600	69%

As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3272957	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3272957	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3329707	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3329707	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3369597	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3369597	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3455149	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3455149	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3488182	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3488182	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3491466	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3491466	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3502036	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3502036	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3514714	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3514714	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3571187	BAR#	IFERC	TRNSZ4			$3.2400			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3571187	BAR#	IFERC	TRNSZ4			$3.2400			
Financial	FIXED SWAP		2/1/2013	2206422	DEU#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2244151	MSCG	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2262127	MSCG	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2346610	JPMC#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2372719	JPMC#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3472851	BAR#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3502917	BOA#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3508829	DEU#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3514195	BOA#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3526029	CEH#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3534317	CEH#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2625164	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	2640236	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	2656080	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3002229	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3207967	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3213905	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3217520	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3222400	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3229266	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3231886	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3274075	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3295357	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3298001	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3301234	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3309049	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3312395	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3321931	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3329694	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3334011	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3341167	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3347574	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3349581	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3353528	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3355368	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3357375	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3371831	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3371672	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3372244	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3373821	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3377743	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3379139	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3383971	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3386627	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3395964	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3448437	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3456973	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3461249	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3478079	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3479625	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3490399	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3522743	SG#	NYMEX	NG			$3.2260			
												11,917,200	69%

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As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3272958	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3272958	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3329708	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3329708	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3369598	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3369598	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3455150	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3455150	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3488183	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3488183	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3491467	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3491467	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3502037	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3502037	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3514715	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3514715	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3571188	BAR#	IFERC	TRNSZ4			$3.4400			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3571188	BAR#	IFERC	TRNSZ4			$3.4400			
Financial	FIXED SWAP		3/1/2013	2209423	DEU#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2244152	MSCG	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2262126	MSCG	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2348611	JPMC#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2372722	JPMC#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3472652	BAR#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3502918	BOM#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3508830	DEU#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3514196	BOM#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3526030	CEH#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3534318	CEH#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2625165	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	2640237	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	2656081	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3202230	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3207068	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3213906	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3217521	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3222401	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3225056	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3231887	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3274075	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3295358	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3298002	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3301235	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3309050	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3312396	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3321932	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3329695	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3334012	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3341168	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3347575	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3349582	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3353529	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3355369	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3367376	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3371632	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3371573	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3372245	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3373822	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3377744	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3379140	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3383972	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3386628	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3395985	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3448438	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3456974	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3461250	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3478080	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3479626	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3490402	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3522744	SG#	NYMEX	NG			$3.4270			
												13,746,900	66%

As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3272959	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3272959	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3329709	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3329709	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3369599	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3369599	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3455151	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3455151	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3488184	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3488184	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3491468	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3491468	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3502038	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3502038	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3514716	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3514716	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3571189	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3571189	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3584202	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3584202	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3623744	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3623744	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3660088	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3660088	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	2126529	JPMC#	IFERC	HHUB			$3.9600			
Financial	FIXED SWAP		4/1/2013	2130415	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2140270	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2165078	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2181888	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2194798	MLC	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2209424	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2220225	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2244153	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2262132	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2287617	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2298914	DEU#	IFERC	HHUB			$3.9600			
Financial	FIXED SWAP		4/1/2013	2304860	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2334863	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2348612	JPMC#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2372723	JPMC#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2407829	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2451040	BAR#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2469665	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2579397	BAR#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	3500329	CIT#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3503785	BAR#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3514205	CSEL	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3521382	CIT#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3531923	CIT#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	2622814	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	2655321	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3161180	CIT#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3172596	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3203152	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3220882	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3223660	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3225045	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3277225	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3295358	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3301238	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3309825	CIT#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3334607	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3341189	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3347061	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3371635	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3477373	CIT#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3490468	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3541880	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3581792	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3762627	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3778389	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3780732	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3785688	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3786475	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3788055	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3801713	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3804746	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3806227	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3809620	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3394493	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3608565	DEU#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3640046	BPEC	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3667235	MSCG	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3681581	CEH#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3696841	CEH#	IFERC	TRNSZ4			$4.0000			
												12,722,600	73%

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DEF Gas Hedging Status
REDACTED

Hystical/ financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3272960	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3272960	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3329710	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3329710	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3369500	JPMC#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3369500	JPMC#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3455152	MSCG	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3455152	MSCG	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3488185	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3488185	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3491469	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3491469	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3502039	MSCG	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3502039	MSCG	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3514717	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3514717	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3571190	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3571190	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3584203	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3584203	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3623745	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3623745	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3660089	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3660089	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	2126530	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2130416	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2140273	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2165079	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2181889	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2194799	MLC	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2209425	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2220226	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2244154	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2262133	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2287618	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2298915	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2304861	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2334864	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2348513	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2372724	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2407830	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2451041	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2469666	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2579398	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3350077	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3353485	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3355370	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3368710	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3372246	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3377902	CIT#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3384457	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3388619	CIT#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3458817	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3473251	CIT#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3590330	CIT#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3503788	BAR#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3514206	CSEL	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3531383	CIT#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3537824	CIT#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	2632615	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	2655322	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3185161	CIT#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3172567	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3203153	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3220883	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3223681	JPMC#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3225046	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3277229	JPMC#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3295360	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3301237	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3309626	CIT#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3334808	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3341170	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3347062	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3371636	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3477374	CIT#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3490469	CSEL	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3541881	BAR#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3581793	JPMC#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3762628	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3778390	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3780733	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3785889	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3786476	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3788056	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3801714	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3804747	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3806228	DEU#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3809621	CEH#	NYMEX	NG			$4.1510			
Financial	FIXED SWAP		5/1/2013	3394494	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3608565	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3640047	BPEC	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3667236	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3681894	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3696842	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3704585	MACQ#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3743525	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3749645	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3749672	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3751096	CEH#	IFERC	TRNSZ4			$4.1800			
												14,867,700	80%

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DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3272961	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3272961	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3329711	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3329711	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3369501	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3369501	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3455153	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3455153	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3488186	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3488186	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3491470	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3491470	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3502040	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3502040	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3514718	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3514718	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3571191	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3571191	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3584204	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3584204	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3623746	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3623746	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3660090	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3660090	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	2126531	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2130421	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2140274	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2165082	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2181890	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2194800	MLC	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2209426	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2220227	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2244155	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2262135	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2287619	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2298916	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2304862	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2334865	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2348614	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2372725	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2407831	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2451044	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2469669	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2579399	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3350080	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3353486	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3355371	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3368711	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3372247	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3377903	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3384408	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3386620	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3458818	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3473262	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3500331	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3503789	BAR#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3514207	CSEL	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3521384	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3531926	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3830732	CSEL	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3856030	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3857445	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3859785	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3864907	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	2622816	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	2655323	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3161182	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3172598	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3203154	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3220584	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3223662	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3225047	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3277230	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3295361	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3301238	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3309427	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3334909	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3341171	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3347063	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3371637	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3477375	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3490470	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3541882	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3581794	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3762629	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3778391	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3780734	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3785890	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3786477	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3788057	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3801715	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3804750	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3806229	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3809622	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3394495	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3608567	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3640048	BPEC	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3667237	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3681700	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3696843	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3704586	MACQ#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3743526	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3749648	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3749673	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3751097	CEH#	IFERC	TRNSZ4			$4.1800			
												18,572,900	66%

As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3272982	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3272982	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3329712	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3329712	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3369602	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3369602	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3455154	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3455154	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3488187	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3488187	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3491471	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3491471	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3502041	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3502041	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3514719	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3514719	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3571192	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3571192	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3584205	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3584205	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3623747	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3623747	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3660091	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3660091	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	2126532	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2130422	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2140353	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2165083	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2181891	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2194801	MLC	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2209427	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2220228	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2244156	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2262136	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2287820	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2298917	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2304863	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2334866	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2348615	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2372726	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2407832	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2451045	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2469670	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2579400	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3350081	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3353487	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3355372	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3368712	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3372248	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3377904	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3384409	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3386621	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3458819	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3473253	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3500332	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3503790	BAR#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3514208	CSEL	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3521385	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3531926	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3530733	CSEL	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3856031	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3857446	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3859786	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3864908	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	2622817	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	2655324	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3161163	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3172599	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3203155	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3220885	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3223665	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3225048	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3277231	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3295362	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3301239	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3309828	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3334610	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3341172	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3347064	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3371638	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3477376	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3480471	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3541883	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3561795	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3762630	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3778392	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3780735	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3785891	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3786478	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3788056	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3801716	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3804751	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3806230	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3809623	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3394496	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3608566	DEU#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3640049	BPEC	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3667238	MSCG	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3681701	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3696844	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3704591	MACQ#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3743527	DEU#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3749547	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3749674	MSCG	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3751098	CEH#	IFERC	TRNSZ4			$3.7300			
												19,247,800	66%

As of December 31, 2013

DEF Gas Hedging Status
REDACTED

Docket No. 140001-EI
Witness: McClay
Exhibit No. ___ (JM-1T)
Hedging Details (Jan - Dec 2013)
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Hypical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3272963	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3272963	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3329713	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3329713	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3369603	JPMC#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3369603	JPMC#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3455155	MSCG	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3455155	MSCG	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3488188	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3488188	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3491472	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3491472	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3502042	MSCG	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3502042	MSCG	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3514720	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3514720	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3571193	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3571193	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3584206	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3584206	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3623748	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3623748	BAR#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2013	3660092	JPMC#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2013	3660092	JPMC#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	2126534	JPMC#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2130423	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2140354	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2165086	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2181492	MSCG	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2194802	MLC	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2209428	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2220229	MSCG	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2244157	MSCG	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2262137	MSCG	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2287622	CSEL	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2298918	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2304864	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2334867	CSEL	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2348515	JPMC#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2372727	JPMC#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2407833	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2451046	BAR#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2469671	CSEL	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	2579403	BAR#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3350082	BAR#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3353486	CSEL	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3353373	CSEL	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3368713	DEU#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3372249	BAR#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3377905	CIT#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3384410	JPMC#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3388622	CIT#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3458820	BAR#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3473254	CIT#	IFERC	HHUB			$3.4500			
Financial	FIXED SWAP		8/1/2013	3500333	CIT#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3503791	BAR#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3514209	CSEL	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3521386	CIT#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3531939	CIT#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3630734	CSEL	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3856032	MACQ#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3857447	MACQ#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3859787	MACQ#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	3864906	CIT#	IFERC	MAINLN			$3.4000			
Financial	FIXED SWAP		8/1/2013	2622818	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	2855325	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3161164	CIT#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3172600	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3203156	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3220686	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3223672	JPMC#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3225048	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3277232	JPMC#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3295363	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3301240	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3309829	CIT#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3334611	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3341173	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3347065	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3371639	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3477379	CIT#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3490472	CSEL	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3541884	BAR#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3581796	JPMC#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3762631	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3778393	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3780736	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3785892	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3786479	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3788059	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3804719	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3804752	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3806231	DEU#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3809624	CEH#	NYMEX	NG			$3.4590			
Financial	FIXED SWAP		8/1/2013	3394497	JPMC#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3606569	DEU#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3640090	BPEC	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3667239	MSCG	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3681714	CEH#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3696847	CEH#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3704592	MACQ#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3743528	DEU#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3749648	CEH#	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3749675	MSCG	IFERC	TRNSZ4			$3.4500			
Financial	FIXED SWAP		8/1/2013	3751099	CEH#	IFERC	TRNSZ4			$3.4500			
												21,038,906	62%

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DEF Gas Hedging Status
REDACTED

As of December 31, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3272964	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3272964	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3329714	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3329714	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3369604	JPMC#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3369604	JPMC#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3455156	MSCG	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3455156	MSCG	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3488189	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3488189	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3491475	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3491475	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3502043	MSCG	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3502043	MSCG	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3514721	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3514721	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3571194	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3571194	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3584207	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3584207	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3623749	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3623749	BAR#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2013	3660093	JPMC#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2013	3660093	JPMC#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	2126536	JPMC#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2130424	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2140355	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2165087	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2181893	MSCG	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2194803	MLC	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2209429	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2220230	MSCG	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2244158	MSCG	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2262138	MSCG	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2287623	CSEL	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2298919	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2304865	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2334868	CSEL	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2348517	JPMC#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2372726	JPMC#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2407834	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2451047	BAR#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2489672	CSEL	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	2579404	BAR#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3350083	BAR#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3353489	CSEL	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3353374	CSEL	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3368714	DEU#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3372250	BAR#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3377906	CITI#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3384411	JPMC#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3388623	CITI#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3458821	BAR#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3473255	CITI#	IFERC	HHUB			$3.5700			
Financial	FIXED SWAP		9/1/2013	3500334	CITI#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3503792	BAR#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3514210	CSEL	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3521387	CITI#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3531931	CITI#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3630795	CSEL	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3856033	MACQ#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3857448	MACQ#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3859788	MACQ#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	3864911	CITI#	IFERC	MAINLN			$3.5000			
Financial	FIXED SWAP		9/1/2013	2622819	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	2855326	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3161165	CITI#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3172601	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3203157	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3220687	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3223673	JPMC#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3225050	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3277233	JPMC#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3295364	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3301241	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3309830	CITI#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3334612	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3341174	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3347066	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3371640	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3477380	CITI#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3490473	CSEL	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3541685	BAR#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3581797	JPMC#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3762632	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3778394	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3780737	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3785693	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3786480	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3788060	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3801720	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3804753	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3806232	DEU#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3809625	CEH#	NYMEX	NG			$3.5660			
Financial	FIXED SWAP		9/1/2013	3394498	JPMC#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3608570	DEU#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3640051	BPEC	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3667240	MSCG	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3681728	CEH#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3696848	CEH#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3704593	MACQ#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3743529	DEU#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3749649	CEH#	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3749676	MSCG	IFERC	TRNSZ4			$3.5500			
Financial	FIXED SWAP		9/1/2013	3751100	CEH#	IFERC	TRNSZ4			$3.5500			
												19,306,300	87%

As of December 31, 2013

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Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3272995	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3272995	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3329715	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3329715	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3369605	JPMC#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3369605	JPMC#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3455157	MSCG	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3455157	MSCG	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3488190	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3488190	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3491476	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3491476	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3502044	MSCG	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3502044	MSCG	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3514722	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3514722	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3571195	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3571195	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3584208	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3584208	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3623750	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3623750	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2013	3660094	JPMC#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2013	3660094	JPMC#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	2126537	JPMC#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2130427	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2140358	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2165088	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2181896	MSCG	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2194604	MLC	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2209430	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2220231	MSCG	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2244159	MSCG	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2262139	MSCG	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2287824	CSEL	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2298920	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2304866	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2334869	CSEL	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2348618	JPMC#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2372729	JPMC#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2407835	DEU#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2451048	BAR#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2469677	CSEL	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	2579405	BAR#	IFERC	HHUB			$3.5000			
Financial	FIXED SWAP		10/1/2013	3500335	CITI#	IFERC	MAINLN			$3.4500			
Financial	FIXED SWAP		10/1/2013	3503793	BAR#	IFERC	MAINLN			$3.4500			
Financial	FIXED SWAP		10/1/2013	3514211	CSEL	IFERC	MAINLN			$3.4500			
Financial	FIXED SWAP		10/1/2013	3521388	CITI#	IFERC	MAINLN			$3.4500			
Financial	FIXED SWAP		10/1/2013	3531932	CITI#	IFERC	MAINLN			$3.4500			
Financial	FIXED SWAP		10/1/2013	2622820	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	2655327	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3161166	CITI#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3172602	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3203158	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3220688	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3223674	JPMC#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3225051	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3277234	JPMC#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3285365	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3301242	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3309831	CITI#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3334613	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3341175	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3347067	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3371641	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3477381	CITI#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3490474	CSEL	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3541886	BAR#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3581798	JPMC#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3762633	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3778395	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3780738	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3785894	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3786489	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3788061	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3801721	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3804754	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3806233	DEU#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3809626	CEH#	NYMEX	NG			$3.4980			
Financial	FIXED SWAP		10/1/2013	3394499	JPMC#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3608571	DEU#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3640052	BPEC	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3667241	MSCG	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3681729	CEH#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	36968-89	CEH#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3704594	MACQ#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3743530	DEU#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3749650	CEH#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3749677	MSCG	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		10/1/2013	3751101	CEH#	IFERC	TRNSZ4			$3.5000			
												16,634,900	62%

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DEF Gas Hedging Status
REDACTED

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3272996	BAR#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3272996	BAR#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3329716	CSEL	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3329716	CSEL	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3369606	JPMC#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3369606	JPMC#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3455158	MSCG	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3455158	MSCG	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3488191	CSEL	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3488191	CSEL	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3491477	DEU#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3491477	DEU#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3502045	MSCG	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3502045	MSCG	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3514723	DEU#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3514723	DEU#	NYMEX	NG			$3.4970			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2013	3571196	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2013	3571196	BAR#	IFERC	TRNSZ4			$3.5000			
Financial	FIXED SWAP		11/1/2013	2206431	DEU#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	2244160	MSCG	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	2262140	MSCG	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	2348619	JPMC#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	2372730	JPMC#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3350084	MSCG	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3354102	DEU#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3355375	BAR#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3370117	JPMC#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3371642	CSEL	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3372251	JPMC#	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3378586	MSCG	IFERC	HHUB			$3.4900			
Financial	FIXED SWAP		11/1/2013	3386629	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3458328	CSEL	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3461636	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3473268	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3478026	CITI#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3491022	CSEL	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3523051	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3605382	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3609020	BAR#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3636123	JPMC#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3681868	CEH#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3681980	CSEL	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3699718	CEH#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3749651	MSCG	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3758099	BOM#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3762634	MACQ#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3767486	CEH#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3778415	MACQ#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3786532	CITI#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3788062	MACQ#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3804135	CEH#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3806256	CEH#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3810167	CITI#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3819267	MACQ#	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3859900	CSEL	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	4071983	MLC	IFERC	MAINLN			$3.4600			
Financial	FIXED SWAP		11/1/2013	3321941	JPMC#	NYMEX	NG			$3.4970			
Financial	FIXED SWAP		11/1/2013	3330352	CITI#	NYMEX	NG			$3.4970			
Financial	FIXED SWAP		11/1/2013	3334623	DEU#	NYMEX	NG			$3.4970			
Financial	FIXED SWAP		11/1/2013	3347576	MSCG	NYMEX	NG			$3.4970			
												13,699,000	53%

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DEF Gas Hedging Status
REDACTED

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Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3272967	BAR#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3272967	BAR#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3329717	CSEL	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3329717	CSEL	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3369607	JPMC#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3369607	JPMC#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3455159	MSCG	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3455159	MSCG	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3488192	CSEL	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3488192	CSEL	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3491486	DEU#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3491486	DEU#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3502046	MSCG	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3502046	MSCG	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3514724	DEU#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3514724	DEU#	NYMEX	NG			$3.8180			
Financial	FIXED FINANCIAL OPTION	CALL	12/1/2013	3571197	BAR#	IFERC	TRNSZ4			$3.8000			
Financial	FIXED FINANCIAL OPTION	PUT	12/1/2013	3571197	BAR#	IFERC	TRNSZ4			$3.8000			
Financial	FIXED SWAP		12/1/2013	2209432	DEU#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	2244161	MSCG	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	2262141	MSCG	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	2348820	JPMC#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	2372731	JPMC#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3350967	MSCG	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3354103	DEU#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3355376	BAR#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3370120	JPMC#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3371543	CSEL	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3372252	JPMC#	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3378587	MSCG	IFERC	HHUB			$3.8200			
Financial	FIXED SWAP		12/1/2013	3386530	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3458329	CSEL	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3461537	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3473269	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3478027	CITI#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3491023	CSEL	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3523062	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3605383	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3609021	BAR#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3636124	JPMC#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3661871	CEH#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3681981	CSEL	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3699719	CEH#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3749652	MSCG	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3758100	BOM#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3762635	MACQ#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3767487	CEH#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3778416	MACQ#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3786533	CITI#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3788063	MACQ#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3804136	CEH#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3806257	CEH#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3810158	CITI#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3819268	MACQ#	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3859901	CSEL	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	4071984	MLC	IFERC	MAINLN			$3.7400			
Financial	FIXED SWAP		12/1/2013	3321842	JPMC#	NYMEX	NG			$3.8180			
Financial	FIXED SWAP		12/1/2013	3330353	CITI#	NYMEX	NG			$3.8180			
Financial	FIXED SWAP		12/1/2013	3334624	DEU#	NYMEX	NG			$3.8180			
Financial	FIXED SWAP		12/1/2013	3347577	MSCG	NYMEX	NG			$3.8180			
												15,336,200	49%

DEF Gas Storage Hedging Status
REDACTED

As of December 31, 2013

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	6/1/2013	3966424	CSEL	IFERC	FGTZ3	[redacted]	[redacted]	$4.2600	[redacted]		
Financial	FIXED SWAP	6/1/2013	3971356	MACQ#	IFERC	FGTZ3	[redacted]	[redacted]	$4.2600	[redacted]		
							[redacted]	[redacted]		[redacted]	250,000	60%

DEF #2 Oil Hedging Status
REDACTED

As of December 31, 2013

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume (Bbls)	Fixed Price ($/Bbl)	Market Scan Biz Average ($/Bbl)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	1/1/2013	3532485	BOM#	USGLF	NO2ULS			$128.0832			
											9,306	32%
Financial	FIXED SWAP	2/1/2013	3532486	BOM#	USGLF	NO2ULS			$134.7402			
											15,500	19%
Financial	FIXED SWAP	3/1/2013	3532489	BOM#	USGLF	NO2ULS			$126.4494			
											8,402	36%
Financial	FIXED SWAP	4/1/2013	3532491	BOM#	USGLF	NO2ULS			$120.8046			
Financial	FIXED SWAP	4/1/2013	3748949	DEU#	USGLF	NO2ULS			$120.8046			
											11,026	36%
Financial	FIXED SWAP	5/1/2013	3532493	BOM#	USGLF	NO2ULS			$119.3724			
Financial	FIXED SWAP	5/1/2013	3748956	DEU#	USGLF	NO2ULS			$119.3724			
Financial	FIXED SWAP	5/1/2013	3937694	BOM#	USGLF	NO2ULS			$119.3724			
											13,004	62%
Financial	FIXED SWAP	6/1/2013	3532495	BOM#	USGLF	NO2ULS			$120.1242			
Financial	FIXED SWAP	6/1/2013	3748958	DEU#	USGLF	NO2ULS			$120.1242			
											17,314	23%
Financial	FIXED SWAP	7/1/2013	3544366	MACQ#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3599953	JPMC#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3674000	JPMC#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3748960	DEU#	USGLF	NO2ULS			$125.2902			
											14,843	34%
Financial	FIXED SWAP	8/1/2013	3544368	MACQ#	USGLF	NO2ULS			$127.8312			
Financial	FIXED SWAP	8/1/2013	3599955	JPMC#	USGLF	NO2ULS			$127.8312			
Financial	FIXED SWAP	8/1/2013	3674002	JPMC#	USGLF	NO2ULS			$127.8312			
Financial	FIXED SWAP	8/1/2013	3748962	DEU#	USGLF	NO2ULS			$127.8312			
											20,254	25%
Financial	FIXED SWAP	9/1/2013	3544370	MACQ#	USGLF	NO2ULS			$126.4956			
Financial	FIXED SWAP	9/1/2013	3599957	JPMC#	USGLF	NO2ULS			$126.4956			
Financial	FIXED SWAP	9/1/2013	3674004	JPMC#	USGLF	NO2ULS			$126.4956			
Financial	FIXED SWAP	9/1/2013	3748964	DEU#	USGLF	NO2ULS			$126.4956			
											8,504	59%
Financial	FIXED SWAP	10/1/2013	3544372	MACQ#	USGLF	NO2ULS			$123.1692			
Financial	FIXED SWAP	10/1/2013	3748966	DEU#	USGLF	NO2ULS			$123.1692			
Financial	FIXED SWAP	10/1/2013	3749710	DEU#	USGLF	NO2ULS			$123.1692			
											6,209	48%
Financial	FIXED SWAP	11/1/2013	3544374	MACQ#	USGLF	NO2ULS			$119.6622			
Financial	FIXED SWAP	11/1/2013	3748968	DEU#	USGLF	NO2ULS			$119.6622			
Financial	FIXED SWAP	11/1/2013	3749712	DEU#	USGLF	NO2ULS			$119.6622			
											4,147	72%
Financial	FIXED SWAP	12/1/2013	3544376	MACQ#	USGLF	NO2ULS			$123.9630			
Financial	FIXED SWAP	12/1/2013	3748970	DEU#	USGLF	NO2ULS			$123.9630			
Financial	FIXED SWAP	12/1/2013	3749714	DEU#	USGLF	NO2ULS			$123.9630			
											3,491	86%

As of December 31, 2013

DEF Coal Transportation Hedging Status - Barge
REDACTED

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2013	3521823	USGLF	NO2ULS	[redacted]	[redacted]	$3.0496	[redacted]		
Financial	FIXED SWAP	1/1/2013	3736415	USGLF	NO2ULS			$3.0496			
Financial	FIXED SWAP	1/1/2013	3761003	USGLF	NO2ULS			$3.0496			
Financial	FIXED SWAP	1/1/2013	3801025	USGLF	NO2ULS			$3.0496			
										521,349	48%
Financial	FIXED SWAP	2/1/2013	3521824	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3736417	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3761005	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3801027	USGLF	NO2ULS			$3.2081			
										528,738	48%
Financial	FIXED SWAP	3/1/2013	3521825	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3736419	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3761007	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3801029	USGLF	NO2ULS			$3.0107			
										528,738	48%
Financial	FIXED SWAP	4/1/2013	3540872	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3711714	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3776782	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3803835	USGLF	NO2ULS			$2.8763			
										528,738	48%
Financial	FIXED SWAP	5/1/2013	3540873	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3711716	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3776784	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3803837	USGLF	NO2ULS			$2.8422			
										528,738	48%
Financial	FIXED SWAP	6/1/2013	3540875	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3711718	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3776786	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3803839	USGLF	NO2ULS			$2.8601			
										530,468	48%
Financial	FIXED SWAP	7/1/2013	3544398	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3599947	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3714481	USGLF	NO2ULS			$2.9831			
										337,958	50%
Financial	FIXED SWAP	8/1/2013	3544399	USGLF	NO2ULS			$3.0436			
Financial	FIXED SWAP	8/1/2013	3599948	USGLF	NO2ULS			$3.0436			
Financial	FIXED SWAP	8/1/2013	3714483	USGLF	NO2ULS			$3.0436			
										431,233	39%
Financial	FIXED SWAP	9/1/2013	3544401	USGLF	NO2ULS			$3.0118			
Financial	FIXED SWAP	9/1/2013	3599949	USGLF	NO2ULS			$3.0118			
Financial	FIXED SWAP	9/1/2013	3714485	USGLF	NO2ULS			$3.0118			
Financial	FIXED SWAP	9/1/2013	4051835	USGLF	NO2ULS			$3.0118			
										431,233	49%
Financial	FIXED SWAP	10/1/2013	3544402	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	3674012	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	3764151	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	4051836	USGLF	NO2ULS			$2.9326			
										337,162	50%
Financial	FIXED SWAP	11/1/2013	3544404	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	3674014	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	3764156	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	4051837	USGLF	NO2ULS			$2.8491			
										337,162	50%
Financial	FIXED SWAP	12/1/2013	3544406	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	3674016	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	3764158	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	4051838	USGLF	NO2ULS			$2.9515			
										337,162	50%

DEF Coal Transportation Hedging Status - Rail
REDACTED

As of December 31, 2013

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2013	3521797	USGLF	NO2ULS			$3.0496			
										176,906	47%
Financial	FIXED SWAP	2/1/2013	3521798	USGLF	NO2ULS			$3.2081			
										176,477	48%
Financial	FIXED SWAP	3/1/2013	3521799	USGLF	NO2ULS			$3.0107			
										176,477	48%
Financial	FIXED SWAP	4/1/2013	3540866	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3711704	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3751199	USGLF	NO2ULS			$2.8763			
										176,477	71%
Financial	FIXED SWAP	5/1/2013	3540867	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3711706	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3751200	USGLF	NO2ULS			$2.8422			
										176,477	71%
Financial	FIXED SWAP	6/1/2013	3540868	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3711708	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3751203	USGLF	NO2ULS			$2.8601			
										174,082	72%
Financial	FIXED SWAP	7/1/2013	3599941	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3764916	USGLF	NO2ULS			$2.9831			
										174,082	48%
Financial	FIXED SWAP	8/1/2013	3599942	USGLF	NO2ULS			$3.0436			
Financial	FIXED SWAP	8/1/2013	3764918	USGLF	NO2ULS			$3.0436			
										328,967	26%
Financial	FIXED SWAP	9/1/2013	3599943	USGLF	NO2ULS			$3.0118			
Financial	FIXED SWAP	9/1/2013	3764920	USGLF	NO2ULS			$3.0118			
Financial	FIXED SWAP	9/1/2013	4051847	USGLF	NO2ULS			$3.0118			
	FIXED SWAP	9/1/2013	4062519	USGLF	NO2ULS			$3.0118			
										352,465	48%
Financial	FIXED SWAP	10/1/2013	3674018	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	4051848	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	4062520	USGLF	NO2ULS			$2.9326			
Financial	FIXED SWAP	10/1/2013	4097039	USGLF	NO2ULS			$2.9326			
										352,465	48%
Financial	FIXED SWAP	11/1/2013	3674020	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	4051849	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	4062521	USGLF	NO2ULS			$2.8491			
Financial	FIXED SWAP	11/1/2013	4097040	USGLF	NO2ULS			$2.8491			
										352,465	48%
Financial	FIXED SWAP	12/1/2013	3674022	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	4051850	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	4062522	USGLF	NO2ULS			$2.9515			
Financial	FIXED SWAP	12/1/2013	4097041	USGLF	NO2ULS			$2.9515			
										352,465	48%

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Duke Energy Florida, Inc.
Risk Management Plan for
Fuel Procurement and Wholesale Power Purchases
For 2015

Duke Energy Florida, Inc. (DEF) is submitting its 2015 Risk Management Plan for review by the Florida Public Service Commission. The Risk Management 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 Risk Management Plan. These groups include Fuels and System Optimization (FSO), Global Risk Management (GRM), which includes Enterprise and Regulated Risk and Credit (Risk Management), Regulated Accounting, Internal Audit, Legal, and Information Technology. The activities supported by these groups include the following: procuring competitively priced fuel, performing active asset optimization and portfolio management, executing DEF's 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 July 2014 Fuels and Operations Forecast (FOF), DEF's estimated fuel consumption and economy transaction projections for 2015 are as follows:

Coal

Based on current projections, DEF forecasts to burn approximately [redacted] tons of coal in 2015. DEF's forecasted coal requirements for 2015 will primarily be purchased under term coal supply agreements. The coal supply will be delivered to DEF's plants via railroad and barge transportation agreements. 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 2015. DEF's forecasted light fuel oil requirements

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 25
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: James McClay JM-1P

REDACTED

for 2015 are expected to be purchased primarily under term supply 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 2015, 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 2015 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 2015. 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 2015 Risk Management 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 provide greater 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 during the remainder of 2014 and during 2015

DEF utilizes a phased hedging program where hedge transactions are executed over time with the objective of reducing price risk and providing greater cost certainty for DEF's customers. The hedging program includes executing approved agreements over time for natural gas and light fuel oil usage for generation fuel, and coal rail and river transportation fuel surcharges. 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.

The volumes hedged over time 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 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 hedging transactions are executed. The results of 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 minimum 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 provide greater cost certainty for DEF's customers.

Outlined below for each fuel type and exposure are the targeted minimum hedge percentages to be hedged for the remainder of 2014 and 2015:

Natural Gas

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 hedging program over a rolling 36-month period through time for natural gas through the remainder of 2014 and during 2015. The currently approved rolling hedge percentage that are outlined in DEF's Regulated Utilities Risk Limits as follows:

- [redacted]

DEF will target to hedge a minimum of [redacted], [redacted] and [redacted] of forecasted natural gas burns for the rolling 36-month time period through time, respectively, during the remainder of 2014 and 2015. Given DEF's hedging strategy, DEF will continue to participate in the spot natural gas market for a portion of its estimated natural gas needs.

Light Oil
With respect to light oil forecasted to be burned at DEF's owned generation facilities for calendar year 2015, during the balance of 2014 and 2015, DEF will target to hedge a minimum of [redacted] of its forecasted light oil burns.

Coal Rail and River Transportation Fuel Surcharges
During the balance of 2014 and during 2015, with respect to coal river and rail transportation estimated fuel surcharge exposure, DEF will target to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposure for calendar year 2015.

Summary
Through the remainder of 2014 and during 2015, 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, light oil, and estimated coal rail and river transportation fuel surcharge exposure. 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 A**.

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 are the specific and general risks and DEF's activities to manage overall exposure to these risks. In addition, the processes that DEF has in place to monitor and quantify these risks are also described.

Fuel Price Risk
DEF's customers are exposed to the risk of fuel price movements, which could result in significant variability in projected and actual fuel costs. For natural gas and light oil, the physical fuel is procured under standard industry contracts that are based on published market index pricing that exists during the time periods the fuel is delivered. The published market index prices paid by DEF for these fuels will fluctuate with daily 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. For coal, DEF executes standard

industry 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 Hedge Order), and PSC-09-0349-CO-EI (i.e. Transportation Surcharges), and fixed price coal supply contracts, the projected fuel costs for coal, natural gas, and light oil fuel purchases could vary significantly due to changing market prices over time.

DEF manages and reduces fuel price risks for a portion of its forecasted natural gas and fuel oil burns, and estimated coal rail and river transportation fuel surcharges by utilizing financial transactions over time. As outlined above, DEF enters into standard industry coal supply agreements to fix the price of the underlying commodity exposure. Because of these actions, DEF reduces its overall exposure to changes in projected fuel costs for its customers.

With respect to monitoring and quantifying fuel price risk, Risk Management independently monitors and reports on the percentage of projected fuel burns that have been hedged under physical and financial agreements as compared to the established procurement 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 financial and physical 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, Risk Management performs standard statistical stress tests and portfolio analysis on an as needed basis.

Supplier Performance and Default Risk

Supplier performance and default risk represents the risk of financial loss 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 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 on a daily basis to ensure that DEF has 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 coal, natural gas, and fuel oil 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.

Liquidity Risk

Liquidity risk represents the risk that DEF could not meet the collateral requirements generated from fuel hedging agreements if fuel prices fall substantially. As discussed above, DEF manages fuel price risk for a portion of its forecasted fuel costs through the use of physical and financial hedging agreements. To manage default risk, most of 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. In addition, DEF has continued to maximize the use of hedging agreements with non-marginable provisions that have less impact on collateral requirements and do not require the posting of margin. 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 in fuel agreements, Risk Management independently calculates, monitors, and reports on the amount of liquidity risk associated with coal, natural gas, and fuel oil 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.

In addition, the company continues to monitor the Dodd-Frank Wall Street Reform and Consumer Protection Act (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, including the bilateral and over-the-counter (OTC) derivatives markets, as well as swaps embedded in physical forward transactions. Generally, the Dodd-Frank Act provides for certain exemptions from the mandatory clearing requirements for participants that are "end-users" engaging in hedging activities to mitigate or hedge physical risk. DEF enters into commodity and interest rate hedges to mitigate commercial risk and/or hedge physical positions, rather than as part of a regular swap business, thus it is eligible for the end-user exemption from the law's mandatory clearing and trading provisions.

The Commodity Futures Trading Commission (CFTC) also issued rules for record keeping and reporting. DEF is maintaining records in accordance with the requirements of the CFTC regulations. Further, as an end-user, DEF can shift, and has shifted, 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 study issued rules and timing of their implementation to prepare for applicable compliance requirements. DEF continues to monitor the potential impact of the rules on its hedging transactions; however, it is difficult to predict how the market will ultimately adjust to the new regulations.

In general, proposed regulations are likely to continue to effect changes to the derivatives markets. For example, margining requirements could raise the incremental cost of hedging activities as it may require counterparties to post additional margin and maintenance margin for OTC derivatives, which would then increase the liquidity requirements needed to support these activities. Currently, DEF has credit collateral thresholds in place with its counterparties that do not require the posting of collateral unless the market value of its hedges drops below the negotiated threshold dollar value. Additionally, DEF has negotiated several bi-lateral non-margin hedging agreements with counterparties where margin posting is not required on certain transactions. If some of DEF's counterparties are subject to higher liquidity requirements due to the proposed regulations, DEF could be subject to higher incremental costs for hedging transactions in the form of 1) potential increases in bid / offer spreads on market hedge transactions, 2) potential reduction by certain counterparties in the use of non-marginable OTC transactions, and 3) potential reduction in the number of counterparties who will be available for hedging transactions with DEF.

Credit Risk

On a daily basis, the Credit function within Risk Management 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, two activities take place. First, 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 assigned credit rating and credit limit dictate the size and duration of financial hedging transactions that DEF can enter into with a third party company.

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. See **Attachment B** for the DEF Collateral Report as of July 7, 2014.

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 high deliverability natural gas storage capacity that provides additional access for a portion of its natural gas needs when natural gas supplies are curtailed. In addition, DEF 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, the Transco Mobile Bay South Lateral and purchase for LNG volumes that are delivered out of Elba Island into FGT via the Sonat Cypress Pipeline. DEF monitors actual fuel burns, forecasted fuel burns, and fuel inventory levels. Based on these reviews, DEF may make procurement adjustments to manage any changes to the volume and delivery timing of contracted supplies because of actual burns, changes to forecasted fuel burns, and inventory levels that can be caused by economic factors, weather deviations, fuel-switching trends, 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, provide guidance and oversight to Duke Energy's financial risks. The Chief Risk Officer (CRO) updates the FRMC of any material risks or risk taking activities of the enterprise at every regularly scheduled Board meeting. 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 and 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 Franchised Electric Risk Management Control Manual, the Commodity Risk Policy, the Credit Policy, the DEF Regulated Utilities Risk Limits and the DEF Franchised Electric Credit Limits as **Attachments H, D, E, A, and F**.

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.

Front Office

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 Franchised Electric Credit Limits in **Attachments D, E, A, and F**. In addition, DEF has included the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authorities and the Duke Energy Commodities Approval Matrix from the ABT as **Attachments G and C** 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 the following control functions, 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 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 the Company. This oversight function includes, but is not limited to, review of Duke Energy's risk exposure as related to the overall company portfolio and impact on earnings and review of the financial exposures undertaken by the company in light of the approved Corporate 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 Chief Executive Officer, the Board of Directors, or a committee of the Board of Directors in accordance with the Approval of Business Transactions Policy. The membership of the Committee shall consist of all Senior Management Committee members of the Corporation, excluding the President and Chief Executive Officer, plus the following individuals:

- Vice President and Chief Risk Officer
- Vice President and Treasurer
- Vice President, Internal Audit, Ethics & Compliance

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

Enterprise and Regulated Risk Management (Risk Management)

The Company has an independent Risk Management section, which is overseen by the Director of Enterprise Portfolio and 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 the Company'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.

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

The Franchised Electric 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, Audit Services 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 Franchised Electric Risk Management Control Manual, a Commodity Risk Policy, a Credit Policy, and Franchised Electric 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 Franchised Electric Risk Management Control Manual, Duke Energy Commodity Risk Policy, Duke Energy Credit Policy, the Regulated Utilities Risk Limits, the Franchised Electric Credit Limits, the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, and the Duke Energy Commodities Approval Matrix from the ABT as **Attachments H, D, E, A, F, G, and C**. The fuel purchase and related activities are identified under the Energy Supply Bulk Power Marketing & Trading Delegation of Authority, Regulated Utilities Risk Limits and the Commodities Approval Matrix.

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.**

The Utility has approval requirements, policies, and authorizations in place that outline authorizations for fuel procurement and hedging activities. DEF has included the DEF's Regulated Utilities Risk Limits and corporate Duke Energy Commodity Risk Policy in **Attachments A and D**. 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 Authority, 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 2015 Risk Management 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 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 Risk Management Plan objectives is to engage is 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 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 hedging program, DEF by virtue of locking in fixed price for a portion of forecasted usage over time via its hedging program, achieves this objective as a portion of DEF's fuel costs are no longer subject to changing fuel markets.

Along with the examples noted above, DEF's Risk Management 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 Audit Services, 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 and light oil transactions. CXL will be replacing Align in November 2014 and become the new deal capture system beginning November 2014. In addition to deal capture, CXL is used for deal valuation, position management, mark-to-market calculations, and settlements. CXL will be 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.

The 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. Gas Ops will be replacing GMS in November 2014 as the new scheduling system. 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.

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 calculate VAR and run other 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 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 B

Note 2:
For forecasted calendar year 2014, DEF's estimated hedge percentages based on actual/forecasted burns for natural gas and light oil, are approximately 60% and 33%, respectively. DEF hedge percentages for the estimated fuel surcharges embedded in DEF's coal river and rail transportation in calendar 2014 are 42% and 54%, respectively. The actual hedge percentages for natural gas, light oil, and the estimated fuel surcharges for coal river and rail transportation were within the ranges outlined in the 2014 Risk Management Plan. As outlined in the Plan, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns. For forecasted test period August 2013 through July 2014, DEF's estimated hedge percentages based on actual/forecasted burns for natural gas and light oil, are approximately 60% and 31%, respectively. DEF hedge percentages for the estimated fuel surcharges embedded in DEF's coal river and rail transportation are 42% and 49%, respectively.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 26
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: James McClay JM-2P

Order No. PSC-08-0316-PAA-EI
Duke Energy Florida
Natural Gas and Oil Hedging Detail - Confidential

REDACTED

Attachment B
August 11, 2014

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-14	[redacted]						16,472,700	[redacted]			
Feb-14							11,946,700				
Mar-14							13,190,600				
Apr-14							13,991,600				
May-14							17,687,500				
Jun-14							19,554,500				
Jul-14							20,876,100				See Note 1
YTD	$2,082,063	$0	$2,082,063	69,685,000	0	69,685,000	113,719,900	61%	100%	0%	See Note 2

No. 2 Oil

	Savings/(Cost) on Hedges			Hedged Volumes (Barrels)							
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical	
Jan-14	[redacted]						13,328	[redacted]			
Feb-14							9,352				
Mar-14							10,685				
Apr-14							29,179				
May-14							17,592				
Jun-14							13,592				
Jul-14							2,005				See Note 1
YTD	$50,379	$0	$50,379	24,000	0	24,000	95,733	25%	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-14	[redacted]						250,000	[redacted]			
YTD	$3,225	$0	$3,225	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-14	[redacted]						382,325	[redacted]			
Feb-14							570,791				
Mar-14							503,143				
Apr-14							505,350				
May-14							506,460				
Jun-14							523,974				
Jul-14							584,369				
YTD	$33,386	$0	$33,386	1,386,000	0	1,386,000	3,576,412	39%	100%	0%	See Note 2

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-14	[redacted]						202,649			
Feb-14							164,009			
Mar-14							164,009			
Apr-14							164,009			
May-14							164,009			
Jun-14							164,009			
Jul-14							168,881			
YTD	$20,912	$0	$20,912	588,000	0	588,000	1,191,575	49%	100%	0%

See Note 2

Note 1: Actual burns for periods January 2014 through June 2014. July 2014 burn numbers are considered estimates subject to minor adjustments based on actual bookings.

Note 2: Based on actual fuel burns for January 2014 through June 2014, and forecasted fuel burns and estimated fuel surcharge exposures for the balance of 2014, DEF is currently within all of the hedging targets established in the 2014 Risk Management Plan.

DEF Gas Hedging Status

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3513801	BAR#	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3513801	BAR#	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3523371	MSCG	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3523371	MSCG	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3533846	CSEL	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3533846	CSEL	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3538877	CITI#	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3538877	CITI#	NYMEX	NG			$4.4070			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3551068	BAR#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3551068	BAR#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3581780	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3581780	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3584189	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3584189	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3586962	CSEL	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3586962	CSEL	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3601614	MSCG	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3601614	MSCG	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3608548	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3608548	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3623722	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3623722	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3639220	MSCG	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3639220	MSCG	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3656825	BAR#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3656825	BAR#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3678444	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3678444	JPMC#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2014	3738706	CITI#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2014	3738706	CITI#	IFERC	TRNSZ4			$4.4100			
Financial	FIXED SWAP		1/1/2013	2209433	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	2244162	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	2262173	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	2348625	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	2372732	BAR#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3321943	JPMC#	NYMEX	NG			$4.4070			
Financial	FIXED SWAP		1/1/2013	3330354	CITI#	NYMEX	NG			$4.4070			
Financial	FIXED SWAP		1/1/2013	3334625	DEU#	NYMEX	NG			$4.4070			
Financial	FIXED SWAP		1/1/2013	3347578	MSCG	NYMEX	NG			$4.4070			
Financial	FIXED SWAP		1/1/2013	3350088	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3354106	DEU#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3355377	BAR#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3370121	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3371644	CSEL	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3372253	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3378588	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		1/1/2013	3386631	BAR#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3458330	CSEL	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3461638	BAR#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3473270	BAR#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3478030	CITI#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3491024	CSEL	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3523053	BAR#	IFERC	MAINLN			$4.3400			

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REDACTED **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MM Btu)	IFERC Settlement ($/MM Btu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		1/1/2013	3605384	BAR#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3609022	BAR#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3636125	JPMC#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3661872	CEH#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3681982	CSEL	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3699720	CEH#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3749653	MSCG	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3758101	BOM#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3762636	MACQ#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3767488	CEH#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3778417	MACQ#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3786534	CITI#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3788064	MACQ#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3804137	CEH#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3806258	CEH#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3810169	CITI#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3819269	MACQ#	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	3859902	CSEL	IFERC	MAINLN			$4.3400			
Financial	FIXED SWAP		1/1/2013	4071985	MLC	IFERC	MAINLN			$4.3400			
												16,472,700	51%

DEF Gas Hedging Status

As of July 31, 2014

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Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3513802	BAR#	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3513802	BAR#	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3523372	MSCG	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3523372	MSCG	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3533847	CSEL	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3533847	CSEL	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3538878	CITI#	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3538878	CITI#	NYMEX	NG			$5.5570			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3551069	BAR#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3551069	BAR#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3581781	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3581781	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3584190	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3584190	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3586963	CSEL	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3586963	CSEL	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3601617	MSCG	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3601617	MSCG	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3608549	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3608549	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3623723	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3623723	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3639221	MSCG	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3639221	MSCG	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3656826	BAR#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3656826	BAR#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3678445	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3678445	JPMC#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2014	3738707	CITI#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2014	3738707	CITI#	IFERC	TRNSZ4			$5.6000			
Financial	FIXED SWAP		2/1/2013	2209434	MLC	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	2244163	MSCG	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	2262174	MSCG	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	2348826	JPMC#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	2372733	BAR#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3321944	JPMC#	NYMEX	NG			$5.5570			
Financial	FIXED SWAP		2/1/2013	3330355	CITI#	NYMEX	NG			$5.5570			
Financial	FIXED SWAP		2/1/2013	3334626	DEU#	NYMEX	NG			$5.5570			
Financial	FIXED SWAP		2/1/2013	3347579	MSCG	NYMEX	NG			$5.5570			
Financial	FIXED SWAP		2/1/2013	3350089	MSCG	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3354107	DEU#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3355378	BAR#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3370122	JPMC#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3371652	CSEL	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3372254	JPMC#	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3378589	MSCG	IFERC	HHUB			$5.5800			
Financial	FIXED SWAP		2/1/2013	3386632	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3458331	CSEL	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3461639	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3473271	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3478031	CITI#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3491025	CSEL	IFERC	MAINLN			$5.5200			

DEF Gas Hedging Status

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Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		2/1/2013	3523054	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3605385	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3609023	BAR#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3636126	JPMC#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3661873	CEH#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3681983	CSEL	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3699721	CEH#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3749654	MSCG	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3758102	BOM#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3762637	MACQ#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3767494	CEH#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3778418	MACQ#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3786535	CITI#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3788065	MACQ#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3804138	CEH#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3806259	CEH#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3810170	CITI#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3819270	MACQ#	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	3859903	CSEL	IFERC	MAINLN			$5.5200			
Financial	FIXED SWAP		2/1/2013	4071986	MLC	IFERC	MAINLN			$5.5200			
												11,948,700	64%

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As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3513803	BAR#	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3513803	BAR#	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3523373	MSCG	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3523373	MSCG	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3533848	CSEL	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3533848	CSEL	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3538879	CITI#	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3538879	CITI#	NYMEX	NG			$4.8550			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3551070	BAR#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3551070	BAR#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3581782	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3581782	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3584191	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3584191	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3586968	CSEL	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3586968	CSEL	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3601618	MSCG	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3601618	MSCG	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3608550	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3608550	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3623724	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3623724	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3639222	MSCG	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3639222	MSCG	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3656827	BAR#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3656827	BAR#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3678446	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3678446	JPMC#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2014	3738708	CITI#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2014	3738708	CITI#	IFERC	TRNSZ4			$4.8800			
Financial	FIXED SWAP		3/1/2014	2209435	MLC	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	2244164	MSCG	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	2262175	MSCG	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	2348827	JPMC#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	2372734	BAR#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3321945	JPMC#	NYMEX	NG			$4.8550			
Financial	FIXED SWAP		3/1/2014	3330356	CITI#	NYMEX	NG			$4.8550			
Financial	FIXED SWAP		3/1/2014	3334827	DEU#	NYMEX	NG			$4.8550			
Financial	FIXED SWAP		3/1/2014	3347580	MSCG	NYMEX	NG			$4.8550			
Financial	FIXED SWAP		3/1/2014	3350090	MSCG	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3354108	DEU#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3355379	BAR#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3370123	JPMC#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3371653	CSEL	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3372255	JPMC#	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3378590	MSCG	IFERC	HHUB			$4.8600			
Financial	FIXED SWAP		3/1/2014	3386633	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3458332	CSEL	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3461640	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3473272	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3478032	CITI#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3491026	CSEL	IFERC	MAINLN			$4.8200			

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As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		3/1/2014	3523055	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3605386	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3609024	BAR#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3636127	JPMC#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3661874	CEH#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3681984	CSEL	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3699722	CEH#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3749655	MSCG	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3758103	BOM#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3762638	MACQ#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3767495	CEH#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3778419	MACQ#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3786536	CIT#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3788066	MACQ#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3804139	CEH#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3806260	CEH#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3810171	CIT#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3819271	MACQ#	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	3859904	CSEL	IFERC	MAINLN			$4.8200			
Financial	FIXED SWAP		3/1/2014	4071987	MLC	IFERC	MAINLN			$4.8200			
												13,190,600	64%

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As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3502050	JPMC#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3502050	JPMC#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3513804	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3513804	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3523374	MSCG	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3523374	MSCG	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3533849	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3533849	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3538880	CITI#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3538880	CITI#	NYMEX	NG			$4.5840			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3551071	BAR#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3551071	BAR#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3581783	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3581783	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3584192	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3584192	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3586969	CSEL	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3586969	CSEL	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3601619	MSCG	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3601619	MSCG	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3608551	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3608551	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3623725	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3623725	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3639225	MSCG	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3639225	MSCG	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3656828	BAR#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3656828	BAR#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3678447	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3678447	JPMC#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2014	3738709	CITI#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2014	3738709	CITI#	IFERC	TRNSZ4			$4.5900			
Financial	FIXED SWAP		4/1/2014	2126539	JPMC#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2130431	DEU#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2140359	DEU#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2165108	CSEL	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2181910	MLC	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2194805	MLC	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2209436	MLC	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2220234	JPMC#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2244165	MSCG	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2262176	MSCG	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2287625	CSEL	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2298921	DEU#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2304871	JPMC#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2334872	CSEL	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2348628	JPMC#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2372735	BAR#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2407836	DEU#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2451049	BAR#	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2469678	CSEL	IFERC	HHUB			$4.5900			
Financial	FIXED SWAP		4/1/2014	2579406	BAR#	IFERC	HHUB			$4.5900			

DEF Gas Hedging Status

As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MM Btu)	IFERC Settlement ($/MM Btu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		4/1/2014	2622825	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	2855328	JPMC#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3475426	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3477406	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3479627	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3488862	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3490980	MSCG	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3493027	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3500344	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3503811	DEU#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3520564	MSCG	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3522710	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3531873	BAR#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3605293	CITI#	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3612069	CSEL	NYMEX	NG			$4.5840			
Financial	FIXED SWAP		4/1/2014	3635399	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3643158	MACQ#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3664483	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3667261	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3683555	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3696921	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3704568	MSCG	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3749638	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3765681	BAR#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3777594	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3780649	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3786538	DEU#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3788132	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3804721	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3806323	BAR#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	3849352	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4071971	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4089616	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4107076	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4140422	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4170583	MLC	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4180031	MLC	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4226116	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4235119	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4263594	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4264229	MACQ#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4264956	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		4/1/2014	4268159	BOM#	IFERC	TRNSZ4			$4.5900			
												13,991,800	73%

DEF Gas Hedging Status

As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3502051	JPMC#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3502051	JPMC#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3513805	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3513805	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3523375	MSCG	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3523375	MSCG	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3533850	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3533850	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3536881	CITI#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3536881	CITI#	NYMEX	NG			$4.7950			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3551072	BAR#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3551072	BAR#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3581784	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3581784	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3584193	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3584193	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3586970	CSEL	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3586970	CSEL	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3601620	MSCG	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3601620	MSCG	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3608552	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3608552	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3623726	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3623726	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3639226	MSCG	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3639226	MSCG	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3656829	BAR#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3656829	BAR#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3678448	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3678448	JPMC#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2014	3738710	CITI#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2014	3738710	CITI#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED SWAP		5/1/2014	2126540	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2130432	DEU#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2140360	DEU#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2165109	CSEL	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2181911	MLC	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2194806	MLC	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2209439	MLC	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2220237	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2244166	MSCG	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2262177	MSCG	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2287626	CSEL	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2298922	DEU#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2304872	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2334873	CSEL	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2348629	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2372736	BAR#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2407837	DEU#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2451050	BAR#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2469679	CSEL	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	2579409	BAR#	IFERC	HHUB			$4.8100			

DEF Gas Hedging Status

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REDACTED

Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		5/1/2014	2622828	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	2655329	JPMC#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3475427	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3477407	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3479628	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3488883	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3490981	MSCG	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3493028	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3500345	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3503812	DEU#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3520565	MSCG	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3522711	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3531874	BAR#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3536399	BAR#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	3542891	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	3547123	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	3605294	CITI#	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3612070	CSEL	NYMEX	NG			$4.7950			
Financial	FIXED SWAP		5/1/2014	3635402	CSEL	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3643161	MACQ#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3664486	JPMC#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3667262	JPMC#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3683556	CSEL	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3696922	CSEL	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3704569	MSCG	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3749839	CSEL	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3765682	BAR#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3777595	JPMC#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3780650	JPMC#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3786539	DEU#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3788133	CITI#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3804722	CITI#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3806324	BAR#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	3849353	CSEL	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4071972	JPMC#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4089617	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4107077	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4140423	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4170584	MLC	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4180032	MLC	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4226117	CITI#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4235120	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4263595	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4264232	MACQ#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4264959	BOM#	IFERC	MAINLN			$4.7200			
Financial	FIXED SWAP		5/1/2014	4268180	BOM#	IFERC	TRNSZ4			$4.7700			
Financial	FIXED SWAP		5/1/2014	4268838	JPMC#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	4271209	MLC	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	4271925	BOM#	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	4273041	MLC	IFERC	HHUB			$4.8100			
Financial	FIXED SWAP		5/1/2014	4290395	BOM#	IFERC	HHUB			$4.8100			
												17,687,500	67%

DEF Gas Hedging Status

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3502052	JPMC#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3502052	JPMC#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3513806	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3513806	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3523376	MSCG	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3523376	MSCG	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3533851	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3533851	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3538882	CITI#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3538882	CITI#	NYMEX	NG			$4.6190			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3551073	BAR#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3551073	BAR#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3581785	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3581785	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3584194	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3584194	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3586971	CSEL	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3586971	CSEL	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3601621	MSCG	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3601621	MSCG	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3608553	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3608553	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3623727	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3623727	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3639227	MSCG	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3639227	MSCG	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3656830	BAR#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3656830	BAR#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3676449	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3676449	JPMC#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2014	3738711	CITI#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2014	3738711	CITI#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED SWAP		6/1/2014	2126541	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2130433	DEU#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2140361	DEU#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2165110	CSEL	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2181914	MLC	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2194807	MLC	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2209440	MLC	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2220238	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2244167	MSCG	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2262178	MSCG	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2287627	CSEL	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2298923	DEU#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2304873	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2334874	CSEL	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2348638	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2372739	BAR#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2407838	DEU#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2451051	BAR#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2469680	CSEL	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	2579412	BAR#	IFERC	HHUB			$4.6300			

DEF Gas Hedging Status

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		6/1/2014	2822829	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	2855330	JPMC#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3475428	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3477408	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3479629	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3488884	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3490982	MSCG	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3493029	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3500346	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3503813	DEU#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3520566	MSCG	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3522712	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3531875	BAR#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3536402	BAR#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	3542892	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	3547124	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	3605295	CITI#	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3612071	CSEL	NYMEX	NG			$4.6190			
Financial	FIXED SWAP		6/1/2014	3635403	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3643162	MACQ#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3664487	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3667263	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3683561	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3696923	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3704570	MSCG	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3749640	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3765683	BAR#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3777596	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3780651	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3786540	DEU#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3788134	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3804723	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3806325	BAR#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	3849354	CSEL	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4071973	JPMC#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4089618	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4107078	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4140424	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4170585	MLC	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4180033	MLC	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4226118	CITI#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4235121	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4263596	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4264233	MACQ#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4264962	BOM#	IFERC	MAINLN			$4.5400			
Financial	FIXED SWAP		6/1/2014	4268161	BOM#	IFERC	TRNSZ4			$4.5700			
Financial	FIXED SWAP		6/1/2014	4268839	JPMC#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	4271210	MLC	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	4271926	BOM#	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	4273042	MLC	IFERC	HHUB			$4.6300			
Financial	FIXED SWAP		6/1/2014	4290396	BOM#	IFERC	HHUB			$4.6300			
												19,554,500	58%

DEF Gas Hedging Status

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3502053	JPMC#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3502053	JPMC#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3513807	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3513807	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3523377	MSCG	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3523377	MSCG	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3533852	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3533852	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3536883	CITI#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3536883	CITI#	NYMEX	NG			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3551074	BAR#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3551074	BAR#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3581786	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3581786	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3584195	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3584195	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3586972	CSEL	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3586972	CSEL	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3601622	MSCG	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3601622	MSCG	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3608554	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3608554	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3623730	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3623730	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3639228	MSCG	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3639228	MSCG	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3656831	BAR#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3656831	BAR#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3678450	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3678450	JPMC#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2014	3738712	CITI#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2014	3738712	CITI#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED SWAP		7/1/2014	2126543	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2130434	DEU#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2140382	DEU#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2165111	CSEL	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2181915	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2194808	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2209443	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2220243	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2244168	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2262179	MSCG	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2287628	CSEL	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2298924	DEU#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2304874	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2334875	CSEL	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2348839	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2372742	BAR#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2407839	DEU#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2451052	BAR#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2469881	CSEL	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	2579413	BAR#	IFERC	HHUB			$4.4100			

DEF Gas Hedging Status

As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual Projected Burns	% Hedged
Financial	FIXED SWAP		7/1/2014	2622830	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	2655333	JPMC#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3475429	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3477409	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3479630	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3488885	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3490983	MSCG	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3493030	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3500347	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3503814	DEU#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3520567	MSCG	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3522713	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3531678	BAR#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3536403	BAR#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	3542893	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	3547125	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	3605298	CITI#	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3612072	CSEL	NYMEX	NG			$4.4000			
Financial	FIXED SWAP		7/1/2014	3635404	CSEL	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3643183	MACQ#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3664488	JPMC#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3667264	JPMC#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3683562	CSEL	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3696924	CSEL	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3704571	MSCG	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3749641	CSEL	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3765684	BAR#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3777597	JPMC#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3780652	JPMC#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3786541	DEU#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3788135	CITI#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3804724	CITI#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3806326	BAR#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	3849355	CSEL	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4071974	JPMC#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4089619	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4107079	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4140425	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4170586	MLC	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4180034	MLC	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4226121	CITI#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4235122	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4263597	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4264234	MACQ#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4264965	BOM#	IFERC	MAINLN			$4.3300			
Financial	FIXED SWAP		7/1/2014	4268182	BOM#	IFERC	TRNSZ4			$4.4000			
Financial	FIXED SWAP		7/1/2014	4268840	JPMC#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	4271211	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	4271927	BOM#	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	4273043	MLC	IFERC	HHUB			$4.4100			
Financial	FIXED SWAP		7/1/2014	4290397	BOM#	IFERC	HHUB			$4.4100			
												20,878,100	58%

DEF #2 Oil Hedging Status

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume (Bbls)	Fixed Price ($/Bbl)	Market Scan Biz Average ($/Bbl)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	1/1/2014	4239468	JPMC#	USGLF	NO2ULS			121.8462			
Financial	FIXED SWAP	1/1/2014	4242337	MSCG	USGLF	NO2ULS			121.8462			
											13,328	23%
Financial	FIXED SWAP	2/1/2014	4239469	JPMC#	USGLF	NO2ULS			124.9500			
Financial	FIXED SWAP	2/1/2014	4242354	MSCG	USGLF	NO2ULS			124.9500			
											9,352	32%
Financial	FIXED SWAP	3/1/2014	4239470	JPMC#	USGLF	NO2ULS			122.5308			
Financial	FIXED SWAP	3/1/2014	4242355	MSCG	USGLF	NO2ULS			122.5308			
											10,685	28%
Financial	FIXED SWAP	4/1/2014	4239471	JPMC#	USGLF	NO2ULS			123.1482			
Financial	FIXED SWAP	4/1/2014	4318164	BOM#	USGLF	NO2ULS			123.1482			
											29,179	14%
Financial	FIXED SWAP	5/1/2014	4239472	JPMC#	USGLF	NO2ULS			121.9470			
Financial	FIXED SWAP	5/1/2014	4318165	BOM#	USGLF	NO2ULS			121.9470			
											17,592	23%
Financial	FIXED SWAP	6/1/2014	4239473	JPMC#	USGLF	NO2ULS			122.6316			
Financial	FIXED SWAP	6/1/2014	4318166	BOM#	USGLF	NO2ULS			122.6316			
											13,592	29%
Financial	FIXED SWAP	7/1/2014	4239474	JPMC#	USGLF	NO2ULS			119.4606			
Financial	FIXED SWAP	7/1/2014	4320148	MLC	USGLF	NO2ULS			119.4606			
											2,005	150%

DEF Gas Storage Hedging Status

As of July 31, 2014 **REDACTED** **Attachment B**

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge		% Hedged
Financial	FIXED SWAP	6/1/2014	4370899	MACQ#	IFERC	FGTZ3		4.6320	4.7100			
Financial	FIXED SWAP	6/1/2014	4436487	JPMC#	IFERC	FGTZ3		4.7450	4.7100			
											250,000	80%

DEF Coal Transportation Hedging Status - Barge

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2014	3880008	USGLF	NO2ULS			$2.9011			
Financial	FIXED SWAP	1/1/2014	3971448	USGLF	NO2ULS			$2.9011			
Financial	FIXED SWAP	1/1/2014	4105864	USGLF	NO2ULS			$2.9011			
Financial	FIXED SWAP	1/1/2014	4219684	USGLF	NO2ULS			$2.9011			
										382,325	44%
Financial	FIXED SWAP	2/1/2014	3881971	USGLF	NO2ULS			$2.9750			
Financial	FIXED SWAP	2/1/2014	3971450	USGLF	NO2ULS			$2.9750			
Financial	FIXED SWAP	2/1/2014	4105865	USGLF	NO2ULS			$2.9750			
Financial	FIXED SWAP	2/1/2014	4219685	USGLF	NO2ULS			$2.9750			
										570,791	29%
Financial	FIXED SWAP	3/1/2014	3881974	USGLF	NO2ULS			$2.9174			
Financial	FIXED SWAP	3/1/2014	3971452	USGLF	NO2ULS			$2.9174			
Financial	FIXED SWAP	3/1/2014	4105866	USGLF	NO2ULS			$2.9174			
Financial	FIXED SWAP	3/1/2014	4219686	USGLF	NO2ULS			$2.9174			
										503,143	33%
Financial	FIXED SWAP	4/1/2014	3926543	USGLF	NO2ULS			$2.9321			
Financial	FIXED SWAP	4/1/2014	3978961	USGLF	NO2ULS			$2.9321			
Financial	FIXED SWAP	4/1/2014	4185805	USGLF	NO2ULS			$2.9321			
Financial	FIXED SWAP	4/1/2014	4226098	USGLF	NO2ULS			$2.9321			
Financial	FIXED SWAP	4/1/2014	4374228	USGLF	NO2LSF			$2.9321			
										505,350	42%
Financial	FIXED SWAP	5/1/2014	3926545	USGLF	NO2ULS			$2.9035			
Financial	FIXED SWAP	5/1/2014	3978963	USGLF	NO2ULS			$2.9035			
Financial	FIXED SWAP	5/1/2014	4165806	USGLF	NO2ULS			$2.9035			
Financial	FIXED SWAP	5/1/2014	4226105	USGLF	NO2ULS			$2.9035			
Financial	FIXED SWAP	5/1/2014	4374230	USGLF	NO2LSF			$2.9035			
										508,460	41%
Financial	FIXED SWAP	6/1/2014	3926546	USGLF	NO2ULS			$2.9198			
Financial	FIXED SWAP	6/1/2014	3978965	USGLF	NO2ULS			$2.9198			
Financial	FIXED SWAP	6/1/2014	4165807	USGLF	NO2ULS			$2.9198			
Financial	FIXED SWAP	6/1/2014	4226106	USGLF	NO2ULS			$2.9198			
Financial	FIXED SWAP	6/1/2014	4374231	USGLF	NO2LSF			$2.9198			
										523,974	40%
Financial	FIXED SWAP	7/1/2014	3965095	USGLF	NO2ULS			$2.8443			
Financial	FIXED SWAP	7/1/2014	4062561	USGLF	NO2ULS			$2.8443			
Financial	FIXED SWAP	7/1/2014	4175876	USGLF	NO2ULS			$2.8443			
Financial	FIXED SWAP	7/1/2014	4226107	USGLF	NO2ULS			$2.8443			
Financial	FIXED SWAP	7/1/2014	4397348	USGLF	NO2ULS			$2.8443			
Financial	FIXED SWAP	7/1/2014	4405946	USGLF	NO2ULS			$2.8443			
										584,369	43%

DEF Coal Transportation Hedging Status - Rail

As of July 31, 2014

REDACTED

Attachment B

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2014	3887237	USGLF	NO2ULS	[redacted]	[redacted]	$2.9011	[redacted]		
Financial	FIXED SWAP	1/1/2014	4170809	USGLF	NO2ULS	[redacted]	[redacted]	$2.9011	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	202,649	41%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	2/1/2014	3887241	USGLF	NO2ULS	[redacted]	[redacted]	$2.9750	[redacted]		
Financial	FIXED SWAP	2/1/2014	4170810	USGLF	NO2ULS	[redacted]	[redacted]	$2.9750	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	164,009	51%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	3/1/2014	3887242	USGLF	NO2ULS	[redacted]	[redacted]	$2.9174	[redacted]		
Financial	FIXED SWAP	3/1/2014	4170811	USGLF	NO2ULS	[redacted]	[redacted]	$2.9174	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	164,009	51%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	4/1/2014	3937698	USGLF	NO2ULS	[redacted]	[redacted]	$2.9321	[redacted]		
Financial	FIXED SWAP	4/1/2014	4177258	USGLF	NO2ULS	[redacted]	[redacted]	$2.9321	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	164,009	51%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	5/1/2014	3937709	USGLF	NO2ULS	[redacted]	[redacted]	$2.9035	[redacted]		
Financial	FIXED SWAP	5/1/2014	4177259	USGLF	NO2ULS	[redacted]	[redacted]	$2.9035	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	164,009	51%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	6/1/2014	3937710	USGLF	NO2ULS	[redacted]	[redacted]	$2.9198	[redacted]		
Financial	FIXED SWAP	6/1/2014	4177260	USGLF	NO2ULS	[redacted]	[redacted]	$2.9198	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	164,009	51%
						[redacted]	[redacted]	[redacted]	[redacted]		
Financial	FIXED SWAP	7/1/2014	3984928	USGLF	NO2ULS	[redacted]	[redacted]	$2.8443	[redacted]		
Financial	FIXED SWAP	7/1/2014	4175879	USGLF	NO2ULS	[redacted]	[redacted]	$2.8443	[redacted]		
						[redacted]	[redacted]	[redacted]	[redacted]	168,881	50%

Duke Energy Florida
Docket No. 140001-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
Calculation of System Actual GPIF Points	4
GPIF Unit Performance Summary	5
Actual Unit Performance Data	6
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Generating Performance Incentive Points Table	9-15
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Planned Outage Schedules (Actual)	23-24

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 27
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Matthew J. Jones MJJ-1T

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Duke Energy Florida
Janauary 2013 - December 2013

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 56,876,790	$ 19,475,153
	9	$ 51,189,111	$ 17,527,638
	8	$ 45,501,432	$ 15,580,122
	7	$ 39,813,753	$ 13,632,607
	6	$ 34,126,074	$ 11,685,092
	5	$ 28,438,395	$ 9,737,577
	4	$ 22,750,716	$ 7,790,061
	3	$ 17,063,037	$ 5,842,546
	2	$ 11,375,358	$ 3,895,031
****	1.146	$ 6,518,080	$ 2,231,853
	1	$ 5,687,679	$ 1,947,515
	0	$ -	$ -
	-1	$ (7,503,449)	$ (1,947,515)
	-2	$ (15,006,898)	$ (3,895,031)
	-3	$ (22,510,347)	$ (5,842,546)
	-4	$ (30,013,796)	$ (7,790,061)
	-5	$ (37,517,245)	$ (9,737,577)
	-6	$ (45,020,694)	$ (11,685,092)
	-7	$ (52,524,143)	$ (13,632,607)
	-8	$ (60,027,592)	$ (15,580,122)
	-9	$ (67,531,041)	$ (17,527,638)
	-10	$ (75,034,490)	$ (19,475,153)

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Original Sheet No. 6.101.2

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Duke Energy Florida
Janauary 2013 - December 2013

1	Beginning of period balance of common equity	$ 4,800,425,527	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2013	$ 4,850,812,763	
3	Month of FEBRUARY 2013	$ 4,853,882,921	
4	Month of MARCH 2013	$ 4,909,798,160	
5	Month of APRIL 2013	$ 4,944,084,607	
6	Month of MAY 2013	$ 4,771,136,451	
7	Month of JUNE 2013	$ 4,627,399,344	
8	Month of JULY 2013	$ 4,686,299,857	
9	Month of AUGUST 2013	$ 4,748,056,595	
10	Month of SEPTEMBER 2013	$ 4,823,338,799	
11	Month of OCTOBER 2013	$ 4,869,939,718	
12	Month of NOVEMBER 2013	$ 4,903,848,180	
13	Month of DECEMBER 2013	$ 4,797,389,578	
14	Average common equity for the period	$ 4,814,339,423	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars	$ 19,608,491	
18	Jurisdictional Sales *	36,615,989	MWH
19	Total Sales *	36,865,423	MWH
20	Jurisdictional Separation Factor	99.3200%	
21	Maximum allowed jurisdictional incentive dollars	$ 19,475,153	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 6.101.1	$ 28,438,395	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$ 19,475,153	

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Duke Energy Florida
Janauary 2013 - December 2013

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Bartow CC	EAF	8.38	10.000	0.838
	ANOHR	22.21	0.000	0.000
Crystal River 4	EAF	5.59	0.038	0.002
	ANOHR	13.84	-1.825	-0.253
Crystal River 5	EAF	4.57	-0.372	-0.017
	ANOHR	13.44	-0.925	-0.124
Hines 1	EAF	1.86	10.000	0.186
	ANOHR	5.29	-1.841	-0.097
Hines 2	EAF	1.85	9.224	0.171
	ANOHR	5.87	-4.462	-0.262
Hines 3	EAF	1.62	9.883	0.161
	ANOHR	6.83	4.629	0.316
Hines 4	EAF	2.25	10.000	0.225
	ANOHR	6.40	0.000	0.000
GPIF System		100.00		1.146

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Duke Energy Florida
Janauary 2013 - December 2013

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	8.38	89.08	92.61	81.95	$4,768	($10,085)	94.17	$4,768
Crystal River 4	5.59	87.03	90.40	80.28	$3,178	($6,487)	87.05	$12
Crystal River 5	4.57	94.57	97.12	89.38	$2,597	($6,007)	94.38	($223)
Hines 1	1.86	79.35	81.83	74.36	$1,057	($2,504)	83.22	$1,057
Hines 2	1.85	87.70	89.50	83.97	$1,054	($3,815)	89.36	$972
Hines 3	1.62	89.17	90.66	86.10	$924	($1,940)	90.64	$913
Hines 4	2.25	88.69	90.41	85.11	$1,278	($2,176)	91.97	$1,278
GPIF System	26.12				$14,855.8	($33,013.5)		$8,776.8

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	22.21	7,323	83.3	6,947	7,699	$12,632	($12,632)	7,390	$0
Crystal River 4	13.84	10,317	73.8	9,749	10,885	$7,873	($7,873)	10,482	($1,437)
Crystal River 5	13.44	10,351	71.0	9,820	10,882	$7,647	($7,647)	10,468	($707)
Hines 1	5.29	7,231	92.1	6,975	7,487	$3,008	($3,008)	7,340	($554)
Hines 2	5.87	7,166	83.5	6,917	7,415	$3,336	($3,336)	7,319	($1,488)
Hines 3	6.83	7,192	91.1	6,927	7,456	$3,884	($3,884)	7,029	$1,798
Hines 4	6.40	6,939	94.2	6,697	7,181	$3,641	($3,641)	6,939	$0
GPIF System	73.88					$42,021.0	($42,021.0)		($2,388.6)

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida
Janauary 2013 - December 2013

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	92.57	1.60	94.17
Crystal River 4	86.91	0.13	87.05
Crystal River 5	94.38	0.00	94.38
Hines 1	87.10	-3.88	83.22
Hines 2	92.13	-2.77	89.36
Hines 3	92.31	-1.67	90.64
Hines 4	91.51	0.46	91.97

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,356.5	33.2	7,389.6
Crystal River 4	10,514.3	-32.0	10,482.3
Crystal River 5	10,472.3	-4.4	10,467.9
Hines 1	7,409.5	-69.9	7,339.6
Hines 2	7,324.4	-5.4	7,319.0
Hines 3	7,239.4	-210.8	7,028.6
Hines 4	6,956.7	-18.0	6,938.6

(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 2013 - December 2013

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.	437.49	516.80	0.00	998.17	495.57	523.30	712.22
2	Target POH	Hrs.	294.00	504.00	0.00	1,344.00	744.00	672.00	672.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.02	1.00	1.00	0.96	0.97	0.98	1.00
4	Actual EUOH	Hrs.	213.25	629.71	492.50	132.21	193.76	150.40	31.58
5	Adj. EUOH (3*4)	Hrs.	216.93	630.69	492.50	126.32	187.94	147.68	31.74
6	Actual EAF	%	92.57	86.91	94.38	87.10	92.13	92.31	91.51
7	Adjusted EAF (using 2 & 5)	%	94.17	87.05	94.38	83.22	89.36	90.64	91.97
8	Difference (7-6)	%	1.60	0.13	0.00	-3.88	-2.77	-1.67	0.46
9	Total adj. to EAF	%	1.60	0.13	0.00	-3.88	-2.77	-1.67	0.46

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Duke Energy Florida
Janauary 2013 - December 2013

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	%	83.3	73.8	71.0	92.1	83.5	91.1	94.2
2	Target ANOHR	Btu/kwh	7323.0	10317.3	10350.7	7231.2	7166.3	7191.5	6939.1
3	Actual NOF	%	87.5	72.8	70.8	84.6	82.4	77.3	88.4
4	Calc. ANOHR (using 3)	Btu/kwh	7,289.8	10,349.3	10,355.2	7,301.1	7,171.7	7,402.3	6,957.1
5	Total adj. to ANOHR (2-4)	Btu/kwh	33.2	-32.0	-4.4	-69.9	-5.4	-210.8	-18.0

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$4,767,800	92.61	10	$12,632,078	6,946.8	
	10	$4,767,800	92.61	9	$11,368,870	6,976.9	
	9	$4,291,020	92.26	8	$10,105,662	7,007.0	
	8	$3,814,240	91.91	7	$8,842,455	7,037.2	
	7	$3,337,460	91.55	6	$7,579,247	7,067.3	
	6	$2,860,680	91.20	5	$6,316,039	7,097.4	
	5	$2,383,900	90.85	4	$5,052,831	7,127.5	
	4	$1,907,120	90.49	3	$3,789,623	7,157.6	
	3	$1,430,340	90.14	2	$2,526,416	7,187.8	
	2	$953,560	89.78	1	$1,263,208	7,217.9	
	1	$476,780	89.43	0	$0	7,248.0	
		$0	89.08	0.000	$0	7,389.6	****
	0	$0	89.08	0	$0	7,323.0	
		$0	89.08	0	$0	7,398.0	
	-1	($1,008,450)	88.36	-1	($1,263,208)	7,428.1	
	-2	($2,016,900)	87.65	-2	($2,526,416)	7,458.2	
	-3	($3,025,350)	86.94	-3	($3,789,623)	7,488.4	
	-4	($4,033,800)	86.23	-4	($5,052,831)	7,518.5	
	-5	($5,042,250)	85.51	-5	($6,316,039)	7,548.6	
	-6	($6,050,700)	84.80	-6	($7,579,247)	7,578.7	
	-7	($7,059,150)	84.09	-7	($8,842,455)	7,608.8	
	-8	($8,067,600)	83.38	-8	($10,105,662)	7,638.9	
	-9	($9,076,050)	82.66	-9	($11,368,870)	7,669.1	
	-10	($10,084,500)	81.95	-10	($12,632,078)	7,699.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.38%	22.21%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

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	$3,177,900	90.40	10	$7,873,341	9,749.3	
	9	$2,860,110	90.06	9	$7,086,007	9,798.6	
	8	$2,542,320	89.73	8	$6,298,673	9,847.9	
	7	$2,224,530	89.39	7	$5,511,339	9,897.2	
	6	$1,906,740	89.05	6	$4,724,005	9,946.5	
	5	$1,588,950	88.72	5	$3,936,670	9,995.8	
	4	$1,271,160	88.38	4	$3,149,336	10,045.1	
	3	$953,370	88.04	3	$2,362,002	10,094.4	
	2	$635,580	87.71	2	$1,574,668	10,143.7	
	1	$317,790	87.37	1	$787,334	10,193.0	
****	0.038	$12,076	87.05	0	$0	10,242.3	
		$0	87.03	0	$0	10,317.3	
	0	$0	87.03	0	$0	10,392.3	
		$0	87.03	-1	($787,334)	10,441.6	
	-1	($648,720)	86.36	-1.825	($1,436,885)	10,482.3	****
	-2	($1,297,440)	85.68	-2	($1,574,668)	10,490.9	
	-3	($1,946,160)	85.01	-3	($2,362,002)	10,540.2	
	-4	($2,594,880)	84.33	-4	($3,149,336)	10,589.5	
	-5	($3,243,600)	83.65	-5	($3,936,670)	10,638.8	
	-6	($3,892,320)	82.98	-6	($4,724,005)	10,688.1	
	-7	($4,541,040)	82.30	-7	($5,511,339)	10,737.4	
	-8	($5,189,760)	81.63	-8	($6,298,673)	10,786.7	
	-9	($5,838,480)	80.95	-9	($7,086,007)	10,836.0	
	-10	($6,487,200)	80.28	-10	($7,873,341)	10,885.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.59%	13.84%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

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	$2,597,100	97.12	10	$7,646,693	9,819.8	
	9	$2,337,390	96.86	9	$6,882,023	9,865.4	
	8	$2,077,680	96.61	8	$6,117,354	9,911.0	
	7	$1,817,970	96.35	7	$5,352,685	9,956.6	
	6	$1,558,260	96.10	6	$4,588,016	10,002.2	
	5	$1,298,550	95.84	5	$3,823,346	10,047.8	
	4	$1,038,840	95.59	4	$3,058,677	10,093.4	
	3	$779,130	95.34	3	$2,294,008	10,139.0	
	2	$519,420	95.08	2	$1,529,339	10,184.6	
	1	$259,710	94.83	1	$764,669	10,230.1	
		$0	94.57	0	$0	10,275.7	
	0	$0	94.57	0	$0	10,350.7	
		$0	94.57	0	$0	10,425.7	
****	-0.372	($223,472)	94.38	-0.925	($707,319)	10,467.9	****
	-1	($600,730)	94.05	-1	($764,669)	10,471.3	
	-2	($1,201,460)	93.53	-2	($1,529,339)	10,516.9	
	-3	($1,802,190)	93.01	-3	($2,294,008)	10,562.5	
	-4	($2,402,920)	92.49	-4	($3,058,677)	10,608.1	
	-5	($3,003,650)	91.98	-5	($3,823,346)	10,653.7	
	-6	($3,604,380)	91.46	-6	($4,588,016)	10,699.3	
	-7	($4,205,110)	90.94	-7	($5,352,685)	10,744.9	
	-8	($4,805,840)	90.42	-8	($6,117,354)	10,790.5	
	-9	($5,406,570)	89.90	-9	($6,882,023)	10,836.1	
	-10	($6,007,300)	89.38	-10	($7,646,693)	10,881.6	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.57%	13.44%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$1,057,300	81.83	10	$3,007,939	6,975.1	
	10	$1,057,300	81.83	9	$2,707,145	6,993.2	
	9	$951,570	81.58	8	$2,406,351	7,011.3	
	8	$845,840	81.33	7	$2,105,557	7,029.4	
	7	$740,110	81.08	6	$1,804,763	7,047.5	
	6	$634,380	80.83	5	$1,503,969	7,065.7	
	5	$528,650	80.59	4	$1,203,175	7,083.8	
	4	$422,920	80.34	3	$902,382	7,101.9	
	3	$317,190	80.09	2	$601,588	7,120.0	
	2	$211,460	79.84	1	$300,794	7,138.1	
	1	$105,730	79.59	0	$0	7,156.2	
		$0	79.35	0	$0	7,231.2	
	0	$0	79.35	0	$0	7,306.2	
		$0	79.35	-1	($300,794)	7,324.4	
	-1	($250,380)	78.85	-1.841	($553,762)	7,339.6	****
	-2	($500,760)	78.35	-2	($601,588)	7,342.5	
	-3	($751,140)	77.85	-3	($902,382)	7,360.6	
	-4	($1,001,520)	77.35	-4	($1,203,175)	7,378.7	
	-5	($1,251,900)	76.85	-5	($1,503,969)	7,396.8	
	-6	($1,502,280)	76.35	-6	($1,804,763)	7,415.0	
	-7	($1,752,660)	75.86	-7	($2,105,557)	7,433.1	
	-8	($2,003,040)	75.36	-8	($2,406,351)	7,451.2	
	-9	($2,253,420)	74.86	-9	($2,707,145)	7,469.3	
	-10	($2,503,800)	74.36	-10	($3,007,939)	7,487.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.86%	5.29%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
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Unit: Hines 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,054,000	89.50	10	$3,335,858	6,917.4	
****	9.224	$972,210	89.36	9	$3,002,272	6,934.8	
	9	$948,600	89.32	8	$2,668,686	6,952.1	
	8	$843,200	89.14	7	$2,335,100	6,969.5	
	7	$737,800	88.96	6	$2,001,515	6,986.9	
	6	$632,400	88.78	5	$1,667,929	7,004.3	
	5	$527,000	88.60	4	$1,334,343	7,021.7	
	4	$421,600	88.42	3	$1,000,757	7,039.1	
	3	$316,200	88.24	2	$667,172	7,056.5	
	2	$210,800	88.06	1	$333,586	7,073.9	
	1	$105,400	87.88	0	$0	7,091.3	
		$0	87.70	0	$0	7,166.3	
	0	$0	87.70	0	$0	7,241.3	
		$0	87.70	-1	($333,586)	7,258.7	
	-1	($381,500)	87.33	-2	($667,172)	7,276.1	
	-2	($763,000)	86.96	-3	($1,000,757)	7,293.5	
	-3	($1,144,500)	86.58	-4	($1,334,343)	7,310.9	
	-4	($1,526,000)	86.21	-4.462	($1,488,460)	7,318.9	****
	-5	($1,907,500)	85.84	-5	($1,667,929)	7,328.3	
	-6	($2,289,000)	85.47	-6	($2,001,515)	7,345.7	
	-7	($2,670,500)	85.09	-7	($2,335,100)	7,363.1	
	-8	($3,052,000)	84.72	-8	($2,668,686)	7,380.5	
	-9	($3,433,500)	84.35	-9	($3,002,272)	7,397.9	
	-10	($3,815,000)	83.97	-10	($3,335,858)	7,415.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.85%	5.87%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$924,000	90.66	10	$3,883,895	6,926.6	
****	9.883	$913,189	90.64	9	$3,495,505	6,945.6	
	9	$831,600	90.51	8	$3,107,116	6,964.6	
	8	$739,200	90.36	7	$2,718,726	6,983.6	
	7	$646,800	90.21	6	$2,330,337	7,002.6	
	6	$554,400	90.06	5	$1,941,947	7,021.6	
	5	$462,000	89.92	4.629	$1,797,855	7,028.6	****
	4	$369,600	89.77	4	$1,553,558	7,040.6	
	3	$277,200	89.62	3	$1,165,168	7,059.6	
	2	$184,800	89.47	2	$776,779	7,078.6	
	1	$92,400	89.32	1	$388,389	7,097.6	
		$0	89.17	0	$0	7,116.5	
	0	$0	89.17	0	$0	7,191.5	
		$0	89.17	0	$0	7,266.5	
	-1	($193,980)	88.86	-1	($388,389)	7,285.5	
	-2	($387,960)	88.56	-2	($776,779)	7,304.5	
	-3	($581,940)	88.25	-3	($1,165,168)	7,323.5	
	-4	($775,920)	87.94	-4	($1,553,558)	7,342.5	
	-5	($969,900)	87.63	-5	($1,941,947)	7,361.5	
	-6	($1,163,880)	87.33	-6	($2,330,337)	7,380.5	
	-7	($1,357,860)	87.02	-7	($2,718,726)	7,399.5	
	-8	($1,551,840)	86.71	-8	($3,107,116)	7,418.5	
	-9	($1,745,820)	86.40	-9	($3,495,505)	7,437.5	
	-10	($1,939,800)	86.10	-10	($3,883,895)	7,456.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.62%	6.83%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2013 - December 2013

Unit: Hines 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$1,277,700	90.41	10	$3,641,187	6,697.0	
	10	$1,277,700	90.41	9	$3,277,068	6,713.7	
	9	$1,149,930	90.24	8	$2,912,950	6,730.4	
	8	$1,022,160	90.07	7	$2,548,831	6,747.1	
	7	$894,390	89.89	6	$2,184,712	6,763.8	
	6	$766,620	89.72	5	$1,820,594	6,780.5	
	5	$638,850	89.55	4	$1,456,475	6,797.2	
	4	$511,080	89.38	3	$1,092,356	6,813.9	
	3	$383,310	89.20	2	$728,237	6,830.7	
	2	$255,540	89.03	1	$364,119	6,847.4	
	1	$127,770	88.86	0	$0	6,864.1	
		$0	88.69	0.000	$0	6,938.6	****
	0	$0	88.69	0	$0	6,939.1	
		$0	88.69	0	$0	7,014.1	
	-1	($217,590)	88.33	-1	($364,119)	7,030.8	
	-2	($435,180)	87.97	-2	($728,237)	7,047.5	
	-3	($652,770)	87.62	-3	($1,092,356)	7,064.2	
	-4	($870,360)	87.26	-4	($1,456,475)	7,080.9	
	-5	($1,087,950)	86.90	-5	($1,820,594)	7,097.7	
	-6	($1,305,540)	86.54	-6	($2,184,712)	7,114.4	
	-7	($1,523,130)	86.18	-7	($2,548,831)	7,131.1	
	-8	($1,740,720)	85.83	-8	($2,912,950)	7,147.8	
	-9	($1,958,310)	85.47	-9	($3,277,068)	7,164.5	
	-10	($2,175,900)	85.11	-10	($3,641,187)	7,181.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.25%	6.40%

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Bartow CC	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	97.92	84.48	56.60	93.13	95.12	99.03	95.48	99.91	97.59	100.00	99.95	95.89	92.57
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	612.5	539.2	406.6	632.5	653.5	690.7	696.7	744.0	670.1	702.6	673.1	699.8	7,721.2
4. RSH	117.6	28.8	18.6	70.7	60.5	23.5	14.4	0.0	36.9	41.4	47.6	17.4	477.4
5. UH	13.9	104.0	317.8	16.8	30.1	5.9	33.0	0.0	13.0	0.0	0.3	26.8	561.5
6. POH	0.0	87.0	317.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	404.4
7. FOH	7.6	16.9	0.4	0.6	3.9	4.1	4.3	0.0	6.2	0.0	0.3	26.8	70.9
8. MOH	6.3	0.2	0.0	16.2	26.2	1.8	28.7	0.0	6.8	0.0	0.0	0.0	86.2
9. PPOH	0.0	168.8	58.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	227.3
10. LR PP (MW)	0.0	156.5	156.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	156.5
11. PFOH	8.0	1.7	32.3	223.6	8.9	9.0	10.5	45.8	60.3	0.0	0.7	58.5	459.1
12. LR PF (MW)	214.6	156.3	156.5	157.0	90.2	99.5	69.3	16.2	77.8	0.0	69.6	69.5	117.8
13. PMOH	0.0	0.0	0.0	0.0	57.8	4.0	0.0	0.0	0.0	0.0	0.0	0.0	61.8
14. LR PM (MW)	0.0	0.0	0.0	0.0	101.8	67.5	0.0	0.0	0.0	0.0	0.0	0.0	99.6
15. NSC (MW)	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074
16. OPER MBTU	4,127,193	3,712,463	3,068,324	4,104,517	4,284,649	4,783,269	4,989,524	5,260,497	4,439,902	4,796,678	4,668,594	5,130,762	53,366,372
17. NET GEN (MWH)	563,341	502,626	366,800	560,403	588,872	654,808	664,060	724,554	602,661	663,492	650,482	712,229	7,254,328
18. ANOHR (BTU/KWH)	7,326.3	7,386.1	8,365.1	7,324.2	7,276.0	7,304.8	7,513.7	7,260.3	7,367.2	7,229.4	7,177.1	7,203.8	7,356.5
19. NOF (%)	85.64	86.80	84.00	82.50	83.91	88.28	88.75	90.68	83.74	87.92	89.99	94.77	87.48
20. NPC (MW)	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,074
ANOHR EQUATION:	ANOHR=	-7.985	x NOF +	7,988.41									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 4	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	100.00	99.40	30.07	99.40	73.17	69.97	80.26	96.83	99.27	99.57	96.78	99.91	86.91
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	669.8	225.5	720.0	545.0	503.8	597.3	744.0	720.0	744.0	721.0	744.0	7,678.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	2.2	517.5	0.0	199.0	216.2	146.7	0.0	0.0	0.0	0.0	0.0	1,081.6
6. POH	0.0	0.0	516.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	516.8
7. FOH	0.0	2.2	0.7	0.0	38.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.2
8. MOH	0.0	0.0	0.0	0.0	160.8	216.2	146.7	0.0	0.0	0.0	0.0	0.0	523.7
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	16.0	10.8	8.7	0.0	1.5	135.5	4.8	8.2	0.0	0.0	185.5
12. LR PF (MW)	0.0	0.0	93.0	5.0	44.2	0.0	93.2	84.0	96.7	93.0	0.0	0.0	79.1
13. PMOH	0.0	30.0	0.0	12.5	0.0	0.0	0.0	35.4	15.1	34.8	217.1	5.0	349.8
14. LR PM (MW)	0.0	42.8	0.0	241.7	0.0	0.0	0.0	153.6	217.1	44.2	76.0	93.0	90.1
15. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
16. OPER MBTU	3,665,173	3,389,230	1,043,604	4,691,727	3,416,885	3,079,048	3,314,511	4,042,517	3,803,752	3,904,927	3,560,705	3,962,997	41,875,076
17. NET GEN (MWH)	351,098	326,307	98,909	441,792	312,393	290,324	301,999	386,618	365,924	381,891	340,952	384,476	3,982,683
18. ANOHR (BTU/KWH)	10,439.2	10,386.6	10,551.2	10,619.8	10,937.8	10,605.6	10,975.2	10,456.1	10,394.9	10,225.2	10,443.4	10,307.5	10,514.3
19. NOF (%)	66.28	68.43	61.60	86.18	80.51	80.94	71.01	72.98	71.38	72.09	66.42	72.58	72.85
20. NPC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
ANOHR EQUATION:	ANOHR=	-32.774	x NOF +	12,736.87									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 5	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	75.56	90.09	86.71	99.73	99.00	92.32	99.77	97.95	93.32	99.32	98.55	100.00	94.38
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	597.6	635.0	645.0	720.0	736.8	666.3	744.0	733.6	678.3	744.0	554.0	0.0	7,454.6
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	167.1	744.0	911.1
5. UH	146.4	37.0	98.0	0.0	7.2	53.7	0.0	10.5	41.7	0.0	0.0	0.0	394.5
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	146.4	0.0	98.0	0.0	7.2	53.7	0.0	6.7	41.7	0.0	0.0	0.0	353.7
8. MOH	0.0	37.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	0.0	0.0	0.0	40.8
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	48.1	49.9	0.6	19.4	5.5	4.5	9.2	18.0	0.0	0.0	0.0	0.0	155.1
12. LR PF (MW)	523.9	286.4	79.0	45.7	28.8	91.0	63.4	99.3	0.0	0.0	0.0	0.0	279.5
13. PMOH	0.0	43.3	2.0	5.5	0.0	8.0	7.0	3.4	30.1	62.5	96.0	0.0	257.8
14. LR PM (MW)	0.0	155.1	234.0	91.0	0.0	91.0	91.0	472.5	151.6	57.6	77.6	0.0	101.9
15. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
16. OPER MBTU	2,595,380	3,126,153	3,988,380	4,364,618	4,373,920	3,818,889	3,798,563	3,817,476	3,363,239	3,455,004	2,557,182	0	39,258,804
17. NET GEN (MWH)	242,344	300,323	390,822	414,469	415,235	363,532	353,702	364,433	320,502	336,002	247,447	0	3,748,811
18. ANOHR (BTU/KWH)	10,709.5	10,409.3	10,205.1	10,530.6	10,533.6	10,505.0	10,739.4	10,475.1	10,493.7	10,282.7	10,334.3	0.0	10,472.3
19. NOF (%)	57.12	66.61	85.34	81.08	79.38	76.84	66.96	69.97	66.55	63.61	62.91	0.00	70.83
20. NPC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
ANOHR EQUATION:	ANOHR=	-24.700	x NOF +	12,104.66									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 1	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	100.00	100.00	100.00	40.53	76.25	95.02	97.27	96.65	95.13	99.92	98.70	100.00	87.10
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	672.0	743.0	291.8	567.3	699.0	744.0	744.0	720.0	744.0	358.7	0.0	7,027.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.6	744.0	1,104.6
5. UH	0.0	0.0	0.0	428.2	176.7	21.0	0.0	0.0	0.0	0.0	1.8	0.0	627.7
6. POH	0.0	0.0	0.0	428.2	170.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	598.9
7. FOH	0.0	0.0	0.0	0.0	6.1	21.0	0.0	0.0	0.0	0.0	1.8	0.0	28.9
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	216.0	291.8	383.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	891.2
10. LR PP (MW)	0.0	0.0	207.0	207.0	207.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	207.0
11. PFOH	0.0	0.0	0.0	0.0	0.0	28.6	55.3	45.5	0.0	0.0	10.2	0.0	139.6
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	229.0	169.6	247.0	0.0	0.0	347.0	0.0	219.9
13. PMOH	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.4	71.2	1.3	0.0	0.0	75.5
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	198.6	0.0	199.5	227.5	199.0	0.0	0.0	225.9
15. NSC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
16. OPER MBTU	2,402,918	2,210,653	2,097,737	429,245	970,603	1,985,653	2,144,916	2,381,294	2,239,789	2,449,392	1,036,963	0	20,349,163
17. NET GEN (MWH)	333,404	312,259	266,812	53,909	123,979	255,827	292,937	319,038	306,641	340,734	140,822	0	2,746,362
18. ANOHR (BTU/KWH)	7,207.2	7,079.6	7,862.2	7,962.4	7,828.8	7,761.7	7,322.1	7,464.0	7,304.3	7,188.6	7,363.6	0.0	7,409.5
19. NOF (%)	97.00	100.58	77.73	39.99	47.31	79.22	85.22	92.82	92.18	99.13	84.98	0.00	84.59
20. NPC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
ANOHR EQUATION:	ANOHR=	-9.354	x NOF +	8,092.38									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 2	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	100.00	11.25	96.56	100.00	96.39	96.68	98.57	100.00	99.84	99.96	100.00	99.39	92.13
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	335.8	51.6	717.4	720.0	717.2	696.5	744.0	744.0	720.0	744.0	721.0	739.6	7,651.1
4. RSH	408.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	432.2
5. UH	0.0	596.4	25.6	0.0	26.8	23.6	0.0	0.0	0.0	0.0	0.0	4.4	676.7
6. POH	0.0	495.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	495.6
7. FOH	0.0	100.8	25.6	0.0	26.8	23.6	0.0	0.0	0.0	0.0	0.0	4.4	181.2
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	0.0	0.0	0.0	0.0	22.7	0.0	1.1	0.0	0.0	61.1	84.8
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	230.3	0.0	313.1	0.0	0.0	1.0	66.4
13. PMOH	0.0	0.0	0.0	0.0	0.0	1.5	0.0	0.0	1.5	1.1	0.0	0.0	4.1
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	127.0	0.0	0.0	136.0	136.0	0.0	0.0	132.7
15. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
16. OPER MBTU	573,429	172,528	1,727,376	2,023,581	2,120,946	2,330,984	2,274,828	2,371,095	2,409,757	2,490,114	1,946,361	2,187,619	22,628,618
17. NET GEN (MWH)	76,912	10,384	251,308	279,001	283,907	303,656	310,483	335,282	331,030	343,888	267,229	296,418	3,089,498
18. ANOHR (BTU/KWH)	7,455.6	16,614.8	6,873.5	7,253.0	7,470.6	7,676.4	7,326.7	7,071.9	7,279.6	7,241.1	7,283.5	7,380.2	7,324.4
19. NOF (%)	46.74	41.05	71.49	79.08	80.79	88.98	85.17	91.97	93.83	94.33	75.64	81.79	82.41
20. NPC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
ANOHR EQUATION:	ANOHR=	-5.098	x NOF +	7,591.86									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 3	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	100.00	100.00	76.90	100.00	100.00	100.00	93.52	100.00	99.90	99.80	97.21	89.27	92.31
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	672.0	571.4	720.0	744.0	720.0	700.4	744.0	720.0	744.0	721.0	664.2	8,464.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	171.7	0.0	0.0	0.0	43.6	0.0	0.0	0.0	0.0	79.9	295.1
6. POH	0.0	0.0	171.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	171.7
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	43.6	0.0	0.0	0.0	0.0	79.9	123.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	571.4	176.5	8.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	756.7
10. LR PP (MW)	0.0	0.0	228.0	228.0	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	226.8
11. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	17.1	0.0	0.0	2.8	25.8	0.0	45.7
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	132.2	0.0	0.0	257.7	381.0	0.0	280.5
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	2.2
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	156.2	0.0	0.0	0.0	156.2
15. NSC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
16. OPER MBTU	1,400,404	1,320,380	1,005,540	1,778,298	2,300,689	2,158,319	2,125,122	2,338,002	2,315,333	2,436,523	2,038,698	1,912,920	23,130,228
17. NET GEN (MWH)	187,931	174,079	129,263	243,767	309,630	297,713	294,815	329,808	325,268	343,398	286,692	272,679	3,195,043
18. ANOHR (BTU/KWH)	7,451.7	7,584.9	7,779.0	7,295.1	7,430.4	7,249.7	7,208.3	7,089.0	7,118.2	7,095.3	7,111.1	7,015.3	7,239.4
19. NOF (%)	51.76	53.08	46.36	69.38	85.28	84.73	86.25	90.84	92.57	94.58	81.48	84.13	77.35
20. NPC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
ANOHR EQUATION:	ANOHR=	-15.348	x NOF +	8,589.40									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 4	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-Dec Period
1. EAF	100.00	100.00	98.78	100.00	98.25	99.91	100.00	99.93	99.50	29.03	74.07	100.00	91.51
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	672.0	733.9	720.0	731.0	720.0	744.0	744.0	716.9	216.0	534.0	744.0	8,019.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	9.1	0.0	13.0	0.0	0.0	0.0	3.2	528.0	187.0	0.0	740.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	528.0	182.3	0.0	710.3
7. FOH	0.0	0.0	0.0	0.0	13.0	0.0	0.0	0.0	3.2	0.0	4.7	0.0	20.9
8. MOH	0.0	0.0	9.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.1
9. PPOH	0.0	0.0	0.0	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6
10. LR PP (MW)	0.0	0.0	0.0	0.0	140.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.0
11. 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
12. 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
13. PMOH	0.0	0.0	0.0	0.0	0.0	2.2	0.0	2.4	1.8	0.0	0.0	0.0	6.4
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	139.8	0.0	100.1	119.8	0.0	0.0	0.0	119.4
15. NSC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
16. OPER MBTU	1,589,486	1,692,970	2,231,910	1,839,618	1,797,414	2,158,318	2,439,978	2,490,011	2,263,525	707,124	1,729,222	2,348,259	23,287,836
17. NET GEN (MWH)	229,724	249,046	334,726	255,052	252,425	333,089	346,547	342,271	319,809	96,892	247,727	340,253	3,347,561
18. ANOHR (BTU/KWH)	6,919.1	6,797.8	6,667.9	7,212.7	7,120.6	6,479.7	7,040.8	7,275.0	7,077.7	7,298.1	6,980.4	6,901.5	6,956.7
19. NOF (%)	65.42	78.52	96.63	75.05	73.16	98.01	98.68	97.47	94.52	95.03	98.28	96.89	88.44
20. NPC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
ANOHR EQUATION:	ANOHR=	-3.122	x NOF +	7,233.17									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Duke Energy Florida
Janauary 2013 - December 2013

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow Unit 4	02/08 (0900) - 03/24 (1400)	Balance of Plant
Crystal River 4	03/02 (0000) - 03/23 (1400)	Boiler Inspection
Hines 1	03/23 (0000) - 05/24 (0800)	Major Outage
Hines 2	02/02 (0000) - 02/22 (1600)	Boroscope Inspection
Hines 3	03/01 (0000) - 04/08 (0800)	Major Outage
Hines 4	05/04 (2300) - 05/15 (0800)	Turbine Valve

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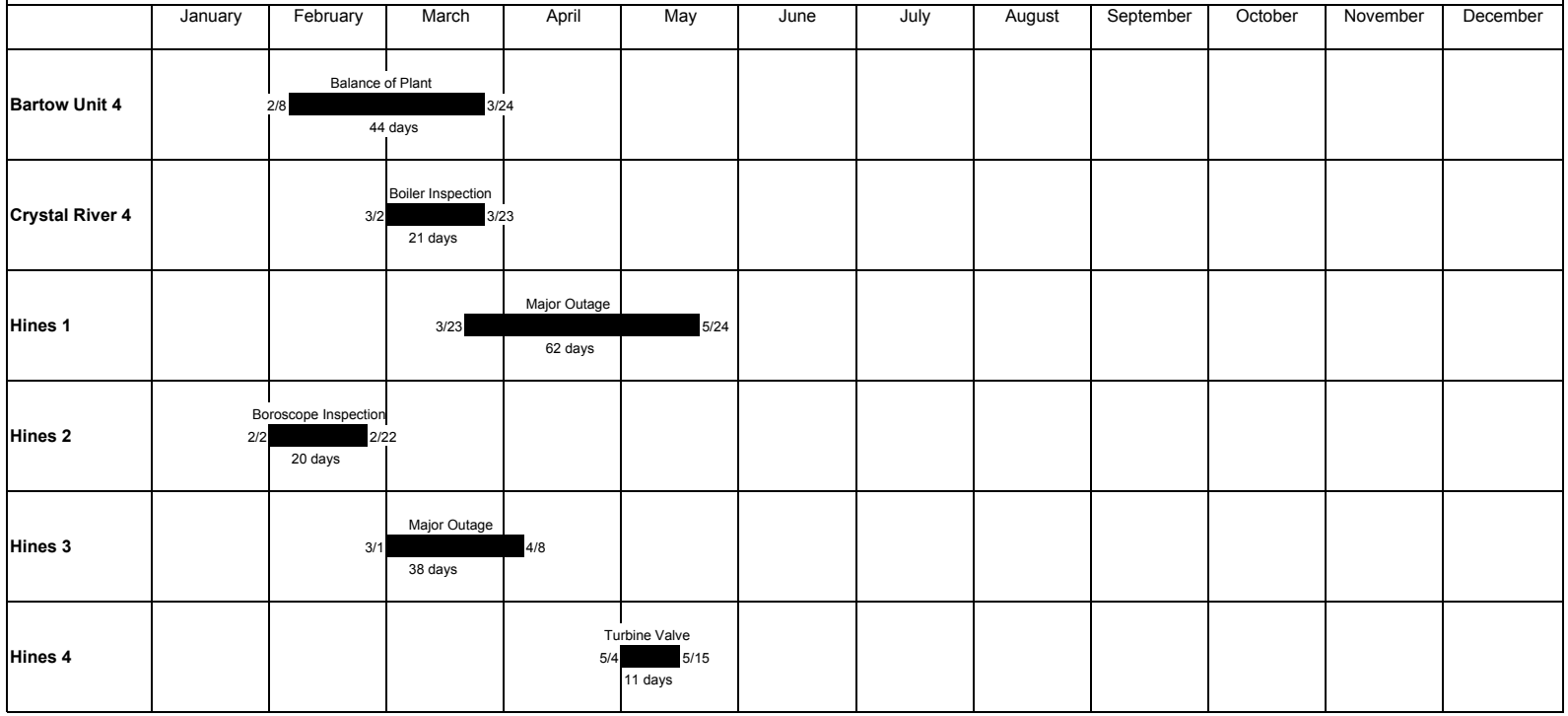
Planned Outage Schedule - Actual

Duke Energy Florida

Janauary 2013 - December 2013



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Docket No. 140001-EI
Witness: Jones
Exhibit No. ____ (MJJ-1P)

GPIF Targets and Ranges for January through December 2015

STANDARD FORM GPIF SCHEDULES

Description	Page
Index	1
Reward/Penalty Table (Estimated)	2
Maximum Incentive Dollars (Estimated)	3
Target and Range Summary	4
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 28
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Matthew J. Jones MJJ-1P

Original Sheet No. 7.101.1

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2015 - December 2015

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$68,790,939	$21,941,791
9	$61,911,845	$19,747,612
8	$55,032,751	$17,553,433
7	$48,153,657	$15,359,254
6	$41,274,563	$13,165,075
5	$34,395,469	$10,970,895
4	$27,516,375	$8,776,716
3	$20,637,282	$6,582,537
2	$13,758,188	$4,388,358
1	$6,879,094	$2,194,179
0	$0	$0
-1	($7,477,634)	($2,194,179)
-2	($14,955,268)	($4,388,358)
-3	($22,432,902)	($6,582,537)
-4	($29,910,535)	($8,776,716)
-5	($37,388,169)	($10,970,895)
-6	($44,865,803)	($13,165,075)
-7	($52,343,437)	($15,359,254)
-8	($59,821,071)	($17,553,433)
-9	($67,298,705)	($19,747,612)
-10	($74,776,339)	($21,941,791)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Duke Energy Florida
Period of: January 2015 - December 2015

1	Beginning of period balance of common equity	$5,379,770,166	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2015	$5,430,650,780	
3	Month of FEBRUARY 2015	$5,470,233,073	
4	Month of MARCH 2015	$5,283,094,337	
5	Month of APRIL 2015	$5,321,150,216	
6	Month of MAY 2015	$5,377,130,923	
7	Month of JUNE 2015	$5,438,541,792	
8	Month of JULY 2015	$5,506,973,455	
9	Month of AUGUST 2015	$5,351,557,373	
10	Month of SEPTEMBER 2015	$5,412,543,079	
11	Month of OCTOBER 2015	$5,463,253,750	
12	Month of NOVEMBER 2015	$5,499,542,091	
13	Month of DECEMBER 2015	$5,543,413,041	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$5,421,373,390	
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)	$22,080,901	
18	Jurisdictional Sales	37,785,591	MWH
19	Total Sales	38,025,013	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	99.37%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$21,941,791	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 7.101.1	$34,395,469	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$21,941,791	

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GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
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)
Bartow 4	3.62	87.48	89.95	82.43	2,487	(3,099)
Crystal River 4	4.62	91.86	95.65	84.32	3,181	(5,861)
Crystal River 5	3.34	89.21	91.57	84.43	2,301	(4,230)
Hines 1	0.58	86.26	87.32	84.08	397	(1,007)
Hines 2	0.63	89.24	89.79	88.08	431	(406)
Hines 3	1.07	92.28	93.21	90.36	734	(987)
Hines 4	0.57	86.67	87.08	85.81	391	(318)
GPIF System	14.42				9,922	(15,907)

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	23.18	7,451	75.9	7,060	7,842	15,949	(15,949)
Crystal River 4	11.58	10,354	83.3	9,885	10,823	7,968	(7,968)
Crystal River 5	10.49	10,157	83.5	9,715	10,600	7,214	(7,214)
Hines 1	11.37	7,266	96.1	6,823	7,708	7,824	(7,824)
Hines 2	7.99	7,225	87.0	6,870	7,579	5,495	(5,495)
Hines 3	13.42	7,151	95.1	6,680	7,623	9,234	(9,234)
Hines 4	7.54	6,964	92.1	6,695	7,233	5,185	(5,185)
GPIF System	85.58					58,869	(58,869)

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

Duke Energy Florida
Period of: January 2015 - December 2015

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2014 POF	1st Prior Period Jan-Jun 2014 EUOF	1st Prior Period Jan-Jun 2014 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2013 POF	2nd Prior Period Jan-Dec 2013 EUOF	2nd Prior Period Jan-Dec 2013 EUOR
Bartow 4	3.63	25.07	7.26	5.26	5.26	6.90	14.87	16.07	4.62	2.43	2.71
Crystal River 4	4.65	32.06	0.00	8.14	8.21	0.00	16.59	17.95	5.90	7.19	7.64
Crystal River 5	3.36	23.19	5.75	5.03	5.39	10.95	5.78	6.70	0.00	5.62	6.27
Hines 1	0.58	4.00	11.51	2.23	2.65	0.00	0.20	0.25	6.84	1.51	1.87
Hines 2	0.63	4.34	9.59	1.17	1.59	0.00	0.83	1.05	5.66	2.21	2.47
Hines 3	1.07	7.40	5.75	1.97	2.15	11.86	6.02	7.87	1.96	1.72	1.75
Hines 4	0.57	3.94	12.47	0.87	0.93	0.00	0.96	1.02	8.11	0.36	0.39
GPIF System Wghtd. Avg.	14.49	100.00	4.95	5.41	5.57	5.15	10.91	12.02	4.03	4.52	4.91

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2012 POF	3rd Prior Period Jan-Dec 2012 EUOF	3rd Prior Period Jan-Dec 2012 EUOR	Actual Performance 4th Prior Period Jan-Dec 2011 POF	4th Prior Period Jan-Dec 2011 EUOF	4th Prior Period Jan-Dec 2011 EUOR	Actual Performance 5th Prior Period Jan-Dec 2010 POF	5th Prior Period Jan-Dec 2010 EUOF	5th Prior Period Jan-Dec 2010 EUOR
Bartow 4	10.82	2.56	3.04	4.98	3.65	4.03	0.00	8.63	8.63
Crystal River 4	0.00	5.95	5.95	16.53	2.94	3.53	22.53	9.18	11.85
Crystal River 5	17.85	3.76	4.70	7.84	4.09	4.44	2.16	6.77	6.91
Hines 1	6.77	4.45	4.77	21.17	3.65	4.66	11.14	9.61	10.82
Hines 2	6.43	0.14	0.16	16.09	2.92	3.55	6.84	4.79	5.15
Hines 3	19.47	0.29	0.36	10.39	0.86	0.96	9.03	3.46	3.79
Hines 4	9.88	0.80	0.89	13.27	1.81	2.14	9.18	3.18	3.50
GPIF System Wghtd. Avg.	9.23	3.66	4.02	11.20	3.22	3.67	9.50	7.65	8.64

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

Duke Energy Florida
Period of: January 2015 - December 2015

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2013 - Dec 2013	2nd Prior HR Jan 2012 - Dec 2012	3rd Prior HR Jan 2011 - Dec 2011
Bartow 4	23.05	26.96	7,451	7,523	7,330	7,430
Crystal River 4	11.55	13.51	10,354	10,438	10,423	9,967
Crystal River 5	10.54	12.32	10,157	10,186	10,265	9,995
Hines 1	11.37	13.29	7,266	7,247	7,287	7,105
Hines 2	7.98	9.33	7,225	7,248	7,135	7,106
Hines 3	13.49	15.78	7,151	7,051	7,214	7,164
Hines 4	7.53	8.80	6,964	6,975	6,908	6,937
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System Weighted Avg.	85.51	100.00	8,041	8,060	8,030	8,115

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DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2015 - December 2015

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Bartow 4 EA	2,091,203	2,088,716	2,487	3.63
Bartow 4 HR	2,091,203	2,075,421	15,782	23.05
Crystal River 4 EA	2,091,203	2,088,022	3,181	4.65
Crystal River 4 HR	2,091,203	2,083,296	7,907	11.55
Crystal River 5 EA	2,091,203	2,088,902	2,301	3.36
Crystal River 5 HR	2,091,203	2,083,990	7,213	10.54
Hines 1 EA	2,091,203	2,090,806	397	0.58
Hines 1 HR	2,091,203	2,083,422	7,781	11.37
Hines 2 EA	2,091,203	2,090,772	431	0.63
Hines 2 HR	2,091,203	2,085,742	5,461	7.98
Hines 3 EA	2,091,203	2,090,469	734	1.07
Hines 3 HR	2,091,203	2,081,967	9,236	13.49
Hines 4 EA	2,091,203	2,090,813	391	0.57
Hines 4 HR	2,091,203	2,086,052	5,152	7.53

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

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INCENTIVE POINTS TABLES

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2015 - December 2015

Bartow 4

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	$1,243,600	88.72	5	$7,974,373	7,217.9
4	$994,880	88.47	4	$6,379,498	7,249.5
3	$746,160	88.23	3	$4,784,624	7,281.1
2	$497,440	87.98	2	$3,189,749	7,312.7
1	$248,720	87.73	1	$1,594,875	7,344.3
					7,375.9
0	$0	87.48	0	$0	7,450.9
					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
Period of: January 2015 - December 2015

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	$2,862,810	95.27	9	$7,171,247	9,924.0
8	$2,544,720	94.89	8	$6,374,442	9,963.4
7	$2,226,630	94.51	7	$5,577,637	10,002.8
6	$1,908,540	94.13	6	$4,780,832	10,042.2
5	$1,590,450	93.75	5	$3,984,026	10,081.7
4	$1,272,360	93.37	4	$3,187,221	10,121.1
3	$954,270	92.99	3	$2,390,416	10,160.5
2	$636,180	92.62	2	$1,593,611	10,199.9
1	$318,090	92.24	1	$796,805	10,239.3
					10,278.7
0	$0	91.86	0	$0	10,353.7
					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
Period of: January 2015 - December 2015

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
9	$2,070,900	91.34	9	$6,492,445	9,751.7
8	$1,840,800	91.10	8	$5,771,063	9,788.5
7	$1,610,700	90.87	7	$5,049,680	9,825.2
6	$1,380,600	90.63	6	$4,328,297	9,861.9
5	$1,150,500	90.39	5	$3,606,914	9,898.6
4	$920,400	90.16	4	$2,885,531	9,935.4
3	$690,300	89.92	3	$2,164,148	9,972.1
2	$460,200	89.69	2	$1,442,766	10,008.8
1	$230,100	89.45	1	$721,383	10,045.6
					10,082.3
0	$0	89.21	0	$0	10,157.3
					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
Period of: January 2015 - December 2015

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	$317,840	87.11	8	$6,259,219	6,896.9
7	$278,110	87.00	7	$5,476,816	6,933.6
6	$238,380	86.90	6	$4,694,414	6,970.3
5	$198,650	86.79	5	$3,912,012	7,007.0
4	$158,920	86.69	4	$3,129,609	7,043.7
3	$119,190	86.58	3	$2,347,207	7,080.4
2	$79,460	86.47	2	$1,564,805	7,117.1
1	$39,730	86.37	1	$782,402	7,153.8
					7,190.5
0	$0	86.26	0	$0	7,265.5
					7,340.5
-1	($100,740)	86.05	-1	($782,402)	7,377.3
-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
Period of: January 2015 - December 2015

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
					7,149.6
0	$0	89.24	0	$0	7,224.6
					7,299.6
-1	($40,610)	89.12	-1	($549,514)	7,327.6
-2	($81,220)	89.01	-2	($1,099,028)	7,355.6
-3	($121,830)	88.89	-3	($1,648,542)	7,383.5
-4	($162,440)	88.78	-4	($2,198,056)	7,411.5
-5	($203,050)	88.66	-5	($2,747,570)	7,439.5
-6	($243,660)	88.54	-6	($3,297,084)	7,467.5
-7	($284,270)	88.43	-7	($3,846,597)	7,495.5
-8	($324,880)	88.31	-8	($4,396,111)	7,523.4
-9	($365,490)	88.20	-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
Period of: January 2015 - December 2015

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
9	$660,600	93.12	9	$8,310,370	6,719.3
8	$587,200	93.02	8	$7,386,996	6,759.0
7	$513,800	92.93	7	$6,463,621	6,798.7
6	$440,400	92.84	6	$5,540,247	6,838.3
5	$367,000	92.75	5	$4,616,872	6,878.0
4	$293,600	92.65	4	$3,693,498	6,917.6
3	$220,200	92.56	3	$2,770,123	6,957.3
2	$146,800	92.47	2	$1,846,749	6,997.0
1	$73,400	92.37	1	$923,374	7,036.6
					7,076.3
0	$0	92.28	0	$0	7,151.3
					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
Period of: January 2015 - December 2015

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	$195,350	86.87	5	$2,592,702	6,792.3
4	$156,280	86.83	4	$2,074,162	6,811.7
3	$117,210	86.79	3	$1,555,621	6,831.1
2	$78,140	86.75	2	$1,037,081	6,850.5
1	$39,070	86.71	1	$518,540	6,869.9
					6,889.3
0	$0	86.67	0	$0	6,964.3
					7,039.3
-1	($31,780)	86.58	-1	($518,540)	7,058.6
-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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UNIT PERFORMANCE DATA

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Bartow 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.74	75.10	53.62	69.74	92.32	94.74	94.74	94.74	94.74	94.74	94.74	94.74	87.48
2. POF	0.00	19.64	41.13	25.00	2.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.26
3. EUOF	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26
4. EUOR	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	709.1	640.5	709.1	686.2	709.1	686.2	709.1	709.1	686.2	709.1	686.2	709.1	8,349.1
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	34.9	31.5	34.9	33.8	34.9	33.8	34.9	34.9	33.8	34.9	33.8	34.9	410.9
9. POH & PPOH	0.0	132.0	306.0	180.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	636.0
10. FOH & PFOH	30.2	27.3	30.2	29.2	30.2	29.2	30.2	30.2	29.2	30.2	29.2	30.2	355.8
11. MOH & PMOH	8.9	8.0	8.9	8.6	8.9	8.6	8.9	8.9	8.6	8.9	8.6	8.9	104.6
12. Oper. Btu(MBtu)	5,007,147	3,105,540	2,861,840	2,802,012	4,958,090	5,042,833	5,181,969	5,180,307	4,935,840	4,840,021	5,287,951	5,127,423	54,618,829
13. Net Gen. (MWH)	678,808.0	403,517.0	366,590.0	359,218.0	671,204.0	687,739.0	706,110.0	705,849.0	670,961.0	653,003.0	726,661.0	697,557.0	7,327,217.0
14. ANOHR (Btu/KWH)	7,376	7,696	7,807	7,800	7,387	7,332	7,339	7,339	7,356	7,412	7,277	7,351	7,454
15. NOF (%)	82.5	54.3	44.6	45.1	81.6	86.4	85.8	85.8	84.3	79.4	91.3	84.8	75.7
16. NSC (MW)	1160	1160	1160	1160	1160	1160	1160	1160	1160	1160	1160	1160	1160
17. ANOHR Equation	ANOHR=	-11.336 x NOF +		8,311.9									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	91.82	91.88	91.82	91.88	91.91	91.84	91.85	91.87	91.85	91.84	91.83	91.89	91.86
2. 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
3. EUOF	8.18	8.12	8.18	8.12	8.09	8.16	8.15	8.13	8.15	8.16	8.17	8.11	8.14
4. EUOR	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21	8.21
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	692.9	621.1	693.2	665.2	685.4	668.9	690.3	688.4	667.8	691.0	669.7	686.9	8,120.8
7. RSH	2.4	7.2	2.0	8.0	10.4	4.0	5.2	7.2	5.2	4.4	3.2	8.8	68.0
8. UH	48.7	43.7	48.8	46.8	48.2	47.1	48.5	48.4	47.0	48.6	47.1	48.3	571.2
9. POH & 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. FOH & PFOH	23.0	20.6	23.0	22.1	22.8	22.2	22.9	22.9	22.2	23.0	22.3	22.8	269.8
11. MOH & PMOH	37.8	33.9	37.9	36.3	37.4	36.5	37.7	37.6	36.5	37.7	36.6	37.5	443.5
12. Oper. Btu(MBtu)	4,179,308	3,877,375	4,416,007	4,056,550	4,055,004	4,061,140	4,421,127	4,526,879	4,070,030	4,348,294	3,926,662	3,871,459	49,816,332
13. Net Gen. (MWH)	403,133.0	374,943.0	427,678.0	391,598.0	390,611.0	391,915.0	428,353.0	439,500.0	392,882.0	420,732.0	378,013.0	371,712.0	4,811,070.0
14. ANOHR (Btu/KWH)	10,367	10,341	10,326	10,359	10,381	10,362	10,321	10,300	10,359	10,335	10,388	10,415	10,355
15. NOF (%)	81.7	84.8	86.6	82.7	80.0	82.3	87.2	89.7	82.6	85.5	79.3	76.0	83.2
16. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
17. ANOHR Equation	ANOHR=	-8.426 x NOF +		11,055.6									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.62	94.63	94.63	94.64	94.63	94.68	94.64	94.65	94.63	91.57	31.82	94.63	89.21
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.23	66.67	0.00	5.75
3. EUOF	5.38	5.37	5.37	5.36	5.37	5.32	5.36	5.35	5.37	5.20	1.51	5.37	5.03
4. EUOR	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	712.6	643.1	711.4	687.6	711.4	681.8	710.2	708.7	688.4	689.5	193.9	712.2	7,850.8
7. RSH	1.6	2.0	2.8	3.6	2.8	9.6	4.0	5.6	2.8	1.6	38.0	2.0	76.4
8. UH	29.8	26.9	29.8	28.8	29.8	28.6	29.8	29.7	28.8	52.9	488.1	29.8	832.8
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.0	480.0	0.0	504.0
10. FOH & PFOH	21.5	19.4	21.5	20.8	21.5	20.6	21.4	21.4	20.8	20.8	5.9	21.5	237.1
11. MOH & PMOH	18.5	16.7	18.5	17.8	18.5	17.7	18.4	18.4	17.9	17.9	5.0	18.5	203.8
12. Oper. Btu(MBtu)	4,505,880	4,099,489	4,538,060	3,932,761	4,120,151	3,964,836	4,152,846	4,126,318	4,125,235	4,026,799	1,198,211	4,412,129	47,224,199
13. Net Gen. (MWH)	448,771.0	409,116.0	452,957.0	382,934.0	402,227.0	387,393.0	406,239.0	403,279.0	405,716.0	393,808.0	118,680.0	437,264.0	4,648,384.0
14. ANOHR (Btu/KWH)	10,040	10,020	10,019	10,270	10,243	10,235	10,223	10,232	10,168	10,225	10,096	10,090	10,159
15. NOF (%)	88.7	89.6	89.7	78.4	79.6	80.0	80.6	80.1	83.0	80.4	86.2	86.5	83.4
16. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
17. ANOHR Equation	ANOHR=	-22.363 x NOF +		12,024.2									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.67	21.06	34.58	97.35	97.35	97.35	97.35	97.35	97.37	97.36	97.77	97.88	86.28
2. POF	0.00	78.57	64.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.51
3. EUOF	2.33	0.37	0.90	2.65	2.65	2.65	2.65	2.65	2.63	2.64	2.23	2.12	2.22
4. EUOR	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	643.1	91.6	248.2	708.1	731.7	707.5	731.1	731.1	702.8	727.6	595.2	586.3	7,204.3
7. RSH	91.2	51.0	12.0	1.2	1.2	1.8	1.8	1.8	6.6	5.4	115.8	148.8	438.6
8. UH	9.7	529.4	483.8	10.7	11.1	10.7	11.1	11.1	10.6	11.0	9.0	8.9	1117.1
9. POH & PPOH	0.0	528.0	480.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1008.0
10. FOH & PFOH	7.3	1.0	2.8	8.0	8.3	8.0	8.3	8.3	8.0	8.3	6.8	6.7	81.7
11. MOH & PMOH	10.0	1.4	3.9	11.1	11.4	11.0	11.4	11.4	11.0	11.4	9.3	9.2	112.4
12. Oper. Btu(MBtu)	1,932,642	304,866	793,474	2,354,550	2,379,514	2,340,000	2,434,064	2,415,677	2,274,791	2,365,216	1,856,941	1,813,039	23,272,752
13. Net Gen. (MWH)	261,196.0	42,335.0	108,940.0	326,891.0	328,251.0	324,363.0	338,047.0	334,752.0	313,400.0	326,246.0	253,320.0	246,766.0	3,204,507.0
14. ANOHR (Btu/KWH)	7,399	7,201	7,284	7,203	7,249	7,214	7,200	7,216	7,258	7,250	7,330	7,347	7,263
15. NOF (%)	87.9	100.0	95.0	99.9	97.1	99.2	100.1	99.1	96.5	97.1	92.1	91.1	96.3
16. NSC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
17. ANOHR Equation	ANOHR=	-16.349 x NOF +		8,836.5									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.17	98.68	63.54	19.71	98.60	98.57	98.55	98.58	98.58	98.64	98.72	98.93	89.22
2. POF	0.00	0.00	35.48	80.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.59
3. EUOF	0.83	1.32	0.97	0.29	1.40	1.43	1.45	1.42	1.42	1.36	1.28	1.07	1.19
4. EUOR	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	382.5	551.2	448.4	130.2	645.4	637.9	668.5	654.5	635.1	627.4	571.9	493.3	6,446.4
7. RSH	356.8	114.0	26.0	12.2	90.6	74.2	67.2	81.4	77.0	108.8	141.0	244.6	1393.8
8. UH	4.7	6.8	269.6	577.6	8.0	7.9	8.3	8.1	7.9	7.8	7.1	6.1	919.8
9. POH & PPOH	0.0	0.0	264.0	576.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	840.0
10. FOH & PFOH	4.4	6.3	5.1	1.5	7.4	7.3	7.7	7.5	7.3	7.2	6.6	5.7	74.0
11. MOH & PMOH	1.8	2.6	2.1	0.6	3.0	3.0	3.1	3.0	2.9	2.9	2.7	2.3	29.9
12. Oper. Btu(MBtu)	1,137,837	1,716,476	1,378,910	404,759	1,986,659	2,001,512	2,107,157	2,098,041	1,965,824	1,907,222	1,705,162	1,407,859	19,819,644
13. Net Gen. (MWH)	156,865.0	237,893.0	190,821.0	56,086.0	274,959.0	277,647.0	292,463.0	291,802.0	272,252.0	263,579.0	235,135.0	193,214.0	2,742,716.0
14. ANOHR (Btu/KWH)	7,254	7,215	7,226	7,217	7,225	7,209	7,205	7,190	7,221	7,236	7,252	7,287	7,226
15. NOF (%)	83.7	88.1	86.8	87.9	86.9	88.8	89.3	91.0	87.5	85.7	83.9	79.9	86.8
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-8.738	x NOF +	7,985.0									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Hines 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.22	97.89	97.86	81.62	47.32	97.86	97.85	97.86	97.86	97.87	97.86	97.90	92.27
2. POF	0.00	0.00	0.00	16.67	51.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.75
3. EUOF	1.78	2.11	2.14	1.71	1.07	2.14	2.15	2.14	2.14	2.13	2.14	2.10	1.98
4. EUOR	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	605.9	648.5	728.9	563.3	363.6	704.1	729.4	726.5	703.1	724.9	703.9	715.5	7,917.9
7. RSH	126.8	11.4	1.6	26.2	-10.4	2.8	1.0	4.0	3.8	5.6	3.0	15.2	191.0
8. UH	11.3	12.1	13.5	130.5	390.8	13.1	13.6	13.5	13.1	13.5	13.1	13.3	651.1
9. POH & PPOH	0.0	0.0	0.0	120.0	384.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0
10. FOH & PFOH	7.6	8.1	9.1	7.0	4.5	8.8	9.1	9.1	8.8	9.1	8.8	8.9	99.0
11. MOH & PMOH	5.7	6.1	6.8	5.3	3.4	6.6	6.8	6.8	6.6	6.8	6.6	6.7	74.3
12. Oper. Btu(MBtu)	1,953,729	2,199,008	2,490,566	1,885,594	1,174,615	2,348,322	2,447,331	2,400,132	2,304,599	2,346,580	2,367,251	2,368,429	26,288,210
13. Net Gen. (MWH)	271,612.0	308,835.0	350,359.0	264,107.0	163,355.0	328,675.0	342,953.0	335,280.0	321,424.0	326,476.0	331,893.0	330,982.0	3,675,951.0
14. ANOHR (Btu/KWH)	7,193	7,120	7,109	7,140	7,191	7,145	7,136	7,159	7,170	7,188	7,133	7,156	7,151
15. NOF (%)	91.9	97.6	98.5	96.1	92.1	95.7	96.3	94.6	93.7	92.3	96.6	94.8	95.1
16. NSC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
17. ANOHR Equation	ANOHR=	-12.705 x NOF +		8,360.1									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2015 - December 2015

PLANT/UNIT **Hines 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.08	99.07	99.07	99.07	99.07	99.07	99.07	99.08	99.08	39.64	27.83	81.35	86.67
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.68	71.67	17.74	12.47
3. EUOF	0.92	0.93	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.69	0.50	0.91	0.87
4. EUOR	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	735.0	667.1	739.2	714.1	738.2	714.3	738.2	736.8	713.5	546.6	388.7	726.3	8,158.0
7. RSH	4.2	0.6	0.0	1.2	1.0	1.0	1.0	2.4	1.8	1.8	16.8	13.0	44.8
8. UH	4.8	4.3	4.8	4.7	4.8	4.7	4.8	4.8	4.7	195.6	314.5	4.7	557.2
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	444.0	516.0	132.0	1092.0
10. FOH & PFOH	5.0	4.5	5.0	4.8	5.0	4.8	5.0	5.0	4.8	3.7	2.6	4.9	55.0
11. MOH & PMOH	1.9	1.7	1.9	1.8	1.9	1.8	1.9	1.9	1.8	1.4	1.0	1.9	21.1
12. Oper. Btu(MBtu)	2,356,221	2,157,909	2,439,026	2,309,781	2,380,150	2,339,880	2,419,116	2,385,512	2,311,726	957,454	639,410	1,942,778	24,656,295
13. Net Gen. (MWH)	338,843.0	310,401.0	351,030.0	332,245.0	342,338.0	336,692.0	348,098.0	343,148.0	332,540.0	136,037.0	90,770.0	278,144.0	3,540,286.0
14. ANOHR (Btu/KWH)	6,954	6,952	6,948	6,952	6,953	6,950	6,950	6,952	6,952	7,038	7,044	6,985	6,964
15. NOF (%)	97.7	98.6	100.6	98.6	98.3	99.9	99.9	98.7	98.7	52.7	49.5	81.1	91.9
16. NSC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
17. ANOHR Equation	ANOHR=	-1.879 x NOF +		7,137.3									

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PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2015 - December 2015

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	02/08 (0001) - 05/03 (2400)	Balance of Plant, Combustion Turbine Inspection & Steam Turbine Valve Maintinence
Crystal River 5	10/31 (0001) - 11/20 (2400)	Balance of Plant, Turbine Valve Maintinence
Hines 1	02/07 (0001) - 03/20 (2400)	Balance of Plant, Combustion Turbine Inspection & Steam Turbine Valve Maintinence
Hines 2	03/21 (0001) - 04/24 (2400)	Balance of Plant, Combustion Turbine Inspection
Hines 3	04/26 (0001) - 05/15 (2400)	Balance of Plant, Combustion Turbine Inspection
Hines 4	10/03 (0001) - 12/11 (2400)	Balance of Plant, Combustion Turbine Inspection

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AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

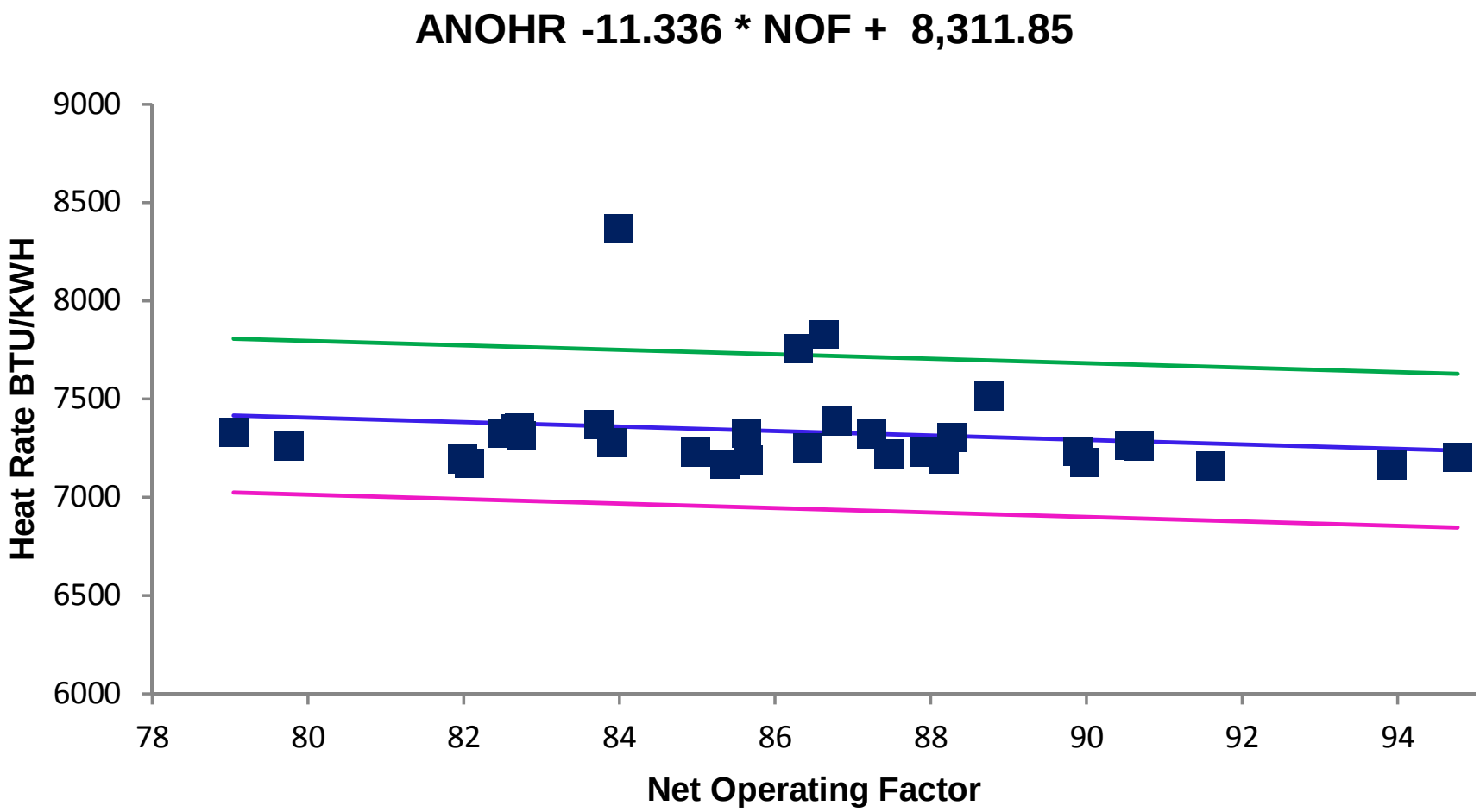
ANOHR -11.336 * NOF + 8,311.85

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	86.3	7,756	7,334	422.2	391.1
Aug-11	87.5	7,222	7,320	-98.6	391.1
Sep-11	82.7	7,312	7,374	-61.7	391.1
Oct-11	85.0	7,230	7,349	-118.3	391.1
Nov-11	89.9	7,231	7,293	-61.4	391.1
Dec-11	91.6	7,158	7,274	-115.4	391.1
Jan-12	88.2	7,192	7,312	-120.1	391.1
Feb-12	85.7	7,188	7,341	-152.9	391.1
May-12	86.4	7,249	7,332	-82.9	391.1
Jun-12	79.0	7,333	7,416	-83.1	391.1
Jul-12	82.7	7,346	7,375	-28.3	391.1
Aug-12	85.4	7,167	7,344	-177.6	391.1
Sep-12	82.7	7,350	7,374	-24.3	391.1
Oct-12	82.1	7,172	7,381	-209.6	391.1
Nov-12	79.8	7,260	7,408	-147.4	391.1
Dec-12	82.0	7,196	7,383	-186.7	391.1
Jan-13	85.6	7,326	7,341	-14.8	391.1
Feb-13	86.8	7,386	7,328	58.2	391.1
Mar-13	84.0	8,365	7,360	1005.4	391.1
Apr-13	82.5	7,324	7,377	-52.5	391.1
May-13	83.9	7,276	7,361	-84.7	391.1
Jun-13	88.3	7,305	7,311	-6.3	391.1
Jul-13	88.8	7,514	7,306	207.9	391.1
Aug-13	90.7	7,260	7,284	-23.6	391.1
Sep-13	83.7	7,367	7,363	4.5	391.1
Oct-13	87.9	7,229	7,315	-85.7	391.1
Nov-13	90.0	7,177	7,292	-114.7	391.1
Dec-13	94.8	7,204	7,238	-33.8	391.1
Jan-14	93.9	7,164	7,247	-82.6	391.1
Feb-14	90.6	7,262	7,285	-23.3	391.1
Mar-14	87.2	7,319	7,323	-3.8	391.1
Jun-14	86.6	7,826	7,330	495.8	391.1

Regression Output:

Constant	8311.85
Std Err of Y Est	241.5852948
R Squared	0.03173913
No. of Observations	32
Degrees of Freedom	30
X Coefficient	-11.33574032
Std Err of Coef.	11.43109789


ANOHR -11.336 * NOF + 8,311.85
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

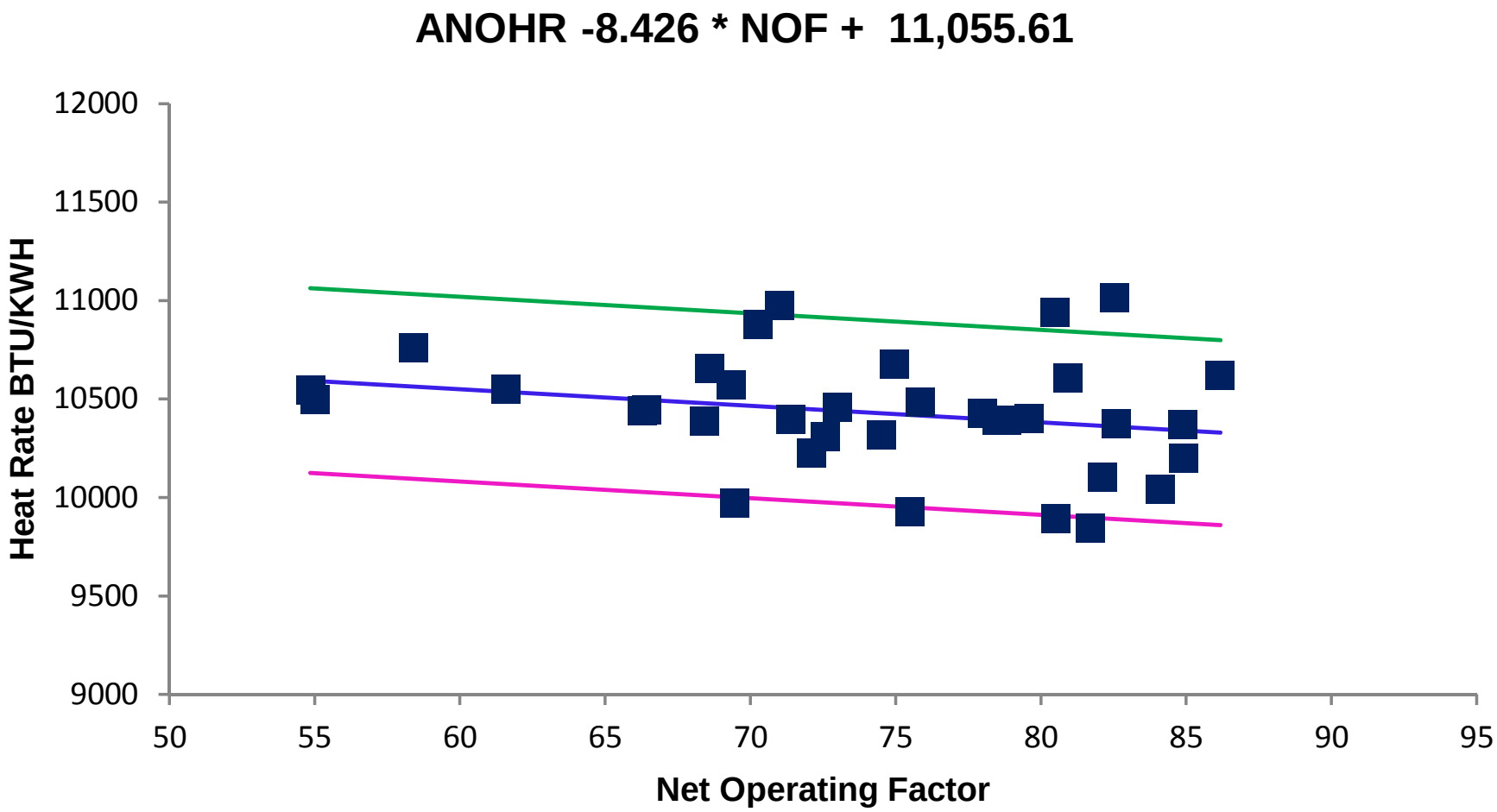
ANOHR -8.426 * NOF + 11,055.61

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	80.5	9,893	10,377	-484.3	469.0
Aug-11	81.7	9,844	10,367	-523.2	469.0
Sep-11	75.5	9,929	10,419	-490.7	469.0
Oct-11	69.5	9,971	10,470	-499.1	469.0
Dec-11	55.0	10,496	10,592	-95.7	469.0
Jan-12	54.9	10,545	10,593	-48.9	469.0
Feb-12	58.4	10,761	10,563	197.6	469.0
Mar-12	75.9	10,486	10,416	69.6	469.0
Apr-12	78.0	10,426	10,398	27.4	469.0
May-12	74.5	10,316	10,428	-111.9	469.0
Jun-12	70.3	10,878	10,463	414.8	469.0
Jul-12	78.5	10,394	10,394	-0.7	469.0
Aug-12	75.0	10,678	10,424	253.9	469.0
Sep-12	68.6	10,655	10,478	177.6	469.0
Oct-12	79.6	10,404	10,385	18.9	469.0
Nov-12	82.1	10,102	10,364	-261.4	469.0
Dec-12	69.3	10,571	10,471	99.4	469.0
Jan-13	66.3	10,439	10,497	-58.0	469.0
Feb-13	68.4	10,387	10,479	-92.4	469.0
Mar-13	61.6	10,551	10,537	14.5	469.0
Apr-13	86.2	10,620	10,329	290.3	469.0
May-13	80.5	10,938	10,377	560.5	469.0
Jun-13	80.9	10,606	10,374	231.9	469.0
Jul-13	71.0	10,975	10,457	518.0	469.0
Aug-13	73.0	10,456	10,441	15.4	469.0
Sep-13	71.4	10,395	10,454	-59.3	469.0
Oct-13	72.1	10,225	10,448	-222.9	469.0
Nov-13	66.4	10,443	10,496	-52.6	469.0
Dec-13	72.6	10,308	10,444	-136.5	469.0
Jan-14	84.9	10,373	10,340	32.5	469.0
Feb-14	78.8	10,390	10,391	-1.1	469.0
Mar-14	82.6	10,374	10,360	14.5	469.0
Apr-14	84.9	10,198	10,340	-141.7	469.0
May-14	84.1	10,039	10,347	-308.0	469.0
Jun-14	82.5	11,012	10,360	651.6	469.0

Regression Output:

Constant	11055.61
Std Err of Y Est	289.2852964
R Squared	0.057422982
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-8.425840147
Std Err of Coef.	5.942535676


ANOHR -8.426 * NOF + 11,055.61
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

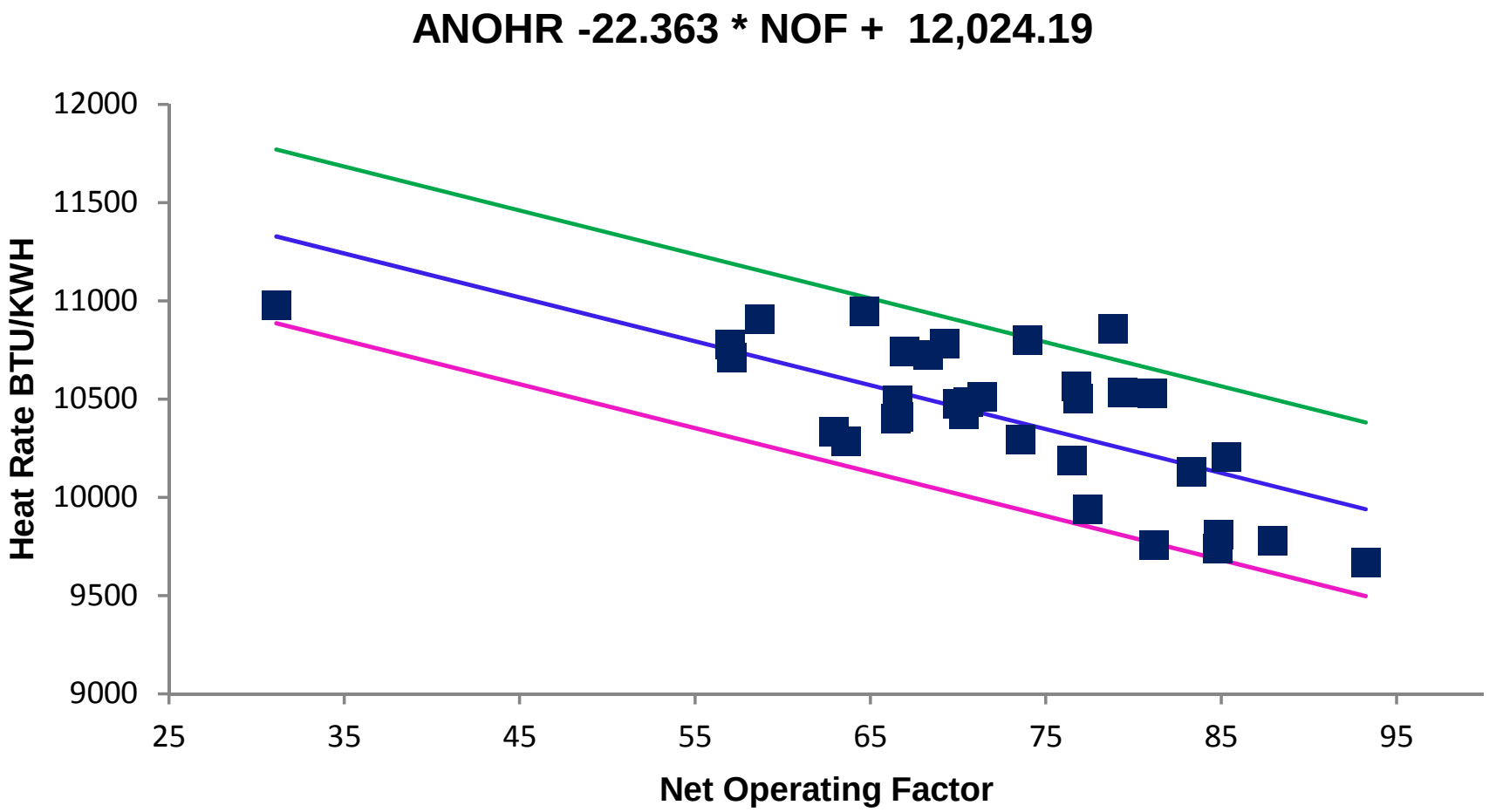
ANOHR -22.363 * NOF + 12,024.19

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	83.3	10,126	10,161	-35.1	442.3
Aug-11	81.2	9,754	10,208	-453.8	442.3
Sep-11	73.6	10,294	10,379	-85.6	442.3
Oct-11	57.0	10,777	10,750	26.8	442.3
Nov-11	76.5	10,185	10,314	-128.3	442.3
Dec-11	69.3	10,781	10,475	305.5	442.3
Jan-12	31.1	10,978	11,328	-349.8	442.3
Feb-12	58.7	10,905	10,711	193.9	442.3
Mar-12	71.4	10,510	10,428	81.4	442.3
Apr-12	70.6	10,484	10,445	39.1	442.3
May-12	66.5	10,398	10,538	-140.4	442.3
Jun-12	64.7	10,948	10,577	370.8	442.3
Jul-12	76.8	10,563	10,307	255.9	442.3
Aug-12	73.9	10,798	10,371	427.1	442.3
Sep-12	68.3	10,724	10,497	227.1	442.3
Oct-12	70.4	10,424	10,451	-26.9	442.3
Jan-13	57.1	10,709	10,747	-37.4	442.3
Feb-13	66.6	10,409	10,535	-125.2	442.3
Mar-13	85.3	10,205	10,116	89.4	442.3
Apr-13	81.1	10,531	10,211	319.6	442.3
May-13	79.4	10,534	10,249	284.5	442.3
Jun-13	76.8	10,505	10,306	199.2	442.3
Jul-13	67.0	10,739	10,527	212.6	442.3
Aug-13	70.0	10,475	10,459	15.7	442.3
Sep-13	66.5	10,494	10,536	-42.3	442.3
Oct-13	63.6	10,283	10,602	-319.0	442.3
Nov-13	62.9	10,334	10,617	-283.0	442.3
Jan-14	87.9	9,778	10,058	-280.1	442.3
Feb-14	93.2	9,665	9,939	-274.1	442.3
Mar-14	77.4	9,937	10,293	-356.6	442.3
Apr-14	84.9	9,810	10,126	-316.7	442.3
May-14	84.8	9,740	10,128	-387.7	442.3
Jun-14	78.8	10,854	10,261	593.4	442.3

Regression Output:

Constant	12024.19
Std Err of Y Est	273.0383913
R Squared	0.485194455
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-22.36281007
Std Err of Coef.	4.137225776


ANOHR -22.363 * NOF + 12,024.19
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

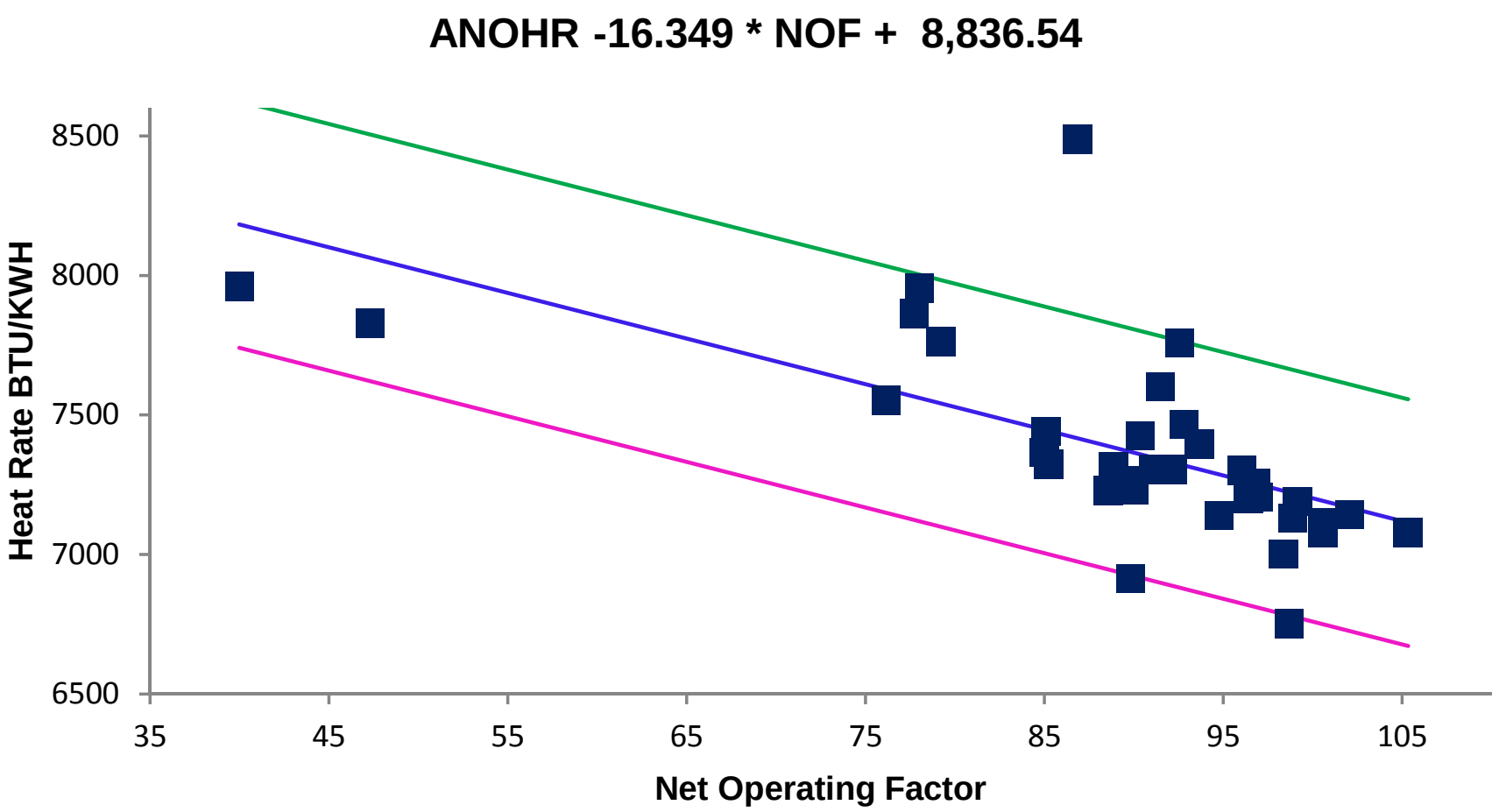
ANOHR -16.349 * NOF + 8,836.54

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	94.8	7,141	7,287	-146.2	442.1
Aug-11	91.1	7,304	7,347	-43.0	442.1
Sep-11	88.6	7,229	7,388	-158.9	442.1
Oct-11	96.1	7,301	7,266	35.1	442.1
Nov-11	98.7	6,752	7,223	-471.3	442.1
Dec-11	105.3	7,077	7,114	-37.1	442.1
Jan-12	89.8	6,914	7,368	-454.3	442.1
Feb-12	102.1	7,143	7,168	-25.0	442.1
Mar-12	100.6	7,113	7,192	-78.8	442.1
Apr-12	96.4	7,199	7,260	-61.5	442.1
May-12	76.2	7,553	7,591	-38.5	442.1
Jun-12	90.4	7,425	7,359	65.7	442.1
Jul-12	89.6	7,264	7,371	-107.4	442.1
Aug-12	92.6	7,758	7,323	434.8	442.1
Sep-12	96.8	7,258	7,253	4.2	442.1
Oct-12	91.5	7,600	7,341	259.0	442.1
Nov-12	78.0	7,955	7,561	393.9	442.1
Dec-12	90.0	7,232	7,365	-132.9	442.1
Jan-13	97.0	7,207	7,251	-43.5	442.1
Feb-13	100.6	7,080	7,192	-112.7	442.1
Mar-13	77.7	7,862	7,566	296.4	442.1
Apr-13	40.0	7,962	8,183	-220.4	442.1
May-13	47.3	7,829	8,063	-234.4	442.1
Jun-13	79.2	7,762	7,541	220.3	442.1
Jul-13	85.2	7,322	7,443	-121.1	442.1
Aug-13	92.8	7,464	7,319	144.9	442.1
Sep-13	92.2	7,304	7,329	-25.2	442.1
Oct-13	99.1	7,189	7,216	-27.3	442.1
Nov-13	85.0	7,364	7,447	-83.5	442.1
Jan-14	98.4	6,999	7,228	-228.9	442.1
Feb-14	93.7	7,395	7,305	89.4	442.1
Mar-14	98.9	7,132	7,219	-87.5	442.1
Apr-14	86.9	8,486	7,416	1070.4	442.1
May-14	88.9	7,314	7,383	-69.4	442.1
Jun-14	85.1	7,440	7,445	-5.1	442.1

Regression Output:

Constant	8836.54
Std Err of Y Est	272.6818116
R Squared	0.400190644
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-16.34878856
Std Err of Coef.	3.484189438


ANOHR -16.349 * NOF + 8,836.54
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

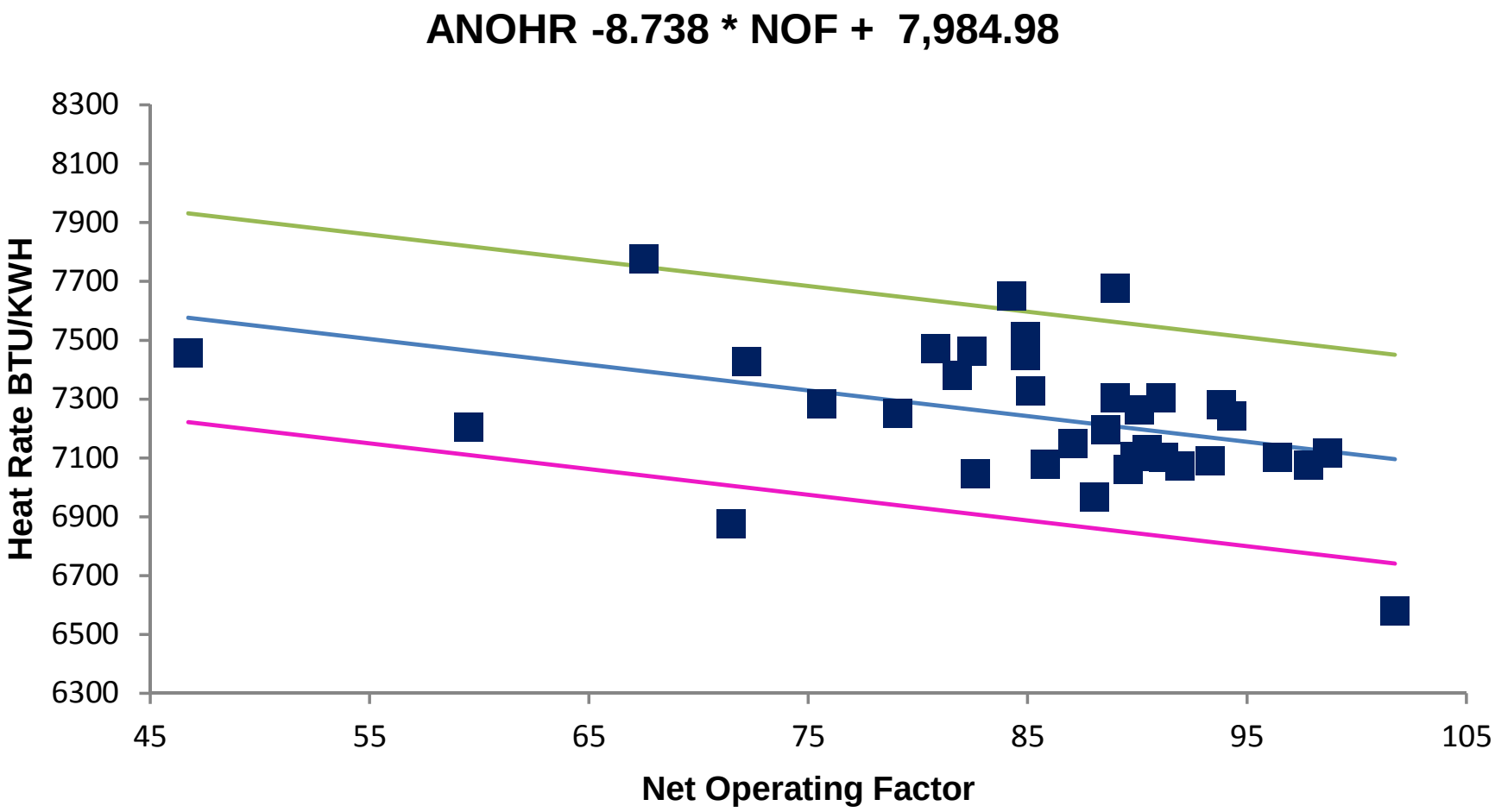
ANOHR -8.738 * NOF + 7,984.98

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	85.8	7,079	7,235	-155.9	354.8
Aug-11	91.1	7,305	7,189	115.4	354.8
Sep-11	90.5	7,130	7,195	-64.7	354.8
Oct-11	91.2	7,102	7,188	-85.6	354.8
Nov-11	101.7	6,578	7,096	-517.5	354.8
Dec-11	88.6	7,196	7,211	-15.2	354.8
Jan-12	82.6	7,047	7,263	-216.4	354.8
Feb-12	72.2	7,426	7,354	71.8	354.8
Mar-12	98.7	7,117	7,123	-5.6	354.8
Apr-12	96.4	7,102	7,143	-41.0	354.8
May-12	97.8	7,075	7,130	-55.0	354.8
Jun-12	89.9	7,105	7,199	-94.5	354.8
Jul-12	87.1	7,149	7,224	-74.9	354.8
Aug-12	89.6	7,061	7,202	-141.3	354.8
Sep-12	93.3	7,090	7,169	-79.2	354.8
Oct-12	88.1	6,967	7,216	-248.1	354.8
Nov-12	90.1	7,263	7,198	64.9	354.8
Dec-12	59.5	7,204	7,465	-260.3	354.8
Jan-13	46.7	7,456	7,577	-120.9	354.8
Mar-13	71.5	6,874	7,360	-486.8	354.8
Apr-13	79.1	7,253	7,294	-41.0	354.8
May-13	80.8	7,471	7,279	191.5	354.8
Jun-13	89.0	7,676	7,207	468.9	354.8
Jul-13	85.2	7,327	7,241	85.9	354.8
Aug-13	92.0	7,072	7,181	-109.4	354.8
Sep-13	93.8	7,280	7,165	114.4	354.8
Oct-13	94.3	7,241	7,161	80.3	354.8
Nov-13	75.6	7,283	7,324	-40.6	354.8
Dec-13	81.8	7,380	7,270	109.9	354.8
Jan-14	84.3	7,649	7,248	400.3	354.8
Feb-14	67.5	7,778	7,395	382.5	354.8
Mar-14	84.9	7,449	7,243	205.6	354.8
Apr-14	89.0	7,303	7,207	95.9	354.8
May-14	84.9	7,512	7,243	269.0	354.8
Jun-14	82.5	7,462	7,264	197.7	354.8

Regression Output:

Constant	7984.98
Std Err of Y Est	218.828228
R Squared	0.168931747
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-8.737696321
Std Err of Coef.	3.373670674


ANOHR -8.738 * NOF + 7,984.98
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

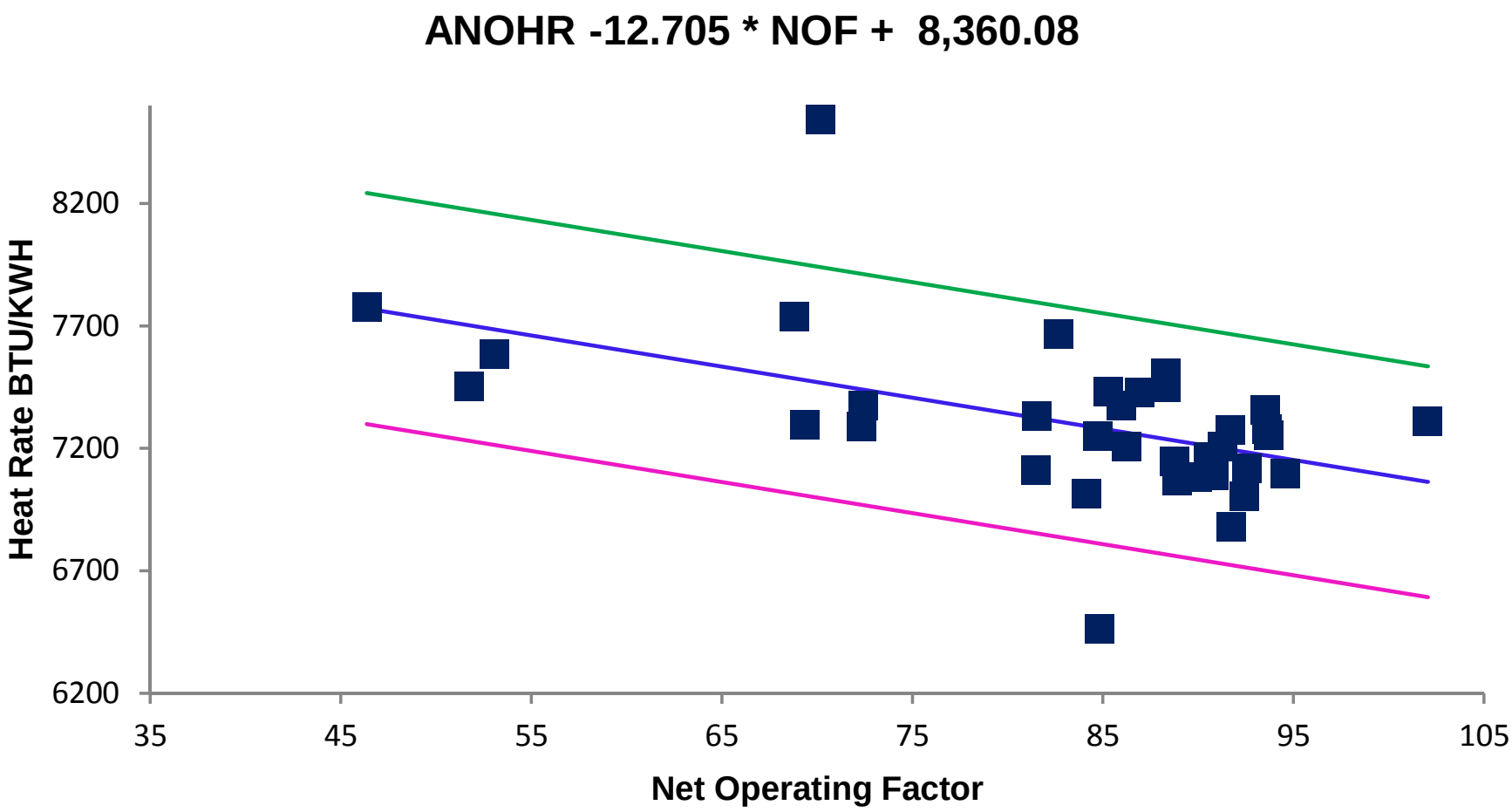
ANOHR -12.705 * NOF + 8,360.08

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	88.3	7,448	7,238	209.9	471.6
Aug-11	91.7	6,879	7,194	-315.6	471.6
Sep-11	93.6	7,278	7,171	107.0	471.6
Oct-11	92.4	7,005	7,186	-180.8	471.6
Nov-11	102.1	7,309	7,063	245.6	471.6
Dec-11	86.0	7,374	7,268	106.1	471.6
Jan-12	72.4	7,372	7,440	-68.0	471.6
Feb-12	88.8	7,145	7,232	-87.4	471.6
Apr-12	72.3	7,290	7,441	-151.5	471.6
May-12	91.7	7,275	7,195	79.6	471.6
Jun-12	93.7	7,254	7,169	84.7	471.6
Jul-12	88.3	7,506	7,238	268.0	471.6
Aug-12	88.9	7,069	7,231	-162.1	471.6
Sep-12	93.5	7,358	7,172	186.5	471.6
Oct-12	82.7	7,667	7,310	357.3	471.6
Nov-12	86.9	7,427	7,256	171.5	471.6
Dec-12	81.6	7,333	7,324	9.3	471.6
Jan-13	51.8	7,452	7,702	-250.8	471.6
Feb-13	53.1	7,585	7,686	-100.7	471.6
Mar-13	46.4	7,779	7,771	7.9	471.6
Apr-13	69.4	7,295	7,479	-183.6	471.6
May-13	85.3	7,430	7,277	153.8	471.6
Jun-13	84.7	7,250	7,284	-33.9	471.6
Jul-13	86.3	7,208	7,264	-55.9	471.6
Aug-13	90.8	7,089	7,206	-117.0	471.6
Sep-13	92.6	7,118	7,184	-65.7	471.6
Oct-13	94.6	7,095	7,158	-63.1	471.6
Nov-13	81.5	7,111	7,325	-213.8	471.6
Dec-13	84.1	7,015	7,291	-275.9	471.6
Jan-14	91.3	7,208	7,200	7.9	471.6
Feb-14	68.8	7,739	7,486	252.8	471.6
Mar-14	70.2	8,545	7,468	1077.2	471.6
Apr-14	90.0	7,082	7,217	-134.7	471.6
May-14	84.8	6,463	7,282	-819.3	471.6
Jun-14	90.5	7,164	7,210	-45.4	471.6

Regression Output:

Constant	8360.08
Std Err of Y Est	290.890769
R Squared	0.243521365
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-12.70484739
Std Err of Coef.	3.898004007


ANOHR -12.705 * NOF + 8,360.08
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

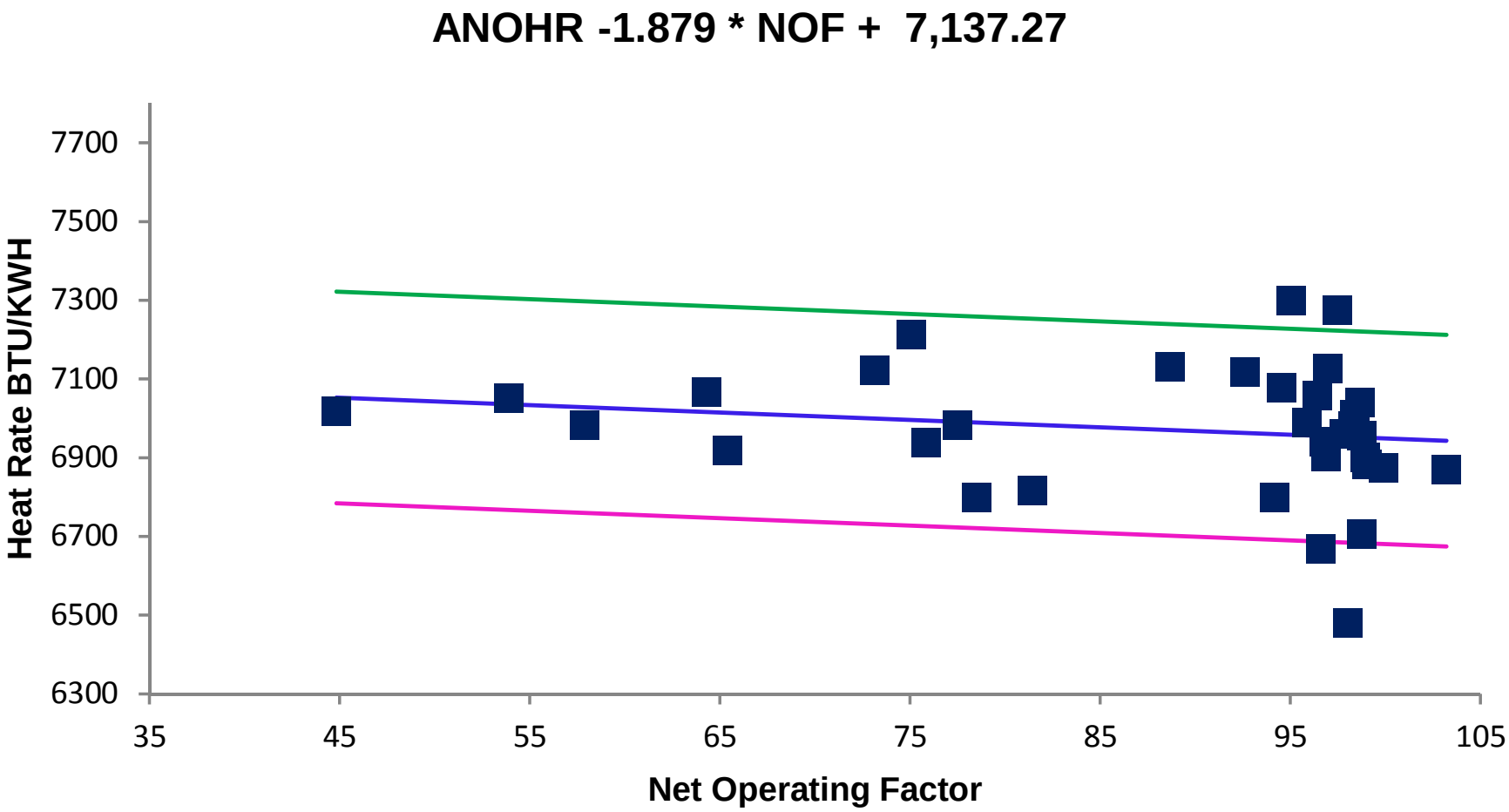
ANOHR -1.879 * NOF + 7,137.27

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-11	98.4	7,010	6,952	57.5	268.9
Aug-11	97.0	7,126	6,955	171.0	268.9
Sep-11	97.9	6,960	6,953	6.2	268.9
Oct-11	81.5	6,816	6,984	-168.1	268.9
Nov-11	44.8	7,018	7,053	-35.1	268.9
Dec-11	57.9	6,981	7,028	-47.1	268.9
Jan-12	75.8	6,939	6,995	-55.4	268.9
Feb-12	64.3	7,066	7,016	49.9	268.9
Mar-12	103.2	6,870	6,943	-72.9	268.9
Apr-12	96.8	6,941	6,955	-14.5	268.9
May-12	53.9	7,051	7,036	15.5	268.9
Jun-12	98.9	6,900	6,951	-50.9	268.9
Jul-12	94.2	6,800	6,960	-160.8	268.9
Aug-12	98.8	6,957	6,952	5.3	268.9
Sep-12	99.9	6,874	6,949	-75.3	268.9
Oct-12	98.7	6,705	6,952	-246.7	268.9
Dec-12	77.5	6,982	6,992	-9.3	268.9
Jan-13	65.4	6,919	7,014	-95.2	268.9
Feb-13	78.5	6,798	6,990	-191.9	268.9
Mar-13	96.6	6,668	6,956	-287.8	268.9
Apr-13	75.1	7,213	6,996	216.5	268.9
May-13	73.2	7,121	7,000	120.8	268.9
Jun-13	98.0	6,480	6,953	-473.4	268.9
Jul-13	98.7	7,041	6,952	89.0	268.9
Aug-13	97.5	7,275	6,954	320.9	268.9
Sep-13	94.5	7,078	6,960	118.1	268.9
Oct-13	95.0	7,298	6,959	339.4	268.9
Nov-13	98.3	6,980	6,953	27.8	268.9
Dec-13	96.9	6,902	6,955	-53.7	268.9
Jan-14	92.6	7,117	6,963	153.4	268.9
Feb-14	88.7	7,129	6,971	158.8	268.9
Mar-14	99.0	6,884	6,951	-67.0	268.9
Apr-14	95.9	6,989	6,957	31.8	268.9
May-14	96.4	7,057	6,956	100.9	268.9
Jun-14	93.8	7,083	6,961	122.4	268.9

Regression Output:

Constant	7137.27
Std Err of Y Est	165.8819035
R Squared	0.029716084
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-1.879183448
Std Err of Coef.	1.869243321


ANOHR -1.879 * NOF + 7,137.27
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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	663.19	737.76	657.26	680.34	602.38	506.66	667.06	491.88	296.17	366.02	686.01	607.19	733.95	736.70	679.47	710.45	596.94	634.05
RSH	18.71	1.02	20.28	59.62	17.11	97.24	76.94	71.42	0.74	60.22	8.24	92.64	0.00	0.00	14.51	6.71	5.50	109.95
UH	62.10	5.22	42.46	4.04	101.51	140.10	0.00	132.70	446.09	293.76	49.75	20.17	10.05	7.30	26.02	26.84	118.56	0.00
POH	0.00	0.00	0.00	0.00	93.24	140.10	0.00	132.70	433.23	232.86	49.75	0.00	0.00	0.00	0.00	0.00	101.62	0.00
FOH	62.10	5.07	42.46	4.04	8.27	0.00	0.00	0.00	0.00	28.74	0.00	3.99	10.05	7.30	0.00	18.34	16.94	0.00
MOH	0.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	12.86	32.15	0.00	16.19	0.00	0.00	26.02	8.50	0.00	0.00
PFOH	0.00	75.57	13.13	9.84	13.33	0.00	0.00	0.00	0.00	50.68	281.71	282.34	314.59	302.40	273.27	413.22	273.00	281.71
LRPF	0.00	66.30	21.81	74.42	170.23	0.00	0.00	0.00	0.00	3.31	12.30	15.41	16.46	15.77	12.35	27.67	11.80	12.21
EFOH	0.00	4.42	0.25	0.65	2.00	0.00	0.00	0.00	0.00	0.15	3.06	3.84	4.57	4.21	2.98	10.09	2.84	3.04
PMOH	29.64	63.19	47.26	16.83	3.92	0.00	5.15	0.00	0.00	37.04	0.00	4.92	21.17	17.06	63.43	9.81	0.00	13.34
LRPM	65.78	65.64	62.00	55.28	75.61	0.00	55.27	0.00	0.00	69.51	0.00	50.58	50.23	39.55	57.20	43.35	0.00	72.92
EMOH	1.72	3.66	2.59	0.82	0.26	0.00	0.25	0.00	0.00	2.27	0.00	0.22	0.94	0.60	3.20	0.38	0.00	0.86
NPC	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00

MONTHLY	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
FOR	8.56	0.68	6.07	0.59	1.35	0.00	0.00	0.00	0.00	7.28	0.00	0.65	1.35	0.98	0.00	2.52	2.76	0.00
MOR	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	4.16	8.07	0.00	2.60	0.00	0.00	3.69	1.18	0.00	0.00
PFOR	0.00	0.60	0.04	0.10	0.33	0.00	0.00	0.00	0.00	0.04	0.45	0.63	0.62	0.57	0.44	1.42	0.48	0.48
PMOR	0.26	0.50	0.39	0.12	0.04	0.00	0.04	0.00	0.00	0.62	0.00	0.04	0.13	0.08	0.47	0.05	0.00	0.14
EUOR	8.80	1.79	6.47	0.80	1.73	0.00	0.04	0.00	4.16	14.83	0.45	3.86	2.09	1.63	4.56	5.06	3.22	0.61
EUOF	8.58	1.79	6.29	0.74	1.46	0.00	0.03	0.00	1.73	8.79	0.41	3.37	2.09	1.63	4.47	5.01	2.74	0.52
POF	0.00	0.00	0.00	0.00	12.93	18.83	0.00	19.07	58.31	32.34	6.69	0.00	0.00	0.00	0.00	0.00	14.09	0.00
EAF	91.42	98.21	93.71	99.26	85.61	81.17	99.97	80.93	39.96	58.87	92.90	96.63	97.91	98.37	95.53	94.99	83.16	99.48

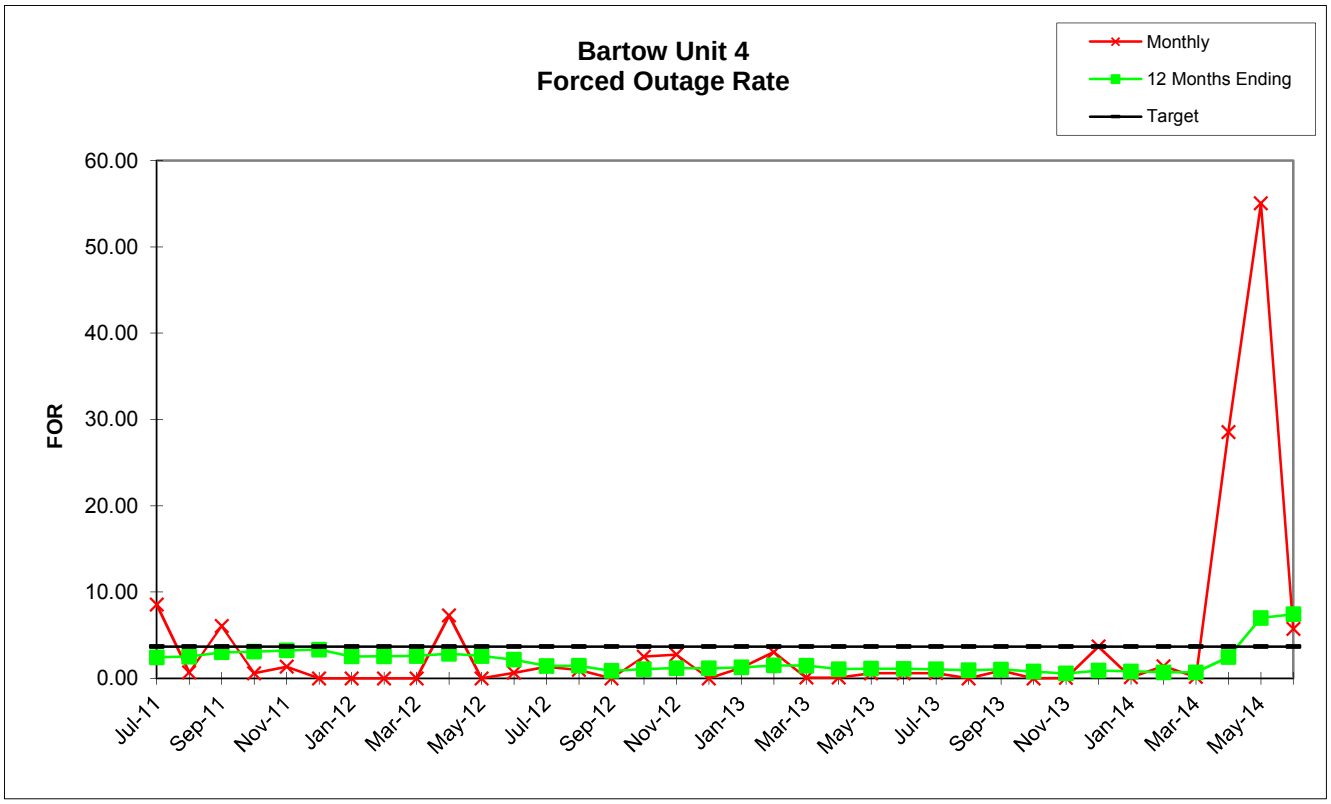
12 MONTHS	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
FOR	2.45	2.51	3.03	3.10	3.24	3.34	2.55	2.55	2.59	2.85	2.60	2.17	1.44	1.47	0.88	1.07	1.19	1.17
MOR	0.40	0.40	0.41	0.41	0.42	0.43	0.43	0.43	0.62	1.08	0.64	0.87	0.86	0.86	1.22	1.33	1.33	1.31
PFOR	0.40	0.32	0.33	0.34	0.32	0.12	0.12	0.12	0.12	0.13	0.17	0.21	0.27	0.27	0.30	0.44	0.45	0.48
PMOR	0.29	0.34	0.35	0.17	0.18	0.19	0.19	0.19	0.20	0.21	0.19	0.17	0.16	0.11	0.12	0.11	0.11	0.12
EUOR	3.51	3.54	4.07	3.98	4.12	4.03	3.25	3.25	3.49	4.20	3.56	3.37	2.69	2.68	2.49	2.91	3.04	3.04
EUOF	3.35	3.38	3.87	3.76	3.84	3.65	2.94	2.93	3.02	3.50	2.94	2.76	2.21	2.19	2.04	2.41	2.51	2.56
POF	2.32	2.32	2.32	2.32	3.39	4.98	4.98	4.74	9.10	11.75	12.32	12.32	12.32	12.32	12.32	12.32	12.41	10.82
EAF	94.33	94.30	93.81	93.92	92.77	91.36	92.08	92.33	87.88	84.75	84.74	84.93	85.48	85.49	85.64	85.28	85.08	86.63

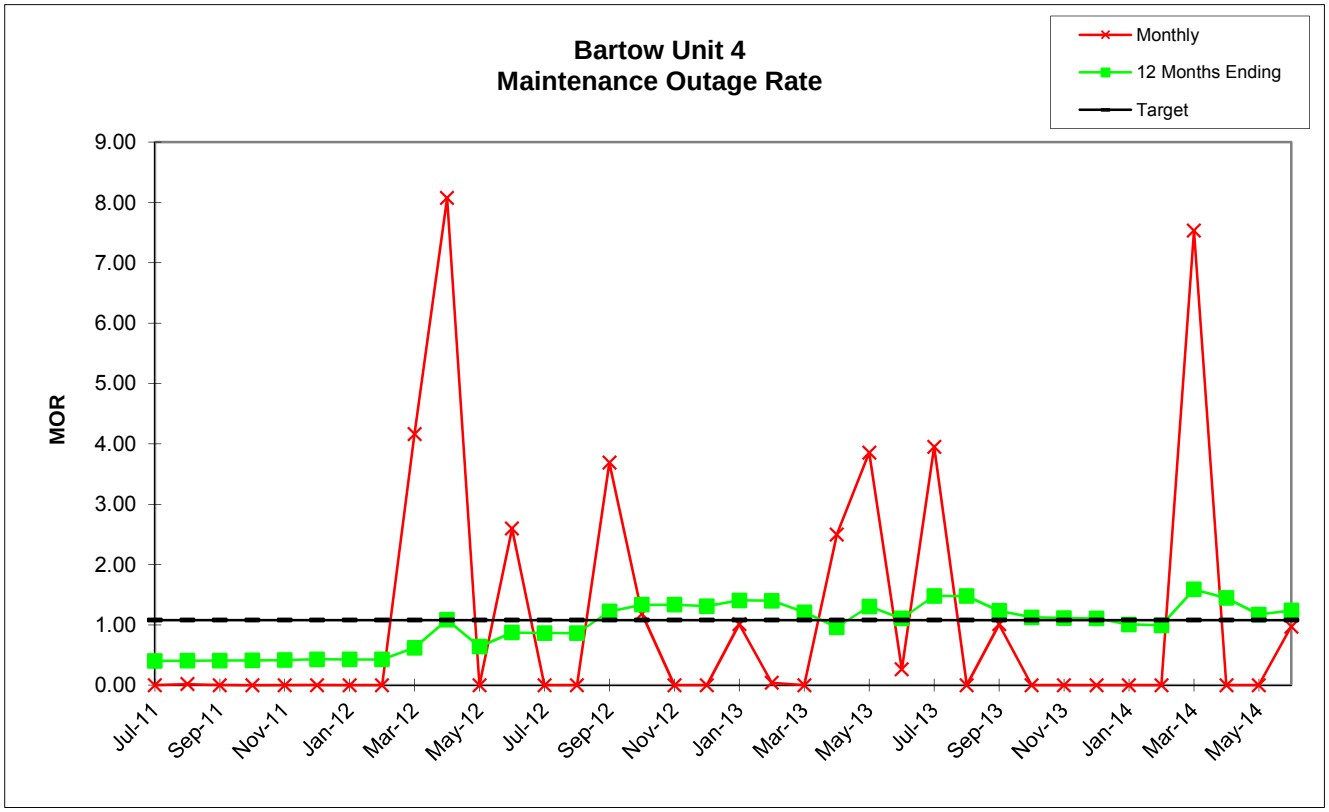
Bartow
Unit 4

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	612.51	539.15	406.59	632.49	653.45	690.66	696.68	744.00	670.11	702.64	673.06	699.77	742.17	660.09	647.94	358.53	306.68	671.92
RSH	117.60	28.82	18.64	70.72	60.46	23.47	14.37	0.00	36.90	41.36	47.62	17.41	0.83	2.53	21.58	0.00	0.00	0.62
UH	13.89	104.03	317.77	16.79	30.09	5.87	32.95	0.00	12.99	0.00	0.32	26.82	1.00	9.38	73.48	361.47	437.32	47.46
POH	0.00	86.97	317.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.61	218.31	61.84	0.00
FOH	7.62	16.85	0.38	0.58	3.89	4.05	4.29	0.00	6.15	0.00	0.32	26.82	1.00	9.38	1.08	143.17	375.49	40.87
MOH	6.27	0.22	0.00	16.21	26.20	1.82	28.66	0.00	6.84	0.00	0.00	0.00	0.00	0.00	52.79	0.00	0.00	6.59
PFOH	8.00	1.65	32.31	223.56	8.86	8.95	10.47	45.75	60.31	0.00	0.71	58.53	2.22	20.76	2.40	0.00	0.00	1.32
LRPF	214.58	156.31	156.49	157.01	90.23	99.51	69.31	16.19	77.82	0.00	69.63	69.50	109.65	98.02	198.57	0.00	0.00	54.76
EFOH	1.60	0.24	4.71	32.68	0.74	0.83	0.68	0.69	4.37	0.00	0.05	3.79	0.23	1.89	0.44	0.00	0.00	0.07
PMOH	0.00	0.00	0.00	0.00	57.82	3.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.81	0.00	0.00	14.55
LRPM	0.00	0.00	0.00	0.00	101.76	67.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	109.50	0.00	0.00	109.52
EMOH	0.00	0.00	0.00	0.00	5.48	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.30	0.00	0.00	1.48
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	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	1.23	3.03	0.09	0.09	0.59	0.58	0.61	0.00	0.91	0.00	0.05	3.69	0.13	1.40	0.17	28.54	55.04	5.73
MOR	1.01	0.04	0.00	2.50	3.85	0.26	3.95	0.00	1.01	0.00	0.00	0.00	0.00	0.00	7.53	0.00	0.00	0.97
PFOR	0.26	0.04	1.16	5.17	0.11	0.12	0.10	0.09	0.65	0.00	0.01	0.54	0.03	0.29	0.07	0.00	0.00	0.01
PMOR	0.00	0.00	0.00	0.00	0.84	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.74	0.00	0.00	0.22
EUOR	2.47	3.11	1.25	7.62	5.31	1.00	4.61	0.09	2.54	0.00	0.05	4.21	0.17	1.68	9.35	28.54	55.04	6.81
EUOF	2.08	2.58	0.68	6.87	4.88	0.97	4.52	0.09	2.41	0.00	0.05	4.11	0.16	1.68	8.83	19.88	50.47	6.81
POF	0.00	12.94	42.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.64	30.32	8.31	0.00
EAF	97.92	84.48	56.60	93.13	95.12	99.03	95.48	99.91	97.59	100.00	99.95	95.89	99.84	98.32	88.53	49.79	41.22	93.19

12 MONTHS	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	1.28	1.50	1.49	1.07	1.13	1.12	1.05	0.95	1.03	0.80	0.57	0.91	0.81	0.71	0.70	2.46	7.00	7.44
MOR	1.41	1.40	1.21	0.96	1.30	1.11	1.48	1.48	1.23	1.12	1.11	1.10	1.01	0.99	1.59	1.44	1.17	1.24
PFOR	0.51	0.51	0.57	0.97	0.95	0.90	0.85	0.80	0.82	0.69	0.65	0.65	0.62	0.64	0.56	0.17	0.17	0.16
PMOR	0.12	0.12	0.12	0.08	0.15	0.15	0.14	0.13	0.09	0.09	0.09	0.07	0.07	0.07	0.21	0.21	0.15	0.17
EUOR	3.26	3.47	3.32	3.05	3.48	3.22	3.46	3.32	3.13	2.67	2.40	2.71	2.49	2.38	3.02	4.21	8.32	8.80
EUOF	2.73	2.94	2.85	2.69	3.07	2.87	3.08	2.95	2.78	2.35	2.13	2.43	2.27	2.20	2.89	3.96	7.84	8.32
POF	10.82	10.32	9.00	6.34	5.78	5.78	5.78	5.78	5.78	5.78	4.62	4.62	4.62	3.62	0.22	2.72	3.42	3.42
EAF	86.45	86.74	88.15	90.97	91.16	91.35	91.15	91.28	91.45	91.87	93.25	92.95	93.11	94.17	96.88	93.32	88.74	88.26


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Bartow Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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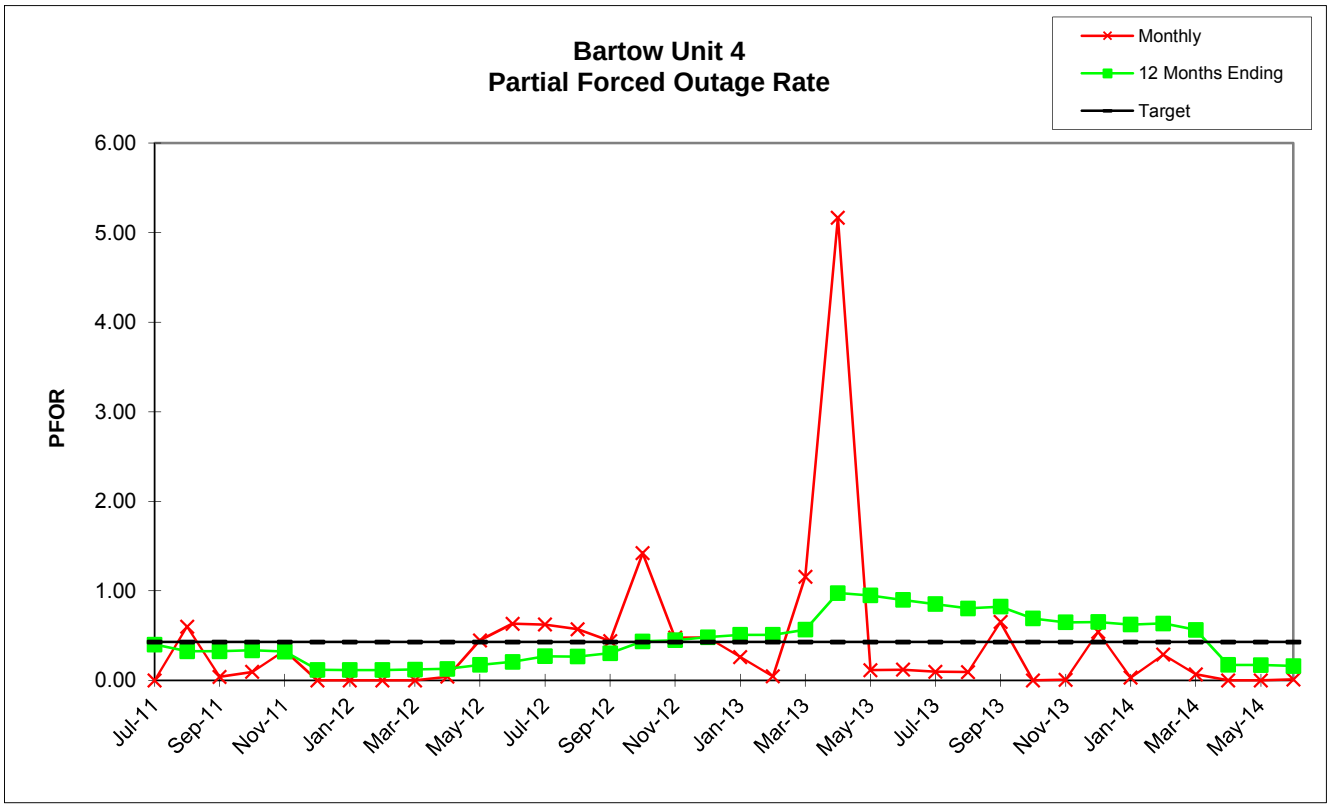
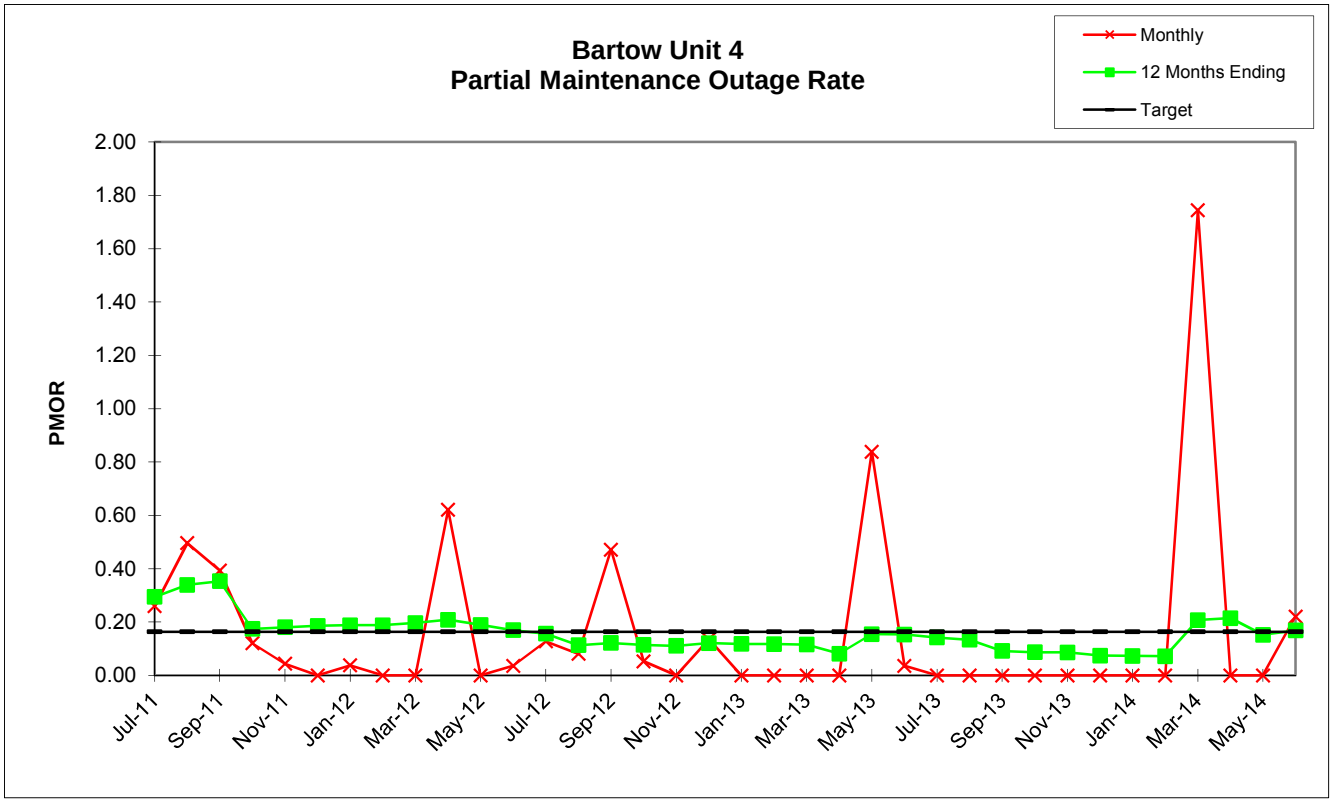
Mar-14
May-14


Bartow Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
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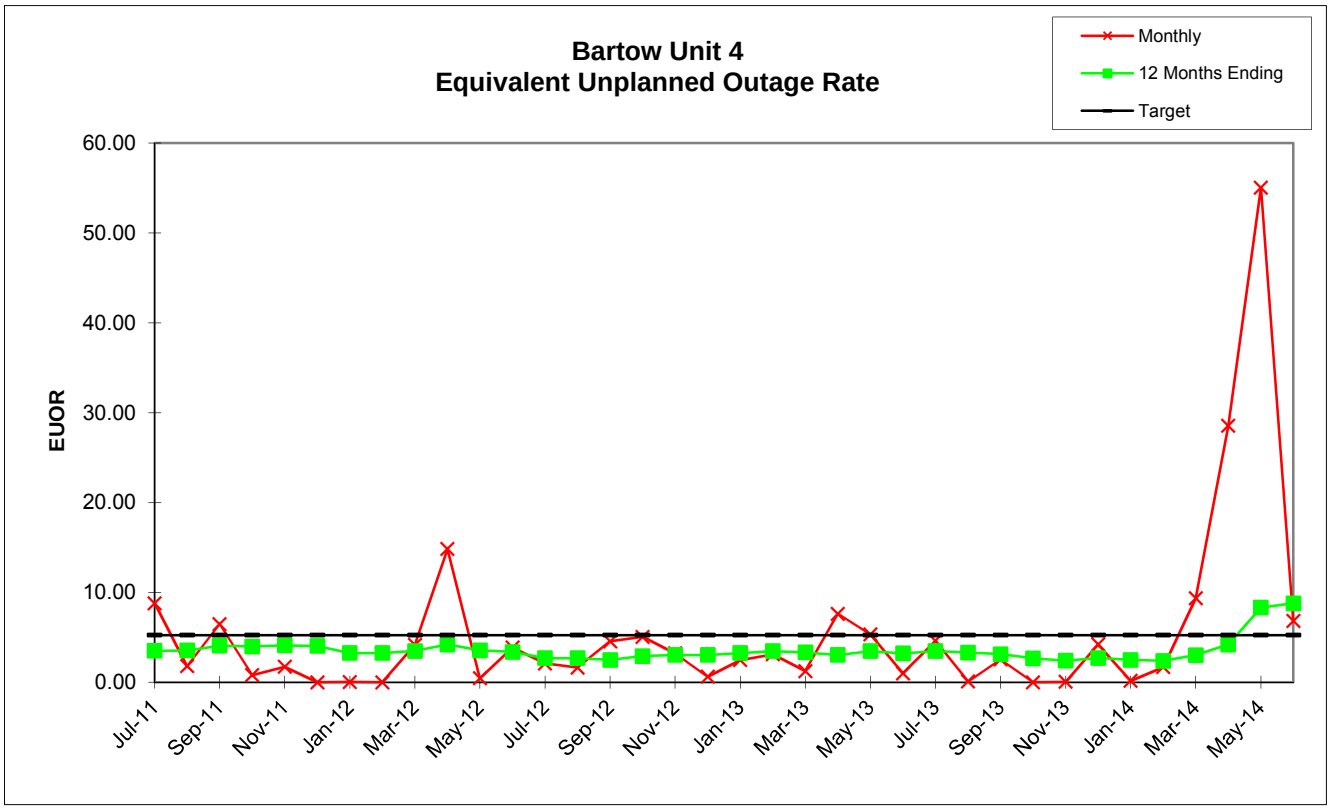
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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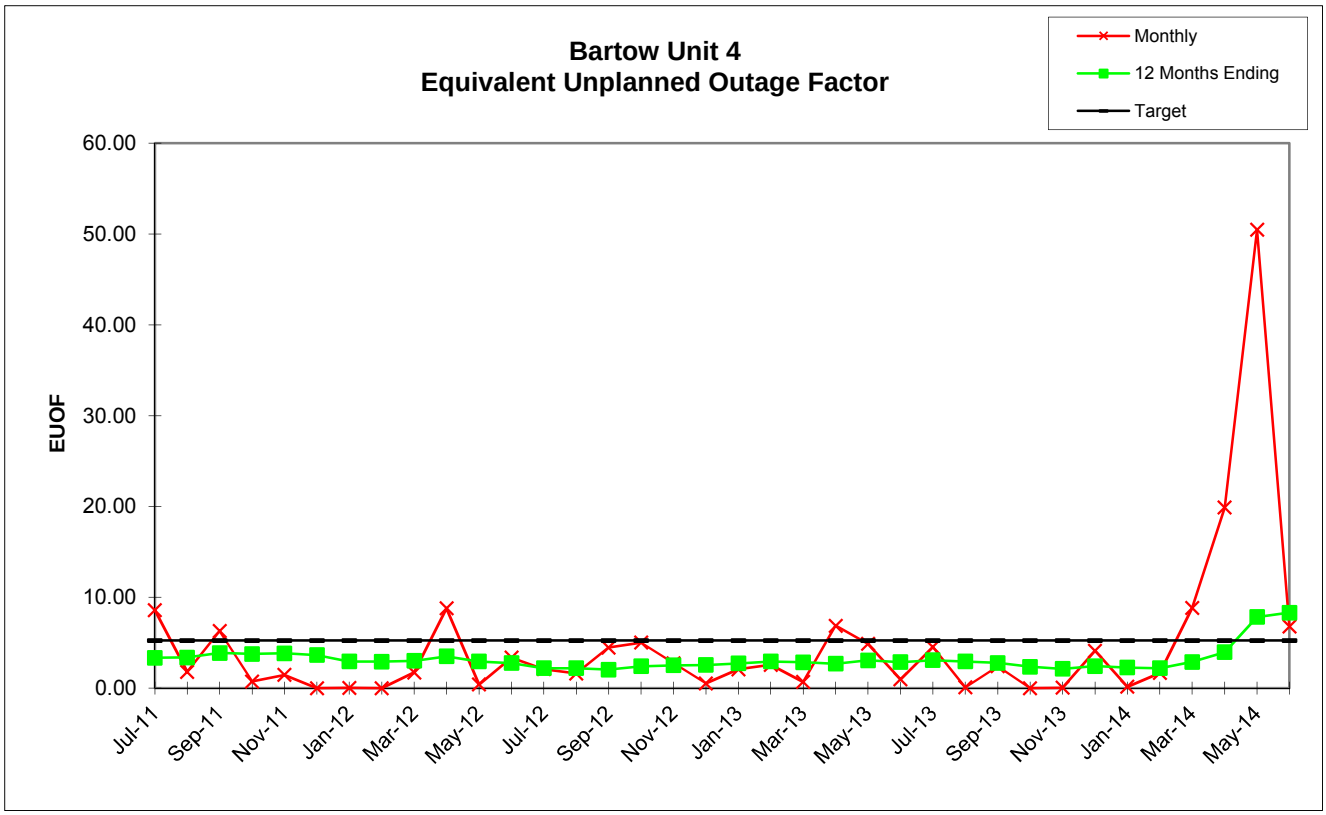
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Crystal River
Unit 4

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	680.27	744.00	720.00	662.85	0.00	300.85	735.00	690.83	743.00	633.70	742.60	720.00	737.88	696.38	720.00	735.23	719.52	642.70
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	63.73	0.00	0.00	81.15	721.00	443.15	9.00	5.17	0.00	86.30	1.40	0.00	6.12	47.62	0.00	8.77	1.48	101.30
POH	0.00	0.00	0.00	81.15	721.00	443.15	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	63.73	0.00	0.00	0.00	0.00	0.00	0.00	5.17	0.00	0.00	1.40	0.00	6.12	0.00	0.00	8.77	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.00	0.00	86.30	0.00	0.00	0.00	47.62	0.00	0.00	1.48	101.30
PFOH	36.34	0.00	0.00	0.00	0.00	0.00	12.00	17.47	0.00	0.00	3.67	10.52	425.00	640.15	118.68	35.73	0.00	0.00
LRPF	333.75	0.00	0.00	0.00	0.00	0.00	74.00	235.95	0.00	0.00	212.90	48.54	65.00	63.14	40.24	29.63	0.00	0.00
EFOH	17.35	0.00	0.00	0.00	0.00	0.00	1.25	5.79	0.00	0.00	1.10	0.72	38.80	56.77	6.71	1.49	0.00	0.00
PMOH	25.71	3.98	28.29	12.00	0.00	0.00	9.00	279.50	23.00	13.75	30.06	26.96	30.75	56.16	46.83	111.46	17.00	4.00
LRPM	294.55	80.07	406.73	318.00	0.00	0.00	52.11	93.00	225.87	303.13	212.31	402.51	267.01	118.80	303.71	99.06	474.00	84.00
EMOH	10.83	0.46	16.46	5.46	0.00	0.00	0.66	36.51	7.30	5.85	8.96	15.24	11.53	9.37	19.98	15.51	11.32	0.47
NPC	699.00	699.00	699.00	699.00	699.00	699.00	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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	8.57	0.00	0.00	0.00	0.00	0.00	0.00	0.74	0.00	0.00	0.19	0.00	0.82	0.00	0.00	1.18	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	1.21	0.00	0.00	11.99	0.00	0.00	0.00	6.40	0.00	0.00	0.21	13.62
PFOR	2.55	0.00	0.00	0.00	0.00	0.00	0.17	0.84	0.00	0.00	0.15	0.10	5.26	8.15	0.93	0.20	0.00	0.00
PMOR	1.59	0.06	2.29	0.82	0.00	0.00	0.09	5.28	0.98	0.92	1.21	2.12	1.56	1.35	2.77	2.11	1.57	0.07
EUOR	12.35	0.06	2.29	0.82	0.00	0.00	1.47	6.82	0.98	12.80	1.54	2.22	7.59	15.29	3.71	3.46	1.77	13.68
EUOF	12.35	0.06	2.29	0.73	0.00	0.00	1.47	6.82	0.98	12.80	1.54	2.22	7.59	15.29	3.71	3.46	1.77	13.68
POF	0.00	0.00	0.00	10.91	100.00	59.56	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	87.65	99.94	97.71	88.36	0.00	40.44	98.53	93.18	99.02	87.20	98.46	97.78	92.41	84.71	96.29	96.54	98.23	86.32

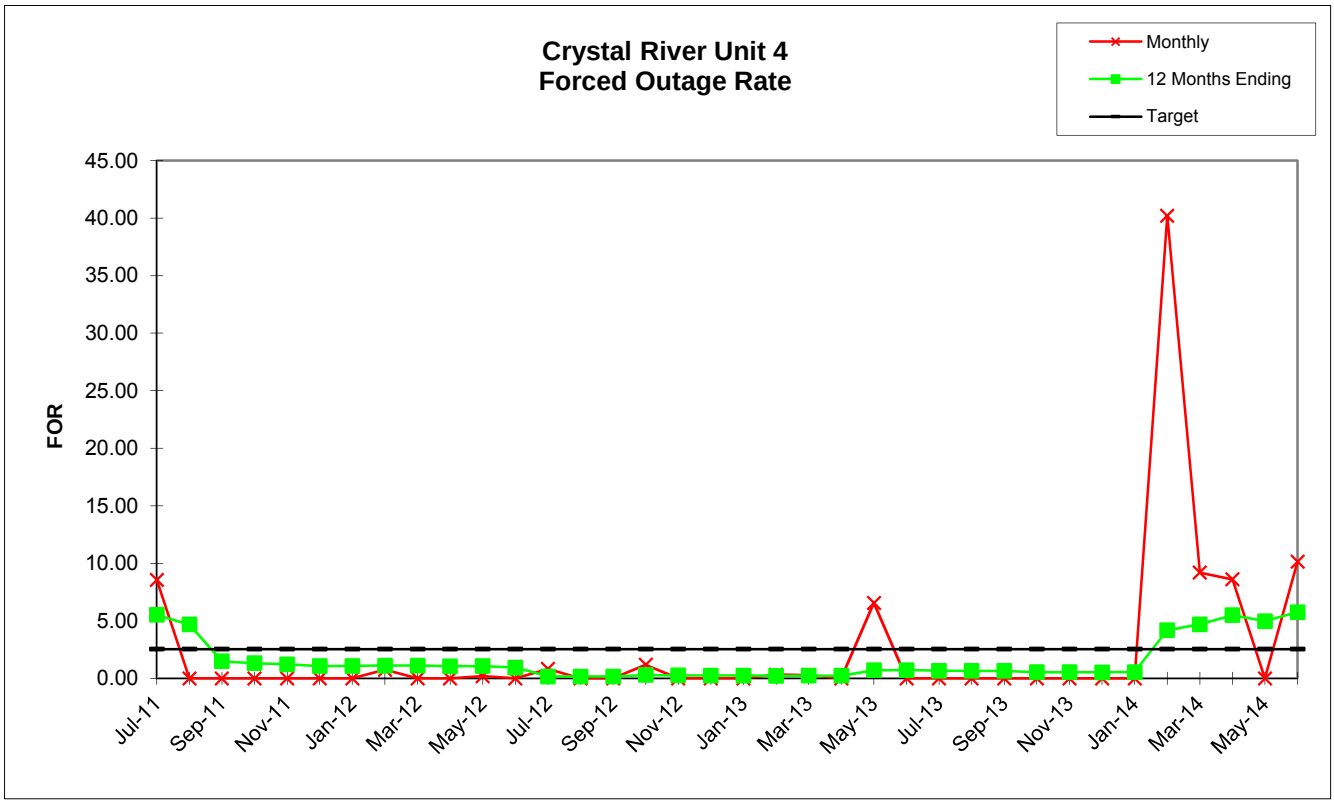
12 MONTHS	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	5.52	4.68	1.48	1.33	1.23	1.08	1.08	1.11	1.11	1.05	1.07	0.94	0.17	0.17	0.17	0.29	0.26	0.25
MOR	1.21	1.20	1.16	0.66	0.72	0.77	0.89	0.89	0.89	2.02	2.02	1.28	1.27	1.90	1.90	1.88	1.74	2.80
PFOR	0.87	0.80	0.68	0.63	0.68	0.62	0.63	0.43	0.38	0.38	0.39	0.36	0.64	1.41	1.51	1.51	1.38	1.32
PMOR	0.95	0.94	1.11	0.99	1.06	1.12	0.95	1.16	1.20	1.18	1.29	1.46	1.46	1.59	1.64	1.76	1.74	1.68
EUOR	8.31	7.41	4.35	3.55	3.64	3.53	3.50	3.54	3.53	4.54	4.68	3.97	3.50	5.01	5.14	5.35	5.04	5.95
EUOF	8.11	7.23	4.25	3.44	3.22	2.94	2.92	2.96	2.95	3.90	4.01	3.41	3.01	4.30	4.41	4.64	4.79	5.95
POF	2.46	2.46	2.32	3.24	11.47	16.53	16.53	16.49	16.49	14.18	14.18	14.18	14.18	14.18	14.18	13.25	5.04	0.00
EAF	89.44	90.31	93.44	93.32	85.31	80.52	80.55	80.56	80.56	81.93	81.81	82.41	82.82	81.53	81.41	82.10	90.17	94.05

Crystal River
Unit 4

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	669.77	225.53	720.00	544.97	503.80	597.30	744.00	720.00	744.00	721.00	744.00	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	0.00	0.00	0.00	0.00	0.00	0.00	329.15	0.00	0.00	0.00	0.00	0.00
UH	0.00	2.23	517.47	0.00	199.04	216.20	146.70	0.00	0.00	0.00	0.00	0.00	0.00	270.22	173.18	61.97	116.98	73.00
POH	0.00	0.00	516.80	0.00	0.00	0.00	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	2.23	0.67	0.00	38.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	270.22	57.70	61.97	0.00	73.00
MOH	0.00	0.00	0.00	0.00	160.77	216.20	146.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	115.48	0.00	116.98	0.00
PFOH	0.00	0.00	16.00	10.75	8.72	0.00	1.53	135.50	4.77	8.23	0.00	0.00	0.00	32.30	10.16	6.01	13.48	0.00
LRPF	0.00	0.00	93.00	4.97	44.17	0.00	93.20	84.00	96.74	93.04	0.00	0.00	0.00	144.39	60.65	117.13	179.04	0.00
EFOH	0.00	0.00	2.09	0.08	0.54	0.00	0.20	15.99	0.65	1.08	0.00	0.00	0.00	6.55	0.87	0.99	3.39	0.00
PMOH	0.00	29.98	0.00	12.50	0.00	0.00	0.00	35.35	15.08	34.77	217.07	5.00	59.75	12.00	7.02	0.00	0.93	0.00
LRPM	0.00	42.78	0.00	241.72	0.00	0.00	0.00	153.58	217.09	44.19	76.04	93.00	116.23	169.33	64.97	0.00	112.40	0.00
EMOH	0.00	1.80	0.00	4.24	0.00	0.00	0.00	7.63	4.60	2.16	23.18	0.65	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	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FOR	0.00	0.33	0.30	0.00	6.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.21	9.19	8.61	0.00	10.14
MOR	0.00	0.00	0.00	0.00	22.78	30.03	19.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.85	0.00	15.72	0.00
PFOR	0.00	0.00	0.93	0.01	0.10	0.00	0.03	2.15	0.09	0.14	0.00	0.00	0.00	1.63	0.15	0.15	0.54	0.00
PMOR	0.00	0.27	0.00	0.59	0.00	0.00	0.00	1.02	0.64	0.29	3.22	0.09	2.35	0.71	0.11	0.00	0.02	0.00
EUOR	0.00	0.60	1.22	0.60	26.83	30.03	19.74	3.17	0.73	0.43	3.22	0.09	2.35	41.61	23.51	8.74	16.20	10.14
EUOF	0.00	0.60	0.37	0.60	26.83	30.03	19.74	3.17	0.73	0.43	3.22	0.09	1.31	41.61	23.51	8.74	16.20	10.14
POF	0.00	0.00	69.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	99.40	30.07	99.40	73.17	69.97	80.26	96.83	99.27	99.57	96.78	99.91	98.69	58.39	76.49	91.26	83.80	89.86

12 MONTHS	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FOR	0.25	0.22	0.24	0.24	0.71	0.73	0.66	0.66	0.66	0.54	0.54	0.53	0.56	4.18	4.70	5.50	4.98	5.75
MOR	2.70	2.71	2.88	1.83	3.80	6.44	8.23	7.65	7.65	7.64	7.62	6.38	6.65	6.89	7.93	7.99	7.40	4.76
PFOR	1.31	1.24	1.35	1.33	1.36	1.39	0.90	0.36	0.28	0.27	0.27	0.27	0.28	0.38	0.35	0.36	0.40	0.39
PMOR	1.67	1.26	1.25	1.22	1.14	0.97	0.83	0.81	0.60	0.43	0.58	0.58	0.73	0.78	0.75	0.70	0.69	0.68
EUOR	5.82	5.34	5.62	4.56	6.84	9.27	10.37	9.27	9.01	8.74	8.87	7.64	8.08	11.56	12.89	13.59	12.65	10.95
EUOF	5.82	5.34	5.29	4.29	6.44	8.72	9.76	8.73	8.48	8.22	8.34	7.19	7.30	10.45	12.41	13.08	12.18	10.54
POF	0.00	0.00	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	0.00	0.00	0.00	0.00
EAF	94.18	94.66	88.81	89.81	87.66	85.38	84.35	85.37	85.62	85.88	85.76	86.91	86.80	83.65	87.59	86.92	87.82	89.46


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
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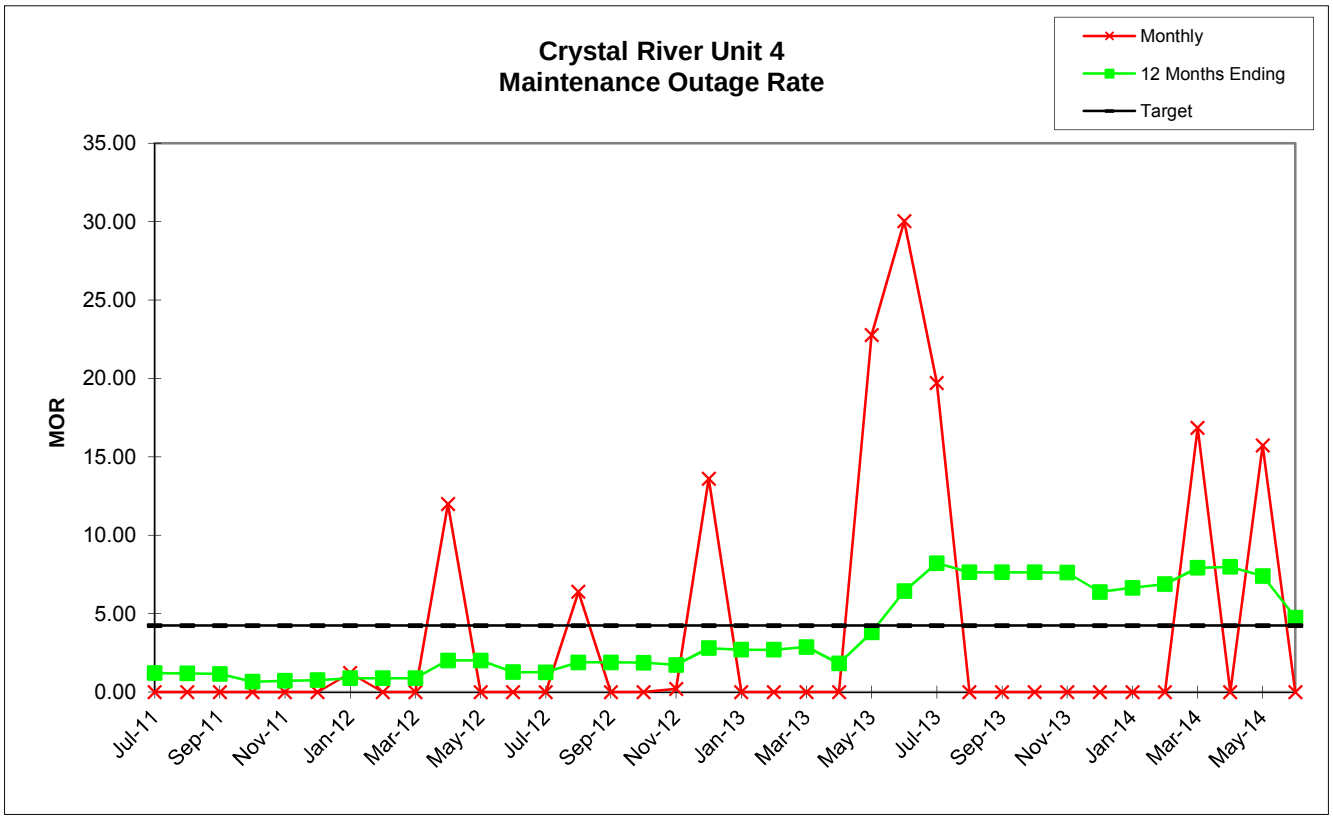
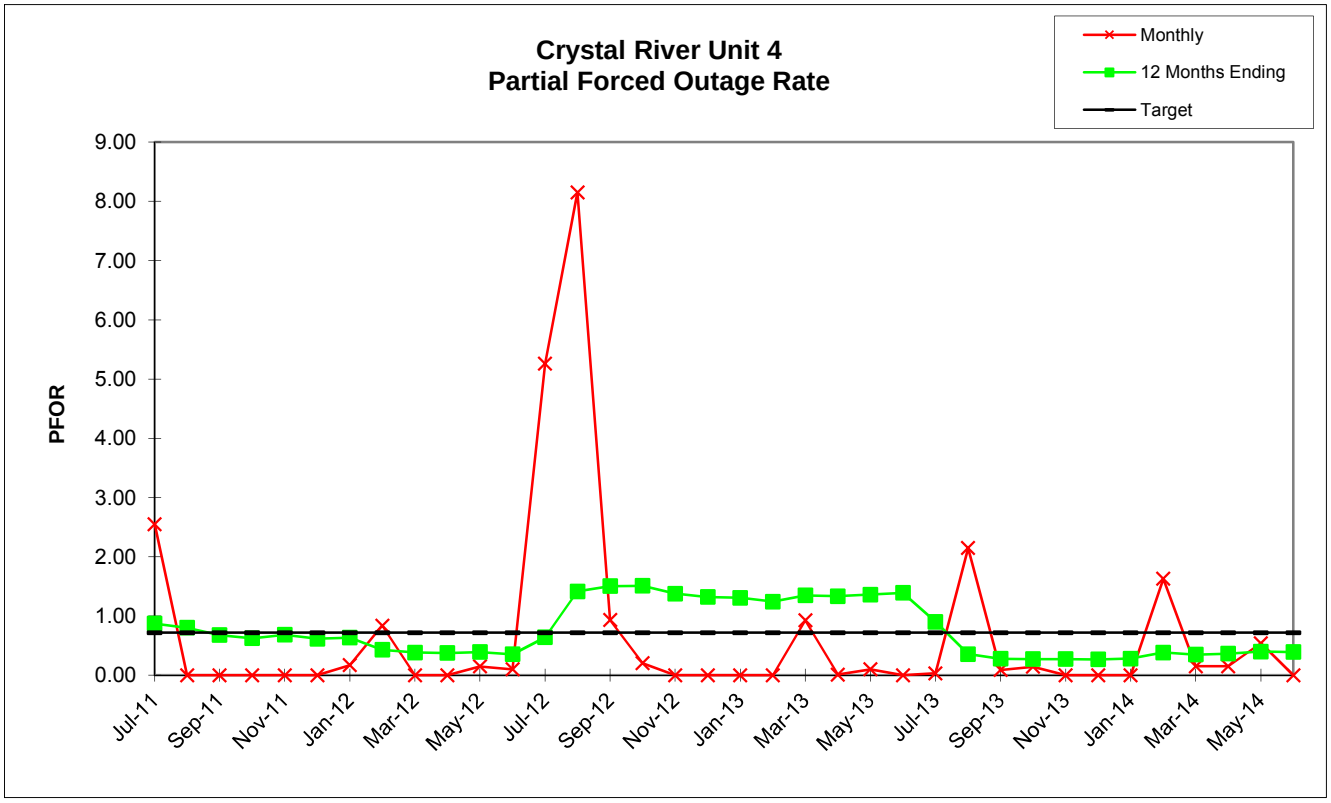
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
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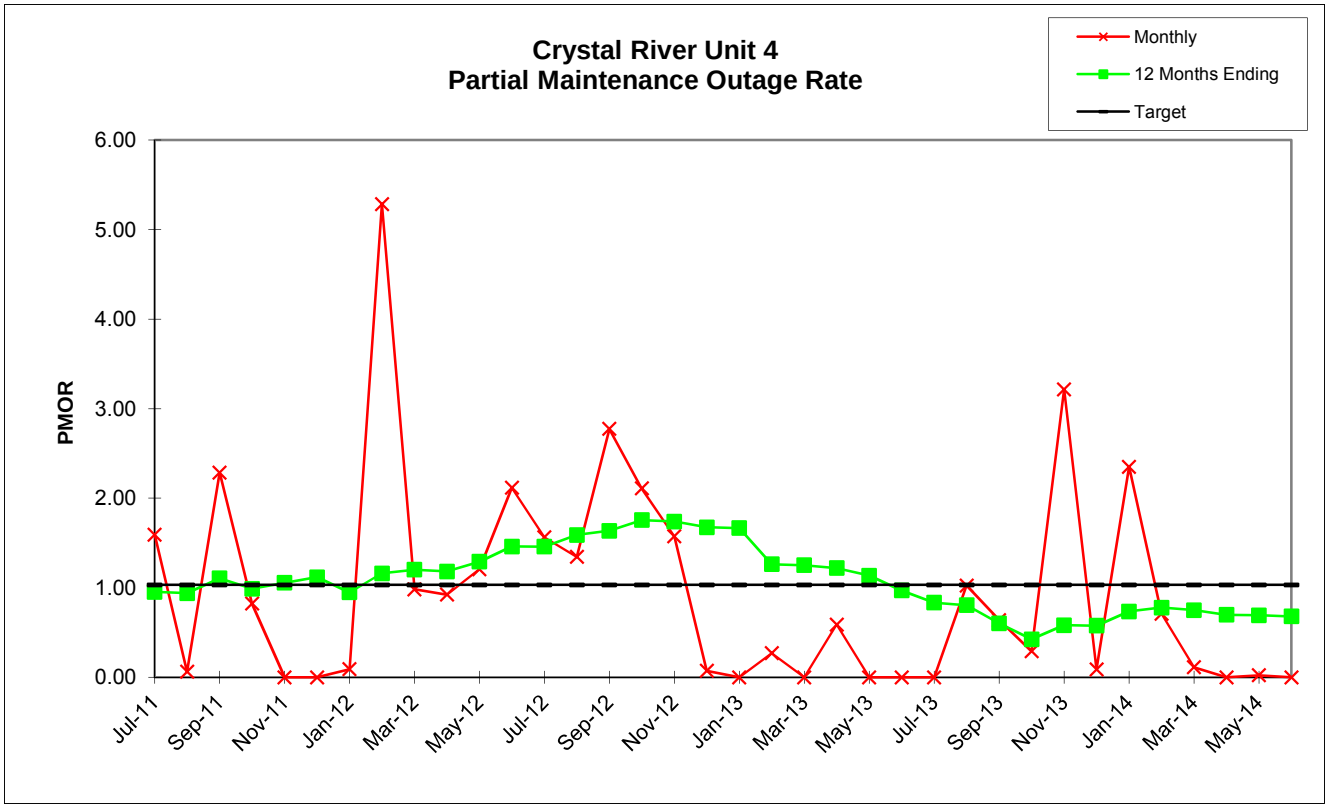
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Crystal River Unit 4
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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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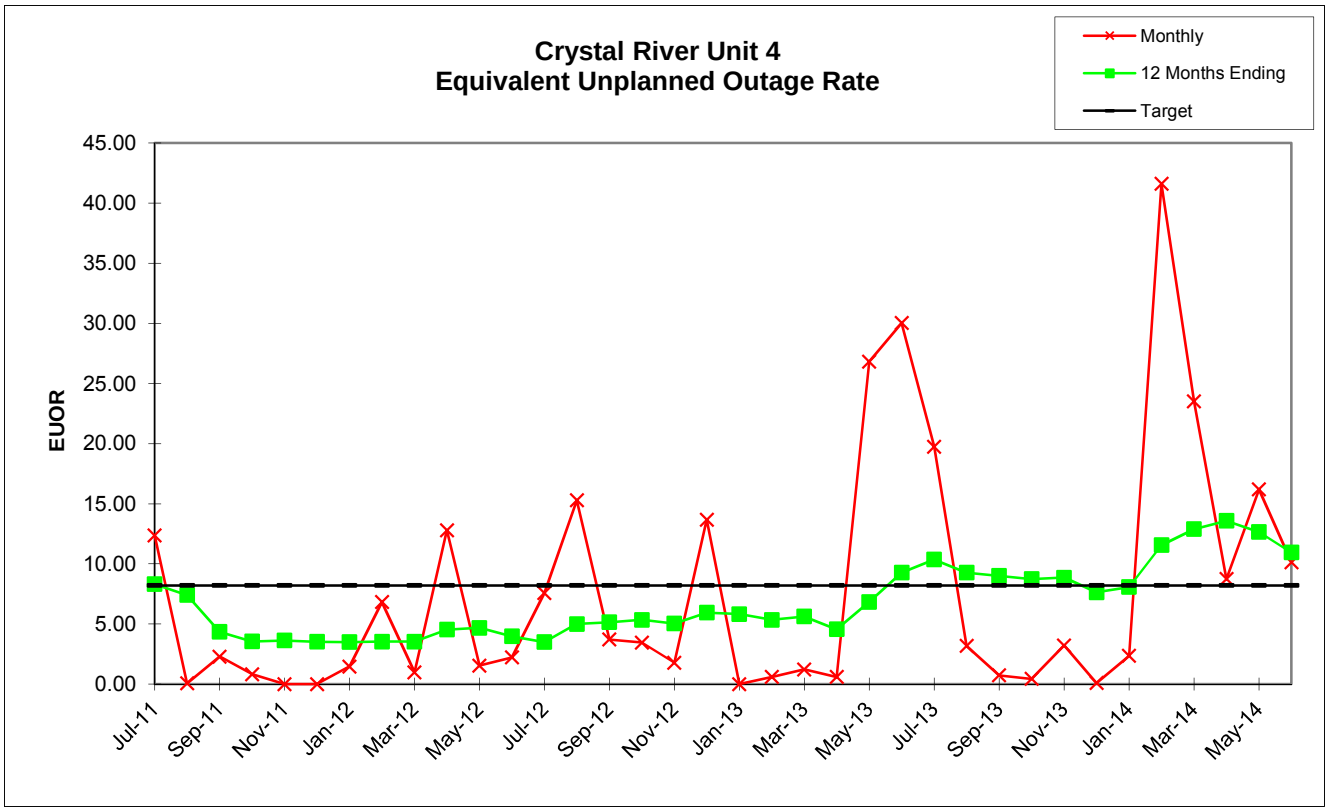
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
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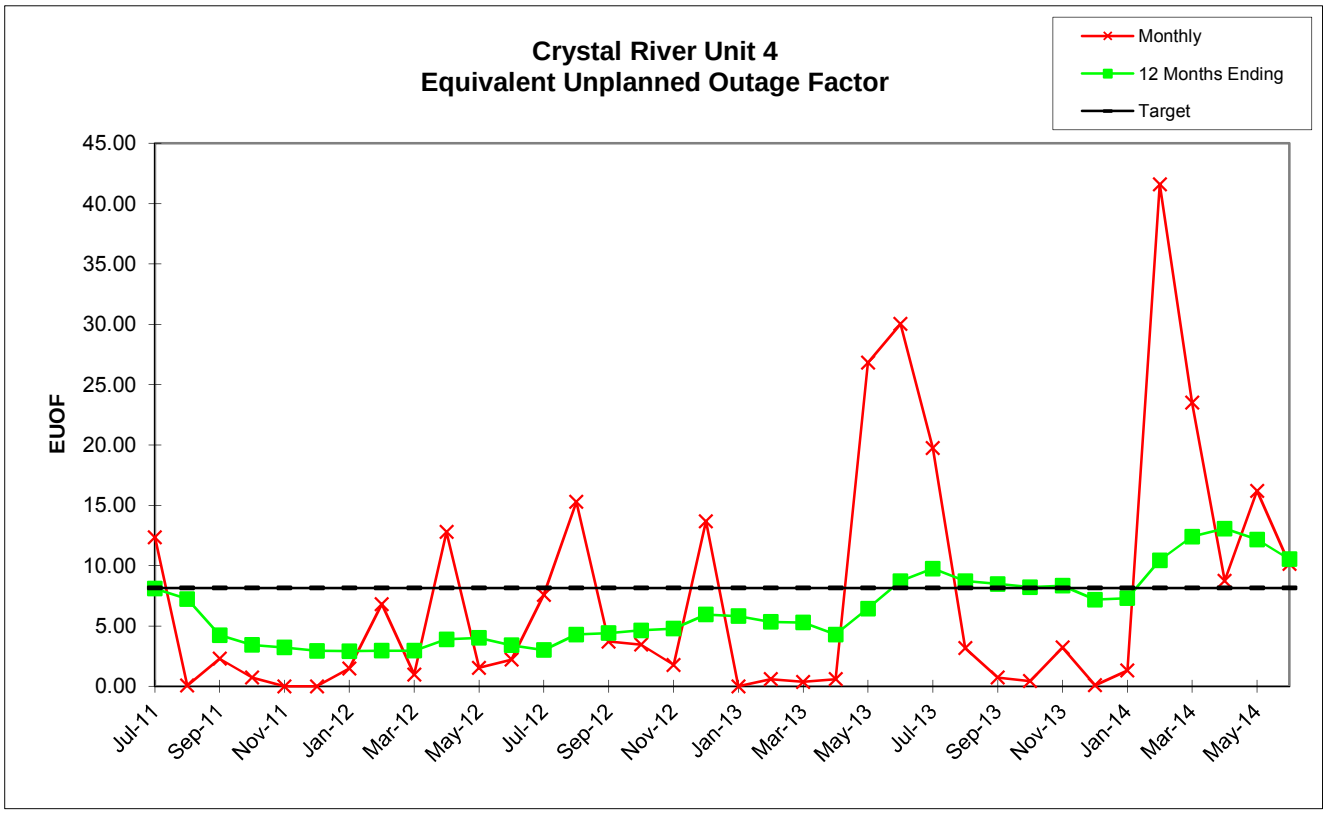
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Crystal River
Unit 5

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	737.62	706.82	720.00	701.28	721.00	744.00	542.45	693.00	735.43	632.17	735.57	720.00	744.00	744.00	720.00	533.12	0.00	16.33
RSH	0.00	0.00	0.00	0.00	0.00	0.00	186.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	6.38	37.18	0.00	42.72	0.00	0.00	14.65	3.00	7.57	87.83	8.43	0.00	0.00	0.00	0.00	210.88	721.00	727.67
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	118.88	721.00	727.67
FOH	6.38	37.18	0.00	5.00	0.00	0.00	14.65	3.00	7.57	7.68	8.43	0.00	0.00	0.00	0.00	92.00	0.00	0.00
MOH	0.00	0.00	0.00	37.72	0.00	0.00	0.00	0.00	0.00	80.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	30.45	18.33	1.50	0.00	8.60	0.00	1.25	1.58	0.00	12.75	9.50	45.59	30.50	2.08	6.63	4.00	0.00	0.00
LRPF	119.14	80.01	99.00	0.00	283.79	0.00	329.00	706.49	0.00	329.00	567.00	97.37	98.70	171.48	72.04	91.00	0.00	0.00
EFOH	5.19	2.10	0.21	0.00	3.49	0.00	0.58	1.57	0.00	5.91	7.59	6.25	4.24	0.50	0.67	0.51	0.00	0.00
PMOH	31.00	21.70	54.77	86.32	39.00	18.50	76.75	17.33	43.30	154.70	35.06	19.57	15.98	70.37	18.58	10.00	0.00	0.00
LRPM	54.45	327.45	233.36	89.46	413.46	227.54	140.62	125.75	112.05	152.62	92.98	312.13	91.02	91.00	209.45	58.00	0.00	0.00
EMOH	2.41	10.17	18.28	11.05	23.07	6.02	15.20	3.07	6.83	33.25	4.59	8.60	2.05	9.02	5.48	0.82	0.00	0.00
NPC	699.00	699.00	699.00	699.00	699.00	699.00	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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.86	5.00	0.00	0.71	0.00	0.00	2.63	0.43	1.02	1.20	1.13	0.00	0.00	0.00	0.00	14.72	0.00	0.00
MOR	0.00	0.00	0.00	5.10	0.00	0.00	0.00	0.00	0.00	11.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.70	0.30	0.03	0.00	0.48	0.00	0.11	0.23	0.00	0.93	1.03	0.87	0.57	0.07	0.09	0.10	0.00	0.00
PMOR	0.33	1.44	2.54	1.58	3.20	0.81	2.80	0.44	0.93	5.26	0.62	1.19	0.28	1.21	0.76	0.15	0.00	0.00
EUOR	1.88	6.65	2.57	7.23	3.68	0.81	5.46	1.10	1.94	17.64	2.77	2.06	0.85	1.28	0.85	14.93	0.00	0.00
EUOF	1.88	6.65	2.57	7.23	3.68	0.81	4.09	1.10	1.94	17.64	2.77	2.06	0.85	1.28	0.85	12.54	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	15.98	100.00	97.81
EAF	98.12	93.35	97.43	92.77	96.32	99.19	95.91	98.90	98.06	82.36	97.23	97.94	99.15	98.72	99.15	71.48	0.00	2.19

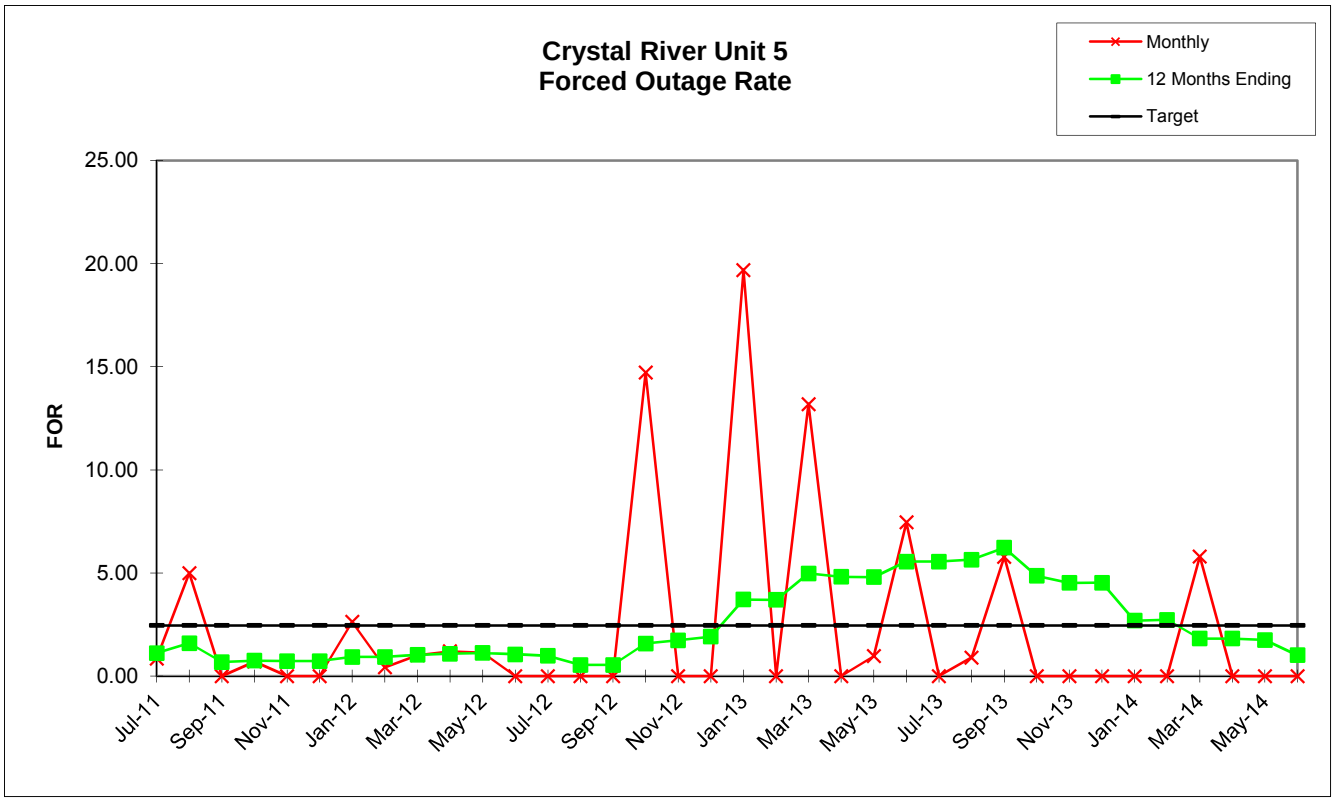
12 MONTHS	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	1.12	1.60	0.68	0.75	0.73	0.73	0.93	0.94	1.03	1.09	1.12	1.06	0.98	0.55	0.55	1.59	1.74	1.92
MOR	1.14	1.15	1.14	1.62	1.58	1.58	0.94	0.94	0.94	1.92	1.81	1.39	1.38	1.38	1.38	0.96	1.05	1.16
PFOR	0.21	0.23	0.17	0.17	0.21	0.21	0.23	0.21	0.21	0.28	0.35	0.39	0.38	0.36	0.37	0.38	0.37	0.41
PMOR	1.53	1.67	1.89	1.93	2.18	1.98	1.97	1.77	1.63	1.75	1.64	1.70	1.69	1.67	1.52	1.43	1.26	1.30
EUOR	3.94	4.55	3.83	4.40	4.63	4.44	4.02	3.80	3.76	4.94	4.83	4.46	4.37	3.90	3.76	4.28	4.33	4.70
EUOF	3.54	4.10	3.45	3.96	4.27	4.09	3.61	3.42	3.38	4.55	4.72	4.36	4.27	3.82	3.68	4.13	3.83	3.76
POF	10.00	10.00	10.00	10.00	7.84	7.84	7.84	7.82	7.82	5.78	0.00	0.00	0.00	0.00	0.00	1.35	9.56	17.85
EAF	86.46	85.91	86.56	86.04	87.90	88.08	88.55	88.76	88.80	89.68	95.28	95.64	95.73	96.18	96.32	94.52	86.61	78.40

Crystal River
Unit 5

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	597.60	635.00	645.00	720.00	736.78	666.30	744.00	733.55	678.32	744.00	553.95	0.00	623.42	541.10	375.38	720.00	641.95	613.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	167.05	744.00	120.58	0.00	0.00	0.00	0.00	0.00
UH	146.40	37.00	98.00	0.00	7.22	53.70	0.00	10.45	41.68	0.00	0.00	0.00	0.00	130.90	367.62	0.00	102.05	107.00
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	130.90	344.50	0.00	0.00	0.00
FOH	146.40	0.00	98.00	0.00	7.22	53.70	0.00	6.65	41.68	0.00	0.00	0.00	0.00	0.00	23.12	0.00	0.00	0.00
MOH	0.00	37.00	0.00	0.00	0.00	0.00	0.00	3.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	102.05	107.00
PFOH	48.07	49.90	0.60	19.35	5.50	4.50	9.18	18.00	0.00	0.00	0.00	0.00	0.00	0.00	6.75	12.85	4.10	2.23
LRPF	523.86	286.44	79.00	45.72	28.82	91.00	63.40	99.28	0.00	0.00	0.00	0.00	0.00	0.00	567.00	91.00	91.00	567.85
EFOH	35.47	20.13	0.07	1.25	0.22	0.58	0.82	2.52	0.00	0.00	0.00	0.00	0.00	0.00	5.39	1.65	0.53	1.78
PMOH	0.00	43.29	2.00	5.50	0.00	8.00	7.00	3.43	30.07	62.53	95.95	0.00	0.00	9.50	0.00	28.67	18.72	7.00
LRPM	0.00	155.06	234.00	91.00	0.00	91.00	91.00	472.46	151.56	57.57	77.62	0.00	0.00	234.00	0.00	72.43	90.98	91.00
EMOH	0.00	9.45	0.66	0.70	0.00	1.03	0.90	2.28	6.42	5.07	10.49	0.00	0.00	3.13	0.00	2.92	2.40	0.90
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-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	19.68	0.00	13.19	0.00	0.97	7.46	0.00	0.90	5.79	0.00	0.00	0.00	0.00	0.00	5.80	0.00	0.00	0.00
MOR	0.00	5.51	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.72	14.86
PFOR	5.93	3.17	0.01	0.17	0.03	0.09	0.11	0.34	0.00	0.00	0.00	0.00	0.00	0.00	1.44	0.23	0.08	0.29
PMOR	0.00	1.49	0.10	0.10	0.00	0.15	0.12	0.31	0.95	0.68	1.89	0.00	0.00	0.58	0.00	0.41	0.37	0.15
EUOR	24.44	9.91	13.29	0.27	1.00	7.68	0.23	2.05	6.68	0.68	1.89	0.00	0.00	0.58	7.15	0.63	14.11	15.23
EUOF	24.44	9.91	13.29	0.27	1.00	7.68	0.23	2.05	6.68	0.68	1.45	0.00	0.00	0.47	3.84	0.63	14.11	15.23
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	19.48	46.37	0.00	0.00	0.00
EAF	75.56	90.09	86.71	99.73	99.00	92.32	99.77	97.95	93.32	99.32	98.55	100.00	100.00	80.05	49.80	99.37	85.89	84.77

12 MONTHS	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	3.71	3.70	4.98	4.82	4.80	5.55	5.55	5.65	6.23	4.86	4.52	4.53	2.70	2.73	1.83	1.83	1.75	1.01
MOR	1.15	1.69	1.71	0.54	0.54	0.54	0.54	0.60	0.60	0.59	0.54	0.54	0.54	0.05	0.05	0.05	1.49	2.96
PFOR	0.91	1.19	1.21	1.13	1.02	0.94	0.89	0.92	0.92	0.88	0.82	0.82	0.34	0.07	0.15	0.16	0.16	0.18
PMOR	1.07	1.18	1.10	0.61	0.54	0.43	0.42	0.32	0.33	0.38	0.50	0.50	0.49	0.42	0.42	0.45	0.49	0.50
EUOR	6.67	7.52	8.69	6.95	6.77	7.33	7.27	7.35	7.93	6.59	6.26	6.27	4.02	3.25	2.44	2.48	3.82	4.57
EUOF	5.48	6.17	7.13	5.71	5.56	6.02	5.97	6.03	6.51	5.50	5.62	5.62	3.55	2.82	2.02	2.05	3.16	3.78
POF	17.85	17.89	17.89	17.89	17.89	17.89	17.89	17.89	17.89	16.54	8.31	0.00	0.00	1.49	5.43	5.43	5.43	5.43
EAF	76.67	75.93	74.97	76.40	76.55	76.09	76.14	76.07	75.60	77.96	86.07	94.38	96.45	95.68	92.55	92.52	91.41	90.79


Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
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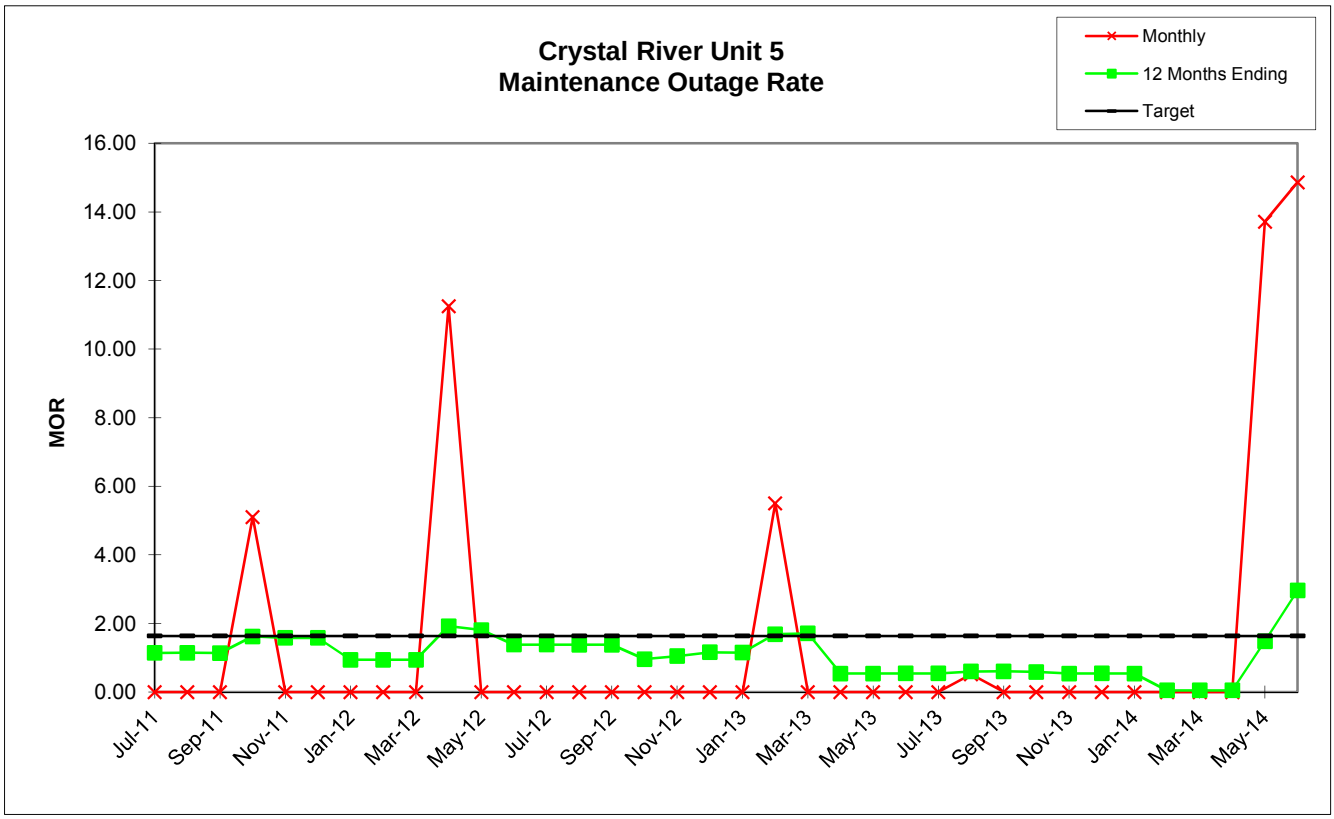
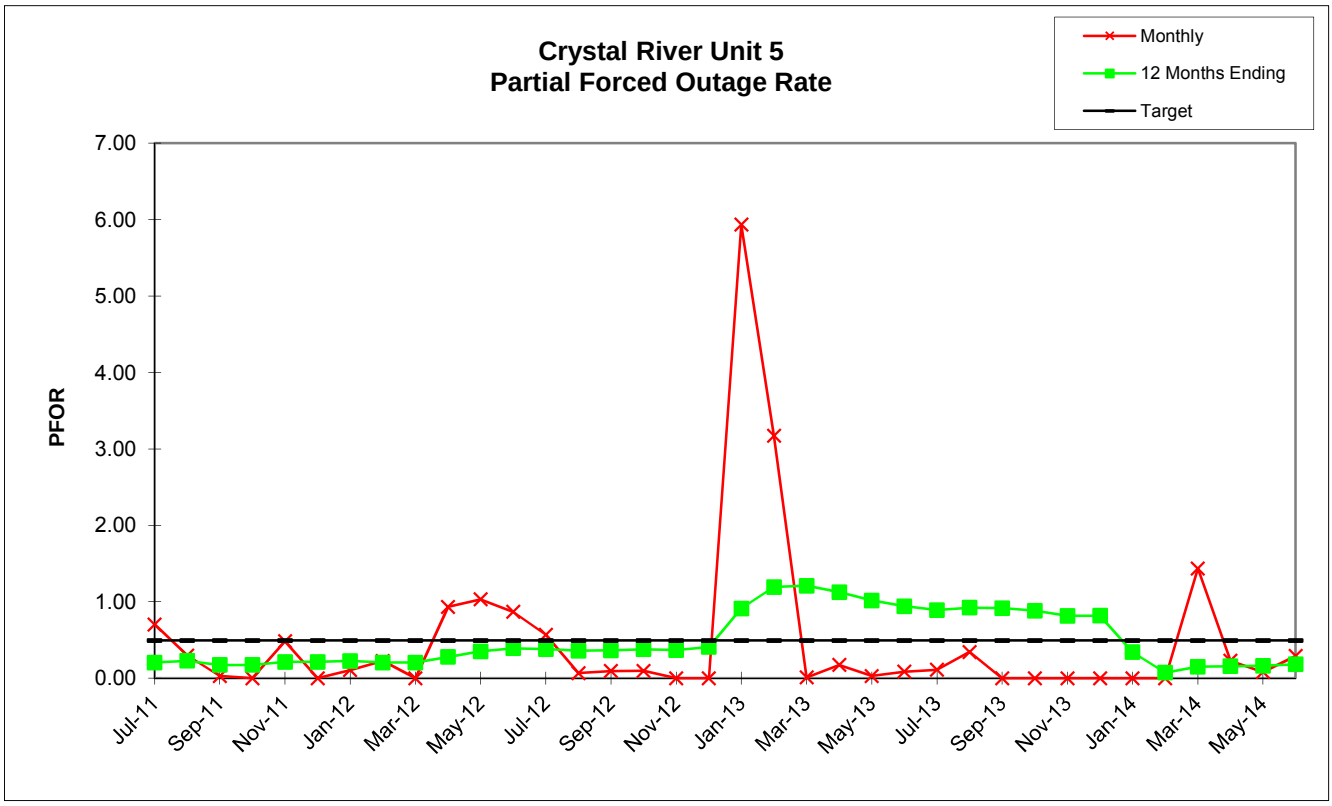
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
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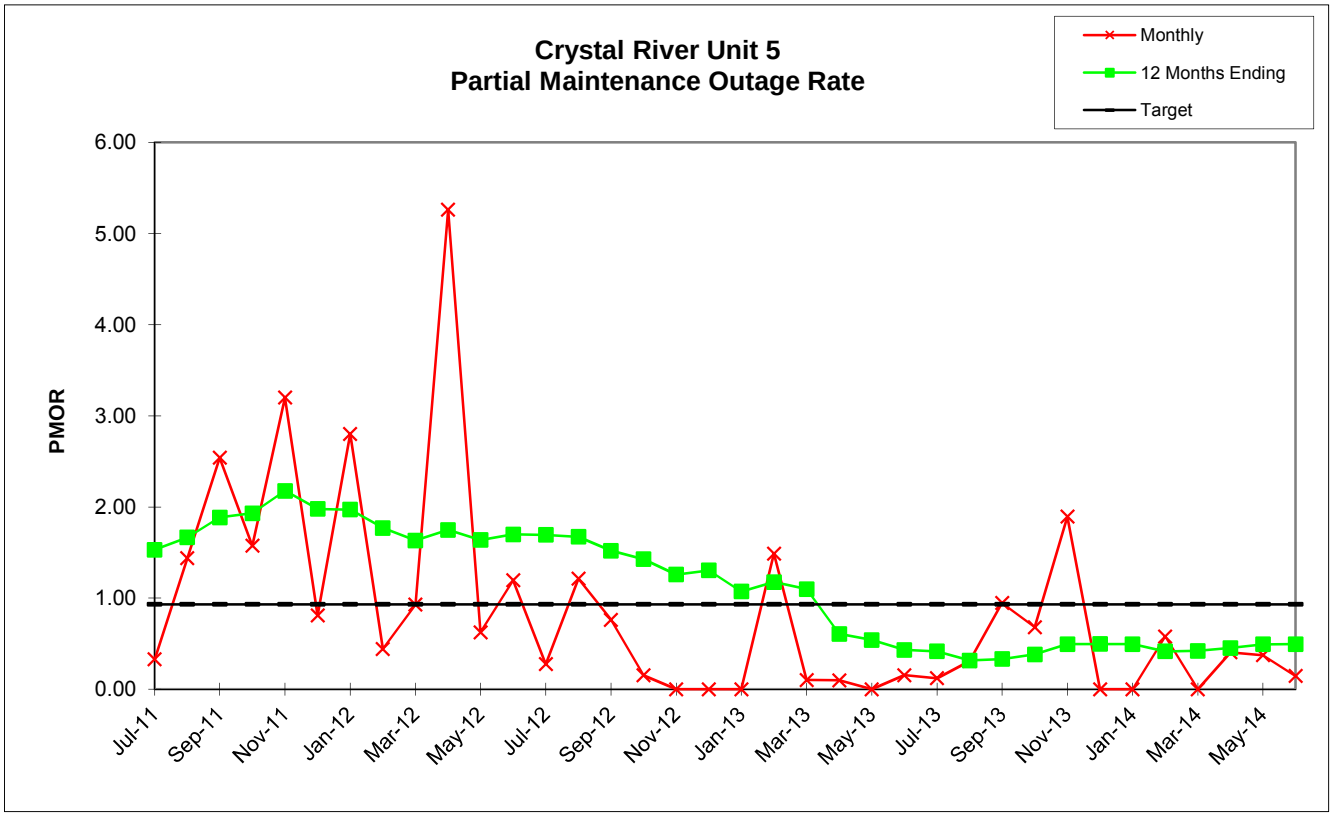
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Crystal River Unit 5
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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
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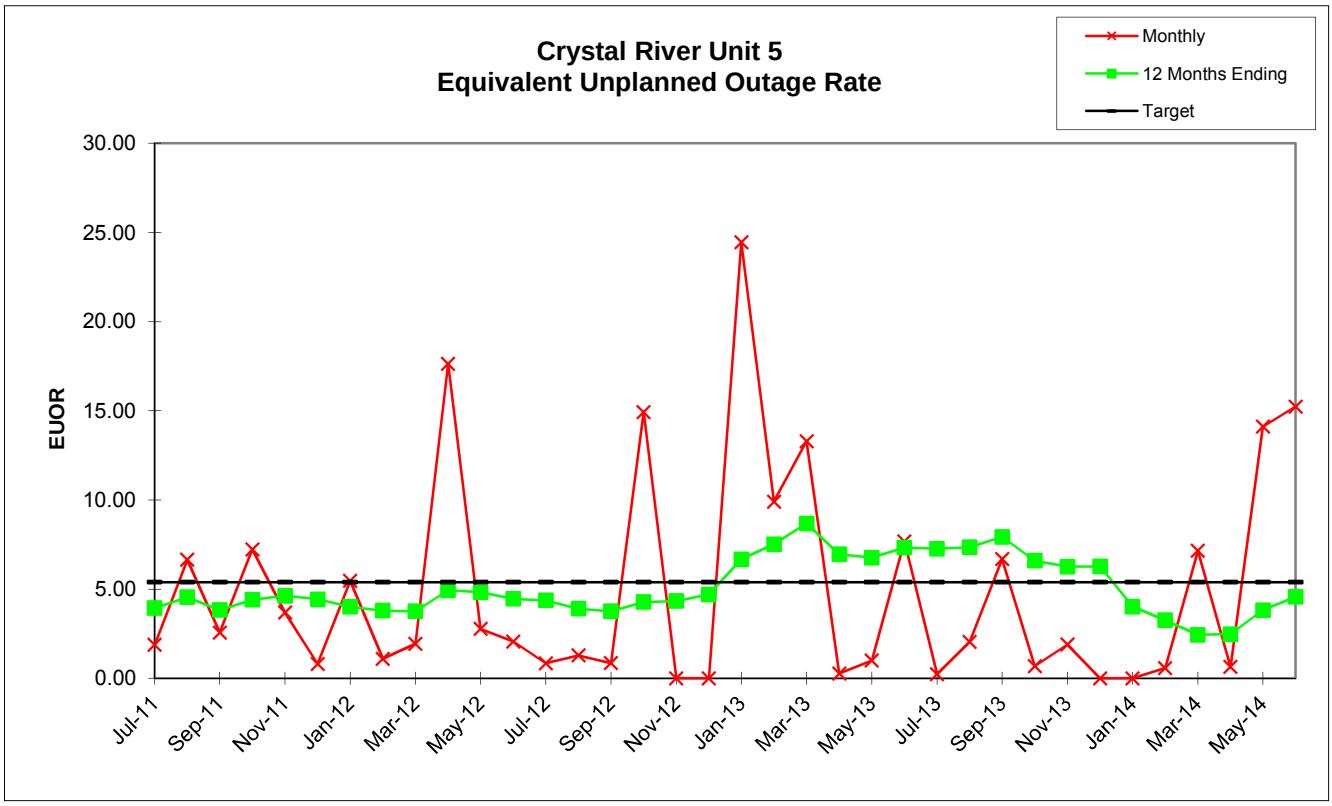
May-14


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
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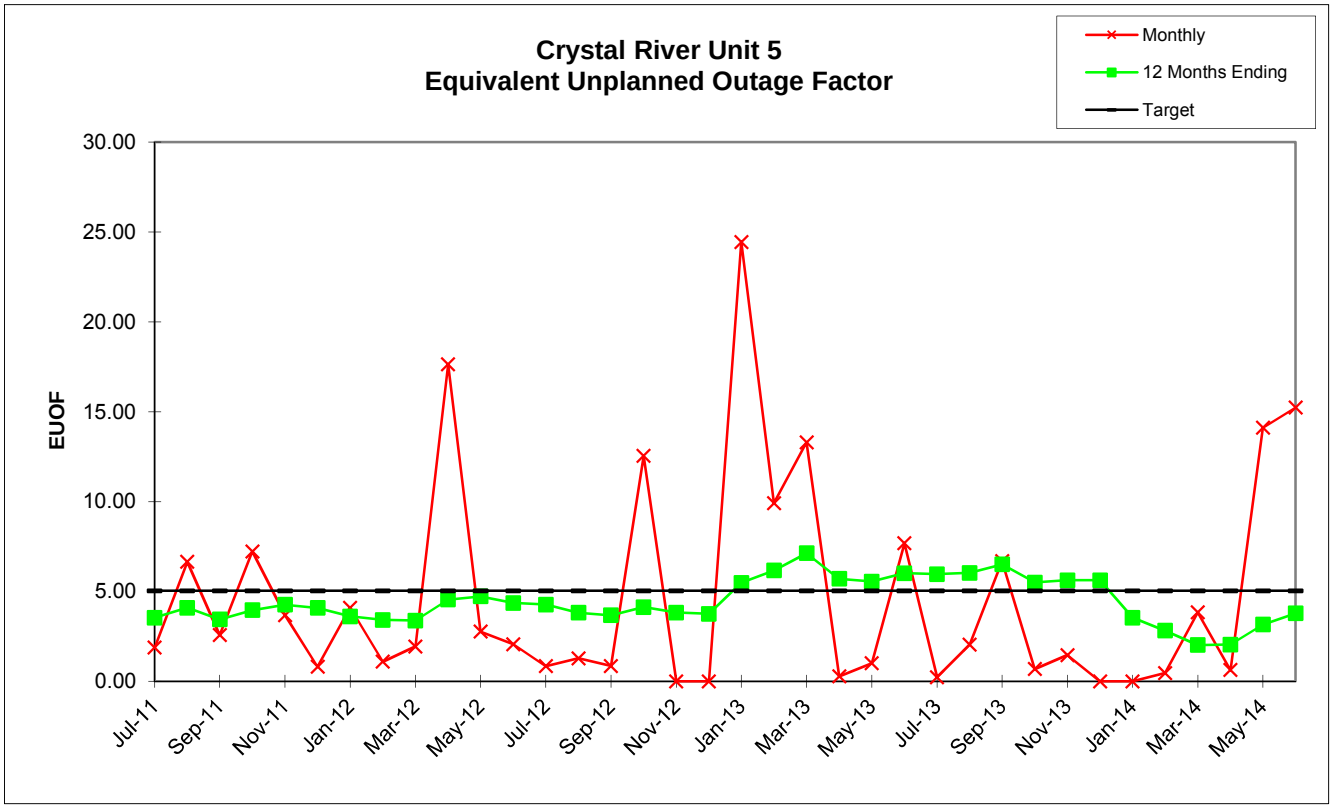
Jan-14
Mar-14
May-14


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Hines
Unit 1

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	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	277.22	744.00	744.00	696.00	743.00	312.78	321.13	720.00	744.00	719.00	701.03	744.00	721.00	718.58
RSH	0.00	0.00	0.00	0.00	47.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	396.28	0.00	0.00	0.00	0.00	407.22	422.87	0.00	0.00	25.00	18.97	0.00	0.00	25.42
POH	0.00	0.00	0.00	0.00	395.75	0.00	0.00	0.00	0.00	407.22	187.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.53	0.00	0.00	0.00	0.00	0.00	11.65	0.00	0.00	0.00	18.97	0.00	0.00	25.42
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	223.55	0.00	0.00	25.00	0.00	0.00	0.00	0.00
PFOH	0.00	291.00	68.17	0.00	0.00	0.00	41.22	0.00	0.00	1.45	0.00	1.87	0.00	21.95	0.00	0.00	0.00	0.00
LRPF	0.00	64.82	177.82	0.00	0.00	0.00	227.98	0.00	0.00	174.00	0.00	241.64	0.00	292.00	0.00	0.00	0.00	0.00
EFOH	0.00	40.83	26.24	0.00	0.00	0.00	20.34	0.00	0.00	0.55	0.00	0.98	0.00	13.87	0.00	0.00	0.00	0.00
PMOH	3.17	5.61	1.05	1.17	1.57	0.00	0.00	0.00	1.40	0.00	45.25	0.00	0.00	1.32	1.98	0.00	42.72	0.00
LRPM	197.79	191.93	208.00	207.41	197.58	0.00	0.00	0.00	199.00	0.00	297.00	0.00	0.00	198.50	130.22	0.00	214.64	0.00
EMOH	1.36	2.33	0.47	0.53	0.67	0.00	0.00	0.00	0.60	0.00	29.09	0.00	0.00	0.57	0.56	0.00	19.85	0.00
NPC	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00

MONTHLY	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
FOR	0.00	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.00	0.00	3.50	0.00	0.00	0.00	2.63	0.00	0.00	3.42
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.04	0.00	0.00	3.36	0.00	0.00	0.00	0.00
PFOR	0.00	5.49	3.64	0.00	0.00	0.00	2.73	0.00	0.00	0.17	0.00	0.14	0.00	1.93	0.00	0.00	0.00	0.00
PMOR	0.18	0.31	0.07	0.07	0.24	0.00	0.00	0.00	0.08	0.00	9.06	0.00	0.00	0.08	0.08	0.00	2.75	0.00
EUOR	0.18	5.80	3.71	0.07	0.43	0.00	2.73	0.00	0.08	0.17	47.51	0.14	0.00	5.30	2.71	0.00	2.75	3.42
EUOF	0.18	5.80	3.71	0.07	0.17	0.00	2.73	0.00	0.08	0.08	35.52	0.14	0.00	5.30	2.71	0.00	2.75	3.42
POF	0.00	0.00	0.00	0.00	54.89	0.00	0.00	0.00	0.00	56.56	25.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.82	94.20	96.29	99.93	44.94	100.00	97.27	100.00	99.92	43.37	39.25	99.86	100.00	94.70	97.29	100.00	97.25	96.58

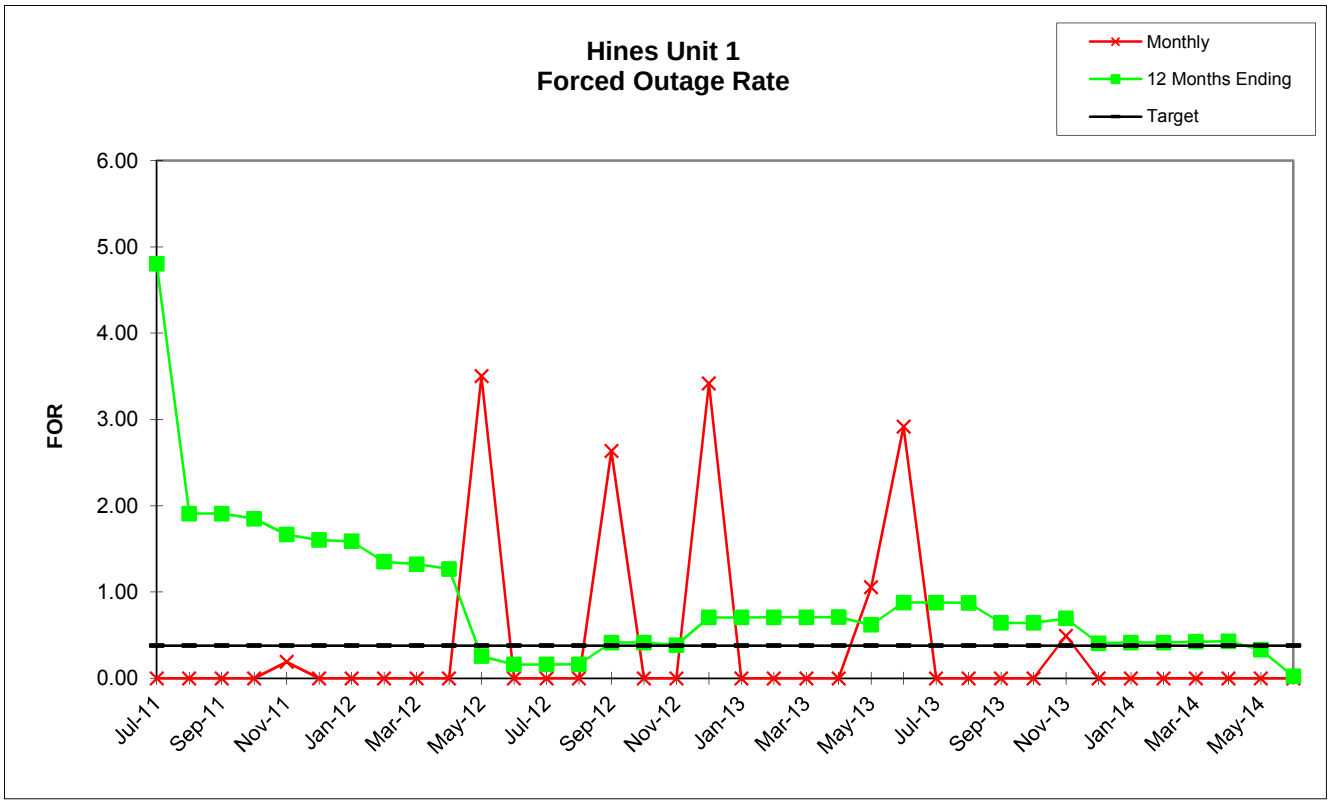
12 MONTHS	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
FOR	4.80	1.91	1.91	1.85	1.67	1.60	1.59	1.35	1.32	1.27	0.26	0.16	0.16	0.16	0.42	0.42	0.39	0.71
MOR	1.43	1.39	1.39	1.34	1.40	1.39	0.53	0.00	0.00	0.00	2.89	2.89	2.89	3.21	3.22	3.22	3.05	3.06
PFOR	1.27	1.84	2.23	1.61	1.65	1.65	1.87	1.71	1.66	1.60	1.51	1.18	1.18	0.83	0.48	0.48	0.45	0.45
PMOR	1.12	1.13	1.13	1.11	1.16	0.10	0.10	0.10	0.11	0.10	0.47	0.47	0.45	0.43	0.43	0.42	0.64	0.64
EUOR	8.34	6.11	6.50	5.77	5.74	4.66	4.03	3.14	3.07	2.95	5.05	4.64	4.63	4.58	4.49	4.48	4.46	4.77
EUOF	6.59	4.83	5.13	4.71	4.50	3.65	3.15	2.46	2.45	2.46	4.46	4.10	4.08	4.04	3.96	3.95	4.16	4.45
POF	20.98	20.98	20.98	18.50	21.17	21.17	21.17	21.11	19.49	15.93	11.28	11.28	11.28	11.28	11.28	11.28	6.77	6.77
EAF	72.42	74.19	73.88	76.79	74.34	75.19	75.68	76.43	78.05	81.61	84.26	84.63	84.64	84.68	84.77	84.77	89.07	88.78

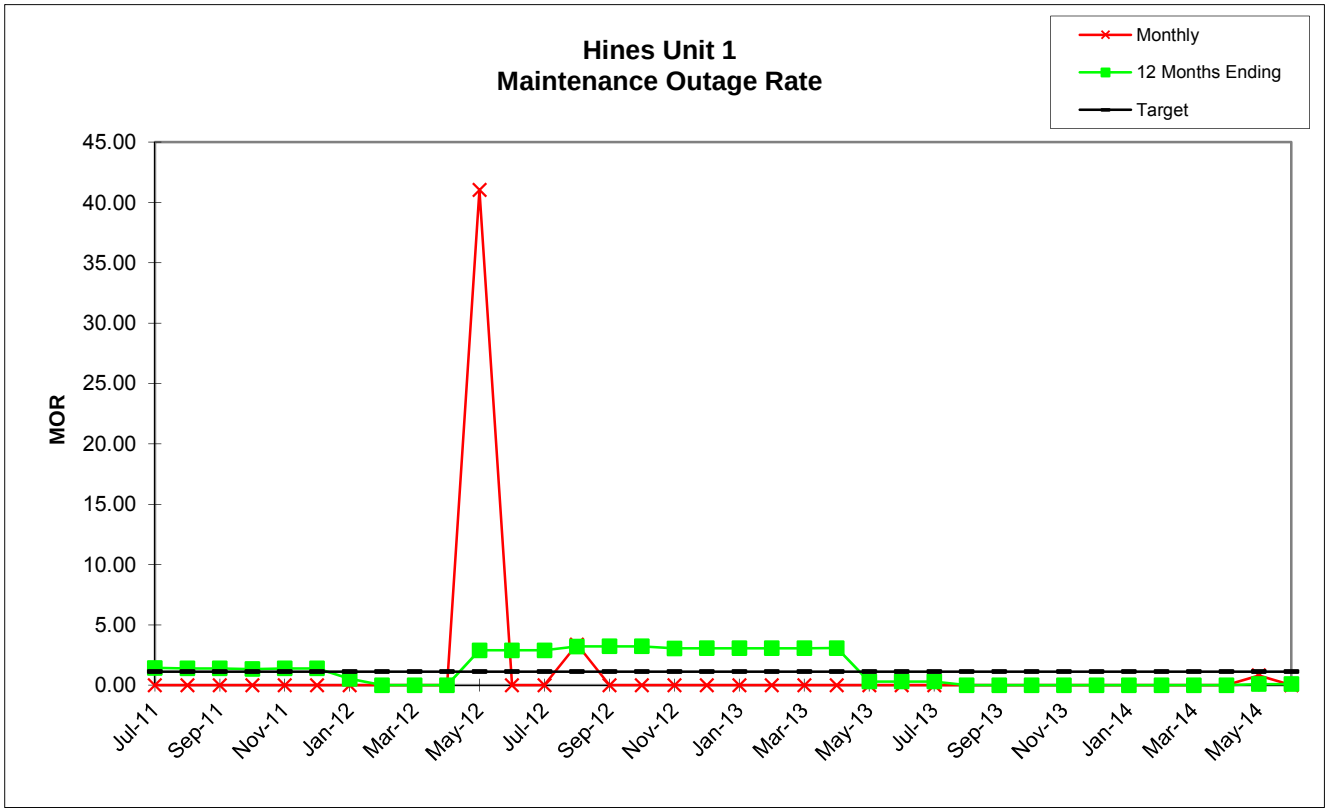
Hines
Unit 1

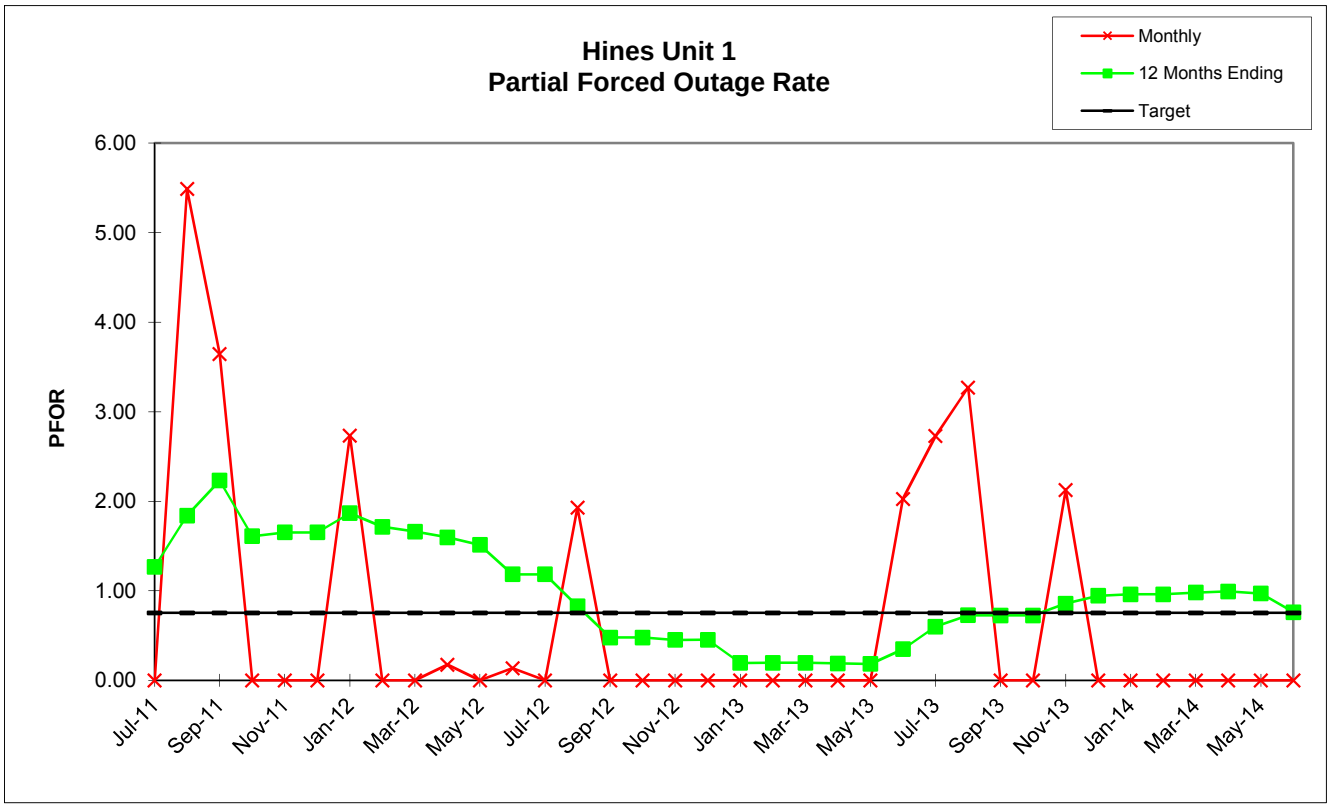
	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	672.00	743.00	291.80	567.27	699.00	744.00	744.00	720.00	744.00	358.67	0.00	631.51	672.00	600.98	202.74	734.24	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	360.55	744.00	112.49	0.00	142.02	517.26	3.78	0.00
UH	0.00	0.00	0.00	428.20	176.73	21.00	0.00	0.00	0.00	0.00	1.78	0.00	0.00	0.00	0.00	0.00	5.98	0.00
POH	0.00	0.00	0.00	428.20	170.68	0.00	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	6.05	21.00	0.00	0.00	0.00	0.00	1.78	0.00	0.00	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	5.98	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	28.58	55.30	45.51	0.00	0.00	10.15	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	229.03	169.59	246.96	0.00	0.00	347.00	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	14.17	20.30	24.33	0.00	0.00	7.62	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	1.62	0.00	1.38	71.19	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.25
LRPM	0.00	0.00	0.00	0.00	0.00	198.59	0.00	199.48	227.48	199.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.78
EMOH	0.00	0.00	0.00	0.00	0.00	0.70	0.00	0.60	35.05	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.87
NPC	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	465.00	465.00	465.00	465.00	465.00	465.00

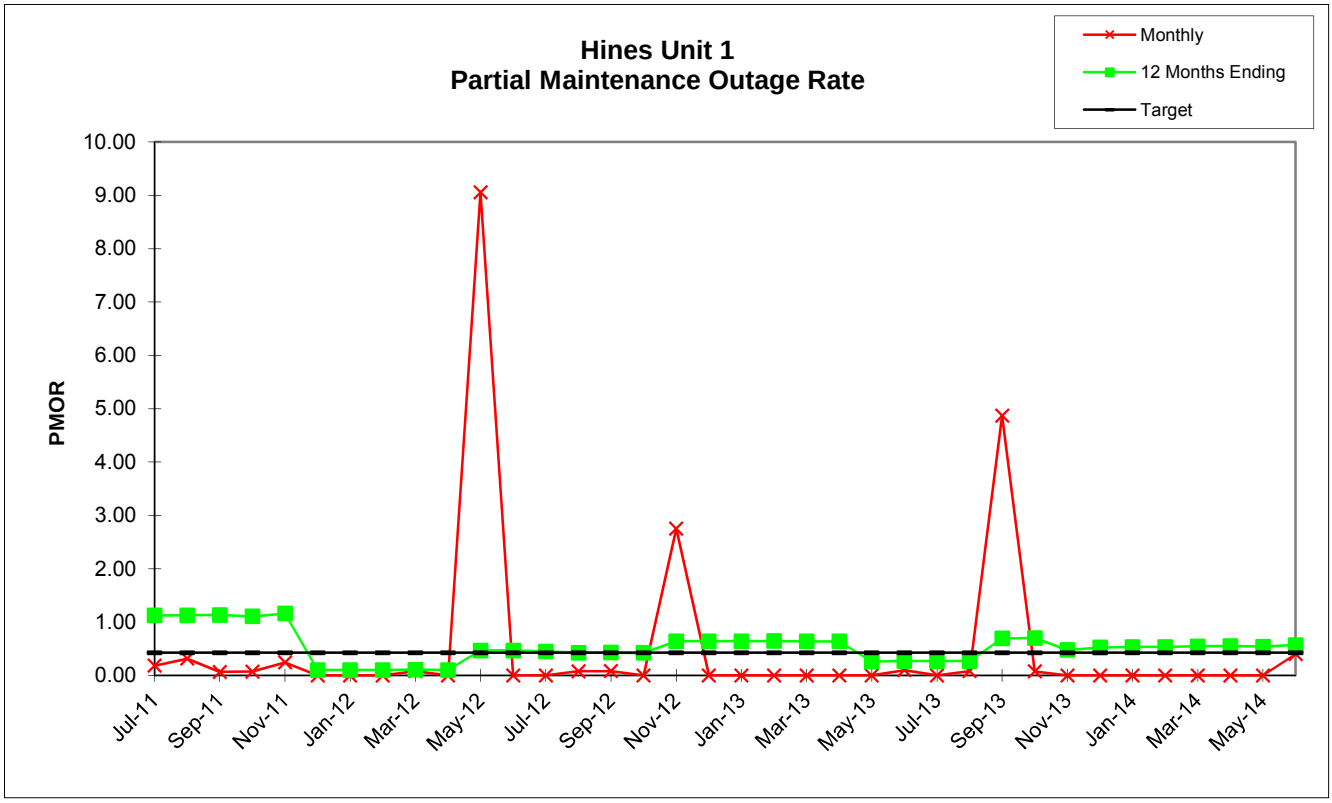
MONTHLY	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.00	0.00	0.00	0.00	1.06	2.92	0.00	0.00	0.00	0.00	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	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	0.81	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	2.03	2.73	3.27	0.00	0.00	2.13	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	0.10	0.00	0.08	4.87	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
EUOR	0.00	0.00	0.00	0.00	1.06	4.98	2.73	3.35	4.87	0.08	2.61	0.00	0.00	0.00	0.00	0.00	0.81	0.40
EUOF	0.00	0.00	0.00	0.00	0.81	4.98	2.73	3.35	4.87	0.08	1.30	0.00	0.00	0.00	0.00	0.00	0.80	0.40
POF	0.00	0.00	0.00	59.47	22.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	100.00	40.53	76.25	95.02	97.27	96.65	95.13	99.92	98.70	100.00	100.00	100.00	100.00	100.00	99.20	99.60

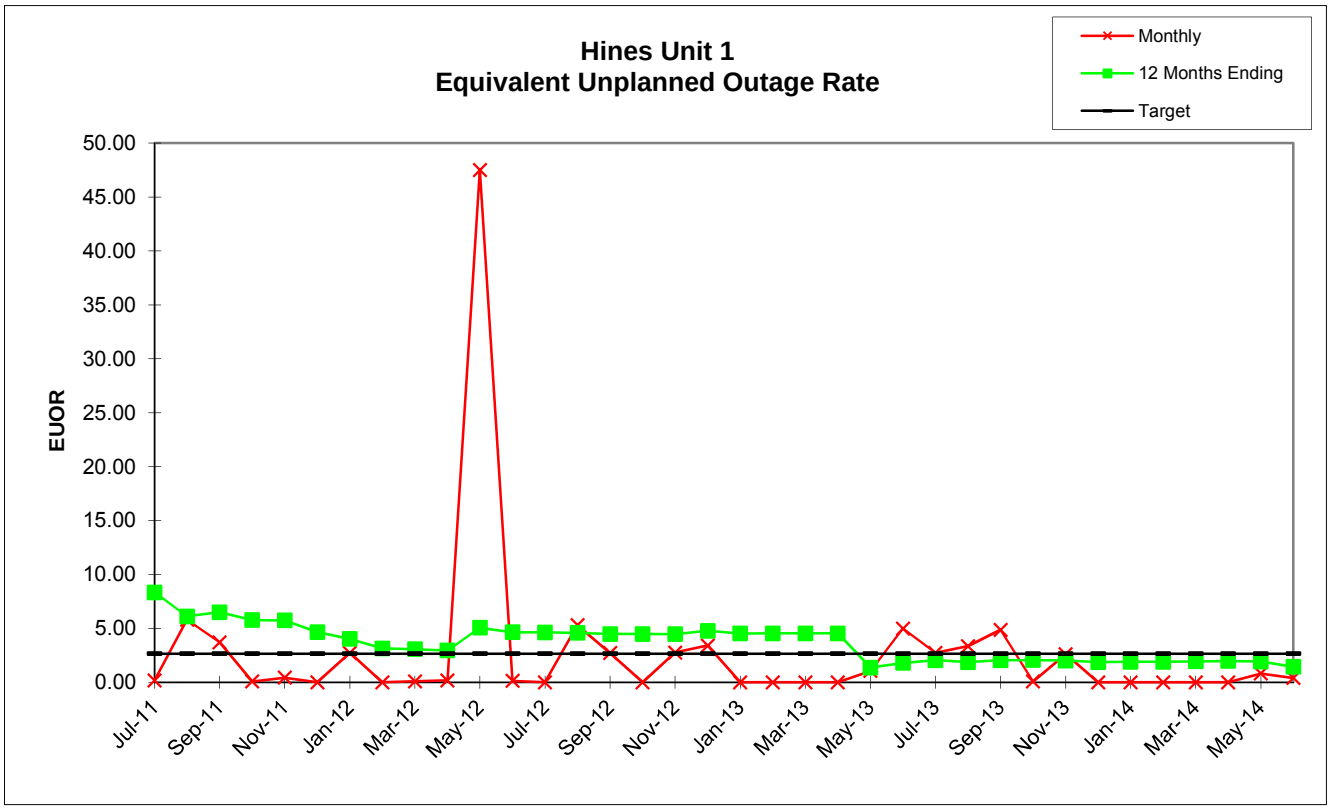
12 MONTHS	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.71	0.71	0.71	0.71	0.62	0.88	0.88	0.88	0.64	0.64	0.70	0.41	0.42	0.42	0.42	0.43	0.33	0.03
MOR	3.06	3.07	3.07	3.07	0.31	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
PFOR	0.20	0.20	0.20	0.19	0.18	0.35	0.60	0.73	0.73	0.73	0.86	0.95	0.96	0.96	0.98	0.99	0.97	0.76
PMOR	0.64	0.64	0.64	0.64	0.26	0.27	0.27	0.27	0.69	0.70	0.48	0.53	0.53	0.53	0.54	0.55	0.54	0.57
EUOR	4.53	4.54	4.53	4.54	1.36	1.79	2.04	1.86	2.05	2.06	2.02	1.87	1.90	1.90	1.94	1.97	1.92	1.44
EUOF	4.22	4.23	4.22	4.22	1.27	1.67	1.90	1.73	1.91	1.92	1.80	1.51	1.51	1.51	1.51	1.51	1.51	1.13
POF	6.77	6.79	6.79	7.03	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	1.95	0.00	0.00
EAF	89.01	88.98	88.98	88.75	91.89	91.50	91.26	91.43	91.25	91.25	91.36	91.65	91.65	91.65	91.65	96.54	98.49	98.87


Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 1
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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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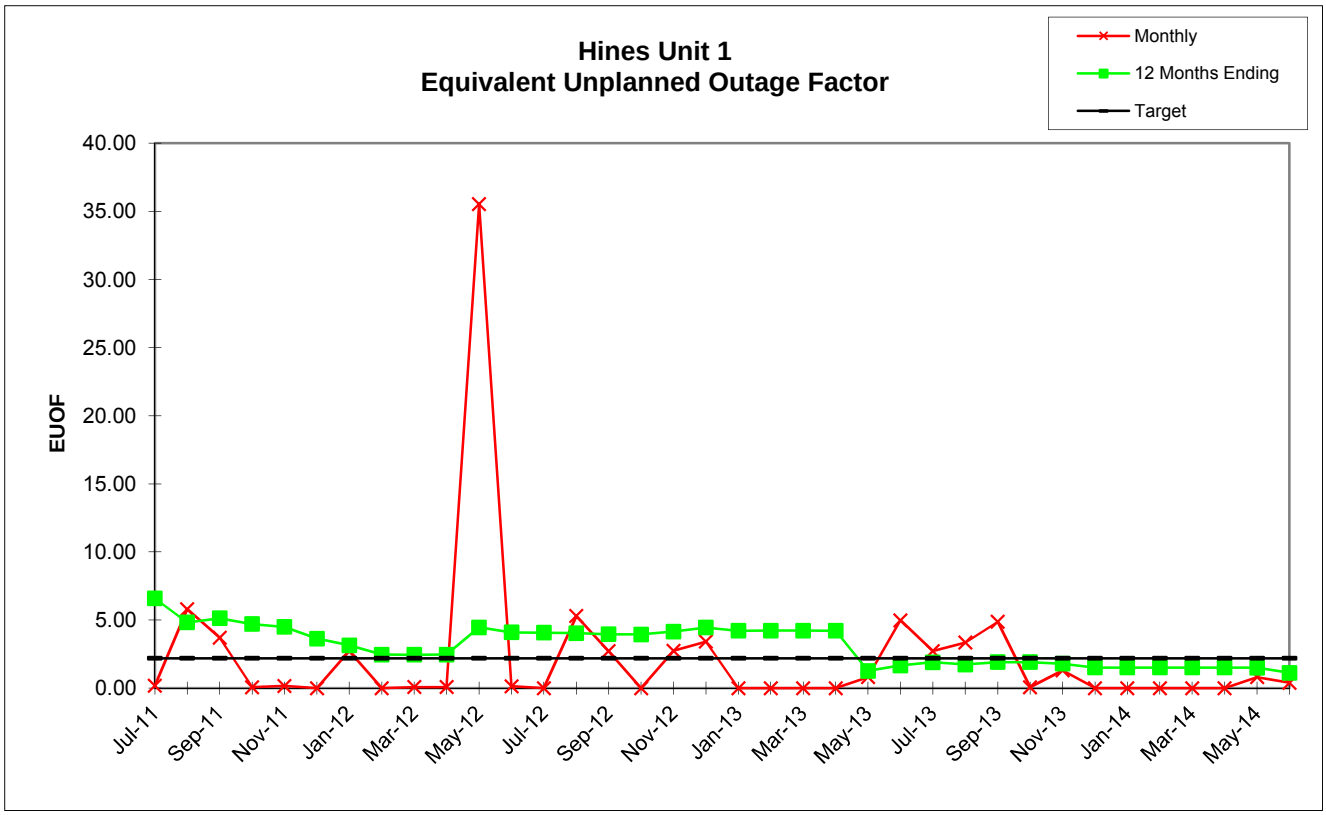
Mar-14
May-14


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Hines
Unit 2

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	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	267.13	523.58	744.00	403.20	217.77	680.65	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	152.97	0.00	292.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	453.87	67.45	0.00	0.00	525.23	39.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	453.87	1.80	0.00	0.00	525.23	39.35	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	65.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	4.98	18.12	0.00	0.00	62.78	1.32	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	280.19	281.33	0.00	0.00	222.18	265.33	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	2.85	10.40	0.00	0.00	28.47	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	2.38	14.59	1.79	0.00	0.00	26.45	3.27	0.00	0.00	12.05	2.55	2.40	0.00	1.95	1.98	0.00	1.98	0.00
LRPM	158.22	157.93	157.41	0.00	0.00	195.00	149.04	0.00	0.00	309.72	127.00	127.00	0.00	147.00	158.27	0.00	170.29	0.00
EMOH	0.77	4.70	0.58	0.00	0.00	10.53	0.99	0.00	0.00	7.62	0.66	0.62	0.00	0.59	0.64	0.00	0.69	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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	11.14	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	0.38	1.44	0.00	0.00	5.44	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.10	0.63	0.08	0.00	0.00	2.01	0.13	0.00	0.00	1.12	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00
EUOR	0.10	1.01	1.52	0.00	0.00	17.76	0.23	0.00	0.00	1.12	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00
EUOF	0.10	1.01	1.52	0.00	0.00	14.06	0.23	0.00	0.00	1.06	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00
POF	0.00	0.00	0.00	0.00	62.95	0.24	0.00	0.00	70.69	5.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.90	98.99	98.48	100.00	37.05	85.69	99.77	100.00	29.31	93.48	99.91	99.91	100.00	99.92	99.91	100.00	99.90	100.00

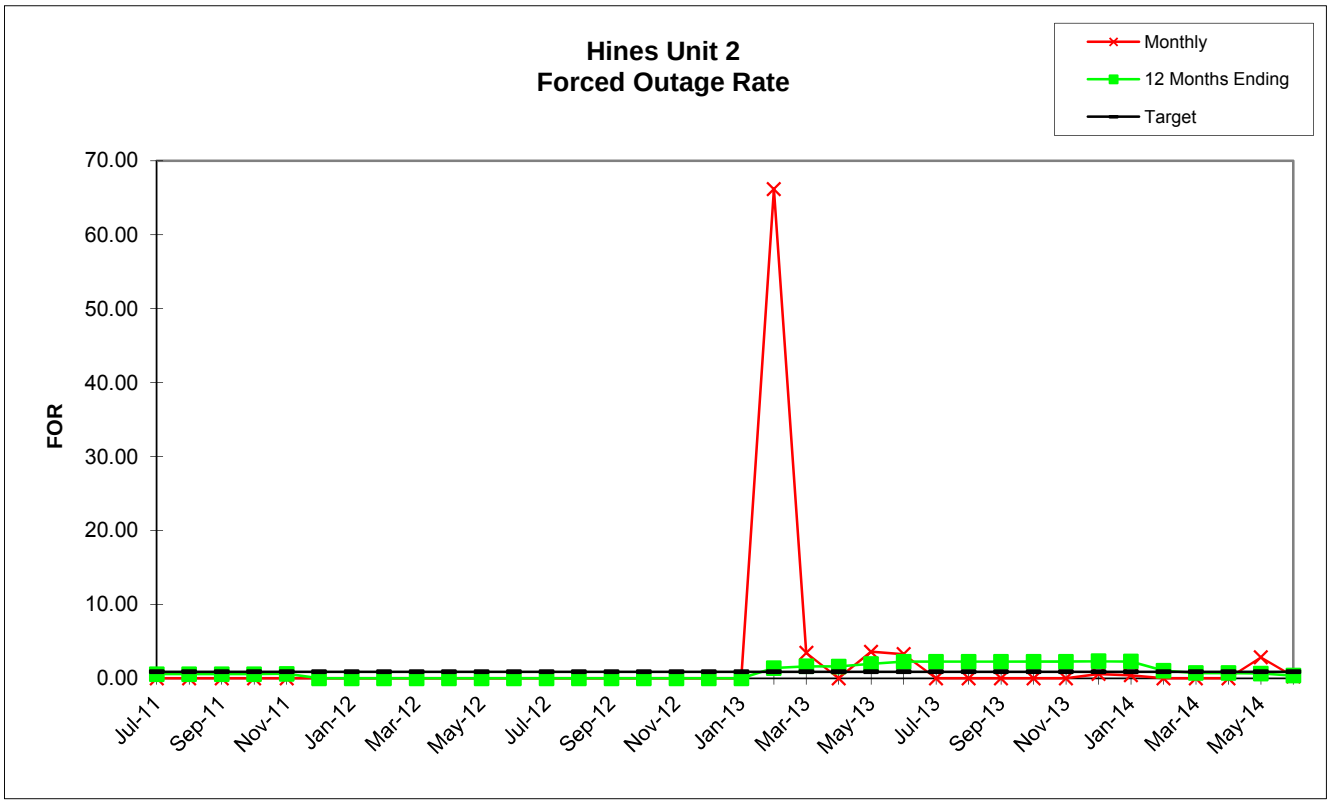
12 MONTHS	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.58	0.58	0.58	0.58	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.91	0.91	0.95	0.92	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.84	0.00
PFOR	0.27	0.31	0.44	0.44	0.47	0.64	0.65	0.64	0.62	0.59	0.59	0.59	0.59	0.55	0.40	0.40	0.38	0.01
PMOR	4.72	4.78	4.79	4.49	1.88	2.03	1.61	1.67	1.62	0.46	0.36	0.36	0.35	0.30	0.30	0.30	0.29	0.15
EUOR	5.53	5.63	5.77	5.48	2.95	3.55	3.15	3.24	3.14	1.94	1.83	1.84	1.83	1.73	1.59	1.59	1.51	0.16
EUOF	4.82	4.91	5.03	4.77	2.42	2.92	2.58	2.55	2.55	1.61	1.52	1.53	1.52	1.44	1.33	1.33	1.33	0.14
POF	12.87	12.87	12.87	12.87	18.05	16.09	16.09	16.04	13.56	11.61	11.61	11.61	11.61	11.61	11.61	11.61	6.45	6.43
EAF	82.31	82.23	82.10	82.36	79.53	80.99	81.32	81.40	83.88	86.77	86.86	86.85	86.86	86.94	87.06	87.06	92.22	93.43

Hines
Unit 2

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	335.82	51.62	717.42	720.00	717.17	696.45	744.00	744.00	720.00	744.00	721.00	739.62	536.53	114.32	629.49	720.00	722.88	690.99
RSH	408.18	24.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	205.18	557.68	113.51	0.00	0.00	17.64
UH	0.00	596.39	25.58	0.00	26.83	23.55	0.00	0.00	0.00	0.00	0.00	4.38	2.29	0.00	0.00	0.00	21.12	11.37
POH	0.00	495.57	0.00	0.00	0.00	0.00	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	100.82	25.58	0.00	26.83	23.55	0.00	0.00	0.00	0.00	0.00	4.38	2.29	0.00	0.00	0.00	21.12	1.84
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	9.53
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	22.66	0.00	1.12	0.00	0.00	61.05	2.71	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	230.33	0.00	313.06	0.00	0.00	1.00	123.07	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	10.65	0.00	0.72	0.00	0.00	0.12	0.68	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	1.50	0.00	0.00	1.50	1.10	0.00	0.00	0.00	0.00	0.00	0.94	0.00	6.03
LRPM	0.00	0.00	0.00	0.00	0.00	127.00	0.00	0.00	136.00	136.00	0.00	0.00	0.00	0.00	0.00	51.88	0.00	55.63
EMOH	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.00	0.42	0.31	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.68
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

MONTHLY	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FOR	0.00	66.14	3.44	0.00	3.61	3.27	0.00	0.00	0.00	0.00	0.00	0.59	0.43	0.00	0.00	0.00	2.84	0.27
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	1.36
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	1.43	0.00	0.10	0.00	0.00	0.02	0.13	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10
EUOR	0.00	66.14	3.44	0.00	3.61	3.32	1.43	0.00	0.16	0.04	0.00	0.61	0.55	0.00	0.00	0.01	2.84	1.72
EUOF	0.00	15.00	3.44	0.00	3.61	3.32	1.43	0.00	0.16	0.04	0.00	0.61	0.40	0.00	0.00	0.01	2.84	1.67
POF	0.00	73.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	11.25	96.56	100.00	96.39	96.68	98.57	100.00	99.84	99.96	100.00	99.39	99.60	100.00	100.00	99.99	97.16	98.33

12 MONTHS	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FOR	0.00	1.39	1.62	1.61	1.96	2.26	2.26	2.26	2.26	2.26	2.26	2.31	2.28	1.03	0.72	0.72	0.65	0.38
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	0.12
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.15	0.16	0.16	0.16	0.16
PMOR	0.14	0.15	0.14	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
EUOR	0.14	1.54	1.76	1.65	1.99	2.29	2.42	2.41	2.42	2.43	2.42	2.47	2.45	1.20	0.89	0.89	0.82	0.67
EUOF	0.12	1.27	1.57	1.48	1.78	2.04	2.17	2.16	2.16	2.17	2.16	2.21	2.25	1.09	0.80	0.80	0.74	0.60
POF	6.43	12.10	6.11	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	0.00	0.00	0.00	0.00	0.00
EAF	93.45	86.62	92.33	92.86	92.56	92.30	92.18	92.18	92.18	92.17	92.18	92.13	92.10	98.91	99.20	99.20	99.26	99.40


Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
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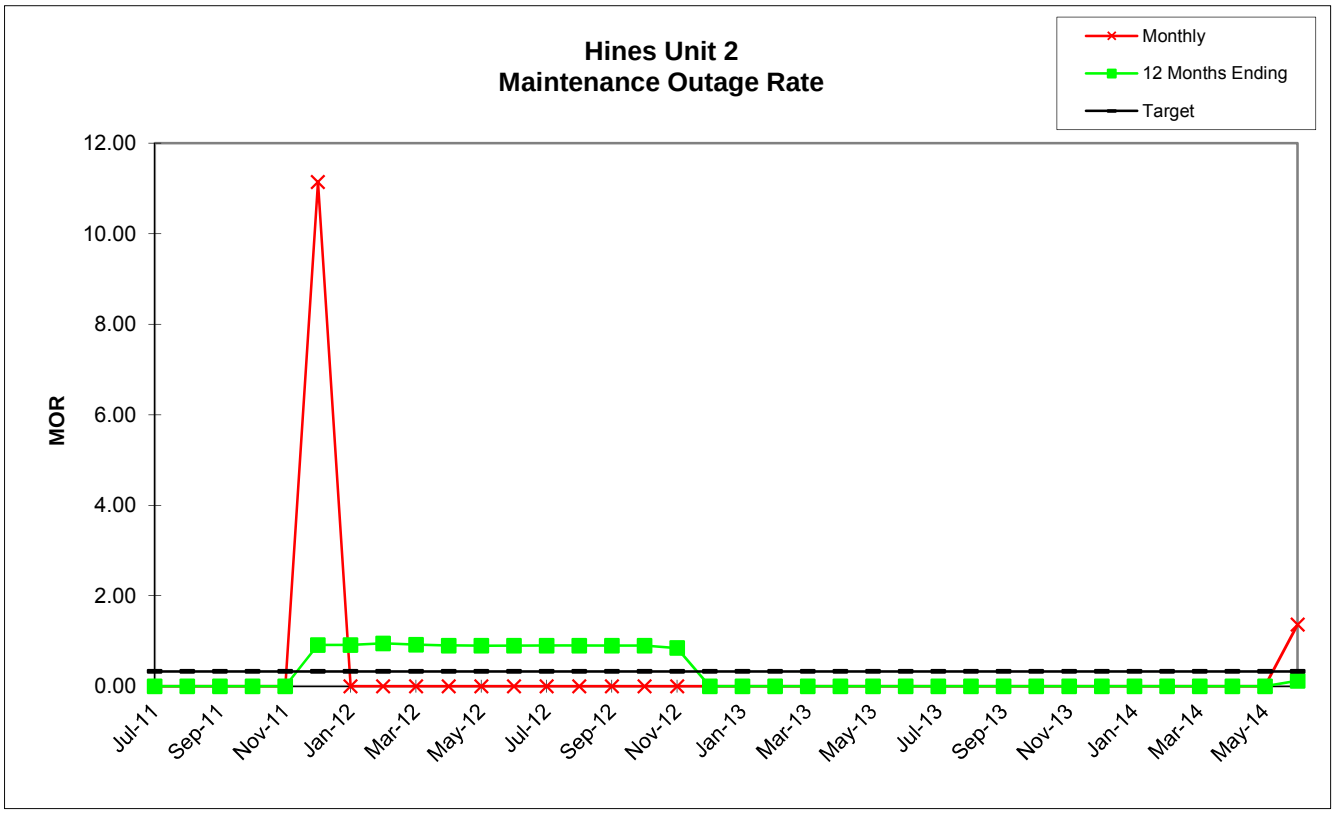
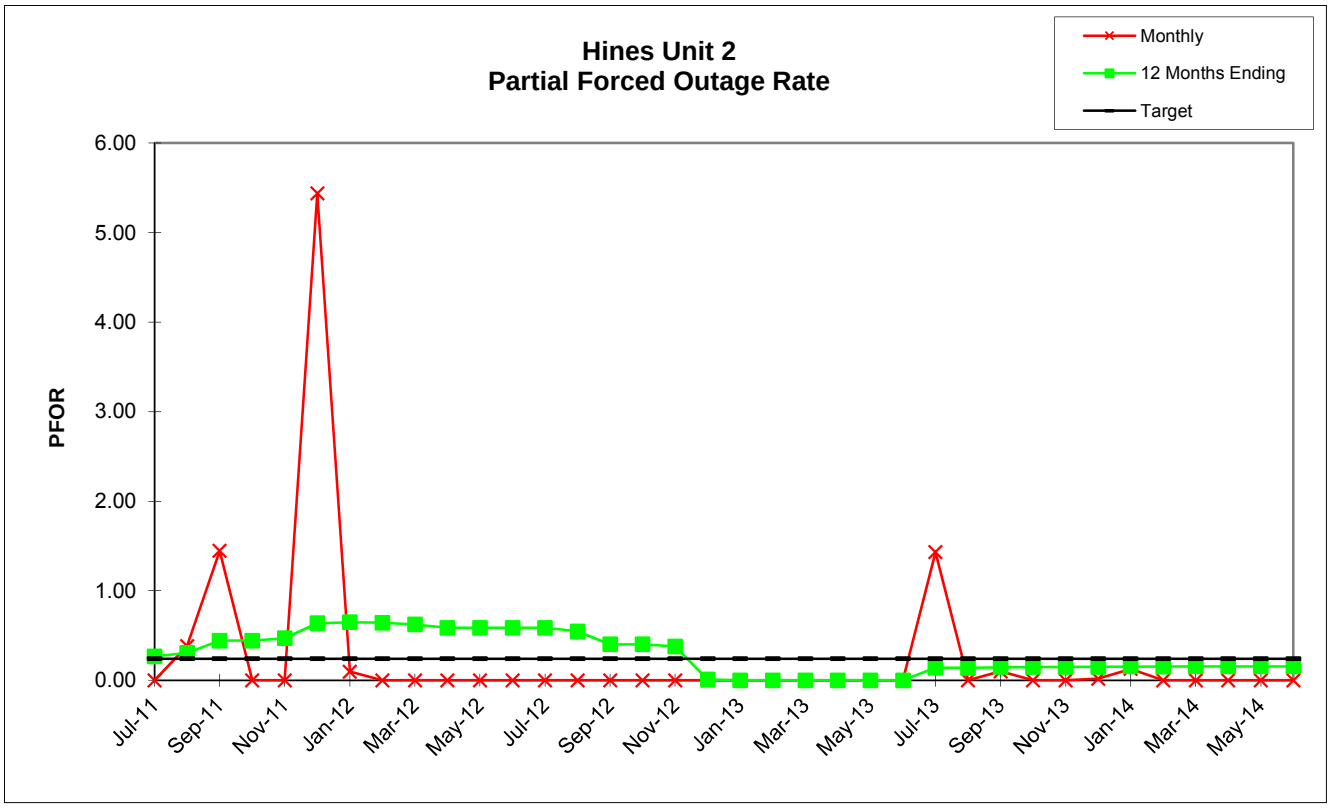
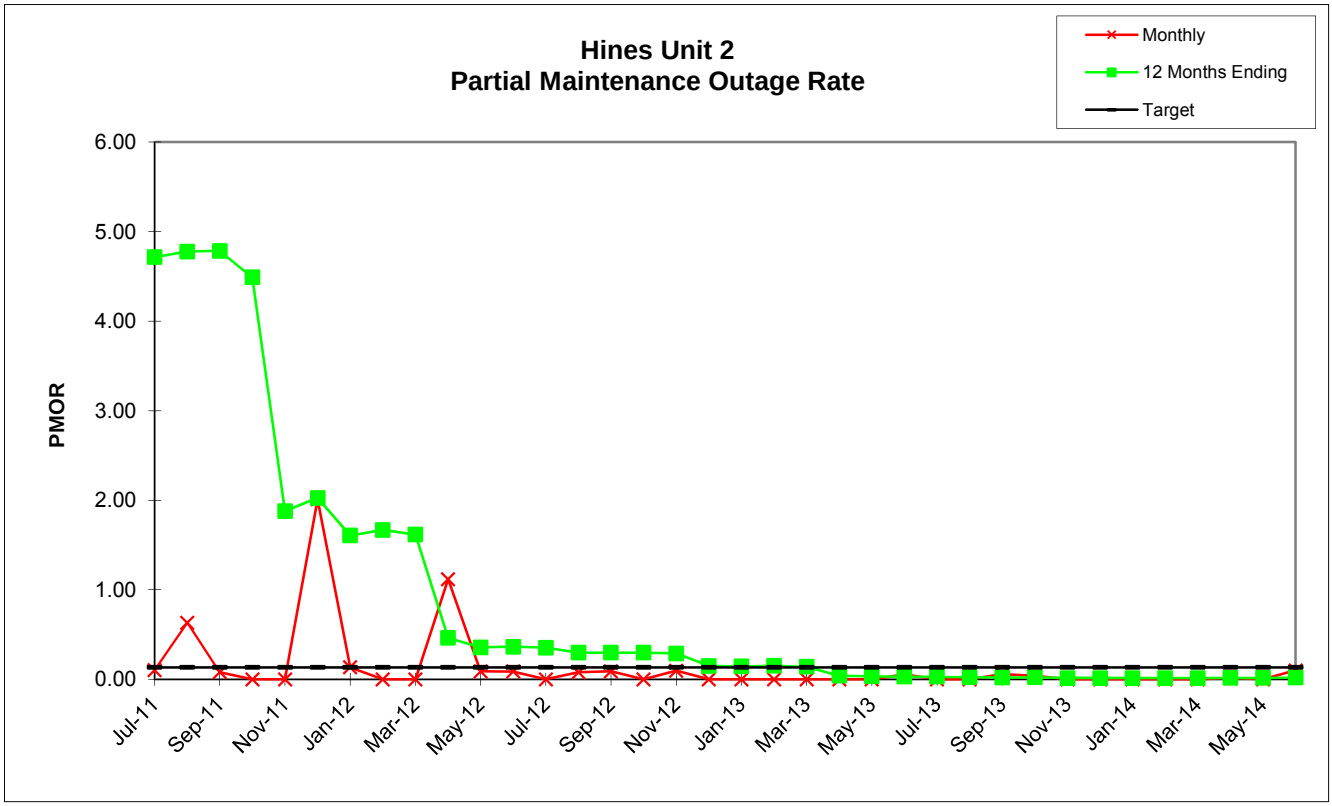
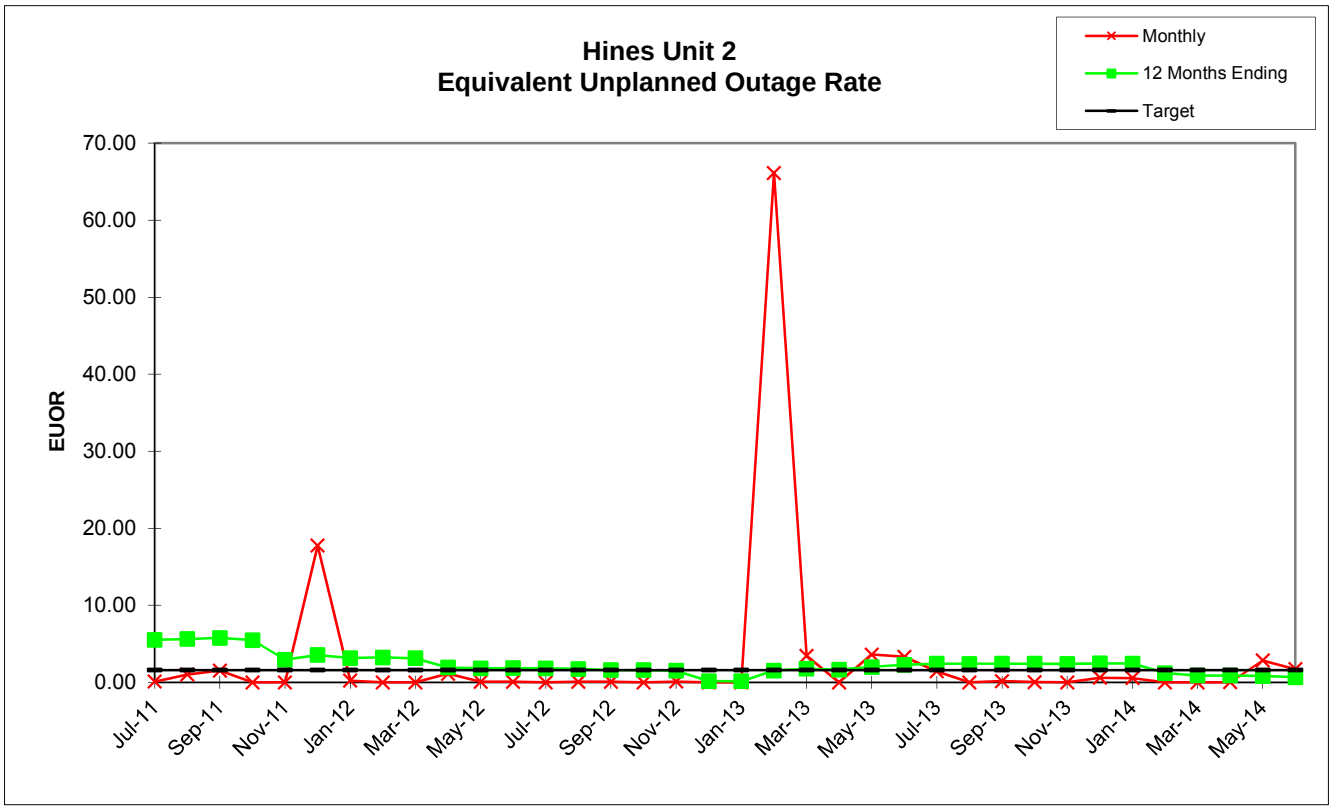
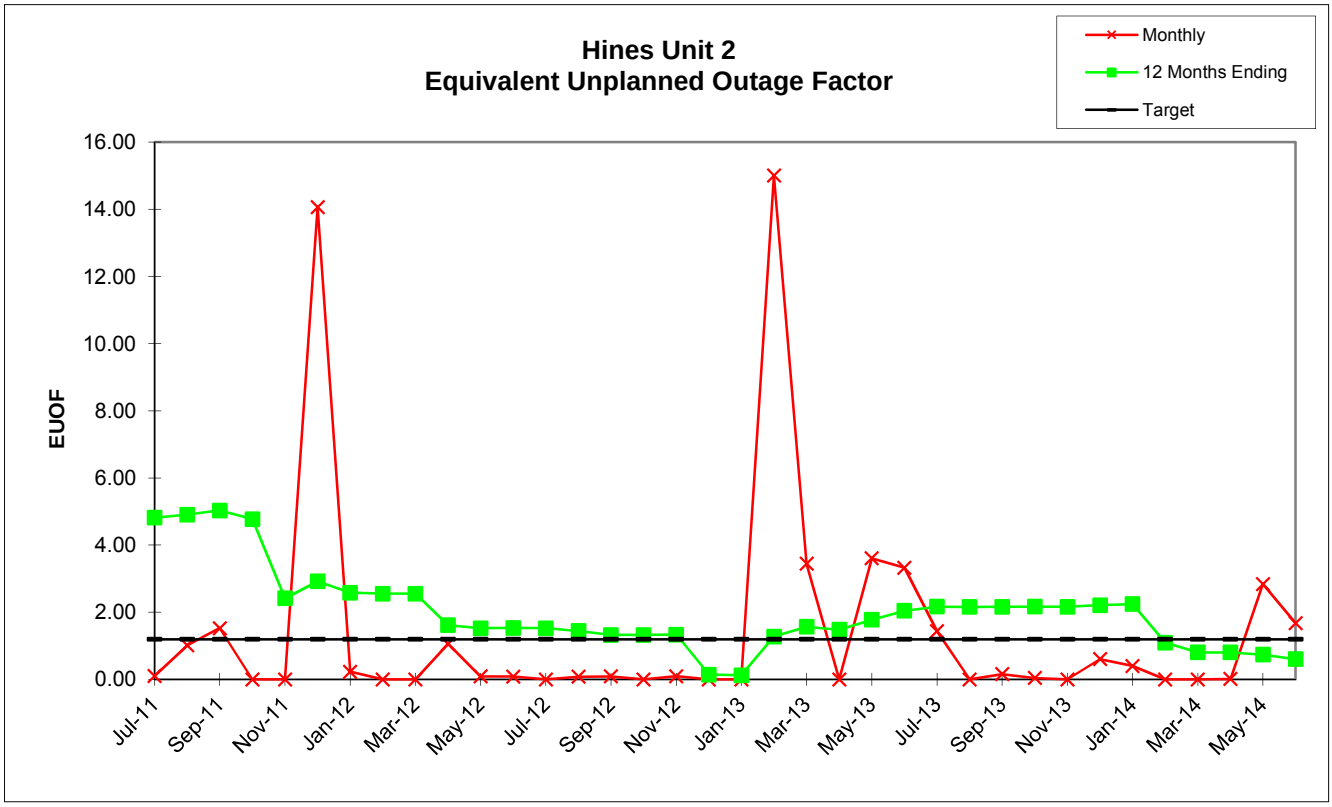
Jan-14
Mar-14
May-14


Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 2
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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 2
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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Hines
Unit 3

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	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	681.42	744.00	601.43	502.13	744.00	696.00	50.07	191.12	744.00	720.00	744.00	744.00	720.00	287.82	688.68	744.00
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	0.00	0.00	38.58	0.00	119.57	241.87	0.00	0.00	692.93	528.88	0.00	0.00	0.00	0.00	0.00	456.18	32.32	0.00
POH	0.00	0.00	0.00	0.00	119.57	241.87	0.00	0.00	692.93	528.88	0.00	0.00	0.00	0.00	0.00	456.18	32.32	0.00
FOH	0.00	0.00	2.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	36.53	0.00	0.00	0.00	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	18.37	7.92	0.22	0.00	6.75	0.00	0.00	0.00	0.00	0.00	0.00	3.78	28.93	0.00	0.00	0.00	0.00
LRPF	0.00	124.98	240.81	123.09	0.00	125.00	0.00	0.00	0.00	0.00	0.00	0.00	328.29	318.04	0.00	0.00	0.00	0.00
EFOH	0.00	4.70	3.91	0.06	0.00	1.73	0.00	0.00	0.00	0.00	0.00	0.00	2.54	18.85	0.00	0.00	0.00	0.00
PMOH	1.00	8.48	1.08	1.02	3.21	18.37	2.05	0.00	0.00	0.00	1.18	1.25	0.00	0.00	0.00	4.68	0.00	0.00
LRPM	125.00	125.05	125.39	124.59	125.26	126.52	125.00	0.00	0.00	0.00	125.36	125.00	0.00	0.00	0.00	318.23	0.00	0.00
EMOH	0.26	2.17	0.28	0.26	0.82	4.76	0.53	0.00	0.00	0.00	0.30	0.32	0.00	0.00	0.00	3.05	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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	5.09	0.00	0.00	0.00	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	0.63	0.57	0.01	0.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.34	2.53	0.00	0.00	0.00	0.00
PMOR	0.03	0.29	0.04	0.04	0.14	0.95	0.07	0.00	0.00	0.00	0.04	0.04	0.00	0.00	0.00	1.06	0.00	0.00
EUOR	0.03	0.92	5.94	0.04	0.14	1.29	0.07	0.00	0.00	0.00	0.04	0.04	0.34	2.53	0.00	1.06	0.00	0.00
EUOF	0.03	0.92	5.94	0.04	0.11	0.87	0.07	0.00	0.00	0.00	0.04	0.04	0.34	2.53	0.00	0.41	0.00	0.00
POF	0.00	0.00	0.00	0.00	16.58	32.51	0.00	0.00	93.26	73.46	0.00	0.00	0.00	0.00	0.00	61.31	4.48	0.00
EAF	99.97	99.08	94.06	99.96	83.30	66.62	99.93	100.00	6.74	26.54	99.96	99.96	99.66	97.47	100.00	38.28	95.52	100.00

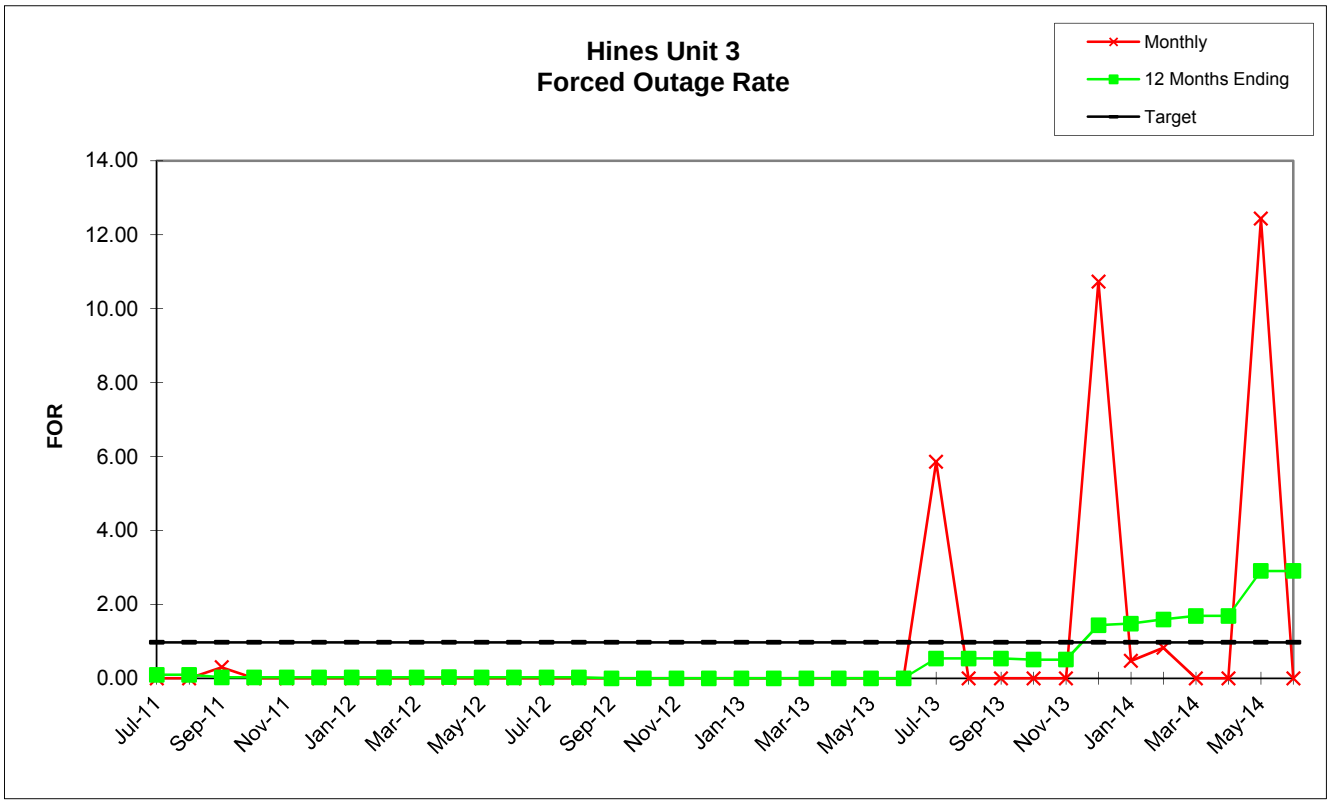
12 MONTHS	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.10	0.10	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.46	0.46	0.45	0.47	0.47	0.46	0.51	0.53	0.51	0.51	0.51	0.51	0.00	0.00	0.00	0.00
PFOR	0.06	0.12	0.17	0.17	0.16	0.16	0.16	0.16	0.17	0.18	0.16	0.15	0.18	0.38	0.32	0.34	0.34	0.30
PMOR	0.33	0.35	0.36	0.36	0.36	0.32	0.12	0.12	0.13	0.13	0.13	0.14	0.13	0.10	0.10	0.15	0.13	0.06
EUOR	0.48	0.57	1.01	1.02	1.00	0.96	0.76	0.76	0.83	0.87	0.82	0.81	0.85	1.01	0.42	0.49	0.47	0.36
EUOF	0.43	0.51	0.91	0.91	0.92	0.86	0.68	0.68	0.68	0.68	0.68	0.67	0.69	0.83	0.34	0.37	0.37	0.29
POF	10.46	10.46	10.46	10.46	7.63	10.39	10.39	10.36	18.25	21.55	18.02	18.02	18.02	18.02	18.02	23.22	22.22	19.47
EAF	89.11	89.03	88.63	88.62	91.45	88.74	88.92	88.96	81.07	77.77	81.30	81.31	81.28	81.15	81.63	76.41	77.41	80.24

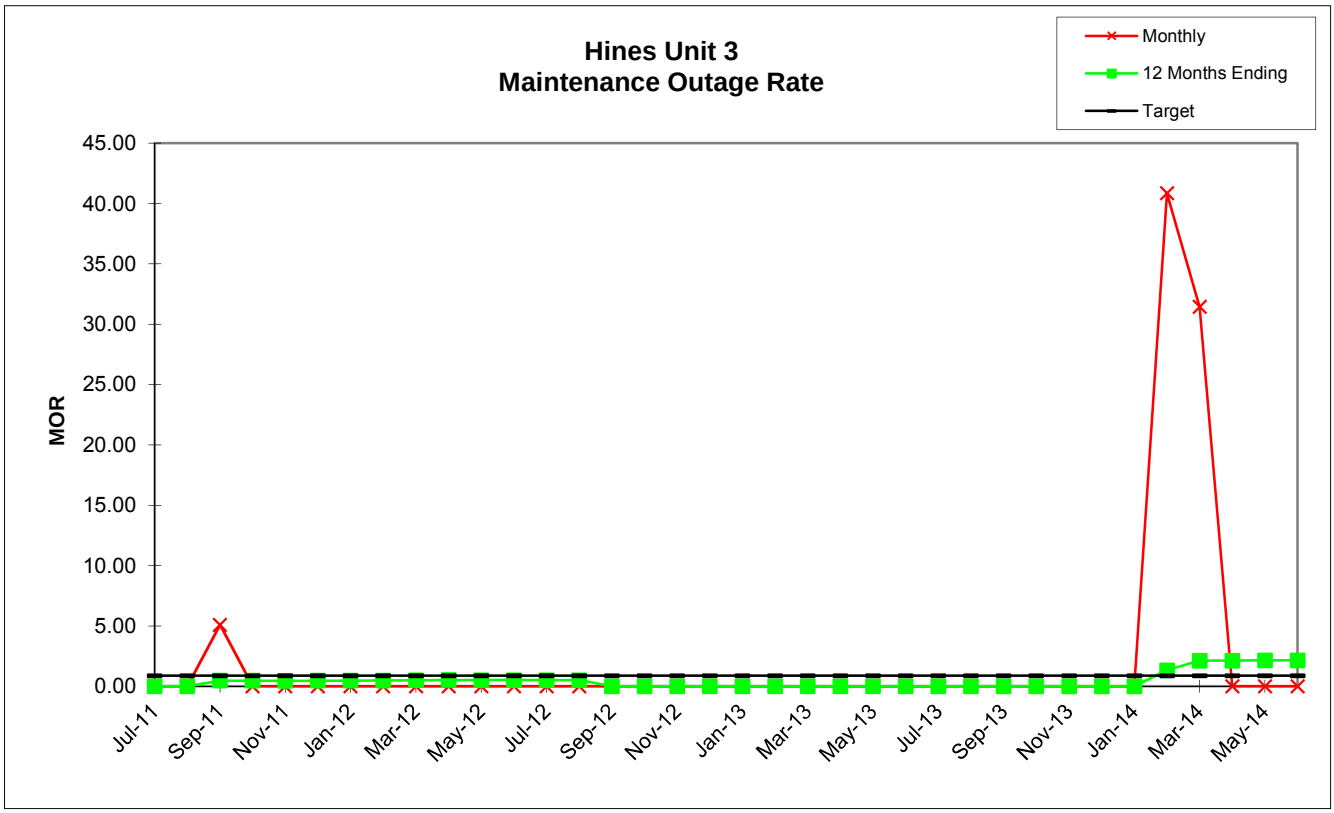
Hines
Unit 3

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	672.00	571.35	720.00	744.00	720.00	700.42	744.00	720.00	744.00	721.00	664.15	704.47	154.38	119.97	715.08	648.03	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	36.19	409.67	52.74	4.92	3.94	0.00
UH	0.00	0.00	171.65	0.00	0.00	0.00	43.58	0.00	0.00	0.00	0.00	79.85	3.34	107.95	570.29	0.00	92.03	0.00
POH	0.00	0.00	171.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	515.29	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	43.58	0.00	0.00	0.00	0.00	79.85	3.34	1.29	0.00	0.00	92.03	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	106.65	55.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	17.06	0.00	0.00	2.82	25.78	0.00	0.00	0.00	0.00	0.00	13.80	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	132.23	0.00	0.00	257.70	381.05	0.00	0.00	0.00	0.00	0.00	88.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	4.62	0.00	0.00	1.49	20.13	0.00	0.00	0.00	0.00	0.00	2.49	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.50	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	156.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.32	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	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	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.00	0.00	0.00	0.00	0.00	0.00	5.86	0.00	0.00	0.00	0.00	10.73	0.47	0.83	0.00	0.00	12.44	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	40.86	31.43	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.00	0.20	2.79	0.00	0.00	0.00	0.00	0.00	0.38	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00
EUOR	0.00	0.00	0.00	0.00	0.00	0.00	6.48	0.00	0.10	0.20	2.79	10.73	0.47	41.15	31.43	0.00	12.85	0.00
EUOF	0.00	0.00	0.00	0.00	0.00	0.00	6.48	0.00	0.10	0.20	2.79	10.73	0.45	16.06	7.40	0.00	12.79	0.00
POF	0.00	0.00	23.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.35	0.00	0.00	0.00
EAF	100.00	100.00	76.90	100.00	100.00	100.00	93.52	100.00	99.90	99.80	97.21	89.27	99.55	83.94	23.24	100.00	87.21	100.00

12 MONTHS	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.54	0.54	0.54	0.51	0.51	1.44	1.48	1.59	1.69	1.69	2.91	2.91
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	1.33	2.12	2.12	2.15	2.15
PFOR	0.30	0.30	0.28	0.26	0.26	0.26	0.29	0.06	0.06	0.07	0.31	0.31	0.31	0.33	0.35	0.35	0.39	0.39
PMOR	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
EUOR	0.35	0.36	0.33	0.31	0.31	0.30	0.87	0.63	0.64	0.59	0.82	1.75	1.80	3.21	4.09	4.09	5.32	5.32
EUOF	0.29	0.29	0.29	0.29	0.28	0.28	0.80	0.59	0.59	0.58	0.81	1.72	1.75	2.99	3.61	3.61	4.70	4.70
POF	19.47	19.52	13.57	7.54	7.54	7.54	7.54	7.54	7.54	2.33	1.96	1.96	1.96	1.96	5.88	5.88	5.88	5.88
EAF	80.24	80.19	86.14	92.18	92.18	92.18	91.66	91.88	91.87	97.10	97.24	96.32	96.29	95.05	90.50	90.50	89.42	89.42


Hines Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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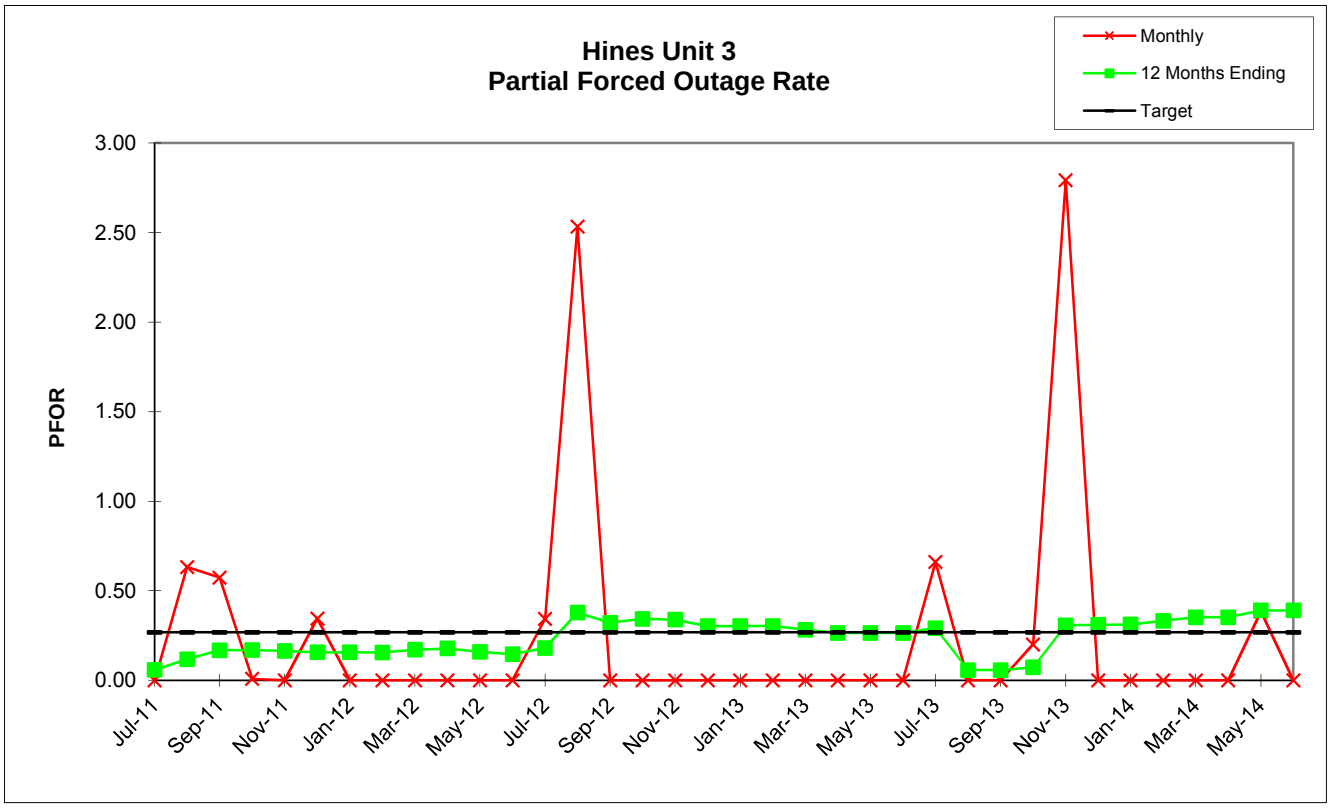
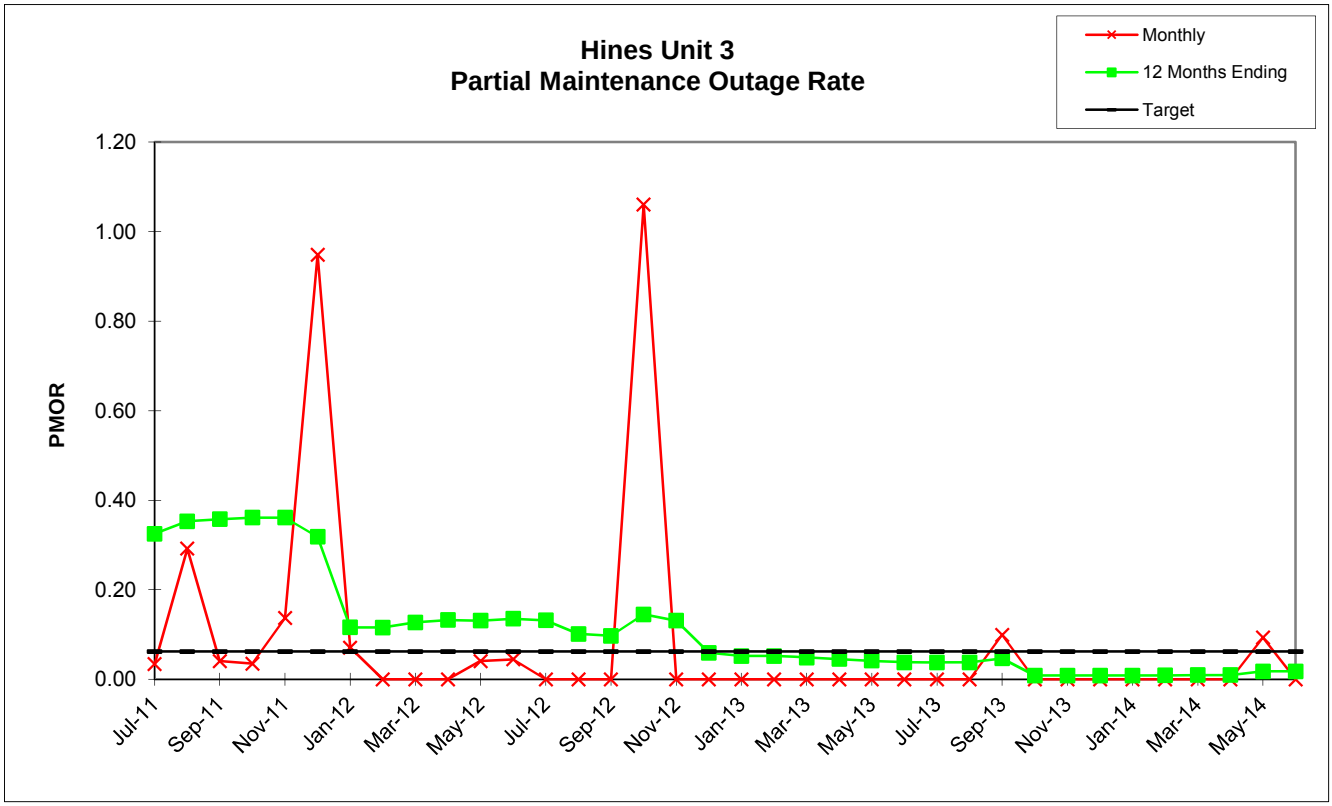
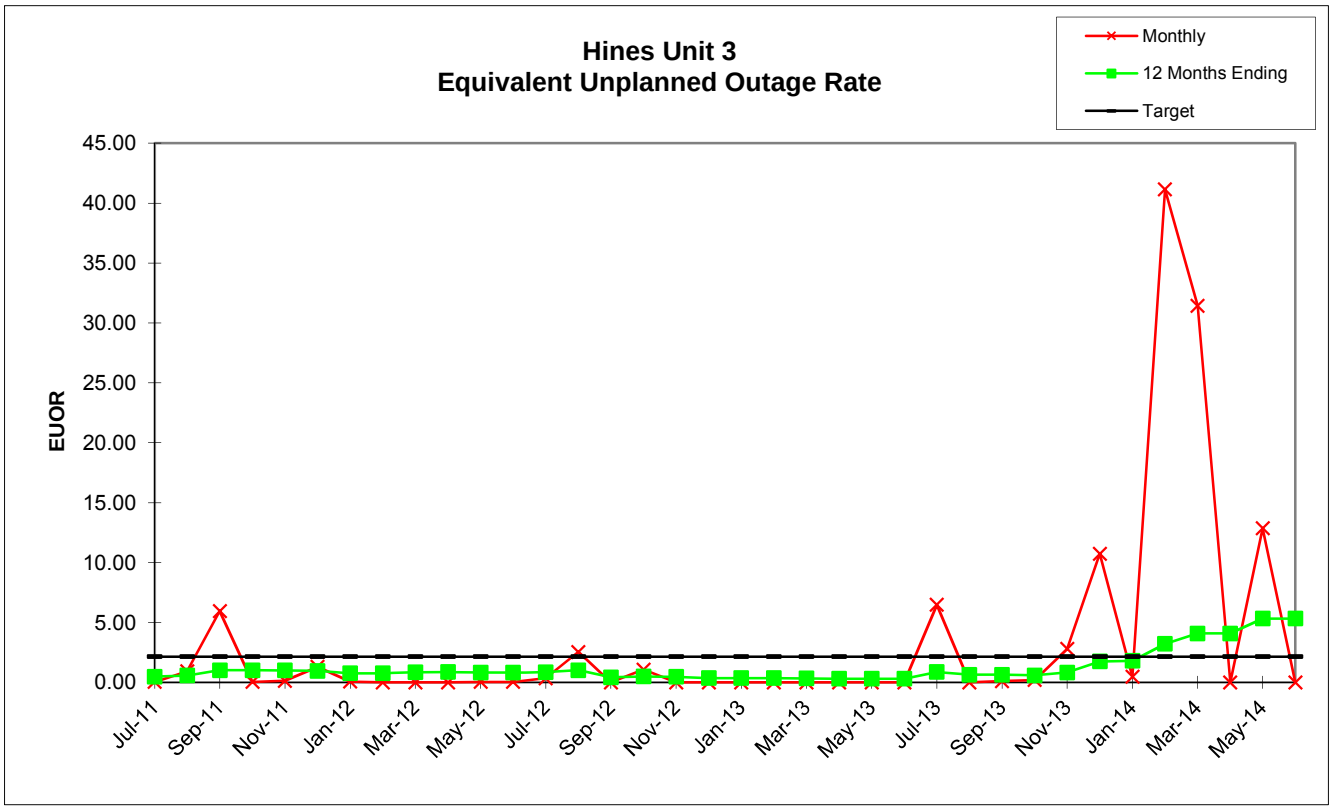
Jan-14
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


Hines Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14


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-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
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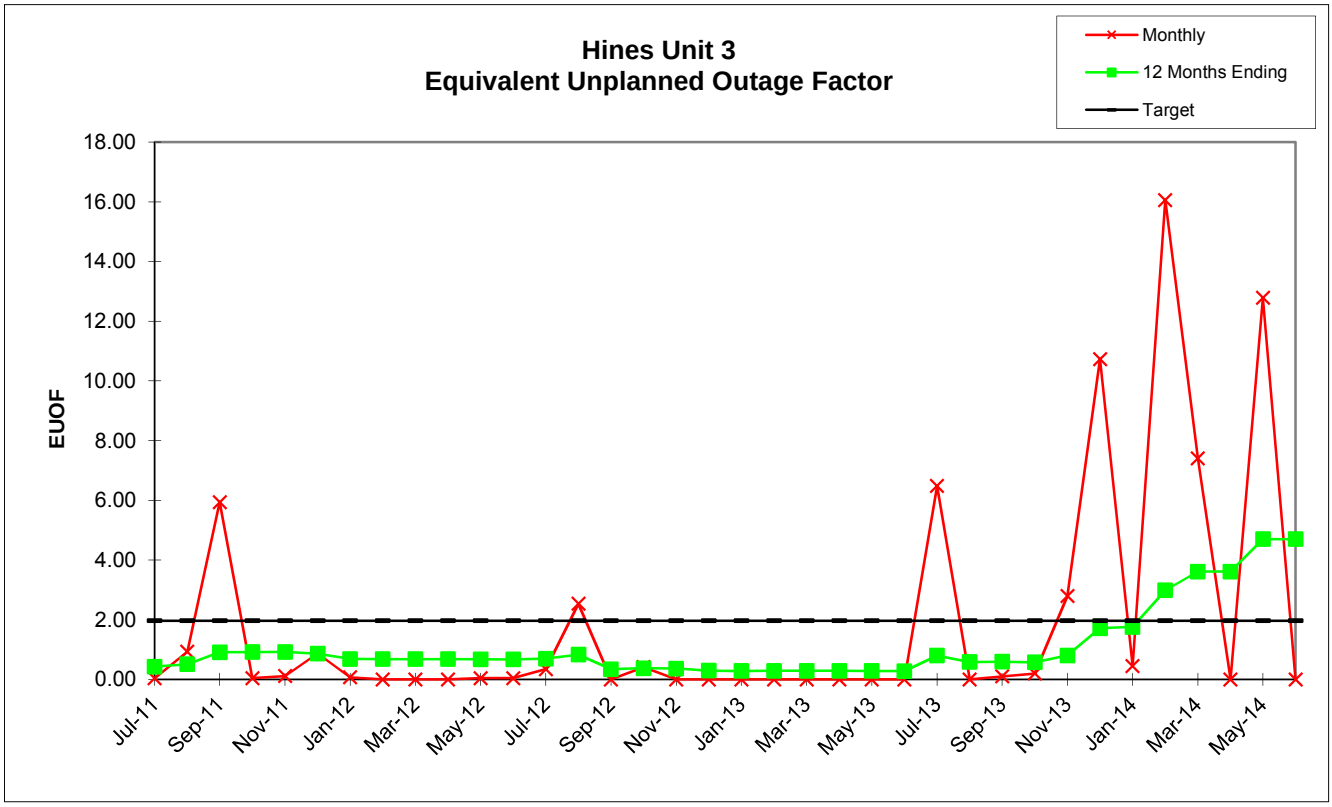
Jan-14
Mar-14
May-14


Hines Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14

Hines
Unit 4

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	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	454.48	198.77	550.94	712.55	689.40	743.00	625.48	429.43	687.59	744.00	744.00	720.00	744.00	261.93	742.47
RSH	0.00	0.00	0.00	0.00	0.00	183.38	31.45	4.35	0.00	0.00	0.00	20.13	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	289.52	522.23	9.68	0.00	2.25	0.00	94.52	314.57	12.28	0.00	0.00	0.00	0.00	459.07	1.53
POH	0.00	0.00	0.00	289.52	463.50	0.00	0.00	0.00	0.00	94.52	314.57	0.00	0.00	0.00	0.00	0.00	459.07	0.00
FOH	0.00	0.00	0.00	0.00	58.73	0.00	0.00	2.25	0.00	0.00	0.00	12.28	0.00	0.00	0.00	0.00	0.00	1.53
MOH	0.00	0.00	0.00	0.00	0.00	9.68	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	1.67	3.80	0.00	0.00	5.65	0.00	0.00	0.00	0.62	51.90	0.00	6.13	2.65	0.00	0.00	0.00	0.00	0.00
LRPF	144.71	145.00	0.00	0.00	69.00	0.00	0.00	0.00	226.77	307.00	0.00	318.17	362.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.51	1.17	0.00	0.00	0.83	0.00	0.00	0.00	0.30	33.76	0.00	4.13	2.03	0.00	0.00	0.00	0.00	0.00
PMOH	2.58	6.49	1.82	0.00	0.00	0.00	2.50	0.00	11.61	6.70	0.00	7.28	2.21	0.00	1.27	3.83	0.00	0.00
LRPM	145.19	144.85	144.74	0.00	0.00	0.00	145.00	0.00	196.80	208.00	0.00	193.60	140.42	0.00	139.63	140.12	0.00	0.00
EMOH	0.79	1.99	0.56	0.00	0.00	0.00	0.77	0.00	4.84	2.95	0.00	2.99	0.66	0.00	0.38	1.14	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-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.00	0.00	0.00	0.00	22.81	0.00	0.00	0.33	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.00	0.00	0.21
MOR	0.00	0.00	0.00	0.00	0.00	1.73	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	0.07	0.16	0.00	0.00	0.42	0.00	0.00	0.00	0.04	5.40	0.00	0.60	0.27	0.00	0.00	0.00	0.00	0.00
PMOR	0.11	0.27	0.08	0.00	0.00	0.00	0.11	0.00	0.65	0.47	0.00	0.43	0.09	0.00	0.05	0.15	0.00	0.00
EUOR	0.18	0.42	0.08	0.00	23.13	1.73	0.11	0.33	0.69	5.87	0.00	2.77	0.36	0.00	0.05	0.15	0.00	0.21
EUOF	0.18	0.42	0.08	0.00	8.26	1.30	0.10	0.32	0.69	5.10	0.00	2.69	0.36	0.00	0.05	0.15	0.00	0.21
POF	0.00	0.00	0.00	38.91	64.29	0.00	0.00	0.00	0.00	13.13	42.28	0.00	0.00	0.00	0.00	0.00	63.67	0.00
EAF	99.82	99.58	99.92	61.09	27.45	98.70	99.90	99.68	99.31	81.77	57.72	97.31	99.64	100.00	99.95	99.85	36.33	99.79

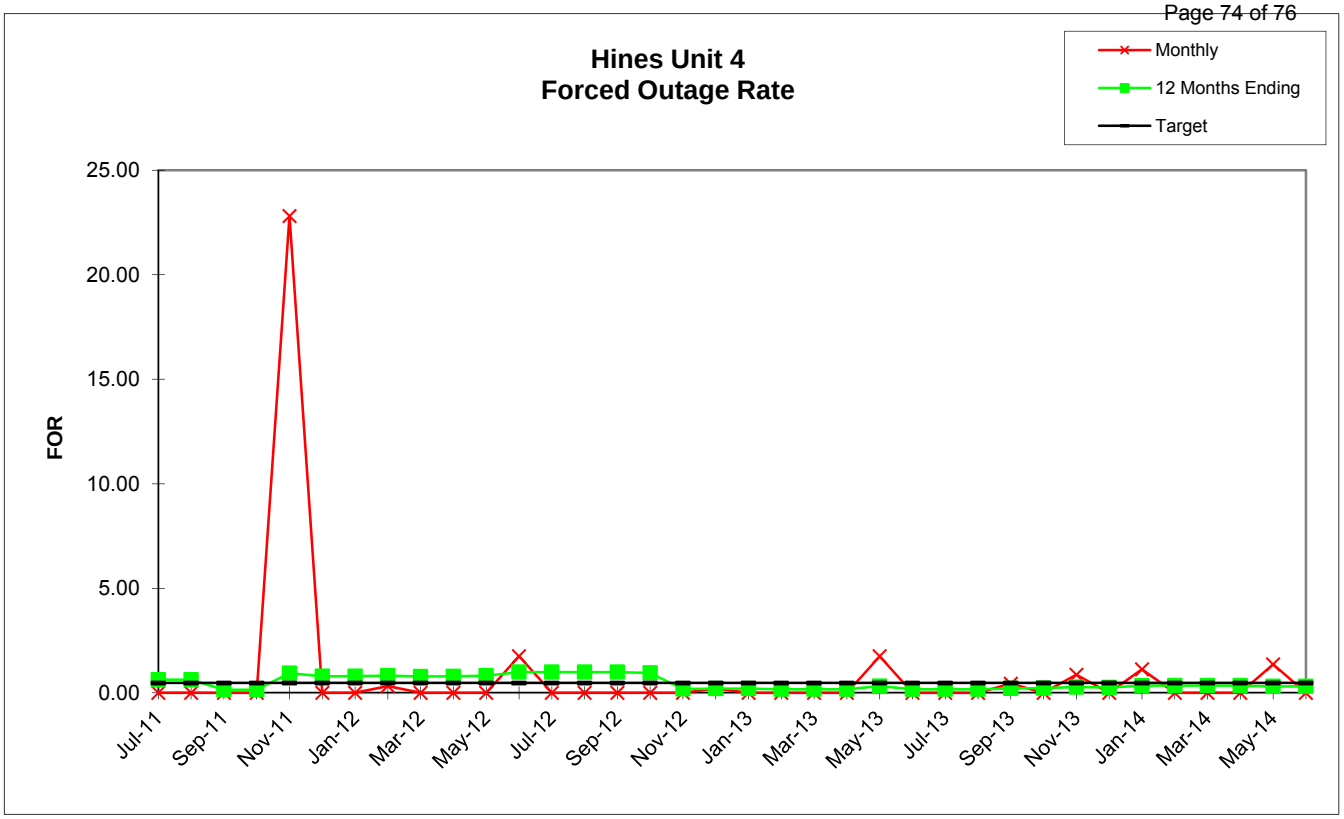
12 MONTHS	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
FOR	0.63	0.63	0.15	0.15	0.94	0.79	0.80	0.82	0.78	0.79	0.82	0.99	0.99	0.99	0.99	0.96	0.19	0.20
MOR	0.00	0.00	0.00	0.00	0.00	0.13	0.13	0.13	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.00
PFOR	1.37	1.39	0.80	0.72	0.70	0.70	0.70	0.70	0.64	0.85	0.52	0.56	0.58	0.56	0.56	0.54	0.53	0.51
PMOR	0.46	0.48	0.49	0.51	0.52	0.53	0.54	0.54	0.57	0.62	0.65	0.20	0.20	0.17	0.17	0.18	0.18	0.17
EUOR	2.45	2.49	1.43	1.37	2.15	2.14	2.16	2.18	2.11	2.37	2.11	1.88	1.90	1.85	1.85	1.79	1.02	0.89
EUOF	2.23	2.26	1.30	1.20	1.83	1.81	1.82	1.84	1.87	2.08	1.78	1.58	1.59	1.56	1.55	1.57	0.89	0.80
POF	9.09	9.09	9.09	12.40	14.67	13.27	13.27	13.23	8.57	9.65	13.23	13.23	13.23	13.23	13.23	9.93	9.88	9.88
EAF	88.68	88.65	89.61	86.40	83.50	84.92	84.91	84.93	89.55	88.27	84.99	85.19	85.18	85.21	85.22	88.50	89.23	89.32

Hines
Unit 4

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	672.00	733.90	720.00	730.98	720.00	744.00	744.00	716.85	216.02	534.02	744.00	557.95	584.94	743.00	720.00	723.95	715.79
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	168.51	87.06	0.00	0.00	0.00	4.21
UH	0.00	0.00	9.10	0.00	13.02	0.00	0.00	0.00	3.15	527.98	186.99	0.00	17.54	0.00	0.00	0.00	20.05	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	527.98	182.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	13.02	0.00	0.00	0.00	3.15	0.00	4.67	0.00	6.34	0.00	0.00	0.00	10.02	0.00
MOH	0.00	0.00	9.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.20	0.00	0.00	0.00	10.02	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.40	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.99	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.61	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	2.22	0.00	2.38	1.77	0.00	0.00	0.00	3.96	0.00	0.00	1.17	8.71	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	139.79	0.00	100.14	119.77	0.00	0.00	0.00	80.04	0.00	0.00	37.85	45.01	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.50	0.45	0.00	0.00	0.00	0.67	0.00	0.00	0.09	0.83	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	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.00	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.44	0.00	0.87	0.00	1.12	0.00	0.00	0.00	1.37	0.00
MOR	0.00	0.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.97	0.00	0.00	0.00	1.37	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.07	0.06	0.00	0.00	0.00	0.12	0.00	0.00	0.01	0.11	0.00
EUOR	0.00	0.00	1.22	0.00	1.75	0.09	0.00	0.07	0.50	0.00	0.87	0.00	3.62	0.00	0.00	0.01	2.81	0.00
EUOF	0.00	0.00	1.22	0.00	1.75	0.09	0.00	0.07	0.50	0.00	0.65	0.00	2.80	0.00	0.00	0.01	2.81	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.97	25.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	98.78	100.00	98.25	99.91	100.00	99.93	99.50	29.03	74.07	100.00	97.20	100.00	100.00	99.99	97.19	100.00

12 MONTHS	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FOR	0.20	0.18	0.18	0.17	0.32	0.18	0.18	0.18	0.21	0.23	0.28	0.26	0.35	0.35	0.35	0.35	0.31	0.31
MOR	0.00	0.00	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.11	0.11	0.26	0.26	0.14	0.14	0.27	0.27
PFOR	0.51	0.51	0.51	0.08	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03
PMOR	0.16	0.16	0.10	0.06	0.06	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.03
EUOR	0.88	0.85	0.90	0.43	0.57	0.34	0.31	0.32	0.36	0.37	0.41	0.39	0.66	0.67	0.56	0.56	0.66	0.65
EUOF	0.79	0.76	0.81	0.39	0.54	0.33	0.29	0.30	0.34	0.32	0.38	0.36	0.60	0.60	0.49	0.50	0.58	0.58
POF	9.88	9.91	9.91	8.83	5.24	5.24	5.24	5.24	5.24	11.27	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11
EAF	89.33	89.32	89.28	90.78	94.22	94.43	94.46	94.46	94.42	88.41	91.51	91.53	91.29	91.29	91.40	91.40	91.31	91.31


Hines Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
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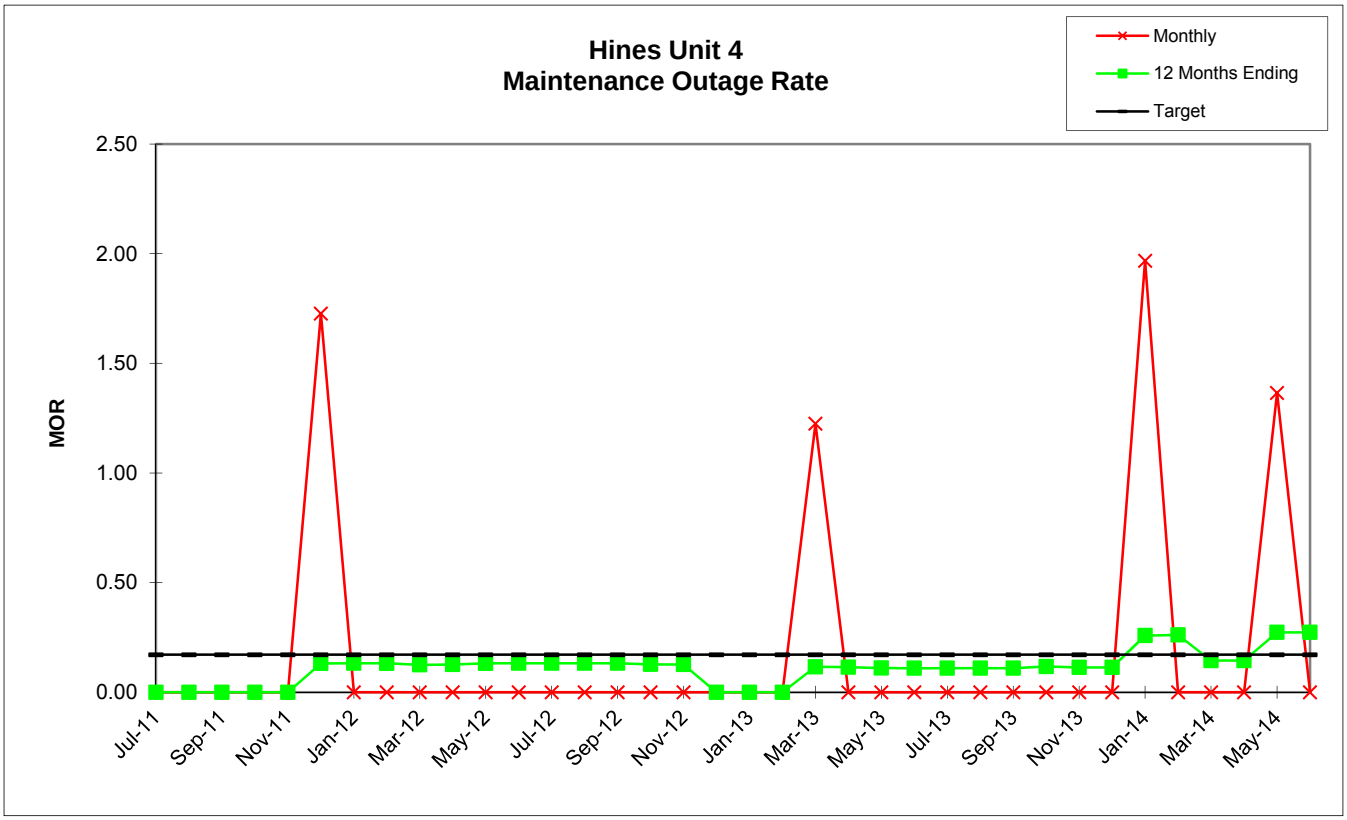
May-14


Hines Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
2.50
2.00
1.50
1.00
0.50
0.00
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
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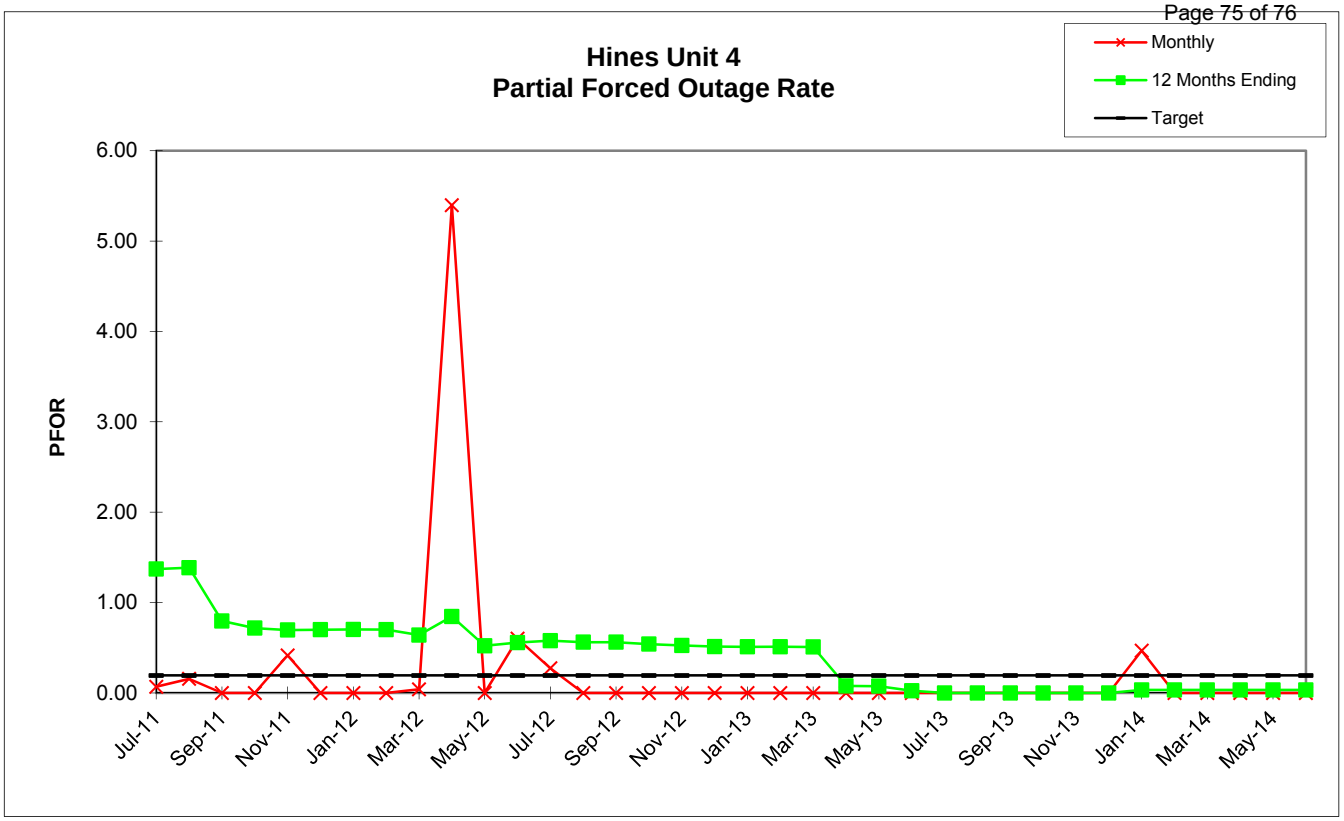
Jan-14
Mar-14
May-14


Hines Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-11
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Mar-12
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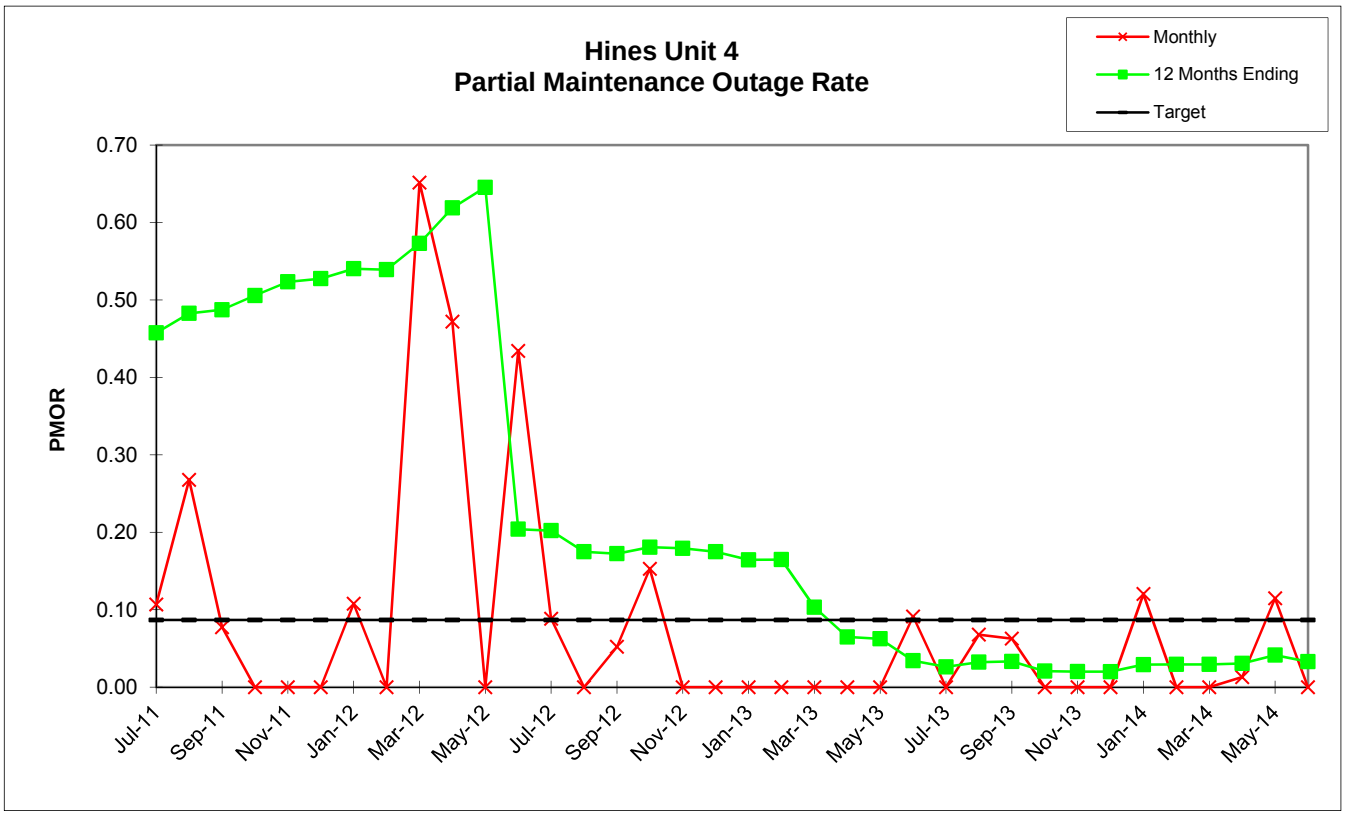
Hines Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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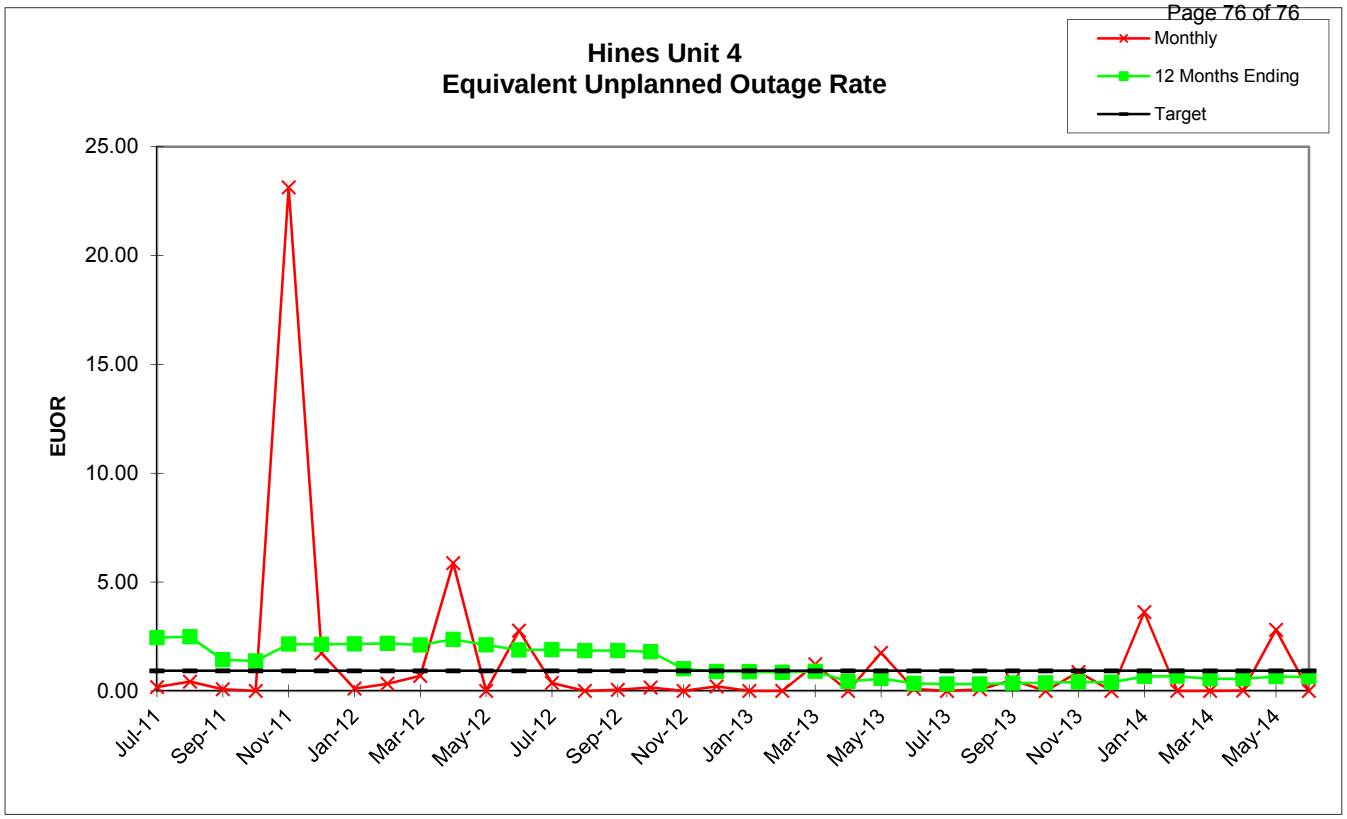
Hines Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-11
Sep-11
Nov-11
Jan-12
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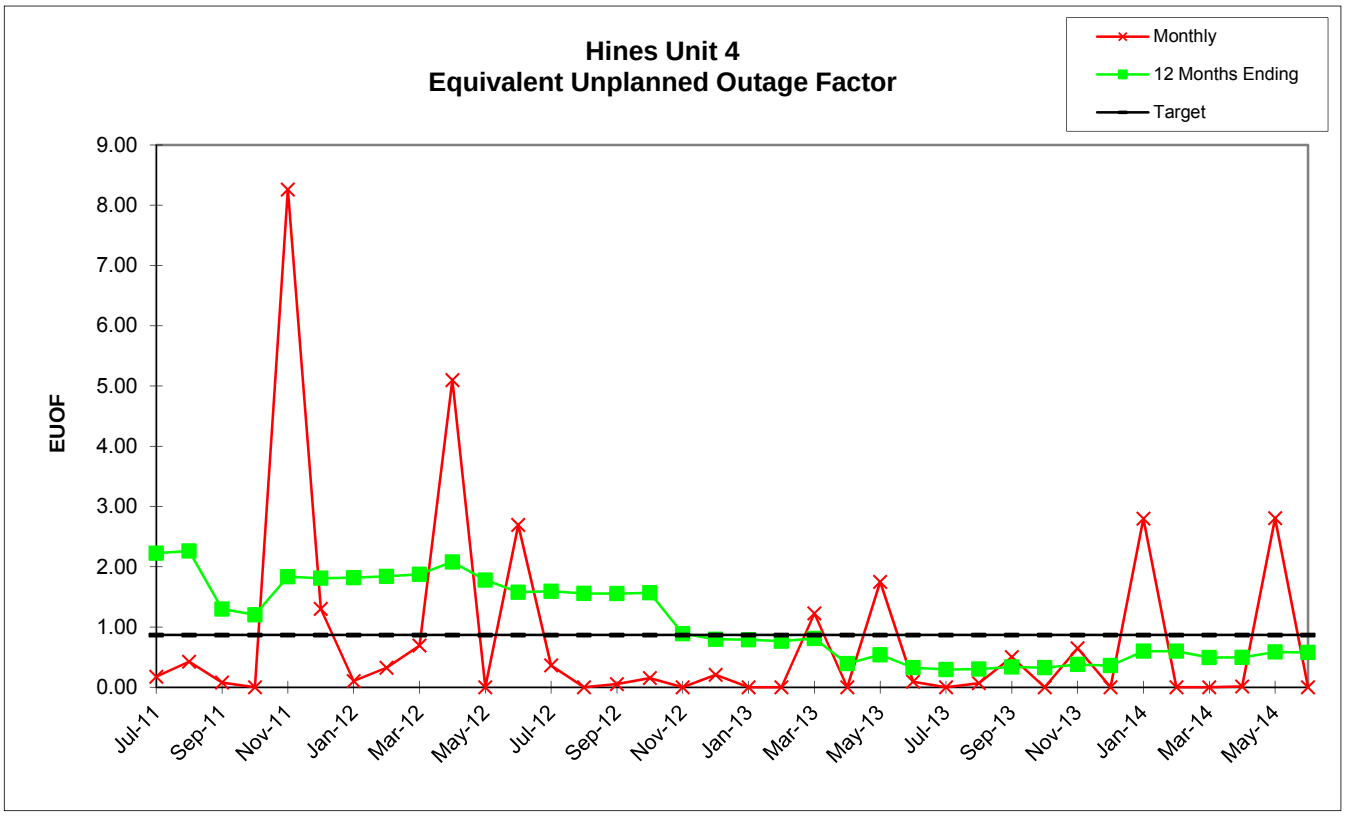
Hines Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
9.00
8.00
7.00
6.00
5.00
4.00
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May-14

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2013 THROUGH DECEMBER 2013

NORTHWEST FLORIDA DIVISION			
1	JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	$	28,302,994
2	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD		28,368,579
3	ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		65,585
4	ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)		(1,477,604)
5	INTEREST		(2,054)
6	TRUE-UP COLLECTED		1,477,604
7	PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/13)		(2,596,293)
8	ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		(2,532,762)
9	PROJECTED UNDER-RECOVERY PER PROJECTION FILED 10/31/13		(755,373)
10	**FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)**		**(1,777,389)**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 29
PARTY: FLORIDA PUBLIC UTILITIES COMPANY (FPUC) (DIRECT)
DESCRIPTION: Curtis D. Young CDY-1

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(CDY - 1)

Schedule B

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2013 THROUGH DECEMBER 2013

NORTHEAST FLORIDA DIVISION		
1 JURISDICTIONAL FUEL COSTS (NET OF GSLD1 / STAND BY FUEL COSTS)	$	28,802,545
2 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD (NET OF GSLD1 /STANDBY FUEL REVENUES)		30,697,713
3 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		1,895,168
4 ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)		258,636
5 INTEREST		2,021
6 TRUE-UP COLLECTED		(258,636)
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/13)		2,044,109
8 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		3,941,298
9 PROJECTED UNDER-RECOVERY PER PROJECTION FILED 10/31/13		2,685,677
## FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)		**1,255,621**

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(CDY - 1)

FLORIDA PUBLIC UTILITIES COMPANY **Schedule M1**

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

BASED ON TWELVE MONTHS ACTUAL

MARIANNA DIVISION

	ACTUAL JANUARY 2013	ACTUAL FEBRUARY 2013	ACTUAL MARCH 2013	ACTUAL APRIL 2013	ACTUAL MAY 2013	ACTUAL JUNE 2013	ACTUAL JULY 2013	ACTUAL AUGUST 2013	ACTUAL SEPTEMBER 2013	ACTUAL OCTOBER 2013	ACTUALS NOVEMBER 2013	ACTUALS DECEMBER 2013	Total
Total System Sales - KWH	24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	28,718,720	28,806,776	27,988,763	24,655,584	20,449,337	23,414,659	293,950,844
Total System Purchases - KWH	24,917,444	22,515,414	24,361,046	21,950,706	25,381,308	29,535,698	29,550,909	30,742,395	28,268,462	23,925,987	23,090,567	25,616,104	309,856,040
System Billing Demand - KW	97,944	97,944	97,944	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,112,832
Peak Billing Demand-KW	58,600	57,108	55,639	55,119	56,630	55,599	55,207	55,338	55,100	54,730	54,648	55,539	669,257
Purchased Power Rates:													
Energy/Environmental - $/KWH (Loss Factor 0.974)	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	
Demand and Non-Fuel:													
Capacity Charge - $/KW	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	9.50000	
Transmission and Interconnection - $/KW	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	
Distribution Charge	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:													
Base Fuel Costs	1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,497,873	1,558,267	1,432,869	1,212,758	1,170,412	1,298,426	15,705,949
Subtotal Fuel Costs	1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,497,873	1,558,267	1,432,869	1,212,758	1,170,412	1,298,426	15,705,949
Demand and Non-Fuel Costs:													
Capacity Charge	930,468	930,468	930,468	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	10,571,904
Transmission and Interconection	141,671	138,064	134,513	133,256	136,909	134,416	133,468	36,545	133,210	132,315	132,117	134,271	1,520,755
Distribution Facilities Charge (incl. FERC l/t chrg)	41,494	41,441	41,276	41,077	41,237	41,472	41,757	41,757	41,839	41,670	41,342	41,286	497,648
Meter Reading and Processing Charge	775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs	1,114,408	1,110,748	1,107,032	1,039,608	1,043,421	1,041,163	1,040,500	943,577	1,040,324	1,039,260	1,038,734	1,040,832	12,599,607
Total System Purchased Power Costs	2,377,421	2,252,007	2,341,842	2,152,243	2,329,946	2,538,265	2,538,373	2,501,844	2,473,193	2,252,018	2,209,146	2,339,258	28,305,556
Special Costs	315	259	838	(286)	237	280	193	(5,531)	288	310	280	255	(2,562)
Total Costs and Charges	2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,538,566	2,496,313	2,473,481	2,252,328	2,209,426	2,339,513	28,302,994
Sales Revenues - Fuel Adjustment Revenues:													
Residential< .09876 .09876	745,459	707,787	719,204	659,211	647,277	745,888	757,794	770,131	763,505	699,386	631,140	727,153	8,573,935
Residential> .10875 .10875	394,100	237,446	275,334	143,191	168,909	369,427	392,762	442,408	410,586	242,025	114,591	305,243	3,496,022
Commercial, Small .09847 .09847	214,315	196,210	200,245	188,608	213,525	255,507	260,553	269,519	262,416	240,364	189,252	202,176	2,692,690
Commercial, Large .09301 .09301	580,696	548,924	543,211	535,886	689,292	708,118	735,120	776,790	751,100	701,270	564,281	570,798	7,705,486
Commercial, Large Demand .08912 .08912	437,664	368,999	375,926	450,323	457,283	415,908	571,980	478,480	469,927	436,948	406,439	409,486	5,279,363
Outside Lighting Private .07405 .07405	25,326	25,079	24,794	25,241	24,983	25,031	25,058	25,035	25,133	25,160	25,079	25,110	301,029
Street Lighting-Public .07468 .07468	7,770	7,770	7,775	7,785	7,805	7,805	7,805	7,805	7,804	7,808	7,808	7,808	93,548
Unbilled Fuel Revenues	101,520	(205,607)	196,775	(168,866)	219,810	73,938	(19,122)	63,187	(104,893)	(119,811)	55,166	134,410	226,506
Total Fuel Revenues	2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,731,950	2,833,355	2,585,578	2,233,150	1,993,756	2,382,184	28,368,579
Non-Fuel Revenues	948,551	868,681	888,817	834,631	860,744	966,273	1,017,404	1,020,597	1,009,669	928,106	818,148	917,258	11,078,880
Total Sales Revenue	3,455,401	2,755,289	3,232,081	2,676,010	3,289,628	3,567,895	3,749,354	3,853,952	3,595,247	3,161,256	2,811,904	3,299,442	39,447,459
KWH Sales:													
Residential< RS	7,547,116	7,165,811	7,283,589	6,676,580	6,553,498	7,554,878	7,672,054	7,801,947	7,730,553	7,082,472	6,391,478	7,363,881	86,823,857
Residential> RS	3,626,066	2,185,023	2,531,775	1,315,649	1,554,563	3,396,095	3,613,479	4,070,309	3,777,254	2,225,479	1,053,699	2,806,786	32,156,177
Commercial, Small GS	2,176,473	1,992,605	2,033,584	1,915,401	2,168,449	2,594,686	2,646,036	2,737,096	2,664,961	2,441,006	1,921,938	2,053,196	27,345,431
Commercial, Large GSD	6,259,027	5,917,326	5,862,447	5,779,032	7,421,683	7,625,833	7,925,641	8,385,230	8,098,764	7,559,047	6,078,109	6,152,063	83,064,202
Industrial GSLD	4,911,176	4,140,672	4,218,392	5,053,236	5,131,332	4,667,052	6,418,392	5,369,188	5,273,212	4,903,152	4,560,792	4,594,984	59,241,580
Outside Lighting-Private OL,OL-2	342,233	338,761	334,913	340,951	337,462	338,130	338,604	338,492	339,505	339,873	338,769	339,197	4,066,890
Street Lighting-Public SL-1, 2, 3	104,050	104,050	104,113	104,265	104,514	104,514	104,514	104,514	104,514	104,555	104,552	104,552	1,252,707
Total KWH Sales	24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	28,718,720	28,806,776	27,988,763	24,655,584	20,449,337	23,414,659	293,950,844
True-up Calculation:													to Date
Fuel Revenues	2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,731,950	2,833,355	2,585,578	2,233,150	1,993,756	2,382,184	28,368,579
True-up Provision for the Period - collect/(refund)	123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
Gross Receipts Tax Refund	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue	2,383,720	1,763,474	2,220,130	1,718,245	2,305,750	2,478,488	2,608,816	2,710,221	2,462,444	2,110,016	1,870,622	2,259,050	26,890,975
Total Purchased Power Costs	2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,538,566	2,496,313	2,473,481	2,252,328	2,209,426	2,339,513	28,302,994
True-up Provision for the Period	5,984	(488,792)	(122,550)	(433,712)	(24,433)	(60,057)	70,250	213,908	(11,037)	(142,312)	(338,804)	(80,463)	(1,412,019)
Interest Provision for the Period	(263)	(321)	(272)	(224)	(179)	(163)	(156)	(110)	(79)	(89)	(114)	(84)	(2,054)
True-up and Interest Provision													
Beginning of Period	(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,789,247)	(2,452,315)	(2,340,298)	(2,359,565)	(2,575,348)	(2,596,293)
True-up Collected or (Refunded)	123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
End of Period, Net True-up	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,789,247)	(2,452,315)	(2,340,298)	(2,359,565)	(2,575,348)	(2,532,761)	(2,532,762)
10% Rule - Interest Provision:													-8.95%
Beginning True-up Amount	(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,789,247)	(2,452,315)	(2,340,298)	(2,359,565)	(2,575,348)	
Ending True-up Amount Before Interest	(2,467,179)	(2,833,100)	(2,832,837)	(3,143,687)	(3,045,210)	(2,982,313)	(2,789,091)	(2,452,205)	(2,340,219)	(2,359,476)	(2,575,234)	(2,532,677)	
Total Beginning and Ending True-up	(5,063,472)	(5,300,542)	(5,666,258)	(5,976,796)	(6,189,122)	(6,027,702)	(5,771,566)	(5,241,452)	(4,792,534)	(4,699,773)	(4,934,799)	(5,108,025)	
Average True-up Amount	(2,531,736)	(2,650,271)	(2,833,129)	(2,988,398)	(3,094,561)	(3,013,851)	(2,885,783)	(2,620,726)	(2,396,267)	(2,349,887)	(2,467,399)	(2,554,013)	
Average Annual Interest Rate	0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.0650%	0.0500%	0.0400%	0.0450%	0.0550%	0.0400%	
Monthly Average Interest Rate	0.0104%	0.0121%	0.0096%	0.0075%	0.0058%	0.0054%	0.0054%	0.0042%	0.0033%	0.0038%	0.0046%	0.0033%	
Interest Provision	(263)	(321)	(272)	(224)	(179)	(163)	(156)	(110)	(79)	(89)	(114)	(84)	

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(CDY-1)
Page 3 of 6

FLORIDA PUBLIC UTILITIES COMPANY

Schedule F1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH

		ACTUAL Jan 2013	ACTUAL Feb 2013	ACTUAL Mar 2013	ACTUAL Apr 2013	ACTUAL May 2013	ACTUAL Jun 2013	ACTUAL Jul 2013	ACTUAL Aug 2013	ACTUAL Sep 2013	ACTUAL Oct 2013	ACTUAL Nov 2013	ACTUAL Dec 2013	Total
Total System Sales - KWH		26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	33,912,847	34,880,178	33,990,122	28,650,438	23,865,697	23,807,884	336,727,208
CCA Purchases - KWH		873,871	686,578	1,078,805	639,052	947,823	717,953	621,421	822,970	907,333	888,710	258,327	3,092,375	11,535,218
Rayonier Purchases - KWH - On Peak		727,244	328,328	392,673	396,848	527,104	698,783	512,543	505,768	479,197	471,661	607,742	371,730	6,019,621
Rayonier Purchases - KWH - Off Peak		1,003,083	539,216	759,721	801,135	1,136,125	1,479,937	1,348,470	1,127,684	1,460,652	1,255,911	911,973	755,591	12,579,498
JEA Purchases - KWH		23,253,095	22,813,142	29,830,181	21,423,671	25,499,052	30,563,602	34,921,745	35,832,685	29,303,339	25,087,971	22,809,879	21,769,084	323,107,446
System Billing Demand - KW		70,246	78,714	80,326	51,654	58,195	73,920	66,976	77,737	76,877	61,286	48,429	56,896	801,256
DEMAND-KW-(network load)		86,197	105,903	102,389	78,286	85,308	103,691	98,493	99,540	79,471	86,922	74,619	96,374	1,097,193
Purchased Power Rates:														
CCA 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		0.09047	0.04563	0.09047	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.10478	0.09097	0.04563	
Rayonier- Energy Charge - Off Peak - $/KWH		0.05822	0.04563	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05460	0.05460	0.04563	
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	
Energy Charge - $/KWH		0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01162	0.01162	0.01162	
Demand and Non-Fuel:														
Demand Charge - $/KW		11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	14.31	14.31	14.31	
Distribution Facilities Charge - $		39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
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	
Purchased Power Costs:	CCA Fuel Costs	38,678	30,388	47,748	28,284	41,951	31,777	27,504	36,425	40,159	39,334	11,433	136,868	510,549
	Rayonier Standby Costs	142,757	39,586	79,756	86,160	118,634	155,746	129,547	116,018	132,757	117,994	105,080	51,440	1,275,475
	JEA Base Fuel Costs	1,013,835	994,653	1,300,596	934,072	143,200	1,332,573	1,522,587	1,562,305	1,277,626	1,093,836	994,511	949,132	13,118,926
	JEA Fuel Adjustment	382,048	374,820	490,110	351,991	418,949	502,160	573,764	588,731	481,454	286,771	265,051	252,957	4,968,806
	Subtotal Fuel Costs	1,577,318	1,439,447	1,918,210	1,400,507	722,734	2,022,256	2,253,402	2,303,479	1,931,996	1,537,935	1,376,075	1,390,397	19,873,756
Demand and Non-Fuel Costs:	Demand Charge	799,399	895,765	914,110	587,822	662,259	841,210	762,188	884,647	874,860	877,003	693,018	814,181	9,606,462
	Distribution Facilities Charg	39,736	39,736	39,736	39,736	39,736	39,737	39,737	39,736	39,736	39,736	39,736	39,736	476,834
	Transmission Charge	130,158	159,914	154,607	118,212	128,815	156,573	148,724	150,305	120,002	131,252	112,675	145,525	1,656,762
Subtotal Demand & Non-Fuel Costs		969,293	1,095,415	1,108,453	745,770	830,810	1,037,520	950,649	1,074,688	1,034,598	1,047,991	845,429	999,442	11,740,058
Total System Purchased Power Costs		2,546,611	2,534,862	3,026,663	2,146,277	1,553,544	3,059,776	3,204,051	3,378,167	2,966,594	2,585,926	2,221,504	2,389,839	31,613,814
Less Direct Billing To GSLD1 Class:	Demand	372,221	133,824	261,366	52,793	56,637	47,776	68,523	60,787	275,280	52,260	47,853	49,180	1,478,500
	Commodity	183,802	152,090	355,136	100,352	135,107	108,294	126,553	75,614	125,009	159,430	183,576	109,435	1,814,398
Net Purchased Power Costs		1,990,588	2,248,948	2,410,161	1,993,132	1,361,800	2,903,706	3,008,975	3,241,766	2,566,305	2,374,236	1,990,075	2,231,224	28,320,916
	Special Costs	16,197	17,040	51,516	15,707	39,981	75,998	48,931	131,098	28,896	34,026	29,085	(6,846)	481,629
Total Costs and Charges		2,006,785	2,265,988	2,461,677	2,008,839	1,401,781	2,979,704	3,057,906	3,372,864	2,595,201	2,408,262	2,019,160	2,224,378	28,802,545
Sales Revenues - Fuel Adjustment Revenues:														
RS< 1,000 kwh	.09779	962,565	926,269	970,561	907,587	890,396	1,048,397	1,123,271	1,121,012	1,100,084	970,469	815,525	892,914	11,729,050
RS> 1,000 kwh	.10778	429,116	304,897	364,796	254,549	310,572	586,390	800,736	802,418	719,363	402,775	195,054	305,488	5,476,154
GS	.09823	216,202	192,353	207,358	204,629	227,038	267,290	287,946	305,147	292,467	251,613	204,556	205,630	2,862,229
GSD	.09370	501,049	456,954	494,316	516,351	593,238	655,077	688,905	721,887	776,568	651,593	550,588	538,677	7,145,203
GSLD	.09045	185,963	152,687	177,737	187,768	210,780	230,779	224,800	238,238	235,658	226,736	183,683	198,608	2,453,437
OL	.06733	7,603	7,620	7,245	7,584	7,598	7,668	7,630	7,634	7,637	7,627	7,621	7,643	91,110
SL,CSL	.06713	4,828	4,828	4,845	4,957	4,969	4,973	4,973	4,973	4,973	4,973	4,973	4,774	59,039
Unbilled Fuel Revenues		140,850	(195,621)	342,734	(349,352)	531,505	(117,346)	391,966	(185,870)	13,537	(147,258)	(413,423)	869,769	881,490
Total Fuel Revenues (Excl. GSLD1)		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,530,227	3,015,439	3,150,287	2,368,528	1,548,577	3,023,503	30,697,713
GSLD1 Fuel Revenues	.00000	556,023	285,914	616,502	153,145	191,744	156,070	195,076	136,401	400,289	211,690	231,429	158,615	3,292,898
Non-Fuel Revenues		955,049	863,007	957,773	901,078	885,378	972,945	1,103,649	1,117,797	1,126,885	964,358	823,192	869,594	11,540,705
Total Sales Revenue		3,959,248	2,998,908	4,143,867	2,788,296	3,853,218	3,812,243	4,828,952	4,269,637	4,677,461	3,544,576	2,603,198	4,051,712	45,531,316
KWH Sales:	RS< 1,000 kwh	9,843,458	9,472,061	9,925,485	9,290,382	9,105,219	10,720,944	11,487,490	11,463,510	11,249,496	9,924,055	8,339,580	9,130,986	119,952,666
	RS> 1,000 kwh	3,981,444	2,828,827	3,384,562	2,366,718	2,881,477	5,440,487	7,429,188	7,444,796	6,674,213	3,736,930	1,809,704	2,834,302	50,812,648
	GS	2,203,160	1,991,950	2,110,953	2,085,158	2,311,302	2,721,087	2,931,363	3,106,481	2,977,395	2,561,490	2,082,435	2,093,367	29,176,141
	GSD	5,350,031	4,876,640	5,275,378	5,568,082	6,331,079	6,991,040	7,352,047	7,704,033	8,276,127	6,953,843	5,875,918	5,748,803	76,303,021
	GSLD	2,055,860	1,688,000	1,964,920	2,075,840	2,330,220	2,551,320	2,485,220	2,633,780	2,605,260	2,506,620	2,030,660	2,195,660	27,123,360
	GSLD1	2,960,000	2,500,000	5,760,000	1,620,000	2,180,000	1,760,000	2,040,000	2,340,000	2,020,000	2,780,000	3,540,000	1,620,000	31,120,000
	OL	113,333	113,299	112,609	112,769	112,974	114,028	113,466	113,503	113,558	113,427	113,327	113,654	1,359,947
	SL,CSL	71,916	71,916	72,175	73,842	74,024	74,073	74,073	74,075	74,073	74,073	74,073	71,112	879,425
Total KWH Sales		26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	33,912,847	34,880,178	33,990,122	28,650,438	23,865,697	23,807,884	336,727,208
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,530,227	3,015,439	3,150,287	2,368,528	1,548,577	3,023,503	30,697,713
True-up Provision - collect/(refund)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		2,469,729	1,871,540	2,591,145	1,755,626	2,797,649	2,704,781	3,551,780	3,036,992	3,171,840	2,390,081	1,570,130	3,045,056	30,956,349
Net Purchased Power and Other Fuel Costs		2,006,785	2,265,988	2,461,677	2,008,839	1,401,781	2,979,704	3,057,906	3,372,864	2,595,201	2,408,262	2,019,160	2,224,378	28,802,545
True-up Provision for the Period		462,944	(394,448)	129,468	(253,213)	1,395,868	(274,923)	493,874	(335,872)	576,639	(18,181)	(449,030)	820,678	2,153,804
Interest Provision for the Period		236	276	204	153	150	169	174	138	111	138	155	117	2,021
Beginning of Period True-up and Interest Provision		2,044,109	2,485,736	2,070,011	2,178,130	1,903,517	3,277,982	2,981,675	3,454,170	3,096,883	3,652,080	3,612,484	3,142,056	2,044,109
True-up Collected or (Refunded)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
End of Period, Net True-up and Int. Prov.		2,485,736	2,070,011	2,178,130	1,903,517	3,277,982	2,981,675	3,454,170	3,096,883	3,652,080	3,612,484	3,142,056	3,941,298	3,941,298
Beginning True-up Amount		2,044,109	2,485,736	2,070,011	2,178,130	1,903,517	3,277,982	2,981,675	3,454,170	3,096,883	3,652,080	3,612,484	3,142,056	
Ending True-up Amount Before Interest		2,485,500	2,069,735	2,177,926	1,903,364	3,277,832	2,981,507	3,453,995	3,096,745	3,651,969	3,612,346	3,141,901	3,941,181	10% Rule Interest Provision: 12.47%
Total Beginning and Ending True-up		4,529,609	4,555,471	4,247,937	4,081,494	5,181,349	6,259,489	6,435,670	6,550,915	6,748,852	7,264,427	6,754,385	7,083,237	
Average True-up Amount		2,264,804	2,277,735	2,123,969	2,040,747	2,590,674	3,129,744	3,217,835	3,275,458	3,374,426	3,632,213	3,377,193	3,541,618	
Average Annual Interest Rate		0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.0650%	0.0500%	0.0400%	0.0450%	0.0550%	0.0400%	
Interest Provision		236	276	204	153	150	169	174	138	111	138	155	117	

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(CDY-1)
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FLORIDA PUBLIC UTILITIES COMPANY

Schedule E1-B

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION **revised 8/30/2013**

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

MARIANNA DIVISION

	ACTUAL JANUARY 2013	ACTUAL FEBRUARY 2013	ACTUAL MARCH 2013	ACTUAL APRIL 2013	ACTUAL MAY 2013	ACTUAL JUNE 2013	Estimated JULY 2013	Estimated AUGUST 2013	Estimated SEPTEMBER 2013	Estimated OCTOBER 2013	Estimated NOVEMBER 2013	Estimated DECEMBER 2013	Total
Total System Sales - KWH	24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	30,440,000	30,068,000	30,610,000	29,829,000	27,292,000	28,596,000	316,752,005
Total System Purchases - KWH	24,917,444	22,515,414	24,361,046	21,950,706	25,381,308	29,535,698	33,120,681	33,477,525	32,093,915	29,566,500	24,623,100	26,977,780	328,521,117
System Billing Demand - KW	97,944	97,944	97,944	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,112,832
Peak Billing Demand-KW	58,600	57,108	55,639	55,119	56,630	55,599	65,761	67,679	63,290	52,589	46,174	61,606	695,794
Purchased Power Rates:													
Energy/Environmental - $/KWH (Loss Factor 0.974)	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	
Demand and Non-Fuel:													
Capacity Charge - $/KWH	9.50000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	
Transmission and Interconnection - $/KWH	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	
Distribution Charge	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:													
Base Fuel Costs	1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,678,817	1,696,905	1,626,773	1,498,663	1,248,093	1,367,447	16,652,042
Subtotal Fuel Costs	1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,678,817	1,696,905	1,626,773	1,498,663	1,248,093	1,367,447	16,652,042
Demand and Non-Fuel Costs:													
Capacity Charge	930,468	930,468	930,468	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	10,571,904
Transmission and Interconection	141,671	138,064	134,513	133,256	136,909	134,416	(17,310)	163,621	153,010	127,139	111,630	148,939	1,505,858
Distribution Facilities Charge (incl. FERC l/t chrg)	41,494	41,441	41,276	41,077	41,237	41,472	42,237	42,264	42,159	41,968	41,595	41,773	499,993
Meter Reading and Processing Charge	775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs	1,114,408	1,110,748	1,107,032	1,039,608	1,043,421	1,041,163	890,202	1,071,160	1,060,444	1,034,382	1,018,500	1,055,987	12,587,055
Total System Purchased Power Costs	2,377,421	2,252,007	2,341,842	2,152,243	2,329,946	2,538,265	2,569,019	2,768,065	2,687,217	2,533,045	2,266,593	2,423,434	29,239,097
Special Costs	315	259	838	(286)	237	280	300	300	300	300	300	300	3,443
Total Costs and Charges	2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,569,319	2,768,365	2,687,517	2,533,345	2,266,893	2,423,734	29,242,540
Sales Revenues - Fuel Adjustment Revenues:													
Residential< .09876 .09876	745,459	707,787	719,204	659,211	647,277	745,888	636,106	622,971	752,839	710,274	742,963	811,107	8,501,086
Residential> .10875 .10875	394,100	237,446	275,334	143,191	168,909	369,427	543,215	606,617	563,769	579,212	540,931	612,598	5,034,749
Commercial, Small .09847 .09847	214,315	196,210	200,245	188,608	213,525	255,507	317,366	301,709	283,985	271,085	221,359	226,479	2,890,393
Commercial, Large .09301 .09301	580,696	548,924	543,211	535,886	689,292	708,118	866,323	829,025	816,933	791,448	652,486	644,580	8,206,922
Industrial .08912 .08912	437,664	368,999	375,926	450,323	457,283	415,908	538,171	515,090	509,208	501,544	455,204	454,134	5,479,454
Outside Lighting Private .07405 .07405	25,326	25,079	24,794	25,241	24,983	25,031	24,658	24,435	24,213	24,213	24,287	24,361	296,621
Street Lighting-Public .07468 .07468	7,770	7,770	7,775	7,785	7,805	7,805	7,094	7,094	7,094	7,020	7,169	7,094	89,275
Unbilled Fuel Revenues	101,520	(205,607)	196,775	(168,866)	219,810	73,938	0	0	0	0	150,000	220,000	587,569
Total Fuel Revenues	2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,932,933	2,906,941	2,958,041	2,884,796	2,794,399	3,000,353	31,086,069
Non-Fuel Revenues	948,551	868,681	888,817	834,631	860,744	966,273	943,867	1,368,409	1,175,438	1,255,289	1,191,429	890,097	12,192,227
Total Sales Revenue	3,455,401	2,755,289	3,232,081	2,676,010	3,289,628	3,567,895	3,876,800	4,275,350	4,133,479	4,140,085	3,985,828	3,890,450	43,278,296
KWH Sales:													
Residential< RS	7,547,116	7,165,811	7,283,589	6,676,580	6,553,498	7,554,878	6,441,000	6,308,000	7,623,000	7,192,000	7,523,000	8,213,000	86,081,472
Residential> RS	3,626,066	2,185,023	2,531,775	1,315,649	1,554,563	3,396,095	4,995,000	5,578,000	5,184,000	5,326,000	4,974,000	5,633,000	46,299,171
Commercial, Small GS	2,176,473	1,992,605	2,033,584	1,915,401	2,168,449	2,594,686	3,223,000	3,064,000	2,884,000	2,753,000	2,248,000	2,300,000	29,353,198
Commercial, Large GSD	6,259,027	5,917,326	5,862,447	5,779,032	7,421,683	7,625,833	9,314,000	8,913,000	8,783,000	8,509,000	7,015,000	6,930,000	88,329,348
Industrial GSLD	4,911,176	4,140,672	4,218,392	5,053,236	5,131,332	4,667,052	6,039,000	5,780,000	5,714,000	5,628,000	5,108,000	5,096,000	61,486,860
Outside Lighting-Private OL,OL-2	342,233	338,761	334,913	340,951	337,462	338,130	333,000	330,000	327,000	327,000	328,000	329,000	4,006,450
Street Lighting-Public SL-1, 2, 3	104,050	104,050	104,113	104,265	104,514	104,514	95,000	95,000	95,000	94,000	96,000	95,000	1,195,506
Total KWH Sales	24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	30,440,000	30,068,000	30,610,000	29,829,000	27,292,000	28,596,000	316,752,005
True-up Calculation:													to Date
Fuel Revenues	2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,932,933	2,906,941	2,958,041	2,884,796	2,794,399	3,000,353	31,086,069
True-up Provision for the Period - collect/(refund)	123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
Gross Receipts Tax Refund	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue	2,383,720	1,763,474	2,220,130	1,718,245	2,305,750	2,478,488	2,809,799	2,783,807	2,834,907	2,761,662	2,671,265	2,877,219	29,608,465
Total Purchased Power Costs	2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,569,319	2,768,365	2,687,517	2,533,345	2,266,893	2,423,734	29,242,540
True-up Provision for the Period	5,984	(488,792)	(122,550)	(433,712)	(24,433)	(60,057)	240,480	15,442	147,390	228,317	404,372	453,485	365,925
Interest Provision for the Period	(263)	(321)	(272)	(224)	(179)	(163)	(269)	(245)	(225)	(195)	(153)	(100)	(2,609)
True-up and Interest Provision													
Beginning of Period	(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	(2,596,293)
True-up Collected or (Refunded)	123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
End of Period, Net True-up	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	(755,372)	(755,373)
10% Rule - Interest Provision:													-2.58%
Beginning True-up Amount	(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	
Ending True-up Amount Before Interest	(2,467,179)	(2,833,100)	(2,832,837)	(3,143,687)	(3,045,210)	(2,982,313)	(2,618,861)	(2,480,554)	(2,210,275)	(1,859,049)	(1,331,738)	(755,272)	
Total Beginning and Ending True-up	(5,063,472)	(5,300,542)	(5,666,258)	(5,976,796)	(6,189,122)	(6,027,702)	(5,601,335)	(5,099,683)	(4,691,073)	(4,069,548)	(3,190,981)	(2,087,162)	
Average True-up Amount	(2,531,736)	(2,650,271)	(2,833,129)	(2,988,398)	(3,094,561)	(3,013,851)	(2,800,668)	(2,549,842)	(2,345,537)	(2,034,774)	(1,595,491)	(1,043,581)	
Average Annual Interest Rate	0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Monthly Average Interest Rate	0.0104%	0.0121%	0.0096%	0.0075%	0.0058%	0.0054%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	
Interest Provision	(263)	(321)	(272)	(224)	(179)	(163)	(269)	(245)	(225)	(195)	(153)	(100)	

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(CDY-1)
Page 5 of 6

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Schedule E-1b

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1 **revised 8/30/2013**

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

NORTHEAST FLORIDA DIVISION

		ACTUAL Jan 2013	ACTUAL Feb 2013	ACTUAL Mar 2013	ACTUAL Apr 2013	ACTUAL May 2013	ACTUAL Jun 2013	Estimated Jul 2013	Estimated Aug 2013	Estimated Sep 2013	Estimated Oct 2013	Estimated Nov 2013	Estimated Dec 2013	Total
Total System Sales - KWH		26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	36,508,000	36,058,000	34,244,000	31,588,000	26,020,000	25,116,000	347,154,042
CCA Purchases - KWH		873,871	686,578	1,078,805	639,052	947,823	717,953	800,000	800,000	800,000	800,000	800,000	800,000	9,744,082
Rayonier Purchases - KWH - On Peak		727,244	328,328	392,673	396,848	527,104	698,783	420,000	420,000	420,000	420,000	420,000	420,000	5,590,980
Rayonier Purchases - KWH - Off Peak		1,003,083	539,216	759,721	801,135	1,136,125	1,479,937	980,000	980,000	980,000	980,000	980,000	980,000	11,599,217
JEA Purchases - KWH		23,253,095	22,813,142	29,830,161	21,423,671	25,499,052	30,563,602	38,240,860	36,725,610	34,829,980	31,009,460	25,190,900	24,246,220	343,625,773
System Billing Demand - KW		70,246	78,714	80,326	51,654	58,195	73,920	89,900	90,600	82,300	74,300	65,600	80,200	895,955
DEMAND-KW-(network load)		86,197	105,903	102,389	78,286	85,308	103,691	106,200	108,400	95,600	89,300	75,100	97,300	1,133,674
Purchased Power Rates:														
CCA 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		0.09047	0.04563	0.09047	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.08812	0.09047	
Rayonier- Energy Charge - Off Peak - $/KWH		0.05822	0.04563	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	
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	
Energy Charge - $/KWH		0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01162	0.01162	0.01162	
Demand and Non-Fuel:														
Demand Charge - $/KW		11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	14.31	14.31	14.31	
Customer Charge - $		39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
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	
Purchased Power Costs:	CCA Fuel Costs	38,678	30,388	47,748	28,284	41,951	31,777	35,408	35,408	35,408	35,408	35,408	35,408	431,274
	Rayonier Standby Costs	142,757	39,586	79,756	86,160	118,634	155,746	98,879	98,879	98,879	98,879	94,066	95,053	1,207,274
	JEA Base Fuel Costs	1,013,835	994,653	1,300,596	934,072	143,200	1,332,573	1,667,301	1,601,237	1,518,587	1,352,012	1,098,323	1,057,135	14,013,524
	JEA Fuel Adjustment	382,048	374,820	490,110	351,991	418,949	502,160	628,297	603,402	572,257	360,330	292,718	281,741	5,258,823
	Subtotal Fuel Costs	1,577,318	1,439,447	1,918,210	1,400,507	722,734	2,022,256	2,429,885	2,338,926	2,225,131	1,846,629	1,520,515	1,469,337	20,910,895
Demand and Non-Fuel Costs:	Demand Charge	799,399	895,765	914,110	587,622	662,259	841,210	1,023,062	1,031,028	936,574	1,063,233	938,736	1,147,662	10,840,860
	Customer Charge	39,736	39,736	39,736	39,736	39,736	39,737	39,736	39,736	39,736	39,736	39,736	39,736	476,833
	Transmission Charge	130,158	159,914	154,607	118,212	128,815	156,573	160,362	163,684	144,356	134,843	113,401	146,923	1,711,848
Subtotal Demand & Non-Fuel Costs		969,293	1,095,415	1,108,453	745,770	830,810	1,037,520	1,223,160	1,234,448	1,120,666	1,237,812	1,091,873	1,334,321	13,029,541
Total System Purchased Power Costs		2,546,611	2,534,862	3,026,663	2,146,277	1,553,544	3,059,776	3,653,045	3,573,374	3,345,797	3,084,441	2,612,388	2,803,658	33,940,436
Less Direct Billing To GSLD1 Class:	Demand	372,221	133,824	261,366	52,793	56,637	47,776	130,264	130,264	130,264	130,264	130,264	130,264	1,706,201
	Commodity	183,802	152,090	355,136	30,870	135,107	108,294	126,995	127,125	127,304	127,725	128,230	128,472	1,731,150
Net Purchased Power Costs		1,990,588	2,248,948	2,410,161	2,062,614	1,361,800	2,903,706	3,395,786	3,315,985	3,088,229	2,826,452	2,353,894	2,544,922	30,503,085
	Special Costs	16,197	17,040	51,516	15,707	39,981	75,998	20,000	20,000	20,000	20,000	20,000	20,000	336,439
Total Costs and Charges		2,006,785	2,265,988	2,461,677	2,078,321	1,401,781	2,979,704	3,415,786	3,335,985	3,108,229	2,846,452	2,373,894	2,564,922	30,839,524
Sales Revenues - Fuel Adjustment Revenues:														
RS<	.09779	962,565	926,269	970,561	907,587	890,396	1,048,397	1,188,144	1,210,146	1,103,556	1,024,737	757,283	758,945	11,748,586
RS>	.10778	429,116	304,897	364,796	254,549	310,572	586,390	837,146	799,853	747,363	660,383	528,780	529,535	6,353,380
GS	.09823	216,202	192,353	207,358	204,629	227,038	267,290	298,813	295,474	275,631	267,184	220,426	201,075	2,873,473
GSD	.09370	501,049	456,954	494,316	516,351	593,238	655,077	839,950	813,900	811,464	749,058	636,709	577,864	7,645,930
GSLD	.09045	185,963	152,687	177,737	187,768	210,780	230,779	214,378	212,931	212,388	186,337	191,583	181,905	2,345,236
OL	.06733	7,603	7,620	7,245	7,584	7,598	7,668	8,080	8,012	7,743	7,608	7,945	8,282	92,988
SL,CSL	.06713	4,828	4,828	4,845	4,957	4,969	4,973	6,378	6,378	6,445	6,378	6,378	6,310	67,667
Unbilled Fuel Revenues		140,850	(195,621)	342,734	(349,352)	531,505	(117,346)	0	0	0	0	0	0	352,770
Total Fuel Revenues (Excl. GSLD1)		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,392,889	3,346,694	3,164,590	2,901,685	2,349,104	2,263,916	31,480,030
GSLD1 Fuel Revenues		556,023	285,914	616,502	83,663	191,744	156,070	257,259	257,389	257,568	257,989	258,494	258,736	3,437,351
Non-Fuel Revenues		955,049	863,007	957,773	901,078	885,378	972,945	1,631,527	1,336,262	1,437,113	910,176	848,011	1,259,070	12,957,388
Total Sales Revenue		3,959,248	2,998,908	4,143,867	2,718,814	3,853,218	3,812,243	5,281,675	4,940,345	4,859,271	4,069,850	3,455,609	3,781,722	47,874,770
KWH Sales:	RS<	9,843,458	9,472,061	9,925,485	9,290,382	9,105,219	10,720,944	12,150,000	12,375,000	11,285,000	10,479,000	7,744,000	7,761,000	120,151,549
	RS>	3,981,444	2,828,827	3,384,562	2,366,718	2,881,477	5,440,487	7,767,000	7,421,000	6,934,000	6,127,000	4,906,000	4,913,000	58,951,515
	GS	2,203,160	1,991,950	2,110,953	2,085,158	2,311,302	2,721,087	3,042,000	3,008,000	2,806,000	2,720,000	2,244,000	2,047,000	29,290,610
	GSD	5,350,031	4,876,640	5,275,378	5,568,082	6,331,079	6,991,040	8,964,000	8,686,000	8,660,000	7,994,000	6,795,000	6,167,000	81,658,250
	GSLD	2,055,860	1,688,000	1,964,920	2,075,840	2,330,220	2,551,320	2,370,000	2,354,000	2,348,000	2,060,000	2,118,000	2,011,000	25,927,160
	GSLD1	2,960,000	2,500,000	5,760,000	1,620,000	2,180,000	1,760,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	28,780,000
	OL	113,333	113,299	112,609	112,769	112,974	114,028	120,000	119,000	115,000	113,000	118,000	123,000	1,387,012
	SL,CSL	71,916	71,916	72,175	73,842	74,024	74,073	95,000	95,000	96,000	95,000	95,000	94,000	1,007,946
	Total KWH Sales	26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	36,508,000	36,058,000	34,244,000	31,588,000	26,020,000	25,116,000	347,154,042
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,392,889	3,346,694	3,164,590	2,901,685	2,349,104	2,263,916	31,480,030
True-up Provision - collect/(refund)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
Gross Receipts Tax Refund														0
Fuel Revenue		2,469,729	1,871,540	2,591,145	1,755,626	2,797,649	2,704,781	3,414,442	3,368,247	3,186,143	2,923,238	2,370,657	2,285,469	31,738,666
Net Purchased Power and Other Fuel Costs		2,006,785	2,265,988	2,461,677	2,078,321	1,401,781	2,979,704	3,415,786	3,335,985	3,108,229	2,846,452	2,373,894	2,564,922	30,839,524
True-up Provision for the Period		462,944	(394,448)	129,468	(322,695)	1,395,868	(274,923)	(1,344)	32,262	77,914	76,786	(3,237)	(279,453)	899,142
Interest Provision for the Period		235	275	204	150	146	165	278	278	281	286	288	272	2,858
Beginning of Period True-up and Interest Provision		2,042,313	2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	2,042,313
True-up Collected or (Refunded)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
End of Period, Net True-up and Int. Prov.		2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	2,685,677	2,685,677
Beginning True-up Amount		2,042,313	2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	
Ending True-up Amount Before Interest		2,483,704	2,067,937	2,176,128	1,832,083	3,206,549	2,910,219	2,887,487	2,898,474	2,955,113	3,010,627	2,986,123	2,685,405	10% Rule Interest Provision: 7.91%
Total Beginning and Ending True-up		4,526,017	4,551,876	4,244,340	4,008,415	5,038,782	6,116,914	5,797,871	5,786,239	5,853,865	5,966,021	5,997,036	5,671,816	
Average True-up Amount		2,263,008	2,275,938	2,122,170	2,004,207	2,519,391	3,058,457	2,898,936	2,893,120	2,926,933	2,983,011	2,998,518	2,835,908	
Average Annual Interest Rate		0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Interest Provision		235	275	204	150	146	165	278	278	281	286	288	272	

Exhibit No._____
DOCKET NO. 140001-EI
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(CDY-1)
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SCHEDULE E1-A

Revised 8/29/2014

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

Northwest Florida Division

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014)(Estimated)	$	2,624,811

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(Revised CDY-2)
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 30
PARTY: FLORIDA PUBLIC UTILITIES COMPANY (FPUC) (DIRECT)
DESCRIPTION: Curtis D. Young CDY-2

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E1-B

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

Revised 8/29/2014

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST DIVISION

			ACTUAL JANUARY 2014	ACTUAL FEBRUARY 2014	ACTUAL MARCH 2014	ACTUAL APRIL 2014	ACTUAL MAY 2014	ACTUAL JUNE 2014	Estimated JULY 2014	Estimated AUGUST 2014	Estimated SEPTEMBER 2014	Estimated OCTOBER 2014	Estimated NOVEMBER 2014	Estimated DECEMBER 2014	Total
Total System Sales - KWH			28,302,737	27,377,767	21,631,850	19,434,427	21,840,965	25,728,498	32,040,000	32,768,000	31,310,000	28,829,000	23,992,000	26,296,000	319,551,244
Total System Purchases - KWH			32,651,753	22,559,528	23,396,311	18,952,601	25,562,899	29,040,143	33,001,200	33,751,040	32,249,300	29,693,870	24,711,760	27,084,880	332,655,285
System Billing Demand - 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-KW			56,046	57,285	59,557	59,533	58,122	57,805	55,053	54,690	54,745	54,447	54,262	54,204	675,749
Purchased Power Rates:															
Energy/Environmental - $/KWH	Loss Factor	0.974	0.05490	0.05490	0.05490	0.05490	0.05490	0.05490	0.05486	0.05486	0.05486	0.05486	0.05486	0.05486	
Demand and Non-Fuel:															
Capacity Charge - $/KWH			10.05000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	10.050000	
Transmission and Interconnection - $/KWH			2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	
Distribution Charge			39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:															
Base Fuel Costs			1,840,432	1,271,579	1,318,745	1,068,273	1,440,866	1,636,862	1,858,774	1,901,008	1,816,424	1,672,490	1,391,876	1,525,541	18,742,870
Subtotal Fuel Costs			1,840,432	1,271,579	1,318,745	1,068,273	1,440,866	1,636,862	1,858,774	1,901,008	1,816,424	1,672,490	1,391,876	1,525,541	18,742,870
Demand and Non-Fuel Costs:															
Capacity Charge			914,550	914,550	914,550	914,550	914,550	914,550	914,550	914,550	914,550	914,550	914,550	914,550	10,974,600
Transmission and Interconection		50%	73,115	74,732	77,696	77,664	75,824	75,410	71,820	71,346	71,418	71,029	70,788	70,712	881,552
Distribution Facilities Charge (incl. FERC l/t chrg)			41,455	41,927	41,250	41,306	41,008	41,453	41,993	42,045	41,942	41,767	41,426	41,589	499,161
Meter Reading and Processing Charge			775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs			1,029,895	1,031,984	1,034,271	1,034,295	1,032,157	1,032,188	1,029,138	1,028,716	1,028,685	1,028,121	1,027,539	1,027,626	12,364,613
Total System Purchased Power Costs			2,870,327	2,303,563	2,353,016	2,102,568	2,473,023	2,669,050	2,887,912	2,929,724	2,845,109	2,700,611	2,419,415	2,553,167	31,107,483
Special Costs			327	431	879	283	(317)	260	300	300	300	300	300	300	3,663
Total Costs and Charges			2,870,654	2,303,994	2,353,895	2,102,851	2,472,706	2,669,310	2,888,212	2,930,024	2,845,409	2,700,911	2,419,715	2,553,467	31,111,146
Sales Revenues - Fuel Adjustment Revenues:															
Residential<	.09733	.09733	771,398	772,111	698,232	624,470	636,651	716,442	785,063	799,273	800,831	734,549	691,626	715,278	8,745,924
Residential>	.10982	.10982	655,404	637,020	232,235	117,373	153,922	321,706	501,882	678,034	557,780	414,135	207,671	438,954	4,916,116
Commercial, Small	.09822	.09822	242,745	247,990	204,771	194,023	215,595	267,372	326,383	310,766	293,086	280,220	230,619	235,726	3,049,296
Commercial, Large	.09315	.09315	629,018	613,550	531,461	532,505	570,341	646,985	872,284	834,930	822,820	797,296	658,125	650,207	8,159,522
Industrial	.08959	.08959	423,141	365,123	366,740	339,952	458,211	476,126	558,924	517,804	511,892	504,187	457,603	456,528	5,436,231
Outside Lighting Private	.07590	.07590	25,952	25,670	25,782	25,691	25,703	25,530	29,068	28,840	28,613	28,613	28,688	28,764	326,914
Street Lighting-Public	.07611	.07611	8,080	7,957	7,957	7,957	7,955	7,955	7,230	7,230	7,230	7,154	7,306	7,230	91,241
Unbilled Fuel Revenues			(1,017,758)	728,709	(20,588)	(103,163)	213,888	95,326	0	0	0	0	0	400,000	296,414
Total Fuel Revenues			1,737,980	3,398,130	2,046,590	1,738,808	2,282,266	2,557,442	3,080,834	3,176,877	3,022,252	2,766,154	2,281,638	2,932,687	31,021,658
Non-Fuel Revenues			2,113,654	(26,965)	829,984	782,968	842,259	929,874	1,207,066	1,127,723	1,107,448	1,042,946	934,462	584,613	11,476,032
Total Sales Revenue			3,851,634	3,371,165	2,876,574	2,521,776	3,124,525	3,487,316	4,287,900	4,304,600	4,129,700	3,809,100	3,216,100	3,517,300	42,497,690
KWH Sales:															
Residential<	RS		7,923,226	7,930,586	7,172,660	6,415,131	6,540,310	7,362,140	8,066,000	8,212,000	8,228,000	7,547,000	7,106,000	7,349,000	89,852,053
Residential>	RS		5,971,445	5,803,049	2,116,354	1,069,962	1,402,648	2,929,366	4,570,000	6,174,000	5,079,000	3,771,000	1,891,000	3,997,000	44,774,824
Commercial, Small	GS		2,471,327	2,524,861	2,084,831	1,975,438	2,195,040	2,722,199	3,323,000	3,164,000	2,984,000	2,853,000	2,348,000	2,400,000	31,045,696
Commercial, Large	GSD		6,765,332	6,600,821	5,719,994	5,736,139	6,144,989	6,959,135	9,364,000	8,963,000	8,833,000	8,559,000	7,065,000	6,980,000	87,690,410
Industrial	GSLD		4,723,320	4,075,688	4,093,748	3,794,720	5,114,788	5,314,760	6,239,000	5,780,000	5,714,000	5,628,000	5,108,000	5,096,000	60,682,024
Outside Lighting-Private	OL,OL-2		341,929	338,210	339,711	338,485	338,669	336,377	383,000	380,000	377,000	377,000	378,000	379,000	4,307,381
Street Lighting-Public	SL-1,2,3		106,158	104,552	104,552	104,552	104,521	104,521	95,000	95,000	95,000	94,000	96,000	95,000	1,198,856
Total KWH Sales			28,302,737	27,377,767	21,631,850	19,434,427	21,840,965	25,728,498	32,040,000	32,768,000	31,310,000	28,829,000	23,992,000	26,296,000	319,551,244
True-up Calculation:															to Date
Fuel Revenues			1,737,980	3,398,130	2,046,590	1,738,808	2,282,266	2,557,442	3,080,834	3,176,877	3,022,252	2,766,154	2,281,638	2,932,687	31,021,658
True-up Provision for the Period - collect/(refund)			62,945	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	755,373
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			1,675,035	3,335,182	1,983,642	1,675,860	2,219,318	2,494,494	3,017,886	3,113,929	2,959,304	2,703,206	2,218,690	2,869,739	30,266,285
Total Purchased Power Costs			2,870,654	2,303,994	2,353,895	2,102,851	2,472,706	2,669,310	2,888,212	2,930,024	2,845,409	2,700,911	2,419,715	2,553,467	31,111,146
True-up Provision for the Period			(1,195,619)	1,031,189	(370,253)	(426,991)	(253,388)	(174,816)	129,675	183,905	113,895	2,295	(201,025)	316,272	(844,861)
Interest Provision for the Period			(102)	(131)	(125)	(141)	(140)	(161)	(331)	(310)	(290)	(278)	(282)	(270)	(2,561)
True-up and Interest Provision															
Beginning of Period			(2,532,762)	(3,665,538)	(2,571,533)	(2,878,962)	(3,243,146)	(3,433,726)	(3,545,755)	(3,353,463)	(3,106,920)	(2,930,367)	(2,865,402)	(3,003,761)	(2,532,762)
True-up Collected or (Refunded)			62,945	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	62,948	755,373
End of Period, Net True-up			(3,665,538)	(2,571,533)	(2,878,962)	(3,243,146)	(3,433,726)	(3,545,755)	(3,353,463)	(3,106,920)	(2,930,367)	(2,865,402)	(3,003,761)	(2,624,811)	(2,624,811)
10% Rule - Interest Provision:															-8.44%
Beginning True-up Amount			(2,532,762)	(3,665,538)	(2,571,533)	(2,878,962)	(3,243,146)	(3,433,726)	(3,545,755)	(3,353,463)	(3,106,920)	(2,930,367)	(2,865,402)	(3,003,761)	
Ending True-up Amount Before Interest			(3,665,436)	(2,571,402)	(2,878,837)	(3,243,005)	(3,433,586)	(3,545,594)	(3,353,132)	(3,106,610)	(2,930,077)	(2,865,124)	(3,003,479)	(2,624,541)	
Total Beginning and Ending True-up			(6,198,198)	(6,236,940)	(5,450,370)	(6,121,967)	(6,676,732)	(6,979,319)	(6,898,887)	(6,460,073)	(6,036,997)	(5,795,491)	(5,868,881)	(5,628,302)	
Average True-up Amount			(3,099,099)	(3,118,470)	(2,725,185)	(3,060,984)	(3,338,366)	(3,489,660)	(3,449,443)	(3,230,037)	(3,018,499)	(2,897,746)	(2,934,441)	(2,814,151)	
Average Annual Interest Rate			0.0400%	0.0500%	0.0550%	0.0550%	0.0500%	0.0550%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Monthly Average Interest Rate			0.0033%	0.0042%	0.0046%	0.0046%	0.0042%	0.0046%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	
Interest Provision			(102)	(131)	(125)	(141)	(140)	(161)	(331)	(310)	(290)	(278)	(282)	(270)	

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 2 of 6

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 2014 - DECEMBER 2014

SCHEDULE E1-B1

Revised 8/29/2014

		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												
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) (A7)	18,742,870	19,156,686	(413,816)	-2.2%	332,655	340,113	(7,458)	-2.2%	5.63433	5.63245	0.00188	0.0%
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)	12,364,613	12,278,445	86,168	0.7%	332,655	340,113	(7,458)	-2.2%	3.71695	3.61011	0.10684	3.0%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	31,107,483	31,435,131	(327,648)	-1.0%	332,655	340,113	(7,458)	-2.2%	9.35127	9.24255	0.10872	1.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					332,655	340,113	(7,458)	-2.2%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Other Fuel Related Costs	3,663	3,600										
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	3,663	3,600	63	1.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	31,111,146	31,438,731	(327,585)	-1.0%	332,655	340,113	(7,458)	-2.2%	9.35238	9.24361	0.10877	1.2%
21	Net Unbilled Sales	0 *	0 *	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
22	Company Use	19,546 *	22,092 *	(2,546)	-11.5%	209	239	(30)	-12.6%	0.00612	0.00669	(0.00057)	-8.5%
23	T & D Losses	1,205,989 *	893,580 *	312,409	35.0%	12,895	9,667	3,228	33.4%	0.37740	0.27061	0.10679	39.5%
24	SYSTEM KWH SALES	31,111,146	31,438,731	(327,585)	-1.0%	319,551	330,207	(10,656)	-3.2%	9.73590	9.52091	0.21499	2.3%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	31,111,146	31,438,731	(327,585)	-1.0%	319,551	330,207	(10,656)	-3.2%	9.73590	9.52091	0.21499	2.3%
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	31,111,146	31,438,731	(327,585)	-1.0%	319,551	330,207	(10,656)	-3.2%	9.73590	9.52091	0.21499	2.3%
28	GPIF**												
29	TRUE-UP**	755,373	755,373	0	0.0%	319,551	330,207	(10,656)	-3.2%	0.23639	0.22876	0.00763	3.3%
30	TOTAL JURISDICTIONAL FUEL COST	31,866,519	32,194,104	(327,585)	-1.0%	319,551	330,207	(10,656)	-3.2%	9.97228	9.74967	0.22261	2.3%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									9.97946	9.75669	0.22277	2.3%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									9.979	9.757	0.222	2.3%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-2)

Schedule E1-A

Revised 8/29/2014

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Northeast Florida Division

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754

Exhibit No._____
DOCKET NO. 140001-EI
Florida Public Utilities Company
(Revised CDY-2)

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E-1b

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

Revised 8/29/2014

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

NORTHEAST FLORIDA DIVISION

		ACTUAL Jan 2014	ACTUAL Feb 2014	ACTUAL Mar 2014	ACTUAL Apr 2014	ACTUAL May 2014	ACTUAL Jun 2014	Estimated Jul 2014	Estimated Aug 2014	Estimated Sep 2014	Estimated Oct 2014	Estimated Nov 2014	Estimated Dec 2014	Total
Total System Sales - KWH		28,944,284	31,839,817	27,828,235	22,564,618	27,330,969	30,058,293	34,657,000	33,410,000	31,854,000	28,716,000	23,935,000	23,159,000	344,297,216
CCA Purchases - KWH		581,556	662,603	440,945	460,817	976,667	1,486,387	600,000	600,000	600,000	600,000	600,000	600,000	8,208,975
Rayonier Purchases - KWH - On Peak		522,269	232,753	440,927	621,637	392,986	479,191	420,000	420,000	420,000	420,000	420,000	420,000	5,209,763
Rayonier Purchases - KWH - Off Peak		675,841	339,791	650,623	1,168,277	746,082	914,696	980,000	980,000	980,000	980,000	980,000	980,000	10,375,310
JEA Purchases - KWH		32,740,736	25,999,885	27,411,795	21,710,309	29,987,884	30,668,645	32,023,000	31,581,833	28,784,807	26,748,032	21,233,919	21,836,320	330,727,165
System Billing Demand - KW		109,088	64,512	74,095	47,255	72,352	68,051	74,600	73,600	72,700	65,300	57,100	63,700	842,353
DEMAND-KW-(network load)		124,915	99,827	75,259	67,726	99,926	100,660	115,072	113,536	112,128	100,736	88,192	98,304	1,196,281
Purchased Power Rates:														
CCA 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		0.09378	0.04563	0.09378	0.10478	0.10478	0.10478	0.09958	0.09958	0.09958	0.09958	0.08812	0.09047	
Rayonier- Energy Charge - Off Peak - $/KWH		0.05460	0.05460	0.05460	0.05460	0.05460	0.05460	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	
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	
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		14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	
Customer Charge - $		39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
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	
Purchased Power Costs:	CCA Fuel Costs	25,743	29,328	19,516	20,396	43,231	65,793	26,556	26,556	26,556	26,556	26,556	26,556	363,343
	Rayonier Standby Costs	85,879	29,175	76,874	128,923	81,913	100,152	98,880	98,880	98,880	98,880	94,066	95,053	1,087,555
	JEA Base Fuel Costs	1,427,496	1,133,595	1,195,154	946,569	1,307,472	1,337,153	1,396,203	1,376,968	1,255,018	1,166,214	925,799	952,064	14,419,705
	JEA Fuel Adjustment	380,447	302,119	318,525	252,274	348,459	356,370	372,107	366,981	334,479	310,812	246,738	253,738	3,843,049
	Subtotal Fuel Costs	1,919,565	1,494,217	1,610,069	1,348,162	1,781,075	1,859,468	1,893,746	1,869,385	1,714,933	1,602,462	1,293,159	1,327,411	19,713,652
Demand and Non-Fuel Costs:	Demand Charge	1,561,050	923,167	1,060,299	676,219	1,035,357	973,810	1,067,526	1,053,216	1,040,337	934,443	817,101	911,547	12,054,072
	Facility Charge	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
	Transmission Charge	261,737	225,470	191,337	179,930	226,712	227,407	245,579	242,785	240,731	223,140	203,958	219,151	2,687,937
Subtotal Demand & Non-Fuel Costs		1,862,523	1,188,373	1,291,372	895,885	1,301,805	1,240,953	1,352,841	1,335,737	1,320,804	1,197,319	1,060,795	1,170,434	15,218,841
Total System Purchased Power Costs		3,782,088	2,682,590	2,901,441	2,244,047	3,082,880	3,100,421	3,246,587	3,205,122	3,035,737	2,799,781	2,353,954	2,497,845	34,932,493
Less Direct Billing To GSLD1 Class:	Demand	377,428	33,966	213,317	47,706	156,512	177,265	188,267	188,267	307,626	188,267	188,267	307,626	2,374,514
	Commodity	84,477	207,633	256,654	94,295	238,394	80,481	159,858	159,928	160,418	160,635	161,751	161,684	1,926,408
Net Purchased Power Costs		3,320,183	2,440,991	2,431,470	2,102,046	2,687,974	2,842,675	2,898,462	2,856,927	2,567,693	2,450,679	2,003,936	2,028,535	30,631,571
	Special Costs	45,241	93,815	44,112	22,118	17,321	6,243	10,000	10,000	10,000	10,000	10,000	10,000	288,850
Total Costs and Charges		3,365,424	2,534,806	2,475,582	2,124,164	2,705,295	2,848,918	2,908,462	2,866,927	2,577,693	2,460,679	2,013,936	2,038,535	30,920,421
Sales Revenues - Fuel Adjustment Revenues:														
RS<	.08969	956,938	986,424	902,117	810,354	838,227	977,094	1,268,963	1,199,543	1,101,785	939,814	694,525	696,048	11,371,832
RS>	.10218	621,290	662,795	335,019	211,397	285,699	535,416	517,421	498,212	471,340	426,689	359,150	359,457	5,283,885
GS	.08329	192,787	213,655	182,562	179,488	215,419	254,711	233,795	231,130	216,804	210,724	176,658	162,582	2,470,315
GSD	.08214	491,296	474,469	414,519	444,351	484,730	545,503	632,485	612,935	612,120	564,061	479,456	435,182	6,191,107
GSLD	.08239	185,232	177,839	179,299	166,320	193,371	216,884	167,583	166,512	166,100	145,749	149,786	142,206	2,056,881
OL	.05224	5,906	5,482	6,338	5,911	5,974	5,956	5,423	5,373	5,163	5,058	5,320	5,529	67,433
SL,CSL	.05202	3,531	3,624	3,625	3,625	3,625	3,625	4,214	4,214	4,266	4,214	4,214	4,214	46,991
Unbilled Fuel Revenues		(1,331,200)	526,583	(433,925)	129,255	55,448	261,287	0	0	0	0	0	0	(792,552)
Total Fuel Revenues (Excl. GSLD1)		1,125,780	3,050,871	1,589,554	1,950,701	2,082,493	2,800,476	2,829,884	2,717,919	2,577,578	2,296,309	1,869,109	1,805,218	26,695,892
GSLD1 Fuel Revenues		461,905	241,599	469,971	142,001	394,906	257,746	348,125	348,195	468,044	349,102	350,018	469,310	4,300,922
Non-Fuel Revenues		1,003,740	1,034,165	969,189	798,032	882,487	1,027,432	2,133,391	2,160,786	1,851,378	1,700,789	1,484,773	1,573,772	16,619,934
Total Sales Revenue		2,591,425	4,326,635	3,028,714	2,890,734	3,359,886	4,085,654	5,311,400	5,226,900	4,897,000	4,346,200	3,703,900	3,848,300	47,616,748
KWH Sales:	RS<	10,669,648	10,998,699	10,058,658	9,035,495	9,346,301	10,893,215	14,150,000	13,375,000	12,285,000	10,479,000	7,744,000	7,761,000	126,796,016
	RS>	6,080,679	6,486,756	3,278,820	2,068,928	2,796,133	5,240,097	5,064,000	4,876,000	4,613,000	4,176,000	3,515,000	3,518,000	51,713,413
	GS	2,314,529	2,565,192	2,191,899	2,168,519	2,586,377	3,058,117	2,807,000	2,775,000	2,603,000	2,530,000	2,121,000	1,952,000	29,672,633
	GSD	5,980,121	5,776,283	5,451,876	5,430,376	5,901,204	6,641,074	7,700,000	7,462,000	7,439,000	6,867,000	5,837,000	5,298,000	75,783,934
	GSLD	2,248,220	2,158,480	2,176,200	2,018,680	2,346,920	2,632,380	2,034,000	2,021,000	2,016,000	1,769,000	1,818,000	1,726,000	24,964,880
	GSLD1	1,470,000	3,680,000	4,480,000	1,660,000	4,170,000	1,410,000	2,717,000	2,717,000	2,717,000	2,717,000	2,717,000	2,717,000	33,172,000
	OL	112,845	104,730	121,110	112,943	114,357	113,732	104,000	103,000	99,000	97,000	102,000	106,000	1,290,717
	SL,CSL	68,242	69,677	69,672	69,677	69,677	69,677	81,000	81,000	82,000	81,000	81,000	81,000	903,622
	Total KWH Sales	28,944,284	31,839,817	27,828,235	22,564,618	27,330,969	30,058,292	34,657,000	33,410,000	31,854,000	28,716,000	23,935,000	23,159,000	344,297,215
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		1,125,780	3,050,871	1,589,554	1,950,701	2,082,493	2,800,476	2,829,884	2,717,919	2,577,578	2,296,309	1,869,109	1,805,218	26,695,892
True-up Provision - collect/(refund)		(223,811)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(2,685,677)
Gross Receipts Tax Refund														0
Fuel Revenue		1,349,591	3,274,677	1,813,360	2,174,507	2,306,299	3,024,282	3,053,690	2,941,725	2,801,384	2,520,115	2,092,915	2,029,024	29,381,569
Net Purchased Power and Other Fuel Costs		3,365,424	2,534,806	2,475,582	2,124,164	2,705,295	2,848,918	2,908,462	2,866,927	2,577,693	2,460,679	2,013,936	2,038,535	30,920,421
True-up Provision for the Period		(2,015,833)	739,871	(662,222)	50,343	(398,996)	175,364	145,228	74,798	223,691	59,436	78,979	(9,511)	(1,538,852)
Interest Provision for the Period		93	82	82	57	36	24	43	32	25	17	2	(16)	477
Beginning of Period True-up and Interest Provision		3,941,298	1,701,747	2,217,894	1,331,948	1,158,542	535,776	487,358	408,823	259,847	259,757	95,404	(49,421)	3,941,298
True-up Collected or (Refunded)		(223,811)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(223,806)	(2,685,677)
End of Period, Net True-up and Int. Prov.		1,701,747	2,217,894	1,331,948	1,158,542	535,776	487,358	408,823	259,847	259,757	95,404	(49,421)	(282,754)	(282,754)
Beginning True-up Amount		3,941,298	1,701,747	2,217,894	1,331,948	1,158,542	535,776	487,358	408,823	259,847	259,757	95,404	(49,421)	
Ending True-up Amount Before Interest		1,701,654	2,217,812	1,331,866	1,158,485	535,740	487,334	408,780	259,815	259,732	95,387	(49,423)	(282,738)	
Total Beginning and Ending True-up		5,642,952	3,919,559	3,549,760	2,490,433	1,694,282	1,023,110	896,138	668,638	519,579	355,144	45,981	(332,159)	
Average True-up Amount		2,821,476	1,959,780	1,774,880	1,245,217	847,141	511,555	448,069	334,319	259,790	177,572	22,991	(166,080)	
Average Annual Interest Rate		0.0400%	0.0500%	0.0550%	0.0550%	0.0500%	0.0550%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Interest Provision		93	82	82	57	36	24	43	32	25	17	2	(16)	

10% Rule Interest Provision: -0.81%

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SCHEDULE E1-B1

Revised 8/29/2014

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2014 - DECEMBER 2014

	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)	18,262,754	16,755,200	1,507,554	9.0%	330,727	303,426	27,301	9.0%	5.52200	5.52201	(0.00001)	0.0%
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)	15,218,841	14,943,859	274,982	1.8%	330,727	303,426	27,301	9.0%	4.60163	4.92504	(0.32341)	-6.6%
11 Energy Payments to Qualifying Facilities (A8a)	1,450,898	1,453,939	(3,041)	-0.2%	23,794	24,000	(206)	-0.9%	6.09775	6.05808	0.03967	0.7%
12 TOTAL COST OF PURCHASED POWER	34,932,493	33,152,998	1,779,495	5.4%	354,521	327,426	27,095	8.3%	9.85343	10.12534	(0.27191)	-2.7%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					354,521	327,426	27,095	8.3%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)	288,850	120,000	168,850	140.7%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	288,850	120,000	168,850	140.7%	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)	35,221,343	33,272,998	1,948,345	5.9%	354,521	327,426	27,095	8.3%	9.93491	10.16199	(0.22708)	-2.2%
21 Net Unbilled Sales (A4)	0 *	0 *	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
22 Company Use (A4)	46,495 *	45,424 *	1,071	2.4%	468	447	21	4.7%	0.01350	0.01394	(0.00044)	-3.2%
23 T & D Losses (A4)	969,250 *	123,773 *	845,477	683.1%	9,756	1,218	8,538	701.0%	0.28152	0.03800	0.24352	640.8%
24 SYSTEM KWH SALES	35,221,343	33,272,998	1,948,345	5.9%	344,297	325,761	18,536	5.7%	10.22993	10.21393	0.01600	0.2%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	35,221,343	33,272,998	1,948,345	5.9%	344,297	325,761	18,536	5.7%	10.22993	10.21393	0.01600	0.2%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	35,221,343	33,272,998	1,948,345	5.9%	344,297	325,761	18,536	5.7%	10.22993	10.21393	0.01600	0.2%
28 GPIF**												
29 TRUE-UP**	(2,685,677)	(2,685,677)	0	0.0%	344,297	325,761	18,536	5.7%	(0.78005)	(0.82443)	0.04438	-5.4%
30 TOTAL JURISDICTIONAL FUEL COST	32,535,666	30,587,321	1,948,345	6.4%	344,297	325,761	18,536	5.7%	9.44988	9.38950	0.06038	0.6%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									9.45668	9.39626	0.06042	0.6%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									9.457	9.396	0.061	0.7%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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)	32,655,875		657,651	4.96553
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)	31,497,027		657,651	4.78932
10a	Demand Costs of Purchased Power	26,518,254	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,978,773	*		
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163		26,400	5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	65,713,065		684,051	9.60646
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	65,713,065		684,051	9.60646
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)	65,713,065		684,051	9.60646
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	65,900	*	686	0.01025
23	T & D Losses	3,872,460	*	40,311	0.60220
24	SYSTEM MWH SALES	65,713,065		643,054	10.21890
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	65,713,065		643,054	10.21890
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	65,713,065		643,054	10.21890
27a	GSLD1 MWH Sales			23,741	
27b	Other Classes MWH Sales			619,313	
27c	GSLD1 CP KW			558,000	*
28	Projected Unbilled Revenues	(500,000)		619,313	-0.08073
29	GPIF **				
30	TRUE-UP (OVER) UNDER RECOVERY **	969,188		619,313	0.15649
31	TOTAL JURISDICTIONAL FUEL COST	66,182,253		619,313	10.68640
31a	Demand Purchased Power Costs (Line 10a)	26,518,254	*		
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	39,194,811	*		
31c	True up Over/Under Recovery (Line 29)	969,188	*		
31d	Unbilled Revenues	(500,000)			

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 31
PARTY: FLORIDA PUBLIC UTILITIES COMPANY (FPUC) (DIRECT)
DESCRIPTION: Curtis D. Young, P. Mark Cutshaw (Panel) CDY-3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	26,518,254		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	23,198,173	619,313	3.74579
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	39,194,811		
35	Total KWH Purchased (Line 12)		684,051	
36	Average Cost per KWH Purchased			5.72981
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.90170
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,832	23,741	5.89205
39	Balance to Other Classes	37,795,979	619,313	6.10289
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,832	23,741	5.89205
40e	Total Non-demand Costs Including True-up	1,398,832	23,741	5.89205
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89629
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	60,994,152	619,313	9.84868
41b	Less: Total Demand Cost Recovery	23,198,173 ***		
41c	Total Other Costs to be Recovered	37,795,979	619,313	6.10289
41d	Unbilled Revenue	(500,000)	619,313	-0.08073
41e	Other Classes' Portion of True-up (Line 30c)	969,188	619,313	0.15649
41f	Total Demand & Non-demand Costs Including True-up	38,265,167	619,313	6.17865
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	38,292,718		6.183

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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	304,265,841	57.313%	60,603.3	1.089	1.030	65,997.0	313,393,816	55.85%	49.13%
45	GS	59,699,265	63.216%	10,780.5	1.089	1.030	11,740.0	61,490,243	9.93%	9.64%
46	GSD	160,601,476	73.904%	24,807.2	1.089	1.030	27,015.0	165,419,521	22.86%	25.93%
47	GSLD	87,197,838	84.021%	11,847.1	1.089	1.030	12,901.5	89,813,773	10.92%	14.08%
48	OL	5,454,211	178.492%	348.8	1.089	1.030	379.8	5,617,837	0.32%	0.88%
49	SL	2,094,412	178.492%	133.9	1.089	1.030	145.8	2,157,244	0.12%	0.34%
	TOTAL	619,313,043		108,520.8			118,179.1	637,892,434	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	51.55%	3.78%	55.33%	$12,835,549	0.04219	0.04222	0.06183	0.10405
51	GS	9.17%	0.74%	9.91%	2,298,939	0.03851	0.03854	0.06183	0.10037
52	GSD	21.10%	1.99%	23.09%	5,356,458	0.03335	0.03337	0.06183	0.09520
53	GSLD	10.08%	1.08%	11.16%	2,588,916	0.02969	0.02971	0.06183	0.09154
54	OL	0.30%	0.07%	0.37%	85,833	0.01574	0.01575	0.06183	0.07758
55	SL	0.11%	0.03%	0.14%	32,477	0.01551	0.01552	0.06183	0.07735
	TOTAL	92.31%	7.69%	100.00%	$23,198,173				

Step Rate Allocation for Residential Customers

		(18)	**(19)**	**(20)**	**(21)** (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	304,265,841	$0.10405	$31,658,861
57	RS	<= 1,000kWh/mo.	200,167,898	$0.09977	$19,971,431
58	RS	> 1,000 kWh/mo.	104,097,943	$0.11227	$11,687,430
59	RS	Total Sales	304,265,841		$31,658,861

(2) From Gulf Power 2009 Load Research results.

TOU Rates

		(22) On Peak Rate	**(23)** Off Peak Rate	**(24)**	**(25)**
	Rate Schedule	Differential	Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
60	RS	0.0840	(0.0390)	$0.18377	$0.06077
61	GS	0.0400	(0.0500)	$0.14037	$0.05037
62	GSD	0.0400	(0.0325)	$0.13520	$0.06270
63	GSLD	0.0600	(0.0300)	$0.15154	$0.06154
64	Interruptible	(0.0150)	-	$0.07654	$0.09154

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	2,907,565
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	969,188
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		619,313,043
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.15649

Exhibit No._____
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Florida Public Utilities Company
(Revised CDY-3)

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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		2,845,312	2,543,306	2,382,618	2,215,999	2,360,557	2,861,980	3,372,457	3,323,552	3,276,256	2,815,571	2,270,645	2,387,622	32,655,875	3
3a	DEMAND & NON FUEL COST OF PUR POWER		2,632,048	2,602,158	2,580,529	2,564,518	2,581,118	2,650,182	2,718,951	2,714,099	2,701,216	2,638,640	2,561,505	2,552,063	31,497,027	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		5,607,821	5,244,754	5,093,608	4,914,805	5,075,963	5,646,450	6,225,696	6,171,939	6,111,760	5,588,499	4,961,624	5,070,146	65,713,065	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,937,442	1,934,464	1,931,118	1,932,428	1,932,583	1,934,082	1,933,893	1,932,984	1,933,123	1,932,376	1,931,914	1,931,771	23,198,173	5a
5b	TOTAL OTHER COST TO BE RECOVERED		3,670,379	3,310,290	3,162,490	2,982,377	3,143,380	3,712,368	4,291,803	4,238,955	4,178,637	3,656,123	3,029,710	3,138,375	42,514,892	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		3,273,529	2,909,700	2,755,455	2,562,258	2,735,256	3,320,768	3,902,538	3,842,244	3,794,654	3,277,526	2,659,416	2,762,635	37,795,979	6a
6b	SYSTEM KWH SOLD (MWH)		55,618	49,880	46,740	43,531	46,338	56,293	66,425	65,504	64,443	55,308	44,438	48,536	643,054	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		53,577	47,739	44,537	41,119	44,122	54,341	64,503	63,455	62,613	53,579	42,859	46,869	619,313	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.10995	6.09502	6.18689	6.23132	6.1993	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	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)		6.10995	6.09502	6.18689	6.23132	6.19930	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)		(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	10
11	GPIF (CENTS/KWH)															11
12	TRUE-UP (CENTS/KWH)	969,188	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	0.15649	12
13	TOTAL		6.18571	6.17078	6.26265	6.30708	6.27506	6.18674	6.12593	6.13083	6.13625	6.19294	6.28079	5.97014	6.17865	13
14	REVENUE TAX FACTOR	0.00072	0.00445	0.00444	0.00451	0.00454	0.00452	0.00445	0.00441	0.00441	0.00442	0.00446	0.00452	0.00430	0.00445	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		6.19016	6.17522	6.26716	6.31162	6.27958	6.19119	6.13034	6.13524	6.14067	6.19740	6.28531	5.97444	6.18310	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.19	6.175	6.267	6.312	6.28	6.191	6.13	6.135	6.141	6.197	6.285	5.974	6.183	16

EXHIBIT NO. _____
DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-3)

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	JEA/GULF	MS	57,078,315			57,078,315	4.984926	9.596219	2,845,312
FEBRUARY 2015	JEA/GULF	MS	51,168,680			51,168,680	4.970435	10.055886	2,543,306
MARCH 2015	JEA/GULF	MS	47,949,117			47,949,117	4.969055	10.350862	2,382,618
APRIL 2015	JEA/GULF	MS	44,641,813			44,641,813	4.963954	10.708608	2,215,999
MAY 2015	JEA/GULF	MS	47,538,143			47,538,143	4.965606	10.395179	2,360,557
JUNE 2015	JEA/GULF	MS	57,784,307			57,784,307	4.952867	9.539202	2,861,980
JULY 2015	JEA/GULF	MS	68,218,775			68,218,775	4.943591	8.929225	3,372,457
AUGUST 2015	JEA/GULF	MS	67,269,693			67,269,693	4.940638	8.975291	3,323,552
SEPTEMBER 2015	JEA/GULF	MS	66,177,020			66,177,020	4.950746	9.032549	3,276,256
OCTOBER 2015	JEA/GULF	MS	56,767,969			56,767,969	4.959788	9.607902	2,815,571
NOVEMBER 2015	JEA/GULF	MS	45,571,217			45,571,217	4.982630	10.603513	2,270,645
DECEMBER 2015	JEA/GULF	MS	47,485,772			47,485,772	5.028079	10.402453	2,387,622
TOTAL			657,650,823	0	0	657,650,823	4.965534	9.754858	32,655,875

EXHIBIT NO. _____
DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-3)
PAGE 6 OF 22

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

EXHIBIT NO. _____
DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-3)

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	9.98	9.98	9.98	9.98	9.98	9.98	9.98
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.77	99.77	99.77	99.77	99.77	99.77	99.77
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	3.45	3.45
TOTAL REVENUES *** $	137.89	137.89	137.89	137.89	137.89	137.89	137.89

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	9.98	9.98	9.98	9.98	9.98	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.77	99.77	99.77	99.77	99.77	1,197.24
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	41.40
TOTAL REVENUES *** $	137.89	137.89	137.89	137.89	137.89	1,654.68

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-3)

FLORIDA PUBLIC UTILITIES COMPANY SCHEDULE E1
FUEL AND PURCHASED POWER PAGE 1 OF 2
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
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)	18,129,824		324,485	5.58726
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 & Transformation Cost of Purch Power (E2)	12,880,871		324,485	3.96964
10a	Demand Costs of Purchased Power	12,370,323	*		
10b	Transformation Energy & Customer Costs of Purchased Power	510,548	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,010,695		324,485	9.55690
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,010,695		324,485	9.55690
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)	31,010,695		324,485	9.55690
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,841	*	239	0.00725
23	T & D Losses	880,477	*	9,213	0.27949
24	SYSTEM MWH SALES	31,010,695		315,033	9.84363
25	Less Total Demand Cost Recovery	12,370,323	***		
26	Jurisdictional MWH Sales	18,640,372		315,033	5.91696
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	18,640,372		315,033	5.91696
28	Projected Unbilled Revenues	(500,000)		315,033	(0.15871)
29	TRUE-UP **	874,937		315,033	0.27773
30	TOTAL JURISDICTIONAL FUEL COST	19,015,309		315,033	6.03597
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.04032
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	19,029,000			6.040

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. _140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 9 OF 22

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	)/Total Col. (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.	2 CP Demar Percentage	Energy Percentage
34	RS	138,567,298	57.313%	27,599.6	1.089	1.030	30,056.0	142,724,317	51.08%	43.98%
35	GS	29,068,201	63.216%	5,249.1	1.089	1.030	5,716.3	29,940,247	9.71%	9.23%
36	GSD	83,570,738	73.904%	12,908.7	1.089	1.030	14,057.6	86,077,860	23.88%	26.53%
37	GSLD	58,534,854	84.021%	7,952.8	1.089	1.030	8,660.6	60,290,900	14.71%	18.58%
38	OL, OL1	4,073,972	178.492%	260.6	1.089	1.030	283.8	4,196,191	0.48%	1.29%
39	SL1, SL2 & SL3	1,218,459	178.492%	77.9	1.089	1.030	84.8	1,255,013	0.14%	0.39%
40	TOTAL	315,033,522		54,048.7			58,859.1	324,484,528	100.00%	100.00%

		(10) 12/13 * (8)	**(11)** 1/13 * (9)	**(12)** (10) + (11)	**(13)** Tot. Col. 13 * (12	**(14)** (13)/(1)	**(15)** (14) * 1.00072	**(16)**	**(17)** (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	47.15%	3.39%	50.54%	$6,251,961	0.04512	0.04515	0.06040	$0.10555
42	GS	8.96%	0.71%	9.67%	1,196,210	0.04115	0.04118	0.06040	$0.10158
43	GSD	22.04%	2.04%	24.08%	2,978,774	0.03564	0.03567	0.06040	$0.09607
44	GSLD	13.58%	1.43%	15.01%	1,856,785	0.03172	0.03174	0.06040	$0.09214
45	OL, OL1	0.44%	0.10%	0.54%	66,800	0.01640	0.01641	0.06040	$0.07681
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%	19,793	0.01624	0.01625	0.06040	$0.07665
47	TOTAL	92.30%	7.70%	100.00%	$12,370,323				

Step Rate Allocation for Residential Customers

		(18)	**(19)**	**(20)**	**(21)** (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	138,567,298	$0.10555	$14,625,778
49	RS	<= 1,000kWh/mo.	77,033,226	$0.10000	$7,703,252
50	RS	> 1,000 kWh/mo.	61,534,072	$0.11250	$6,922,527
51	RS	Total Sales	138,567,298		$14,625,778

TOU Rates

		(22) On Peak Rate Differential	**(23)** Off Peak Rate Differential	**(24)** Levelized Adj. On Peak	**(25)** Levelized Adj. Off Peak
	Rate Schedule				
52	RS	0.0840	(0.0390)	$0.18400	$0.06100
53	GS	0.0400	(0.0500)	$0.14158	$0.05158
54	GSD	0.0400	(0.0325)	$0.13607	$0.06357
55	GSLD	0.0600	(0.0300)	$0.15214	$0.06214
56	Interruptible	(0.0150)	-	$0.07714	$0.09214

(2) From Gulf Power Co. 2009 Load Research data results.

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014; (Estimated)	$	2,624,811
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	874,937
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission.		315,033,522
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015.		0.27773

Exhibit No._____
DOCKET NO. _140001-EI
Florida Public Utilities Company
(CDY-3)

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

LINE NO.		(a) 2015 JANUARY	(b) 2015 FEBRUARY	(c) 2015 MARCH	(d) 2015 APRIL	(e) 2015 MAY	(f) 2015 JUNE	(g) 2015 JULY	(h) 2015 AUGUST	(i) 2015 SEPTEMBER	(j) 2015 OCTOBER	(k) 2015 NOVEMBER	(l) 2015 DECEMBER	(m) 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	1,623,903	1,422,010	1,329,526	1,227,454	1,310,667	1,559,651	1,812,472	1,778,217	1,779,784	1,550,107	1,291,755	1,444,278	18,129,824	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,075,737	1,073,867	1,072,132	1,072,691	1,072,867	1,073,928	1,074,120	1,073,611	1,073,684	1,073,035	1,072,499	1,072,600	12,880,671	3a
3b	QUALIFYING FACILITIES													0	3b
4	ENERGY COST OF ECONOMY PURCHASES													0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	2,699,640	2,495,977	2,401,658	2,300,145	2,383,534	2,633,579	2,886,592	2,851,828	2,853,468	2,623,142	2,364,254	2,516,878	31,010,695	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,033,062	1,031,523	1,029,794	1,030,471	1,030,551	1,031,326	1,031,228	1,030,758	1,030,830	1,030,444	1,030,205	1,030,131	12,370,323	6
7	TOTAL OTHER COST TO BE RECOVERED	1,666,578	1,464,454	1,371,864	1,269,674	1,352,983	1,602,253	1,855,364	1,821,070	1,822,638	1,592,698	1,334,049	1,486,747	18,640,372	7
7a	SYSTEM KWH SOLD (MWH)	28,218	24,710	23,103	21,329	22,775	27 101	31,494	30,899	30,926	26,935	22,446	25,087	315,033	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.924	5.91696	7b
8	JURISDICTIONAL LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)	5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.92400	5.91696	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	10
11	TRUE-UP (CENTS/KWH)	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	11
12	TOTAL	6.02510	6.04558	6.05705	6.07183	6.05967	6.03117	6.01019	6.01264	6.01257	6.03214	6.06239	6.04302	6.03598	12
13	REVENUE TAX FACTOR 0.00072	0.00434	0.00435	0.00436	0.00437	0.00436	0.00434	0.00433	0.00433	0.00433	0.00434	0.00436	0.00435	0.00435	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	6.02944	6.04993	6.06141	6.07620	6.06403	6.03551	6.01452	6.01697	6.01690	6.03648	6.06675	6.04737	6.04033	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	6.029	6.050	6.061	6.076	6.064	6.036	6.015	6.017	6.017	6.036	6.067	6.047	6.040	15

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FLORIDA PUBLIC UTILITIES COMPANY
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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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 2015	GULF POWER COMPANY	RE	29,064,342			29,064,342	5.587269	9.287463	1,623,903
FEBRUARY 2015	GULF POWER COMPANY	RE	25,450,887			25,450,887	5.587271	9.805855	1,422,010
MARCH 2015	GULF POWER COMPANY	RE	23,795,628			23,795,628	5.587271	10.091593	1,329,526
APRIL 2015	GULF POWER COMPANY	RE	21,968,768			21,968,768	5.587268	10.468703	1,227,454
MAY 2015	GULF POWER COMPANY	RE	23,458,093			23,458,093	5.587269	10.159538	1,310,667
JUNE 2015	GULF POWER COMPANY	RE	27,914,377			27,914,377	5.587267	9.433415	1,559,651
JULY 2015	GULF POWER COMPANY	RE	32,439,311			32,439,311	5.587271	8.897513	1,812,472
AUGUST 2015	GULF POWER COMPANY	RE	31,826,220			31,826,220	5.587271	8.959682	1,778,217
SEPTEMBER 2015	GULF POWER COMPANY	RE	31,854,273			31,854,273	5.587269	8.956940	1,779,784
OCTOBER 2015	GULF POWER COMPANY	RE	27,743,559			27,743,559	5.587266	9.453877	1,550,107
NOVEMBER 2015	GULF POWER COMPANY	RE	23,119,617			23,119,617	5.587266	10.224884	1,291,755
DECEMBER 2015	GULF POWER COMPANY	RE	25,849,452			25,849,452	5.587265	9.735518	1,444,278
TOTAL			324,484,528	0	0	324,484,528	5.587269	9.555801	18,129,824

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FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	10.00	10.00
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	100.03	100.03
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	3.45	3.45
TOTAL REVENUES *** $	138.15	138.15	138.15	138.15	138.15	138.15	138.15

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	1,200.36
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	41.40
TOTAL REVENUES *** $	138.15	138.15	138.15	138.15	138.15	1,657.80

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
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FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-3)

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)				
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	14,526,051		333,166	4.36000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Non Fuel Cost of Purch Power (E2)	18,616,156		333,166	5.58765
10a	Demand Costs of Purchased Power	14,147,931	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,468,225	*		
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163		26,400	5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	34,702,370		359,566	9.65118
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	34,702,370		359,566	9.65118
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)	34,702,370		359,566	9.65118
21	Net Unbilled Sales	97	*	1	0.00003
22	Company Use	43,141	*	447	0.01315
23	T & D Losses	3,001,227	*	31,097	0.91495
24	SYSTEM MWH SALES	34,702,370		328,021	10.57931
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	34,702,370		328,021	10.57931
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	34,702,370		328,021	10.57931
27a	GSLD1 MWH Sales			23,741	
27b	Other Classes MWH Sales			304,280	
27c	GSLD1 CP KW			558,000	*
28	GPIF **				
29	TRUE-UP (OVER) UNDER RECOVERY **	94,251		304,280	0.03098
30	TOTAL JURISDICTIONAL FUEL COST	34,796,621		304,280	11.43572
30a	Demand Purchased Power Costs (Line 10a)	14,147,931	*		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	20,554,439	*		
30c	True up Over/Under Recovery (Line 29)	94,251	*		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	14,147,931		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	10,827,850	304,280	3.55852
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	20,554,439		
35	Total KWH Purchased (Line 12)		359,566	
36	Average Cost per KWH Purchased			5.71646
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.89230
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,891	23,741	5.89230
39	Balance to Other Classes	19,155,548	304,280	6.29537
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,891	23,741	5.89230
40e	Total Non-demand Costs Including True-up	1,398,891	23,741	5.89230
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89654
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	29,983,398	304,280	9.85388
41b	Less: Total Demand Cost Recovery	10,827,850 ***		
41c	Total Other Costs to be Recovered	19,155,548	304,280	6.29537
41d	Other Classes' Portion of True-up (Line 30c)	94,251	304,280	0.03098
41e	Total Demand & Non-demand Costs Including True-up	19,249,799	304,280	6.32634
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	19,263,659		6.331

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

NORTHEAST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	)/Total Col. (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.	2 CP Demar Percentage	Energy Percentage
44	RS	165,698,543	57.313%	33,003.6	1.089	1.030	35,940.9	170,669,499	60.60%	54.45%
45	GS	30,631,064	63.216%	5,531.3	1.089	1.030	6,023.6	31,549,996	10.15%	10.07%
46	GSD	77,030,738	73.904%	11,898.5	1.089	1.030	12,957.5	79,341,660	21.84%	25.32%
47	GSLD	28,662,984	84.021%	3,894.3	1.089	1.030	4,240.9	29,522,874	7.15%	9.42%
48	OL	1,380,239	178.492%	88.3	1.089	1.030	96.2	1,421,646	0.16%	0.45%
49	SL	875,953	178.492%	56.0	1.089	1.030	61.0	902,232	0.10%	0.29%
	TOTAL	304,279,521		54,472.0			59,320.1	313,407,907	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	55.95%	4.19%	60.14%	$6,511,869	0.03930	0.03933	0.06331	0.10264
51	GS	9.37%	0.77%	10.14%	1,097,944	0.03584	0.03587	0.06331	0.09918
52	GSD	20.16%	1.95%	22.11%	2,394,038	0.03108	0.03110	0.06331	0.09441
53	GSLD	6.60%	0.72%	7.32%	792,599	0.02765	0.02767	0.06331	0.09098
54	OL	0.15%	0.03%	0.18%	19,490	0.01412	0.01413	0.06331	0.07744
55	SL	0.09%	0.02%	0.11%	11,911	0.01360	0.01361	0.06331	0.07692
	TOTAL	92.32%	7.68%	100.00%	$10,827,850				

Step Rate Allocation for Residential Customers

		(18)	**(19)**	**(20)**	**(21)** (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	165,698,543	$0.10264	$17,007,298
57	RS	<= 1,000kWh/mo.	123,134,672	$0.09943	$12,243,164
58	RS	> 1,000 kWh/mo.	42,563,871	$0.11193	$4,764,134
59	RS	Total Sales	165,698,543		$17,007,298

(2) From Gulf Power Co. 2009 Load Research results.

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	94,251
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		304,279,521
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.03098

Exhibit No._____
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Florida Public Utilities Company
(CDY-3)

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,221,409	1,121,296	1,053,092	988,545	1,049,890	1,302,329	1,559,985	1,545,335	1,496,472	1,265,464	978,890	943,344	14,526,051	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,556,311	1,528,191	1,508,397	1,491,827	1,508,251	1,576,254	1,644,831	1,640,488	1,627,532	1,565,605	1,489,006	1,479,463	18,616,156	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,908,181	2,748,777	2,691,950	2,614,660	2,692,429	3,012,871	3,339,104	3,320,111	3,258,292	2,965,357	2,597,370	2,553,268	34,702,370	5
5a	LESS: TOTAL DEMAND COST RECOVERY		904,380	902,941	901,324	901,957	902,032	902,756	902,665	902,226	902,293	901,932	901,709	901,640	10,827,850	5a
5b	TOTAL OTHER COST TO BE RECOVERED		2,003,801	1,845,836	1,790,626	1,712,703	1,790,397	2,110,115	2,436,439	2,417,885	2,355,999	2,063,425	1,695,661	1,651,628	23,874,520	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		1,606,951	1,445,246	1,383,591	1,292,584	1,382,273	1,718,515	2,047,174	2,021,174	1,972,016	1,684,828	1,325,367	1,275,888	19,155,607	6a
6b	SYSTEM KWH SOLD (MWH)		27,400	25,171	23,638	22,202	23,563	29,192	34,931	34,605	33,516	28,372	21,991	23,440	328,021	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		25,359	23,030	21,435	19,790	21,347	27,240	33,009	32,556	31,686	26,643	20,412	21,773	304,280	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.33681	6.27549	6.45482	6.5315	6.47525	6.30879	6.20187	6.2083	6.22362	6.32372	6.49308	5.85996	6.29539	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)		6.33681	6.27549	6.45482	6.53150	6.47525	6.30879	6.20187	6.20830	6.22362	6.32372	6.49308	5.85996	6.29539	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	94,251	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	0.03098	11
12	TOTAL		6.36779	6.30647	6.48580	6.56248	6.50623	6.33977	6.23285	6.23928	6.25460	6.35470	6.52406	5.89094	6.32637	12
13	REVENUE TAX FACTOR	0.00072	0.00458	0.00454	0.00467	0.00472	0.00468	0.00456	0.00449	0.00449	0.00450	0.00458	0.00470	0.00424	0.00455	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.37237	6.31101	6.49047	6.56720	6.51091	6.34433	6.23734	6.24377	6.25910	6.35928	6.52876	5.89518	6.33092	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.372	6.311	6.49	6.567	6.511	6.344	6.237	6.244	6.259	6.359	6.529	5.895	6.331	15

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR TERRUPTIB	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	28,013,973			28,013,973	4.359999	9.915480	1,221,409
FEBRUARY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	25,717,793			25,717,793	4.360001	10.302155	1,121,296
MARCH 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,153,490			24,153,490	4.359999	10.605047	1,053,092
APRIL 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,673,045			22,673,045	4.360001	10.939739	988,545
MAY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,080,050			24,080,050	4.359999	10.623487	1,049,890
JUNE 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,869,930			29,869,930	4.360000	9.637060	1,302,329
JULY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,779,464			35,779,464	4.360001	8.957138	1,559,985
AUGUST 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,443,472			35,443,472	4.359999	8.988462	1,545,335
SEPTEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,322,747			34,322,747	4.360001	9.101847	1,496,472
OCTOBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,024,410			29,024,410	4.359999	9.754096	1,265,464
NOVEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,451,600			22,451,600	4.360001	10.992072	978,890
DECEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	21,636,320			21,636,320	4.360002	11.197870	943,344
TOTAL			333,166,295	0	0	333,166,295	4.360000	9.947647	14,526,051

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DOCKET NO. 140001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
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SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR TERRUPTIB	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

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FLORIDA PUBLIC UTILITIES COMPANY
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FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	9.95	9.95
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	99.48	99.48
GROSS RECEIPTS TAX	3.44	3.44	3.44	3.44	3.44	3.44	3.44
TOTAL REVENUES *** $	137.59	137.59	137.59	137.59	137.59	137.59	137.59

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	1,193.76
GROSS RECEIPTS TAX	3.44	3.44	3.44	3.44	3.44	41.28
TOTAL REVENUES *** $	137.59	137.59	137.59	137.59	137.59	1,651.08

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
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FLORIDA PUBLIC UTILITIES COMPANY
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ATTACHMENT A

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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	304,265,841	57.313%	60,603.3	1.089	1.030	65,997.0	313,393,816	55.85%	49.13%
45	GS	59,699,265	63.216%	10,780.5	1.089	1.030	11,740.0	61,490,243	9.93%	9.64%
46	GSD	160,601,476	73.904%	24,807.2	1.089	1.030	27,015.0	165,419,521	22.86%	25.93%
47	GSLD	87,197,838	84.021%	11,847.1	1.089	1.030	12,901.5	89,813,773	10.92%	14.08%
48	**LS**	**7,548,623**	**178.492%**	**482.8**	**1.089**	**1.030**	**525.8**	**7,775,082**	**0.44%**	**1.22%**
	TOTAL	619,313,043		108,520.9			118,179.3	637,892,435	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
49	RS	51.55%	3.78%	55.33%	$12,835,549	0.04219	0.04222	0.06183	0.10405
50	GS	9.17%	0.74%	9.91%	2,298,939	0.03851	0.03854	0.06183	0.10037
51	GSD	21.10%	1.99%	23.09%	5,356,458	0.03335	0.03337	0.06183	0.09520
52	GSLD	10.08%	1.08%	11.16%	2,588,916	0.02969	0.02971	0.06183	0.09154
53	**LS**	**0.41%**	**0.10%**	**0.51%**	**118,311**	**0.01567**	**0.01568**	**0.06183**	**0.07751**
	TOTAL	92.31%	7.69%	100.00%	$23,198,173				

Step Rate Allocation for Residential Customers

		(18)		**(19)**	**(20)**	**(21)** (19) * (20)
	Rate Schedule	Allocation		Annual kWh	Levelized Adj.	Revenues
54	RS	Sales		304,265,841	$0.10405	$31,658,861
55	RS	<= 1,000kWh/mo.		200,167,898	$0.09977	$19,971,431
56	RS	> 1,000 kWh/mo.		104,097,943	$0.11227	$11,687,430
57	RS	Total Sales		304,265,841		$31,658,861

(2) From Gulf Power 2009 Load Research results.

TOU Rates

		(22) On Peak	**(23)** Off Peak	**(24)**	**(25)**
	Rate Schedule	Rate Differential	Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
58	RS	0.0840	(0.0390)	$0.18377	$0.06077
59	GS	0.0400	(0.0500)	$0.14037	$0.05037
60	GSD	0.0400	(0.0325)	$0.13520	$0.06270
61	GSLD	0.0600	(0.0300)	$0.15154	$0.06154
62	Interruptible	(0.0150)	-	$0.07654	$0.09154

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 32
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-1

Schedule 1

Contract Coal Suppliers	Tons Recieved (1)(2)	
American Coal Company	259,737	
Foresight Coal Sales	429,202	
Oxbow Carbon & Minerals	127,635	
Patriot Coal Sales, LDC	100,289	
Alpha Coal Sales	357,197	
Twentymile Coal Company (Plant Daniel)	256,046	
Oxbow Carbon & Minerals (Plant Daniel)	709	
TOTAL Contract Coal		1,530,815

Spot Coal Suppliers	Tons Recieved (1)(2)	
Argus Energy	296,571	
Interocean Coal Sales	45,973	
Arch Coal Sales Company	12,302	
Arch Coal Sales Company (Plant Daniel)	20,973	
TOTAL Spot Coal		375,819
		1,906,634

GRAND TOTAL COAL RECEIPTS

(1) Excludes Plant Scherer.
(2) Plant Daniel tons represent Gulf's 50% share of receipts.

Schedule 2

Gulf Contract Coal Supplies

	Supplier	Plant	Received Quantity (tons)	Actual Heating Value	(A) Weighted Avg Price $/MMBTU)
1	American Coal Company	Crist	259,737	11858	[redacted]
2	Foresight Coal Sales	Crist	429,202	11762	
3	Interocean Coal Sales	Crist & Smith	45,973	10874	
4	Oxbow Carbon	Crist & Smith	127,635	12537	
5	Patriot Coal Sales, LDC	Crist & Smith	100,289	11907	
6	Alpha Coal Sales	Crist & Smith	357,197	12296	
7	**Weighted Average**	**Crist & Smith**	**1,274,060**	**12020**	**$3.976**
8					
9	Twentymile Coal Co.	Daniel (Gulf 50%)	256,046	11140	[redacted]
10	Oxbow Carbon	Daniel (Gulf 50%)	709	12020	
11	**Weighted Average**	**Daniel (Gulf 50%)**	**256,755**	**11142**	**$4.926**
12					

13 Gulf Spot Coal Supplies

	Supplier	Plant	Received Quantity (tons)	Actual Heating Value	Weighted Avg Price $/MMBTU)
14					
15					
16	Argus Energy	Crist & Smith	296,571	11815	[redacted]
17	Interocean Coal Sales	Smith	45,973	10874	
18	Arch Coal Sales Company	Smith	12,302	8993	
19	**Weighted Average**	**Crist & Smith**	**354,846**	**11596**	**$3.778**
20					
21	Arch Coal Sales Company	Daniel (Gulf 50%)	**20,973**	**8963**	[redacted]

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit HRB-1, Page 2 of 4

Schedule 3

Gulf Natural Gas Purchase Price Variance
Actual Gas Price vs. Market Gas Price

Gulf Gas Purchase data for Smith 3 taken from Schedules A-5 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	FGT Zone 3 Market Price + $0.50 Storage and Transportation $/MMBtu
Jan-13	5,837,564	$ 22,492,988	$ 2,013,400	$3.40	$0.45	$3.85	$4.20	$3.36	$3.86
Feb-13	5,874,914	$ 22,265,289	$ 2,166,655	$3.39	$0.40	$3.79	$4.16	$3.36	$3.86
Mar-13	4,962,640	$ 21,789,007	$ 793,231	$3.83	$0.56	$4.39	$4.55	$3.76	$4.26
Apr-13	3,645,877	$ 17,910,079	$ 403,524	$4.03	$0.88	$4.91	$5.02	$4.24	$4.74
May-13	4,692,624	$ 22,368,811	$ 493,084	$4.21	$0.56	$4.77	$4.87	$4.06	$4.56
Jun-13	5,154,859	$ 24,017,620	$ 916,010	$3.96	$0.70	$4.66	$4.84	$3.97	$4.47
Jul-13	5,752,089	$ 25,253,907	$ 1,693,990	$3.74	$0.65	$4.39	$4.68	$3.72	$4.22
Aug-13	6,026,717	$ 24,933,131	$ 2,385,644	$3.52	$0.62	$4.14	$4.53	$3.51	$4.01
Sep-13	4,083,146	$ 18,884,559	$ 1,541,155	$3.75	$0.88	$4.63	$5.00	$3.66	$4.16
Oct-13	6,095,217	$ 26,586,943	$ 1,306,667	$3.77	$0.59	$4.36	$4.58	$3.69	$4.19
Nov-13	5,976,048	$ 24,317,072	$ 1,348,136	$3.69	$0.38	$4.07	$4.29	$3.62	$4.12
Dec-13	4,916,083	$ 23,792,055	$ (406,630)	$4.37	$0.47	$4.84	$4.76	$4.35	$4.85
TOTAL	**63,017,778**	**$ 274,611,461**	**$ 14,654,866**	**$3.99**	**$0.36**	**$4.36**	**$4.59**	**$3.77**	**$4.27**

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit HRB-1, Page 1 of 4

Schedule 4

2013 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-13	**5,837,566**	$ 22,589,144	$ 2,013,400	$ 24,602,544	$ 3.87	$ 4.21
Feb-13	**5,865,259**	$ 22,301,579	$ 2,166,655	$ 24,468,234	$ 3.80	$ 4.17
Mar-13	**4,962,640**	$ 21,430,358	$ 793,231	$ 22,223,589	$ 4.32	$ 4.48
Apr-13	**2,825,845**	$ 13,738,181	$ 403,524	$ 14,141,705	$ 4.86	$ 5.00
May-13	**4,577,791**	$ 21,822,624	$ 493,084	$ 22,315,708	$ 4.77	$ 4.87
Jun-13	**5,160,927**	$ 24,059,598	$ 916,010	$ 24,975,608	$ 4.66	$ 4.84
Jul-13	**5,772,089**	$ 25,736,456	$ 1,693,990	$ 27,430,446	$ 4.46	$ 4.75
Aug-13	**6,027,078**	$ 25,476,171	$ 2,385,644	$ 27,861,815	$ 4.23	$ 4.62
Sep-13	**4,108,572**	$ 18,798,331	$ 1,541,155	$ 20,339,486	$ 4.58	$ 4.95
Oct-13	**6,182,345**	$ 27,164,007	$ 1,306,667	$ 28,470,674	$ 4.39	$ 4.61
Nov-13	**6,016,048**	$ 24,928,855	$ 1,348,136	$ 26,276,991	$ 4.14	$ 4.37
Dec-13	**4,900,569**	$ 22,954,447	$ (406,630)	$ 22,547,817	$ 4.68	$ 4.60
TOTAL	**62,236,729**	**$ 270,999,751**	**$ 14,654,866**	**$ 285,654,617**		
Weighted Average Price					**$ 4.35**	**$ 4.59**
Variance					**0.12**	**0.08**
Standard Deviation					**0.34**	**0.28**

AMENDED AND RESTATED NEGOTIATED CONTRACT FOR PURCHASE OF RENEWABLE ENERGY BETWEEN GULF POWER COMPANY AND BAY COUNTY, FLORIDA

THIS AGREEMENT is made and entered into by and between the Board of County Commissioners of Bay County, Florida, hereinafter referred to as the "County"; and Gulf Power Company, a corporation, hereinafter referred to as the "Company". The County and the Company shall collectively be referred to herein as the "Parties".

WITNESSETH:

WHEREAS, the County owns a renewable energy facility located in Panama City, Florida that produces electrical energy from a Renewable Generating Facility as defined in Florida Public Service Commission (FPSC) Rule 25-17.210 (1), Florida Administrative Code (F.A.C.) (the "County's facility"); and

WHEREAS, the County desires to sell, and the Company desires to purchase, electricity to be generated by the County's facility, such sale and purchase to be consistent with applicable sections of Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.310, F.A.C,; and

WHEREAS, the County's facility, in accordance with Rule 25-17.087, F.A.C., is currently interconnected with the Company and the County has entered into an interconnection agreement with the Company, attached hereto as Appendix A; and

WHEREAS, the County's facility is a governmental solid waste facility, pursuant to FPSC Rule 25-17.091, F.A.C., which produces electricity from a renewable energy resource as defined in Section 366.91, Florida Statutes;

NOW THEREFORE, for mutual consideration the Parties agree as follows:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 33
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-2

1. Facility

The County has installed and is operating a facility comprised in whole or in part of the following generator units located at the following address:

6510 Bay Line Drive, Panama City, FL 32404 :

Unit	Description (Type)	Initial In-Service Date	KVA Nameplate Rating	KW Output Rating	Fuel Source	
					Primary	Secondary
TG	Westinghouse-Canada	4/23/1987	15,075	13,650	MSW	Nat Gas

The County's facility, whether comprised in whole or in part of the generator units set forth above, is designed to produce a maximum of 13,650 kilowatts (KW) of electric power at an 85% power factor. The County's facility may be upgraded during the Term hereof to produce as much as 13,650 KW of electric power at 85% power factor.

2. Required Regulatory Approval and Commencement Date

This Agreement shall be effective when executed by both Parties and shall continue throughout the Term hereof, as defined in Paragraph 4 below. The Company shall begin purchasing all of the Net Generation (as defined below) pursuant to the terms hereof as of the hour ending 1:00 A.M. prevailing Central time on July 23, 2014, (Commencement Date). The Company shall use its reasonable efforts to obtain Florida Public Service Commission (FPSC) approval of this Agreement and target a filing for approval as soon as reasonably practicable after execution of this Agreement. The County shall use its reasonable efforts to support the Company's petition for approval of the Agreement. If the FPSC does not approve this Agreement in the time period set forth below or FPSC approval is granted, but such approval is not retroactive to the Commencement Date, the price for all energy delivered pursuant to this Agreement for the period beginning on the Commencement Date and continuing to either the date of the FPSC approval/denial or termination by either party pursuant to this paragraph shall be the Company's "As-Available Energy Cost" (as defined by Florida law). In the event that the actual energy price paid by the Company was greater than the Company's "As-Available Energy Cost", the County shall pay the Company the difference between the actual amounts paid and the Company's "As-Available Energy Cost" Likewise, if the actual energy price paid by the Company was less than the Company's "As-Available Energy Cost", the Company shall pay the County the difference

between the actual amounts paid and the Company's "As-Available Energy Cost". If, after 300 days from the filing date by the Company of the petition with the FPSC for approval of this Agreement, the FPSC has not approved this Agreement through the issuance of an order that has been rendered final as a matter of law, then either Party may terminate this Agreement upon written notice to the other Party, provided that such notice is delivered to such other Party no later than thirty (30) Days after the 300 Days from the FPSC filing date. If such Party fails to exercise the aforementioned termination right within such thirty (30) Day period, then such Party shall be deemed to have waived such termination right. If the FPSC's approval is not obtained as contemplated herein, and neither Party terminates the Agreement within the 30-day timeframe above, then the Agreement will continue in effect for the remaining portion of the Term except that the Company shall pay the County the Company's "As-Available Energy Cost" (as defined by Florida law) for the Net Generation delivered from the County's facility and purchased by the Company during the remaining term of the Agreement, regardless of whether the Company's As-Available Energy Cost is greater than or less than the Contract Price.

3. Sale of Electricity by the County

The Company agrees to purchase all net electrical energy generated at the County's facility and delivered to the Company by the County's facility. The electricity delivered to the Company shall be net of the County facility's station service load. Therefore the billing will be based on Gross Generation less Station Service Load ("Net Generation"). The Company will be the exclusive purchaser of all Net Generation from the County's facility during the term of this Agreement. The billing arrangement will not be changed during the term of the Agreement. The County will use commercially reasonable efforts to maximize the Net Generation, consistent with its waste disposal obligations, operational considerations, and good engineering and utility practices.

4. Payment for Electricity Produced by the County's Facility

The Company agrees to pay the County for the Net Generation on the basis that such Net Generation is "as-available energy" as defined in Rule 25-17.0825(1), Florida Administrative Code. The rates for purchase and sale of energy pursuant to this Agreement shall be for a term of three (3) years beginning on the Commencement Date (the "Term") with rates fixed at Thirty-four Dollars Fifty-six Cents per megawatt-hour ($34.56/MWh) (the "Contract Price") for the entire Term. The Net Generation shall be measured to the nearest whole kilowatt-hour.

5. Metering Requirements

The metering equipment currently existing at the County's facility will remain in place during the Term of this Agreement. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

6. Electricity Production

During the Term of this Agreement, the County agrees to:

(a) Adjust reactive power flow in the interconnection so as to remain within the range of 85% leading to 85% lagging power factor during normal operations, provided that the County will use commercially reasonable efforts to adjust reactive power flow within the above values during start-up and shut-down, but the County will not be deemed to be in violation of this obligation if reactive power flow falls outside the specified range during start-up or shut-down;

(b) Provide the Company, prior to October 1 of each calendar year (January through December), an estimate including the time, duration and magnitude of any planned outages or reductions in generation for the following calendar year; and

(c) Promptly notify the Company of any forced or unplanned outages that occur which would impact the County facility's ability to generate at rated load for periods longer than three (3) days.

7. Default

The County shall be in default under this Agreement if the County fails to perform its material obligations under the Agreement, except to the extent that such failure to perform is the result of a force majeure event as defined below, or to the extent that such failure is cause by the wrongful actions of the Company. In the event that a default occurs, the Company shall notify the County of the default and the County shall have sixty (60) days (or such other amount of time as agreed upon by the parties in writing) to remedy the default. In the event that the default is not cured within the specified timeframe, the Company may terminate the Agreement. The Company's obligation to pay for the Net Generation delivered from the County's facility shall continue throughout the timeframe allotted to the County to cure the default, after which time, the Company's obligations under this Agreement, including the obligation to pay for the Net Generation, shall terminate entirely, provided, however, that the Company's obligations, if any, to purchase the output of the County's facility pursuant to applicable rules of the Federal Energy Regulatory Commission or the FPSC shall not be terminated.

8. General Provisions

8.1 Permits. The County hereby agrees to seek to obtain any and all governmental permits, certifications, or other authority the County is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. The Company hereby agrees to seek to obtain any and all governmental permits, certifications or other authority the Company is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. To the extent that any governmental or other agency is entitled by law to require that certificates for emission allowances to cover any emissions of the County's facility produced in connection with the Net Generation of electricity sold to the Company during the term of this Agreement, it shall be the sole obligation of the County to procure and surrender said certificates to the appropriate governmental or other agency.

8.2 Taxes or Assessments. It is the intent of the Parties under this provision that the County hold the Company and its general body of ratepayers harmless from the effects of any additional taxes, assessments or other impositions that arise as a result of the purchase of energy from the County's facility by the Company. In the event the Company becomes liable for additional taxes, assessments or imposition arising out of its transaction with the County under either this Agreement or any related interconnection agreement or due to changes in laws affecting the Company's purchases of energy from the County's facility occurring after the execution of this Agreement, the Company at its discretion may bill the County monthly for such additional expenses or may offset them against amounts due the County from the Company. It is also the intent of the Parties under this provision that the County hold the Company and its general body of ratepayers harmless from the effects of any additional taxes, assessments or other impositions that arise as a result of the generation and/or sale of energy by the County's facility. During the Term, the County shall be responsible for any and all taxes, assessments or other impositions that arise as a result of the generation or sale of energy from the County's facility, including but not limited to emission allowance expenses, permitting expenses and governmentally-imposed environmental compliance costs regardless of when such taxes, assessments or impositions become effective.

8.3 Force Majeure. If either party shall be unable, by reason of force majeure, to carry out its obligations under this Agreement, either wholly or in part, the party suffering such inability to perform shall give written notice and full particulars of such cause or causes to the other party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended

during the continuance of such hindrance which, however, shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "force majeure" shall be taken to mean acts of God, strikes, lockouts or other industrial disturbances, wars, blockades, insurrections, riots, arrests and restraints of rules and people, environmental constraints lawfully imposed by federal, state or local government bodies, explosions, fires, floods, lightning, wind, perils of the sea, and similar events and occurrences beyond the control of the Party claiming that a force majeure event has occurred, provided, however, that no occurrence may be claimed to be a force majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the party attempting to make such claim or any of such party's agents or contractors.

8.4 Assignment. The County shall have the right to assign its benefits under this Agreement, but the County shall not have the right to assign its obligations and duties without the Company's prior written approval, which shall not be unreasonably withheld or delayed.

8.5 Disclaimer/Third Party Beneficiaries. In executing this Agreement, the Company does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with the County or any assignee of this Agreement. This Agreement is solely for the benefit of the formal parties herein and no right or cause of action shall accrue upon or by reason hereof, to or for the benefit of any third party not a formal party hereto.

8.6 Notification. For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the Parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other party written instructions to contact another individual.

For County:
Jamie Jones
General Services Director
Bay County
8110 John Pitts Road
Panama City, Florida 32409

For Company:
Susan D. Ritenour
Secretary and Treasurer
Gulf Power Company
One Energy Place
Pensacola FL 32520-0780

8.7 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida.

8.8 Severability. If any part of this Agreement, for any reason, shall be declared invalid, or unenforceable by a public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion, provided that, if the severance of any provision from the Agreement shall result in a material change in the economic bargain embodied in the Agreement, the Parties agree to negotiate in good faith toward an equitable resolution that preserves, to the extent legally possible, the original economic bargain embodied in the Agreement.

8.9 Complete Agreement and Amendments. This Agreement sets forth the complete and entire agreement of the Parties with respect to the subject matter hereof, and all previous communications, understandings, undertakings, or agreements between the Parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby superseded, provided, however, that the interconnection agreement between the County and the Company relating to the electrical interconnection of the County's facility to the Company's system shall remain in full force and effect. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both Parties to this Agreement and, if and to the extent required and subject to provisions of Paragraph 2 above, approved by the FPSC.

8.10 Survival of Agreement. This Agreement, as may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

9. Environmental Interests

The Company will be entitled to receive one hundred percent (100%) of all Renewable Energy Certificates, Green Tags, carbon credits or allowances, or other tradable environmental interests, if any, which result from electrical energy generated at the County's facility during the term of this Agreement. Details regarding the delivery of such interests to the Company will be mutually agreed upon by the Parties.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized officers.

ATTEST:

Terry A. Davis
ASST. Secretary TERRY A. DAVIS
7/17/14

GULF POWER COMPANY

BY Michael L. Burroughs
Vice President
Michael L. Burroughs VP & SPO

TITLE

DATE July 16, 2014

ATTEST:

Witness as to County

Witness as to County

County

BY

TITLE Chairman
Official Capacity

DATE July 1, 2014

BOARD OF COUNTY COMMISSIONERS
SEAL
BAY COUNTY, FLORIDA

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 2004	2.0936	2.3270	11.15
December 2005	2.6566	2.8817	8.47
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	4.5498	4.2774	(5.99)
December 2010	4.9626	4.8818	1.66
December 2011	4.7917	4.7259	1.37
December 2012	4.2617	3.9806	(0.28)
December 2013	4.1654	4.2198	1.31
December 2014	4.1673[(2)]		
December 2015	3.7215[(3)]		

(1) Line No. 1 from FPSC Schedule A-1, December, Period To Date
(2) Line No. 1 from FPSC Schedule E-1B-1, 2014 Actual / Estimated True-Up
(3) Line No. 1 from FPSC Schedule E-1, 2015 Projection Filing

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 34
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-3

FILED SEP 04, 2014
DOCUMENT NO. 04949-14
FPSC - COMMISSION CLERK

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, 2014

Docket No. 140001-EI
Audit Control No. 14-083-1-1
August 21, 2014

Debra M. Dobiac
Audit Manager

Lynn M. Deamer
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 35
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-4

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Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated March 20, 2014. We have applied these procedures to the schedules prepared by Gulf Power Company in support of its filing for hedging activities in Docket No. 140001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. 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, 2014. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. 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, 2013 to July 31, 2014. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with GPC's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objectives: The objective was to determine whether the quantities of natural gas, residual oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2014, 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 work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Audit Findings

None

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 36
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-5

Docket No. 140001-EI
January - July 2014 Hedging Report
GULF POWER COMPANY

	A	B	C	D	E	F	G	H	J	K	L
	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	CARGILL	3148	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	01/2014	60,000	
2	CARGILL	3149		Fixed (Lower)							
3	BMO	3366	Unwind	Nymex LD HH		Fixed (Upper)			01/2014	10,000	
4	BMO	3366		Fixed (Upper)		Sell Call					
5	BMO	3367		Buy Put		Fixed (Lower)					
6	JPMORG	3371		Nymex LD HH		Fixed (Upper)				20,000	
7	JPMORG	3371		Fixed (Upper)		Sell Call					
8	CITIGR	3379		Nymex LD HH		Fixed (Upper)				10,000	
9	CITIGR	3379		Fixed (Upper)		Sell Call					
10	MERRIL	3384		Nymex LD HH		Fixed (Upper)				10,000	
11	MERRIL	3384		Fixed (Upper)		Sell Call					
12	MERRIL	3389		Nymex LD HH		Fixed (Upper)				10,000	
13	MERRIL	3389		Fixed (Upper)		Sell Call					
14	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	01/2014	50,000	
15	JPMORG	3192		Fixed (Lower)							
16	BMO	3330	Unwind	Nymex LD HH		Fixed (Upper)			01/2014	10,000	
17	BMO	3330		Fixed (Upper)		Sell Call					
18	BMO	3331		Buy Put		Fixed (Lower)					
19	MERRIL	3341		Nymex LD HH		Fixed (Upper)				10,000	
20	MERRIL	3341		Fixed (Upper)		Sell Call					
21	MERRIL	3342		Buy Put		Fixed (Lower)					
22	CIBC	3349		Nymex LD HH		Fixed (Upper)				10,000	
23	CIBC	3349		Fixed (Upper)		Sell Call					
24	CIBC	3350		Buy Put		Fixed (Lower)					
25	MERRIL	3319		Nymex LD HH		Fixed (Upper)				20,000	
26	MERRIL	3319		Fixed (Upper)		Sell Call					
27	MERRIL	3320		Buy Put		Fixed (Lower)					
28	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	01/2014	30,000	
29	BMO	3201		Fixed (Lower)							
30	MERRIL	3351	Unwind	Nymex LD HH		Fixed (Upper)			01/2014	10,000	
31	MERRIL	3351		Fixed (Upper)		Sell Call					
32	CIBC	3359		Nymex LD HH		Fixed (Upper)				20,000	
33	CIBC	3359		Fixed (Upper)		Sell Call					
34	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
35	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
36	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
37	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	01/2014	60,000	
38	BARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
39	BARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
40	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
41	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
42	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
43	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
44	CIBC	6597	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
45	CIBC	6597	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
46	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
46	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
47	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
47	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
48	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
49	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
50	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
51	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
52	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
53	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
54	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
55	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
56	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
57	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
58	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
59	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
60	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
61	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
62	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
63	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
64	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
65	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
66	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
67	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
68	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
69	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
70	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
71	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
72	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
73	BMO	7361	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	01/2014	30,000	[redacted]
74	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
75	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
76	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
77	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
78	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
79	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
80	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
81	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
82	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
83	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
84	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
85	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
86	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
87	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
88	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
89	BARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
90	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
91	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
92	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
93	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
94	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
95	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	01/2014	60,000	
96	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
97	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
98	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
99	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
100	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
101	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
102	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
103	BNPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
104	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
105	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
106	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
107	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
108	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
109	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
110	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
111	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
112	MERRIL	8500	Swap	Fixed		Nymex LD HH		Nymex	01/2014	60,000	
113	BMO	8517	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
114	JPMORG	8519	Swap	Fixed		Nymex LD HH		Nymex	01/2014	70,000	
115	CARGILL	8535	Swap	Fixed		Nymex LD HH		Nymex	01/2014	70,000	
116	CARGILL	8578	Swap	Fixed		Nymex LD HH		Nymex	01/2014	100,000	
117	CARGILL	8578	Swap	Fixed		Nymex LD HH		Nymex	01/2014	100,000	
118	MERRIL	8597	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
119	CIBC	8648	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
120	CIBC	8673	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
121	BP	8711	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
122	BMO	8723	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
123	CARGILL	8743	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
124	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
125	JPMORG	8793	Swap	Nymex LD HH		Fixed		Nymex	01/2014	150,000	
126	JPMORG	8794	Swap	Fixed		Nymex LD HH		Nymex	01/2014	150,000	
127	BMO	8795	Swap	Nymex LD HH		Fixed		Nymex	01/2014	140,000	
128	BMO	8796	Swap	Fixed		Nymex LD HH		Nymex	01/2014	140,000	
129	SUISSE	8797	Swap	Nymex LD HH		Fixed		Nymex	01/2014	200,000	
130	SUISSE	8798	Swap	Fixed		Nymex LD HH		Nymex	01/2014	200,000	
131	BP	8799	Swap	Nymex LD HH		Fixed		Nymex	01/2014	150,000	
132	BP	8800	Swap	Fixed		Nymex LD HH		Nymex	01/2014	150,000	
133	BARCLAY	8801	Swap	Nymex LD HH		Fixed		Nymex	01/2014	150,000	
134	BARCLAY	8802	Swap	Fixed		Nymex LD HH		Nymex	01/2014	150,000	
135	CIBC	8803	Swap	Nymex LD HH		Fixed		Nymex	01/2014	170,000	
136	CIBC	8804	Swap	Fixed		Nymex LD HH		Nymex	01/2014	170,000	
137	BNPP	8805	Swap	Nymex LD HH		Fixed		Nymex	01/2014	310,000	
138	BNPP	8806	Swap	Fixed		Nymex LD HH		Nymex	01/2014	310,000	
139	JPMORG	8807	Swap	Nymex LD HH		Fixed		Nymex	01/2014	200,000	
140	MERRIL	8810	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
141	SUISSE	8811	Swap	Nymex LD HH		Fixed		Nymex	01/2014	310,000	
142	BMO	8812	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
143	BARCLAY	8813	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
144	BP	8814	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
145	FIFTH	8817	Swap	Nymex LD HH		Fixed		Nymex	01/2014	120,000	
146	CIBC	8819	Swap	Nymex LD HH		Fixed		Nymex	01/2014	360,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
147	CITIGR	8820	Swap	Nymex LD HH		Fixed		Nymex	01/2014	110,000	
148	BMO	8821	Swap	Nymex LD HH		Fixed		Nymex	01/2014	120,000	
149	BARCLAY	8824	Swap	Nymex LD HH		Fixed		Nymex	01/2014	120,000	
150	BP	8825	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
151	SCOTIA	8831	Swap	Nymex LD HH		Fixed		Nymex	01/2014	480,000	
152	CITIGR	8834	Swap	Nymex LD HH		Fixed		Nymex	01/2014	80,000	
153	MITSUI	8837	Swap	Nymex LD HH		Fixed		Nymex	01/2014	50,000	
154	MITSUI	8838	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
155	BNPP	8841	Swap	Nymex LD HH		Fixed		Nymex	01/2014	100,000	
156	FIFTH	8850	Swap	Nymex LD HH		Fixed		Nymex	01/2014	300,000	
157	BNPP	8861	Swap	Nymex LD HH		Fixed		Nymex	01/2014	90,000	
158	CIBC	8868	Swap	Nymex LD HH		Fixed		Nymex	01/2014	90,000	
159	BMO	8869	Swap	Nymex LD HH		Fixed		Nymex	01/2014	90,000	
159	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
160	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
160	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
161	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
161	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
162	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	01/2014	10,000	
163	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
164	BMO	7361	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
165	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
166	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
167	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
168	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
169	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
170	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
171	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
172	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
173	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
174	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
175	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
176	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
177	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
178	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
179	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	01/2014	130,000	
180	BARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	01/2014	130,000	
181	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	01/2014	130,000	
182	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
183	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
184	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	01/2014	50,000	
185	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	01/2014	130,000	
186	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	01/2014	110,000	
187	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	01/2014	80,000	
188	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
189	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
190	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
191	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
192	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
193	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
194	BNPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
195	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
196	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	01/2014	20,000	
197	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	01/2014	40,000	
198	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	01/2014	30,000	
199	MERRIL	8398	Swap	Nymex LD HH		Fixed		Nymex	01/2014	590,000	
200	JPMORG	8403	Swap	Nymex LD HH		Fixed		Nymex	01/2014	580,000	
201	CITIGR	8405	Swap	Nymex LD HH		Fixed		Nymex	01/2014	580,000	
202	**TOTAL**										**$ (1,412,120)**

	A	B	C	D	E	F	G	H	J	K	L
	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	CARGILL	3148	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	02/2014	60,000	
2	CARGILL	3149		Fixed (Lower)							
3	MERRIL	3431	Unwind	Nymex LD HH		Fixed (Upper)			02/2014	10,000	
4	MERRIL	3431		Fixed (Upper)		Sell Call					
5	CARGILL	3435		Nymex LD HH		Fixed (Upper)				10,000	
6	CARGILL	3435		Fixed (Upper)		Sell Call					
7	JPMORG	3441		Nymex LD HH		Fixed (Upper)				20,000	
8	JPMORG	3441		Fixed (Upper)		Sell Call					
9	MERRIL	3451		Nymex LD HH		Fixed (Upper)				10,000	
10	MERRIL	3451		Fixed (Upper)		Sell Call					
11	MERRIL	3452		Buy Put		Fixed (Lower)					
12	JPMORG	3457		Nymex LD HH		Fixed (Upper)				10,000	
13	JPMORG	3457		Fixed (Upper)		Sell Call					
14	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	02/2014	50,000	
15	JPMORG	3192		Fixed (Lower)							
16	JPMORG	3396	Unwind	Nymex LD HH		Fixed (Upper)			02/2014	30,000	
17	JPMORG	3396		Fixed (Upper)		Sell Call					
18	MITSUI	3419		Nymex LD HH		Fixed (Upper)				10,000	
19	MITSUI	3419		Fixed (Upper)		Sell Call					
20	FIFTH	3425		Nymex LD HH		Fixed (Upper)				10,000	
21	FIFTH	3425		Fixed (Upper)		Sell Call					
22	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	02/2014	30,000	
23	BMO	3201		Fixed (Lower)							
24	MERRIL	3473	Unwind	Nymex LD HH		Fixed (Upper)			02/2014	10,000	
25	MERRIL	3473		Fixed (Upper)		Sell Call					
26	JPMORG	3481		Nymex LD HH		Fixed (Upper)				10,000	
27	JPMORG	3481		Fixed (Upper)		Sell Call					
28	JPMORG	3490		Nymex LD HH		Fixed (Upper)				10,000	
29	JPMORG	3490		Fixed (Upper)		Sell Call					
30	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
31	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
32	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
33	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
34	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
35	BARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
36	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
37	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	02/2014	10,000	
38	CIBC	6597	Swap	Fixed		Nymex LD HH		Nymex	02/2014	10,000	
39	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
40	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
41	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
42	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
43	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
44	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
45	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	02/2014	10,000	
46	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
47	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
48	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
49	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
50	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
51	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
52	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
53	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	02/2014	10,000	
54	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
55	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	02/2014	10,000	
56	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
57	BMO	7361	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
58	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
59	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
60	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
61	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
62	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
63	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
64	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
65	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
66	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
67	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
68	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
69	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
70	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
71	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
72	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
73	BARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
74	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
75	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
76	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
77	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
78	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
79	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
80	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
81	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
82	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
83	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
84	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
85	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
86	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
87	BNPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
88	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
89	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	02/2014	20,000	
90	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
91	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
92	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
93	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
94	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
95	MERRIL	8500	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
96	BMO	8517	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
97	JPMORG	8519	Swap	Fixed		Nymex LD HH		Nymex	02/2014	70,000	
98	JPMORG	8519	Swap	Fixed		Nymex LD HH		Nymex	02/2014	70,000	
99	CARGILL	8535	Swap	Fixed		Nymex LD HH		Nymex	02/2014	70,000	
100	CARGILL	8535	Swap	Fixed		Nymex LD HH		Nymex	02/2014	70,000	
101	CARGILL	8566	Swap	Fixed		Nymex LD HH		Nymex	02/2014	140,000	
102	CARGILL	8578	Swap	Fixed		Nymex LD HH		Nymex	02/2014	100,000	
103	MERRIL	8597	Swap	Fixed		Nymex LD HH		Nymex	02/2014	-	
104	CIBC	8648	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
105	CIBC	8673	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
106	BP	8711	Swap	Fixed		Nymex LD HH		Nymex	02/2014	80,000	
107	BMO	8723	Swap	Fixed		Nymex LD HH		Nymex	02/2014	100,000	
108	CARGILL	8743	Swap	Fixed		Nymex LD HH		Nymex	02/2014	100,000	
109	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	02/2014	30,000	
110	CITIGR	8822	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
111	CITIGR	8823	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
112	CIBC	8827	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
113	CIBC	8828	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
114	MERRIL	8829	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
115	MERRIL	8830	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
116	BNPP	8832	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
117	BNPP	8833	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
118	JPMORG	8835	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
119	JPMORG	8836	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
120	CITIGR	8844	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
121	CITIGR	8845	Swap	Fixed		Nymex LD HH		Nymex	02/2014	60,000	
122	JPMORG	8851	Swap	Nymex LD HH		Fixed		Nymex	02/2014	40,000	
123	JPMORG	8852	Swap	Fixed		Nymex LD HH		Nymex	02/2014	40,000	
124	CIBC	8858	Swap	Nymex LD HH		Fixed		Nymex	02/2014	50,000	
125	CIBC	8859	Swap	Fixed		Nymex LD HH		Nymex	02/2014	50,000	
126	MERRIL	8866	Swap	Nymex LD HH		Fixed		Nymex	02/2014	170,000	
127	MERRIL	8867	Swap	Fixed		Nymex LD HH		Nymex	02/2014	170,000	
128	JPMORG	8872	Swap	Nymex LD HH		Fixed		Nymex	02/2014	160,000	
129	JPMORG	8873	Swap	Fixed		Nymex LD HH		Nymex	02/2014	160,000	
130	SUISSE	8874	Swap	Nymex LD HH		Fixed		Nymex	02/2014	160,000	
131	SUISSE	8875	Swap	Fixed		Nymex LD HH		Nymex	02/2014	160,000	
132	SUISSE	8879	Swap	Nymex LD HH		Fixed		Nymex	02/2014	170,000	
133	SHELLTRADE	8880	Swap	Nymex LD HH		Fixed		Nymex	02/2014	160,000	
134	CITIGR	8881	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
135	BARCLAY	8884	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
136	CIBC	8891	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
137	SHELLTRADE	8894	Swap	Nymex LD HH		Fixed		Nymex	02/2014	50,000	
138	CITIGR	8895	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	
139	BP	8896	Swap	Nymex LD HH		Fixed		Nymex	02/2014	330,000	
140	MERRIL	8898	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
141	FIFTH	8900	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
142	CITIGR	8901	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
143	MITSUI	8903	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
144	SCOTIA	8904	Swap	Nymex LD HH		Fixed		Nymex	02/2014	20,000	
145	SUISSE	8905	Swap	Nymex LD HH		Fixed		Nymex	02/2014	440,000	
146	BNPP	8906	Swap	Nymex LD HH		Fixed		Nymex	02/2014	110,000	
147	CARGILL	8911	Swap	Nymex LD HH		Fixed		Nymex	02/2014	120,000	
148	JPMORG	8921	Swap	Nymex LD HH		Fixed		Nymex	02/2014	60,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
149	BMO	8922	Swap	Nymex LD HH	[redacted]	Fixed	[redacted]	Nymex	02/2014	60,000	[redacted]
150	MERRIL	8923	Swap	Nymex LD HH	[redacted]	Fixed	[redacted]	Nymex	02/2014	330,000	[redacted]
151	BP	8926	Swap	Nymex LD HH	[redacted]	Fixed	[redacted]	Nymex	02/2014	120,000	[redacted]
152	FIFTH	8929	Swap	Nymex LD HH	[redacted]	Fixed	[redacted]	Nymex	02/2014	120,000	[redacted]
153	CIBC	8931	Swap	Nymex LD HH	[redacted]	Fixed	[redacted]	Nymex	02/2014	110,000	[redacted]
154	**TOTAL**										**$ (3,266,585)**

	A	B	C	D	E	F	G	H	J	K	L
	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	CARGILL	3148	Option (Collar)	Fixed (Upper)	[redacted]	Nymex LD HH	[redacted]	Nymex	03/2014	60,000	[redacted]
2	CARGILL	3149		Fixed (Lower)							
3	MITSUI	3S38	Unwind	Nymex LD HH		Fixed (Upper)			03/2014	10,000	
4	MITSUI	3538		Fixed (Upper)		Sell Call					
5	MITSUI	3539		Buy Put		Fixed (Lower)					
6	MERRIL	3S44		Nymex LD HH		Fixed (Upper)				10,000	
7	MERRIL	3544		Fixed (Upper)		Sell Call					
8	BMO	3S48		Nymex LD HH		Fixed (Upper)				10,000	
9	BMO	3548		Fixed (Upper)		Sell Call					
10	BMO	3549		Buy Put		Fixed (Lower)					
11	BMO	35S2		Nymex LD HH		Fixed (Upper)				10,000	
12	BMO	35S2		Fixed (Upper)		Sell Call					
13	BMO	3SS3		Buy Put		Fixed (Lower)					
14	SUISSE	35S8		Nymex LD HH		Fixed (Upper)				10,000	
15	SUISSE	3558		Fixed (Upper)		Sell Call					
16	SUISSE	3564		Nymex LD HH		Fixed (Upper)				10,000	
17	SUISSE	3564		Fixed (Upper)		Sell Call					
18	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	03/2014	50,000	
19	JPMORG	3191		Fixed (Lower)							
20	SUISSE	3497	Unwind	Nymex LD HH		Fixed (Upper)			03/2014	30,000	
21	SUISSE	3497		Fixed (Upper)		Sell Call					
22	MERRIL	3S08		Nymex LD HH		Fixed (Upper)				10,000	
23	MERRIL	3508		Fixed (Upper)		Sell Call					
24	MERRIL	3509		Buy Put		Fixed (Lower)					
25	CITIGR	3S16		Nymex LD HH		Fixed (Upper)				10,000	
26	CITIGR	3S16		Fixed (Upper)		Sell Call					
27	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	03/2014	30,000	
28	BMO	3201		Fixed (Lower)							
29	JPMORG	3S29	Unwind	Nymex LD HH		Fixed (Upper)			03/2014	10,000	
30	JPMORG	3529		Fixed (Upper)		Sell Call					
31	SUISSE	3S34		Nymex LD HH		Fixed (Upper)				20,000	
32	SUISSE	3S34		Fixed (Upper)		Sell Call					
33	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
34	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
35	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	03/2014	60,000	
36	BARCLAY	6SS3	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
37	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
38	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
39	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
40	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	03/2014	40,000	
41	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
42	CITIGR	8880	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
43	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
44	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
45	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
46	MERRIL	8399	Swap	Fixed		Nymex LD HH		Nymex	03/2014	$90,000	
47	JPMORG	8404	Swap	Fixed		Nymex LD HH		Nymex	03/2014	$80,000	
48	CITIGR	8406	Swap	Fixed		Nymex LD HH		Nymex	03/2014	580,000	
49	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	03/2014	-	
50	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
51	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
52	MERRIL	8S00	Swap	Fixed		Nymex LD HH		Nymex	03/2014	60,000	
53	BMO	8S17	Swap	Fixed		Nymex LD HH		Nymex	03/2014	40,000	
54	JPMORG	8S19	Swap	Fixed		Nymex LD HH		Nymex	03/2014	70,000	
55	CARGILL	8S35	Swap	Fixed		Nymex LD HH		Nymex	03/2014	70,000	
56	CARGILL	8S78	Swap	Fixed		Nymex LD HH		Nymex	03/2014	100,000	
57	MERRIL	8597	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
58	CIBC	8648	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
59	CIBC	8673	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
60	BP	8711	Swap	Fixed		Nymex LD HH		Nymex	03/2014	80,000	
61	BMO	8723	Swap	Fixed		Nymex LD HH		Nymex	03/2014	100,000	
62	CARGILL	8743	Swap	Fixed		Nymex LD HH		Nymex	03/2014	100,000	
63	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
64	BARCLAY	8846	Swap	Nymex LD HH		Fixed		Nymex	03/2014	30,000	
65	BARCLAY	8847	Swap	Fixed		Nymex LD HH		Nymex	03/2014	30,000	
66	BP	8853	Swap	Nymex LD HH		Fixed		Nymex	03/2014	20,000	
67	BP	8854	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
68	SUISSE	8885	Swap	Nymex LD HH		Fixed		Nymex	03/2014	50,000	
69	SUISSE	8886	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
70	MERRIL	8889	Swap	Nymex LD HH		Fixed		Nymex	03/2014	50,000	
71	MERRIL	8890	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	
72	JPMORG	8892	Swap	Nymex LD HH		Fixed		Nymex	03/2014	50,000	
73	JPMORG	8893	Swap	Fixed		Nymex LD HH		Nymex	03/2014	50,000	

	A	B	C	D	E	F	G	H	J	K	L
	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	CIBC	8907	Swap	Nymex LD HH		Fixed		Nymex	03/2014	80,000	
75	CIBC	8908	Swap	Fixed		Nymex LD HH		Nymex	03/2014	80,000	
76	SCOTIA	8909	Swap	Nymex LD HH		Fixed		Nymex	03/2014	80,000	
77	SCOTIA	8910	Swap	Fixed		Nymex LD HH		Nymex	03/2014	80,000	
78	SUISSE	8912	Swap	Nymex LD HH		Fixed		Nymex	03/2014	40,000	
79	SUISSE	8913	Swap	Fixed		Nymex LD HH		Nymex	03/2014	40,000	
80	MITSUI	8914	Swap	Nymex LD HH		Fixed		Nymex	03/2014	20,000	
81	MITSUI	8915	Swap	Fixed		Nymex LD HH		Nymex	03/2014	20,000	
82	JPMORG	8917	Swap	Nymex LD HH		Fixed		Nymex	03/2014	60,000	
83	JPMORG	8918	Swap	Fixed		Nymex LD HH		Nymex	03/2014	60,000	
84	CITIGR	8932	Swap	Nymex LD HH		Fixed		Nymex	03/2014	60,000	
85	CITIGR	8933	Swap	Fixed		Nymex LD HH		Nymex	03/2014	60,000	
86	BARCLAY	8934	Swap	Nymex LD HH		Fixed		Nymex	03/2014	330,000	
87	CIBC	8935	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
88	BP	8936	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
89	FIFTH	8937	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
90	BNPP	8938	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
91	SHELLTRADE	8939	Swap	Nymex LD HH		Fixed		Nymex	03/2014	330,000	
92	CIBC	8940	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
93	SUISSE	8941	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
94	MERRIL	8942	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
95	CITIGR	8943	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
96	CIBC	8946	Swap	Nymex LD HH		Fixed		Nymex	03/2014	330,000	
97	MITSUI	8947	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
98	BMO	8948	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
99	CARGILL	8954	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
100	SHELLTRADE	8957	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
101	BP	8958	Swap	Nymex LD HH		Fixed		Nymex	03/2014	300,000	
102	SCOTIA	8959	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
103	FIFTH	8960	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
104	CIBC	8962	Swap	Nymex LD HH		Fixed		Nymex	03/2014	110,000	
105	SUISSE	8970	Swap	Nymex LD HH		Fixed		Nymex	03/2014	100,000	
106	**TOTAL**										**$ (1,182,675)**

	A	B	C	D	E	F	G	H	J	K	L
	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	BMO	3133	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	04/2014	30,000	
2	BMO	3134		Fixed (Lower)							
3	JPMORG	3599	Unwind	Nymex LD HH		Fixed (Upper)			04/2014	30,000	
4	JPMORG	3599		Fixed (Upper)		Sell Call					
5	JPMORG	3178	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	04/2014	50,000	
6	JPMORG	3179		Fixed (Lower)							
7	BMO	3597	Unwind	Nymex LD HH		Fixed (Upper)			04/2014	10,000	
8	BMO	3597		Fixed (Upper)		Sell Call					
9	BMO	3598		Buy Put		Fixed (Lower)					
10	BMO	3605		Nymex LD HH		Fixed (Upper)				10,000	
11	BMO	3605		Fixed (Upper)		Sell Call					
12	BMO	3606		Buy Put		Fixed (Lower)					
13	CIBC	3609		Nymex LD HH		Fixed (Upper)				10,000	
14	CIBC	3609		Fixed (Upper)		Sell Call					
15	MERRIL	3611		Nymex LD HH		Fixed (Upper)				10,000	
16	MERRIL	3611		Fixed (Upper)		Sell Call					
17	SUISSE	3616		Nymex LD HH		Fixed (Upper)				10,000	
18	SUISSE	3616		Fixed (Upper)		Sell Call					
19	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	04/2014	-	
20	JPMORG	3192		Fixed (Lower)							
21	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	04/2014	-	
22	BMO	3201		Fixed (Lower)							
23	MERRIL	6S96	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
24	CIBC	6S97	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
25	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
26	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
27	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
28	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
29	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
30	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
31	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
32	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
33	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
34	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
35	BMO	7361	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
36	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
37	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
38	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
39	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
40	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
41	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
42	MERRIL	7S65	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
43	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
44	JPMORG	7S88	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
45	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
46	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
47	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
48	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
49	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
50	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
51	BARCLAY	77S2	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
52	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
53	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
54	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
55	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
56	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	04/2014	10,000	
57	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
58	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
59	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
60	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
61	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
62	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
63	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
64	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
65	BNPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
66	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
67	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	04/2014	20,000	
68	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	04/2014	40,000	
69	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	04/2014	30,000	
70	SHELLTRADE	8322	Swap	Fixed		Nymex LD HH		Nymex	04/2014	50,000	
71	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	04/2014	-	
72	JPMORG	8593	Swap	Fixed		Nymex LD HH		Nymex	04/2014	50,000	
73	MERRIL	8S97	Swap	Fixed		Nymex LD HH		Nymex	04/2014	50,000	
74	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	04/2014	-	
75	BP	8952	Swap	Nymex LD HH		GD HH		Gas Daily	04/2014	300,000	

	A	B	C	D	E	F	G	H	J	K	L
	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	8966	Swap	Nymex LD HH		Fixed		Nymex	04/2014	160,000	
77	BNPP	8967	Swap	Fixed		Nymex LD HH		Nymex	04/2014	160,000	
78	JPMORG	8968	Swap	Nymex LD HH		Fixed		Nymex	04/2014	170,000	
79	JPMORG	8969	Swap	Fixed		Nymex LD HH		Nymex	04/2014	170,000	
80	CIBC	8971	Swap	Nymex LD HH		Fixed		Nymex	04/2014	160,000	
81	CIBC	8972	Swap	Fixed		Nymex LD HH		Nymex	04/2014	160,000	
82	BARCLAY	8973	Swap	Nymex LD HH		Fixed		Nymex	04/2014	160,000	
83	BARCLAY	8974	Swap	Fixed		Nymex LD HH		Nymex	04/2014	160,000	
84	JPMORG	8976	Swap	Nymex LD HH		Fixed		Nymex	04/2014	50,000	
85	JPMORG	8977	Swap	Fixed		Nymex LD HH		Nymex	04/2014	50,000	
86	SCOTIA	8978	Swap	Nymex LD HH		GD HH		Gas Daily	04/2014	300,000	
87	CARGILL	8979	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
88	MERRIL	8985	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
89	CITIGR	8989	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
90	MITSUI	8990	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
91	CIBC	8992	Swap	Nymex LD HH		Fixed		Nymex	04/2014	90,000	
92	SUISSE	8993	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
93	BMO	8994	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
94	SHELLTRADE	8995	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
95	JPMORG	8996	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
96	CITIGR	8998	Swap	Nymex LD HH		Fixed		Nymex	04/2014	70,000	
97	MITSUI	8999	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
98	BMO	9000	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
99	MITSUI	9002	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
100	JPMORG	9004	Swap	Nymex LD HH		Fixed		Nymex	04/2014	80,000	
101	BMO	9005	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
102	CIBC	9007	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
103	CIBC	9009	Swap	Nymex LD HH		Fixed		Nymex	04/2014	30,000	
104	SUISSE	9012	Swap	Nymex LD HH		Fixed		Nymex	04/2014	20,000	
105	SCOTIA	9014	Swap	Nymex LD HH		Fixed		Nymex	04/2014	90,000	
106	CARGILL	9018	Swap	Nymex LD HH		Fixed		Nymex	04/2014	10,000	
107	**TOTAL**										**$ (715,550)**

	A	B	C	D	E	F	G	H	J	K	L
	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	BMO	3133	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	05/2014	30,000	
2	BMO	3134		Fixed (Lower)							
3	SUISSE	3634	Unwind	Nymex LD HH		Fixed (Upper)			05/2014	30,000	
4	SUISSE	3634		Fixed (Upper)		Sell Call					
5	SUISSE	3635		Buy Put		Fixed (Lower)					
6	CARGILL	3164	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	05/2014	80,000	
7	CARGILL	3165		Fixed (Lower)							
8	MITSUI	3637	Unwind	Nymex LD HH		Fixed (Upper)			05/2014	80,000	
9	MITSUI	3637		Fixed (Upper)		Sell Call					
10	MITSUI	3638		Buy Put		Fixed (Lower)					
11	JPMORG	3178	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	05/2014	50,000	
12	JPMORG	3179		Fixed (Lower)							
13	BP	3647	Unwind	Nymex LD HH		Fixed (Upper)			05/2014	40,000	
14	BP	3647		Fixed (Upper)		Sell Call					
15	BP	3648		Buy Put		Fixed (Lower)					
16	CARGILL	3651		Nymex LD HH		Nymex LD HH				10,000	
17	CARGILL	3651		Fixed (Upper)		Sell Call					
18	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	05/2014	50,000	
19	JPMORG	3192		Fixed (Lower)							
20	CITIGR	3628	Unwind	Nymex LD HH		Fixed (Upper)			05/2014	50,000	
21	CITIGR	3628		Fixed (Upper)		Sell Call					
22	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	05/2014	30,000	
23	BMO	3201		Fixed (Lower)							
24	MITSUI	3639	Unwind	Nymex LD HH		Fixed (Upper)			05/2014	30,000	
25	MITSUI	3639		Fixed (Upper)		Sell Call					
26	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
27	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
28	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	05/2014	60,000	
29	BARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
30	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
31	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
32	CIBC	6597	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
33	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
34	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
35	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
36	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
37	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
38	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
39	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
40	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
41	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
42	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
43	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
44	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
45	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
46	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
47	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
48	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
49	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
50	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
51	BMO	7361	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
52	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
53	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
54	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
55	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
56	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
57	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
58	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
59	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
60	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
61	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
62	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
63	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
64	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
65	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
66	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
67	BARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
68	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
69	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
70	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
71	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
72	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
73	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
74	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
75	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	

	A	B	C	D	E	F	G	H	J	K	L
	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	SHELLTRADE	793S	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
77	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
78	8MO	8008	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
79	8NPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
80	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
81	8NPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
82	SUISSE	8088	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
83	8ARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
84	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	05/2014	20,000	
85	MERRIL	8144	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
86	8NPP ET	8151	Swap	Fixed		Nymex LD HH		Nymex	05/2014	70,000	
87	MERRIL	8196	Swap	Fixed		Nymex LD HH		Nymex	05/2014	60,000	
88	DEUTSCH	8211	Swap	Fixed		Nymex LD HH		Nymex	05/2014	60,000	
89	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	05/2014	40,000	
90	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
91	SHELLTRADE	8322	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
92	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	05/2014	-	
93	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
94	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
95	JPMORG	8S19	Swap	Fixed		Nymex LD HH		Nymex	05/2014	70,000	
96	CARGILL	8S35	Swap	Fixed		Nymex LD HH		Nymex	05/2014	70,000	
97	CARGILL	8S78	Swap	Fixed		Nymex LD HH		Nymex	05/2014	100,000	
98	JPMORG	8S93	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
99	MERRIL	8S97	Swap	Fixed		Nymex LD HH		Nymex	05/2014	50,000	
100	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
101	SUISSE	9015	Swap	Nymex LD HH		GD HH		Gas Daily	05/2014	620,000	
102	SHELLTRADE	9016	Swap	Nymex LD HH		GD HH		Gas Daily	05/2014	310,000	
103	CARGILL	9020	Swap	Nymex LD HH		Fixed		Nymex	05/2014	30,000	
104	CARGILL	9021	Swap	Fixed		Nymex LD HH		Nymex	05/2014	30,000	
105	8NPP	9022	Swap	Nymex LD HH		Fixed		Nymex	05/2014	750,000	
106	8NPP	9023	Swap	Fixed		Nymex LD HH		Nymex	05/2014	750,000	
107	MITSUI	9024	Swap	Nymex LD HH		Fixed		Nymex	05/2014	190,000	
108	MITSUI	9025	Swap	Fixed		Nymex LD HH		Nymex	05/2014	190,000	
109	MERRIL	9033	Swap	Nymex LD HH		Fixed		Nymex	05/2014	30,000	
110	CIBC	9034	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
111	JPMORG	9035	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
112	MITSUI	9036	Swap	Nymex LD HH		Fixed		Nymex	05/2014	130,000	
113	CARGILL	9038	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
114	8ARCLAY	9042	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
115	SHELLTRADE	9044	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
116	SUISSE	9045	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
117	MITSUI	9046	Swap	Nymex LD HH		Fixed		Nymex	05/2014	120,000	
118	FIFTH	9047	Swap	Nymex LD HH		Fixed		Nymex	05/2014	50,000	
119	SCOTIA	9050	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
120	BARCLAY	9052	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
121	CARGILL	9053	Swap	Nymex LD HH		Fixed		Nymex	05/2014	40,000	
122	MERRIL	9055	Swap	Nymex LD HH		Fixed		Nymex	05/2014	190,000	
123	SUISSE	9059	Swap	Nymex LD HH		Fixed		Nymex	05/2014	50,000	
124	CIBC	9063	Swap	Nymex LD HH		Fixed		Nymex	05/2014	50,000	
125	8MO	9064	Swap	Fixed		Nymex LD HH		Nymex	05/2014	10,000	
126	**TOTAL**										**$ (804,905)**

	A	B	C	D	E	F	G	H	J	K	L
	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	BMO	3133	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	30,000	
2	BMO	3134		Fixed (Lower)							
3	BMO	3687	Unwind	Nymex LD HH		Fixed (Upper)			06/2014	30,000	
4	BMO	3687		Fixed (Upper)		Sell Call					
5	BMO	3688		Buy Put		Fixed (Lower)					
6	JPMORG	3178	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	50,000	
7	JPMORG	3179		Fixed (Lower)							
8	CARGILL	3703	Unwind	Nymex LD HH		Fixed (Upper)			06/2014	50,000	
9	CARGILL	3703		Fixed (Upper)		Sell Call					
10	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	50,000	
11	JPMORG	3192		Fixed (Lower)							
12	BMO	3689	Unwind	Nymex LD HH		Fixed (Upper)			06/2014	50,000	
13	BMO	3689		Fixed (Upper)		Sell Call					
14	BMO	3690		Buy Put		Fixed (Lower)					
15	BMO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	30,000	
16	BMO	3201		Fixed (Lower)							
17	BMO	3691	Unwind	Nymex LD HH		Fixed (Upper)			06/2014	30,000	
18	BMO	3691		Fixed (Upper)		Sell Call					
19	BMO	3692		Buy Put		Fixed (Lower)					
20	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
21	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
22	BP	6533	Swap	Fixed		Nymex LD HH		Nymex	06/2014	60,000	
23	BARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
24	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
25	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	06/2014	10,000	
26	CIBC	6597	Swap	Fixed		Nymex LD HH		Nymex	06/2014	10,000	
27	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
28	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
29	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
30	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
31	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
32	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
33	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	06/2014	10,000	
34	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
35	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
36	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
37	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
38	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
39	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
40	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
41	CIBC	7263	Swap	Fixed		Nymex LD HH		Nymex	06/2014	10,000	
42	BBVA	7315	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
43	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	06/2014	10,000	
44	BARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
45	BMO	7361	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
46	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
47	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
48	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
49	BARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
50	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
51	BARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
52	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
53	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
54	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
55	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
56	BMO	7642	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
57	BMO	7672	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
58	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
59	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
60	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
61	BARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
62	BNPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
63	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
64	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
65	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
66	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
67	BP	7891	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
68	BNPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
69	BNPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
70	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
71	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
72	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
73	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
74	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
75	8NPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
76	SUISSE	8088	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
77	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
78	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	06/2014	20,000	
79	MERRIL	8144	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
80	8NPP ET	8151	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
81	MERRIL	8196	Swap	Fixed		Nymex LD HH		Nymex	06/2014	-	
82	DEUTSCH	8211	Swap	Fixed		Nymex LD HH		Nymex	06/2014	-	
83	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
84	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
85	BMO	8305	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
86	SHELLTRADE	8322	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
87	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
88	DEUTSCH	8427	Swap	Fixed		Nymex LD HH		Nymex	06/2014	100,000	
89	FIFTH	8432	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
90	DEUTSCH	8449	Swap	Fixed		Nymex LD HH		Nymex	06/2014	40,000	
91	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
92	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
93	JPMORG	8519	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
94	CARGILL	8535	Swap	Fixed		Nymex LD HH		Nymex	06/2014	70,000	
95	CARGILL	8578	Swap	Fixed		Nymex LD HH		Nymex	06/2014	100,000	
96	JPMORG	8593	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
97	MERRIL	8597	Swap	Fixed		Nymex LD HH		Nymex	06/2014	50,000	
98	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	06/2014	30,000	
99	BP	9057	Swap	Nymex LD HH		GD HH		Gas Daily	06/2014	600,000	
100	SUISSE	9058	Swap	Nymex LD HH		GD HH		Gas Daily	06/2014	300,000	
101	SHELLTRADE	9060	Swap	Nymex LD HH		GD HH		Gas Daily	06/2014	300,000	
102	MITSUI	9061	Swap	Nymex LD HH		Fixed		Nymex	06/2014	330,000	
103	MITSUI	9062	Swap	Fixed		Nymex LD HH		Nymex	06/2014	330,000	
104	BMO	9065	Swap	Nymex LD HH		Fixed		Nymex	06/2014	290,000	
105	BMO	9066	Swap	Fixed		Nymex LD HH		Nymex	06/2014	290,000	
106	SUISSE	9067	Swap	Nymex LD HH		GD HH		Gas Daily	06/2014	300,000	
107	SCOTIA	9068	Swap	Nymex LD HH		Fixed		Nymex	06/2014	330,000	
108	SCOTIA	9069	Swap	Fixed		Nymex LD HH		Nymex	06/2014	330,000	
109	FIFTH	9070	Swap	Nymex LD HH		Fixed		Nymex	06/2014	340,000	
110	FIFTH	9071	Swap	Fixed		Nymex LD HH		Nymex	06/2014	340,000	
111	SUISSE	9075	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
112	8NPP ET	9076	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
113	BARCLAY	9078	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
114	MITSUI	9079	Swap	Nymex LD HH		Fixed		Nymex	06/2014	170,000	
115	FIFTH	9080	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
116	BP	9081	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
117	SHELLTRADE	9083	Swap	Nymex LD HH		Fixed		Nymex	06/2014	50,000	
118	MITSUI	9084	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
119	SCOTIA	9085	Swap	Nymex LD HH		Fixed		Nymex	06/2014	180,000	
120	FIFTH	9086	Swap	Nymex LD HH		Fixed		Nymex	06/2014	50,000	
121	SCOTIA	9087	Swap	Nymex LD HH		Fixed		Nymex	06/2014	50,000	
122	CARGILL	9088	Swap	Nymex LD HH		Fixed		Nymex	06/2014	50,000	
123	BP	9089	Swap	Nymex LD HH		Fixed		Nymex	06/2014	50,000	
124	MITSUI	9090	Swap	Nymex LD HH		Fixed		Nymex	06/2014	180,000	
125	BP	9095	Swap	Nymex LD HH		Fixed		Nymex	06/2014	60,000	
126	SUISSE	9099	Swap	Nymex LD HH		Fixed		Nymex	06/2014	70,000	
127	SHELLTRADE	9109	Swap	Nymex LD HH		Fixed		Nymex	06/2014	20,000	
128	**TOTAL**										$ (1,077,520)

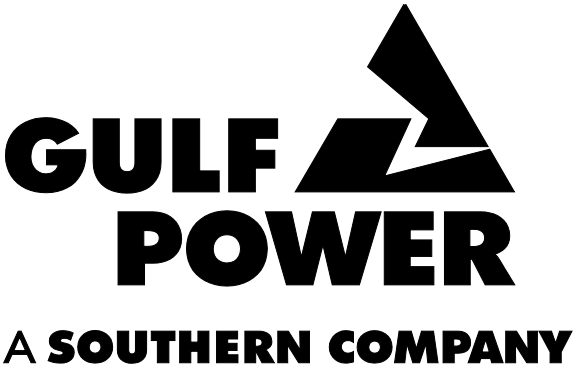
	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	8MO	3133	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	30,000	
2	8MO	3134		Fixed (Lower)							
3	CI8C	3764	Unwind	Fixed (Upper)		Sell Call			06/2014	30,000	
4	JPMORG	3178	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	50,000	
5	JPMORG	3179		Fixed (Lower)							
6	MITSUI	3753	Unwind	Fixed (Upper)		Sell Call			06/2014	50,000	
7	MITSUI	3754		Buy Put		Fixed (Lower)					
8	JPMORG	3191	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	50,000	
9	JPMORG	3192		Fixed (Lower)							
10	SCOTIA	3758	Unwind	Fixed (Upper)		Sell Call		Nymex	06/2014	50,000	
11	8MO	3200	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	30,000	
12	8MO	3201		Fixed (Lower)							
13	CI8C	3804	Unwind	Fixed (Upper)		Sell Call			06/2014	20,000	
14	JPMORG	3772		Fixed (Upper)		Sell Call				10,000	
15	MITSUI	3742	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	150,000	
16	MITSUI	3743		Fixed (Lower)							
17	MERRIL	3745	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	400,000	
18	MERRIL	3746		Fixed (Lower)							
19	CI8C	3766	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	20,000	
20	CI8C	3767		Fixed (Lower)							
21	8MO	3786	Option (Collar)	Fixed (Upper)		Nymex LD HH		Nymex	06/2014	100,000	
22	8MO	3787		Fixed (Lower)							
23	JPMORG	6282	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
24	JPMORG	6446	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
25	8P	6533	Swap	Fixed		Nymex LD HH		Nymex	07/2014	60,000	
26	8ARCLAY	6553	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
27	CITIGR	6573	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
28	MERRIL	6596	Swap	Fixed		Nymex LD HH		Nymex	07/2014	10,000	
29	CI8C	6597	Swap	Fixed		Nymex LD HH		Nymex	07/2014	10,000	
30	SUISSE	6645	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
31	BARCLAY	6658	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
32	MERRIL	6736	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
33	CIBC	6766	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
34	CITIGR	6880	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
35	JPMORG	6926	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
36	JPMORG	6999	Swap	Fixed		Nymex LD HH		Nymex	07/2014	10,000	
37	JPMORG	7096	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
38	SUISSE	7112	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
39	FIFTH	7130	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
40	JPMORG	7181	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
41	SUISSE	7221	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
42	JPMORG	7233	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
43	JPMORG	7250	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
44	CI8C	7263	Swap	Fixed		Nymex LD HH		Nymex	07/2014	10,000	
45	88VA	7315	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
46	CIBC	7330	Swap	Fixed		Nymex LD HH		Nymex	07/2014	10,000	
47	8ARCLAY	7340	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
48	8MO	7361	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
49	JPMORG	7376	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
50	SCOTIA	7385	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
51	JPMORG	7396	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
52	8ARCLAY	7445	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
53	SHELLTRADE	7468	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
54	8ARCLAY	7491	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
55	MERRIL	7565	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
56	JPMORG	7569	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
57	JPMORG	7588	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
58	CITIGR	7624	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
59	8MO	7642	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
60	8MO	7672	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
61	CITIGR	7691	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
62	MERRIL	7712	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
63	MERRIL	7737	Swap	Fixed		Nymex LD HH		Nymex	07/2014	60,000	
64	8ARCLAY	7752	Swap	Fixed		Nymex LD HH		Nymex	07/2014	60,000	
65	8NPP ET	7806	Swap	Fixed		Nymex LD HH		Nymex	07/2014	60,000	
66	SUISSE	7820	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
67	JPMORG	7842	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
68	CITIGR	7854	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
69	MERRIL	7870	Swap	Fixed		Nymex LD HH		Nymex	07/2014	60,000	
70	8P	7891	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
71	8NPP ET	7908	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
72	8NPP ET	7923	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
73	SHELLTRADE	7935	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
74	CITIGR	8001	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	

	A	B	C	D	E	F	G	H	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
75	BMO	8008	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
76	BNPP ET	8032	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
77	MERRIL	8042	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
78	BNPP ET	8071	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
79	SUISSE	8088	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
80	BARCLAY	8118	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
81	JPMORG	8125	Swap	Fixed		Nymex LD HH		Nymex	07/2014	20,000	
82	MERRIL	8144	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
83	BNPP ET	8151	Swap	Fixed		Nymex LD HH		Nymex	07/2014	70,000	
84	MERRIL	8196	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
85	DEUTSCH	8211	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
86	JPMORG	8233	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
87	DEUTSCH	8266	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
88	BMO	8305	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
89	SHELLTRADE	8322	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
90	DEUTSCH	8420	Swap	Fixed		Nymex LD HH		Nymex	07/2014	70,000	
91	DEUTSCH	8427	Swap	Fixed		Nymex LD HH		Nymex	07/2014	100,000	
92	FIFTH	8432	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
93	DEUTSCH	8449	Swap	Fixed		Nymex LD HH		Nymex	07/2014	40,000	
94	DEUTSCH	8467	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
95	JPMORG	8481	Swap	Fixed		Nymex LD HH		Nymex	07/2014	50,000	
96	JPMORG	8519	Swap	Fixed		Nymex LD HH		Nymex	07/2014	100,000	
97	CARGILL	8535	Swap	Fixed		Nymex LD HH		Nymex	07/2014	70,000	
98	MITSUI	8567	Swap	Fixed		Nymex LD HH		Nymex	07/2014	100,000	
99	CARGILL	8578	Swap	Fixed		Nymex LD HH		Nymex	07/2014	100,000	
100	JPMORG	8593	Swap	Fixed		Nymex LD HH		Nymex	07/2014	-	
101	MERRIL	8597	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
102	CARGILL	8764	Swap	Fixed		Nymex LD HH		Nymex	07/2014	30,000	
103	CARGILL	9094	Swap	Nymex LD HH		GD HH		Gas Daily	07/2014	620,000	
104	SCOTIA	9096	Swap	Nymex LD HH		GD HH		Gas Daily	07/2014	310,000	
105	SUISSE	9101	Swap	Nymex LD HH		GD HH		Gas Daily	07/2014	310,000	
106	MACQUARIE	9102	Swap	Nymex LD HH		Fixed		Nymex	07/2014	200,000	
107	MACQUARIE	9103	Swap	Fixed		Nymex LD HH		Nymex	07/2014	200,000	
108	MACQUARIE	9111	Swap	Nymex LD HH		Fixed		Nymex	07/2014	360,000	
109	MACQUARIE	9112	Swap	Fixed		Nymex LD HH		Nymex	07/2014	360,000	
110	CIBC	9113	Swap	Nymex LD HH		Fixed		Nymex	07/2014	360,000	
111	CIBC	9114	Swap	Fixed		Nymex LD HH		Nymex	07/2014	360,000	
112	SUISSE	9115	Swap	Nymex LD HH		Fixed		Nymex	07/2014	360,000	
113	SUISSE	9116	Swap	Fixed		Nymex LD HH		Nymex	07/2014	360,000	
114	BNPP	9117	Swap	Nymex LD HH		Fixed		Nymex	07/2014	370,000	
115	BNPP	9118	Swap	Fixed		Nymex LD HH		Nymex	07/2014	370,000	
116	MACQUARIE	9124	Swap	Nymex LD HH		Fixed		Nymex	07/2014	210,000	
117	MITSUI	9125	Swap	Nymex LD HH		Fixed		Nymex	07/2014	60,000	
118	SCOTIA	9130	Swap	Nymex LD HH		Fixed		Nymex	07/2014	60,000	
119	BMO	9137	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
120	MACQUARIE	9138	Swap	Nymex LD HH		Fixed		Nymex	07/2014	200,000	
121	SCOTIA	9139	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
122	FIFTH	9140	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
123	BP	9142	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
124	SHELLTRADE	9143	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
125	BNPP	9144	Swap	Nymex LD HH		Fixed		Nymex	07/2014	190,000	
126	MITSUI	9145	Swap	Nymex LD HH		Fixed		Nymex	07/2014	60,000	
127	FIFTH	9147	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
128	CIBC	9150	Swap	Nymex LD HH		Fixed		Nymex	07/2014	60,000	
129	CITIGR	9152	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
130	BMO	9153	Swap	Nymex LD HH		Fixed		Nymex	07/2014	190,000	
131	SCOTIA	9155	Swap	Nymex LD HH		Fixed		Nymex	07/2014	70,000	
132	BMO	9160	Swap	Nymex LD HH		Fixed		Nymex	07/2014	60,000	
133	**TOTAL**										**$ 757,874**

GULF POWER COMPANY

Risk Management Plan
For
Fuel Procurement
Docket No. 140001-EI

Date of Filing: July 25, 2014



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 37
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: H. R. Ball HRB-6

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GULF POWER
COAL PROCUREMENT STRATEGY FOR 2015

Coal Procurement Plan

Based on burn forecast from the June update to the 2014 Energy Budget, the Gulf Power Company program has an uncommitted need in 2015 of 500,000 tons. Coal burn remains 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 [redacted]
- Long term: Current plan is to continue to utilize [redacted] however, in 2014 Crist will test [redacted] for potential long-term use.

Plant Smith

- Short Term: Current marginal fuel selection is based on 100% CAPP coal.
- Long Term: Smith is currently testing [redacted] and if successful, there is potential for a transition to this fuel to occur in 2015.

Plant Scholz

- Short Term: Current marginal fuel selection is based on 100% IB coal.
- Long Term: The decision to retire Scholz in 2015 has been made.

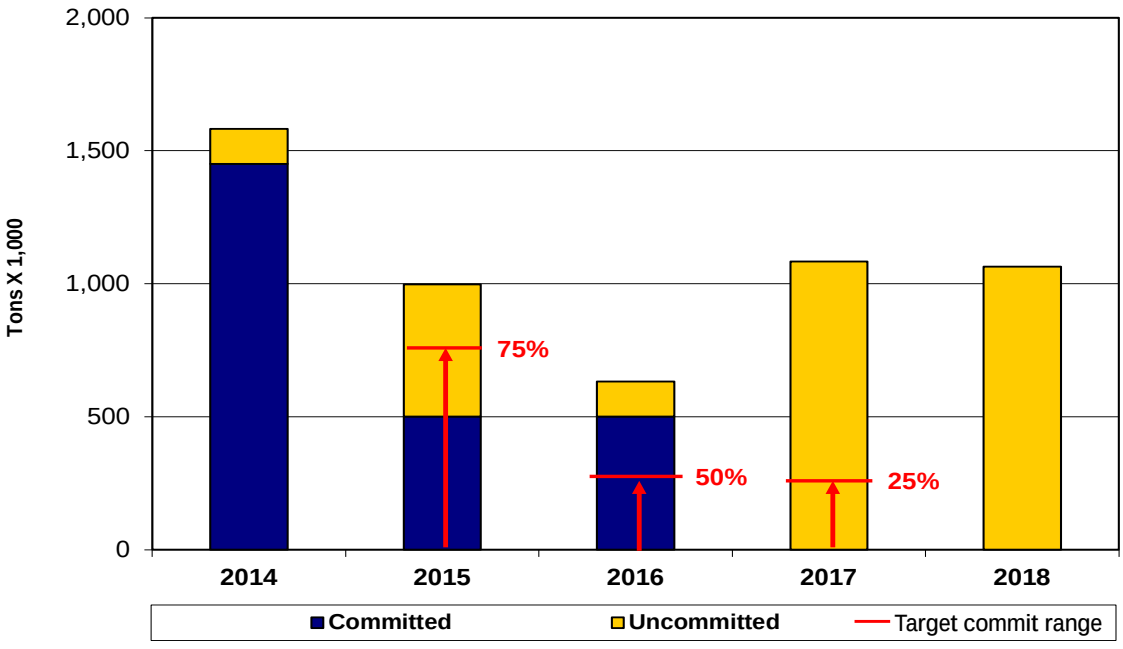
This document lays out a tactical plan that will be implemented to secure coal for 2015 forward. The goal for 2015-2017 is to continue to commit to percentages

that conform to the Coal Procurement Strategy guidelines; however, the process will continue to require a level of subjectivity in addressing volatility associated with coal burn projections.

Plant Classification:

The Gulf plants are forecasted to have capacity factors of [redacted] through 2017. To better understand the expected operations of Gulf's coal fleet, the group's collective forecasted run hours were considered. An evaluation of when this group of units is 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, whereas forecasts show very little runtime at Smith.

State of the Program:



Source: 2014 Energy Budget 2014-2017

Spot Coal Plan:

Gulf's plants have potential small need of late in 2014 depending on summer loads. Beginning in 2014, quarterly system-wide bituminous and sub-bituminous solicitations are being issued to address any quarterly spot coal supply needs. 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:

The Gulf program has 50% of its coal supply needs committed in 2015, 79% committed in 2016 and no commitments in 2017. A system-wide long-term bituminous solicitation will be issued in 2014 and Gulf will evaluate the need for long-term purchase of up to 0.5M tons annually with delivery beginning in 2015. If PRB becomes a coal supply option, Gulf will participate in the system-wide sub-bituminous solicitation in September-October 2014. The purchases made will adhere to the percentage commitment guidelines set forth in the Coal Procurement Strategy.

Market Reviews:

Gulf will need to perform a market review with Foresight Energy between January 1 and July 31, 2014 for coal to be delivered in CY 2015 and CY 2016.

GULF POWER
COAL TRANSPORTATION STRATEGY FOR 2015

Transportation Program Overview

Plants Crist and Smith

Crist and Smith have the ability to 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, Ala., and then barged to the plants. Illinois Basin or Central Appalachian coal can be transported by barge or by a combination of rail and barge to these plants as well.

Eastern coal can be transloaded at 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. Import coal can be delivered by ocean vessel to the Alabama State Docks for barge movement to the plants. Currently, Crist and Smith receive Central Appalachian coal and Illinois Basin coal. Smith also has received some western test coal.

NS agreement NS-9679 provides for rail transportation of the Alpha Coal Sales Company, LLC coal to the Alabama State Docks through December 31, 2014. The agreement has an annual minimum volume requirement of [redacted]

CN Agreement CN-517554-AB provides for rail transportation of Illinois Basin coal from Foresight Energy and American Coal Company to the Alabama State Docks through December 31, 2014. There are no annual minimum or maximum volume requirements in this rail agreement.

Fuel movement to Crist and Smith from Mobile, Alabama is primarily by a single barge carrier, Marquette Transportation Company, LLC (Marquette). The Marquette agreement (SC09005-T) provides for transportation of coal to both plants from the Alabama State Docks and Mobile Bay and River area. The Marquette agreement expires December 31, 2016.

Plant Scholz

Scholz has an agreement with the CSXT railroad (CSXT-C-83791) that expires December 31, 2014.

No coal deliveries are expected to Scholz in 2014 and the plant will consume inventory prior to the plant's retirement in April 2015.

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 hauls to 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 transloaded from an ocean vessel at the Alabama State Docks facility to railcars for shipment to the plant by the CN and interchanged with the MSE. Daniel can also receive Central Appalachian coal via the CSXT and interchange with the MSE. Another potential source of Central

Appalachian coal is via the NS railroad through an interchange agreement with the CN railroad.

UP agreement UP-55105 provides for rail transportation of Colorado coal to Memphis in conjunction with CN-523746-AA for final delivery to Daniel through December 31, 2014. The agreement has no annual minimum or maximum volume requirement.

BNSF agreement BNSF-12677 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, 2014. The agreement has no minimum volume requirements.

CN/MSE agreement CN-526887-AA provides for rail transportation of PRB and Colorado coal from Memphis, TN to Daniel. The CN/MSE agreement expires December 31, 2014. The agreement has no annual minimum volume requirement.

It is anticipated that existing rail transportation agreements will be extended to cover 2015 needs.

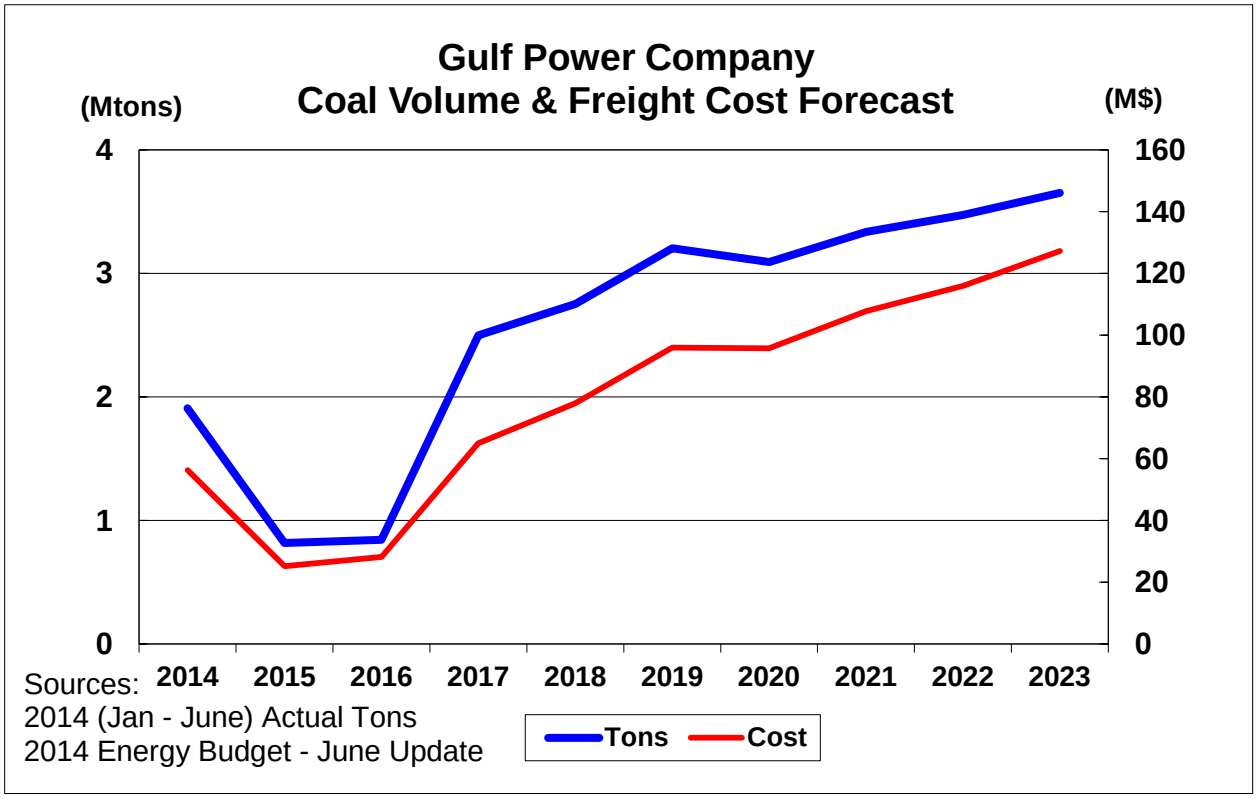
Budget

During the next 10 years, Gulf is budgeted to transport approximately 2-3 million tons of coal per year. There is a decrease in transportation costs from 2014 to 2016 that is directly tied to the loss of burn during this period.

From 2015 to 2022, the majority of the uncommitted coal requirements are projected to be met by purchasing a [redacted] The increase in transportation costs are directly related to the increase of the volume of coal to be transported and changes related to the

forecast for rail rates. Actual coal purchases may be different than current projections based on economic evaluations.

The chart below shows the forecasted coal volume and transportation costs for Gulf's coal-fueled plants.



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.

Tactical Plan

Plants Crist and Smith

NS agreement NS-9679 provides for rail transportation of Central Appalachian coal to the Alabama State Docks through December 31, 2014. The tactical plan is to maintain this agreement until its expiration date.

CN Agreement CN-517554-AB provides for rail transportation of Illinois Basin coal to the Alabama State Docks through December 31, 2014. The tactical plan is to extend this agreement prior to its expiration date. Discussions with the railroad regarding this agreement have begun with the goal to maintain a no minimum volume requirement.

Marquette agreement (SC09005-T) provides primary barge transportation of coal from the Alabama State Docks to Crist and Smith. Marquette agreement (SC09006-T) and Heartland Barge Management agreement (SC09004-T) provide a supply of barges to move coal to Crist and Smith. The Heartland agreement expires December 31, 2014. The Marquette agreements have been extended through December 31, 2016.

Under these agreements, Gulf charters approximately 50 barges from Marquette and Heartland. The agreement with Marquette also includes towboat services to support transport of coal to the plants. Three towboats are used to transport coal by barge to Crist and Smith. There are no minimum annual volumes included in the agreements.

The tactical plan for the Marquette agreements is to maintain the agreements through 2016 at reduced levels in order to match reduced levels of coal shipments in 2015 and 2016, as they provide a very stable and flexible supply of towboats and barges that are controlled totally by Southern Company Generation

Fuel Services for Gulf. The Heartland agreement will be allowed to expire because of reduced levels of coal shipments in 2015 and 2016.

Plant Scholz

With the retirement of Plant Scholz in early 2015 the CSXT railroad (CSXT-C-83791) agreement will be allowed to expire December 31, 2014.

Plant Daniel

UP agreement UP-55105 provides for rail transportation of Colorado coal to Memphis in conjunction with CN-526887-AA for final delivery to Daniel through December 31, 2014. The tactical plan is to let this agreement expire unless additional Western coal is required for blending in 2015.

BNSF agreement BNSF-12677 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, 2014. The tactical plan is to submit the movement for competitive bid during the third quarter of 2014 to cover shipments in 2015.

CN/MSE agreement CN-526887-AA provides for rail transportation of PRB and Colorado coal from Memphis, TN to Daniel. The CN/MSE agreement expires December 31, 2014. The tactical plan is to extend this agreement only for PRB coal unless additional Western coal is needed for blending in 2015. Discussions with the railroad regarding this agreement are underway with the goal to maintain a no minimum volume requirement.

Gulf Power 2015 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 Smith 3 combined-cycle unit in 2002, natural gas became a more significant portion of Gulf's overall fuel budget.

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

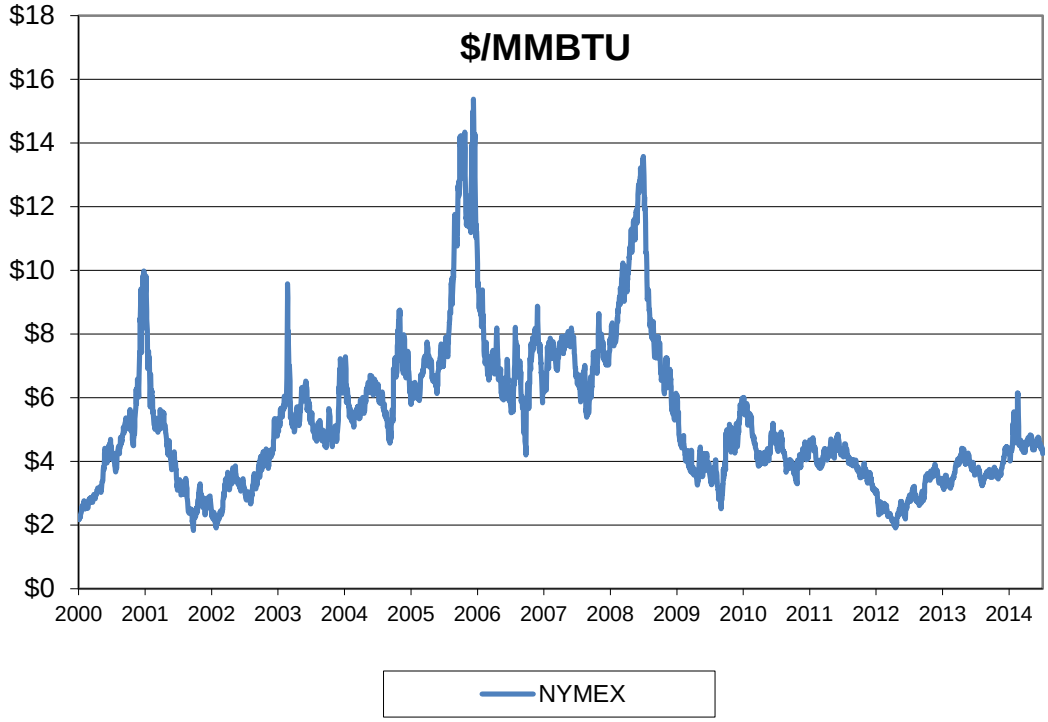
Southern Company Services (SCS) as agent for Gulf purchases natural gas to be delivered to Plant Crist for lighter purposes on the coal fired units and to Plant Smith as primary fuel for Unit 3 which is a combined cycle generating unit. SCS will also purchase natural gas to serve as primary fuel for 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.

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] 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 60 months, per the following schedule:

Period	Lower Target Hedge %	Upper Target Hedge %
Prompt Year (2015)	[redacted]	[redacted]
Year 2 (2016)		
Year 3 (2017)		
Year 4 (2018)		
Year 5 (2019)		

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. As a result of market conditions, Gulf recently has been utilizing Collars as a hedging

tool. A Collar is an option-based hedging tool that allows Gulf to protect its customers from upward price swings while at the same time increasing the benefit to the customer should the current low-price market conditions persist.

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.

Gulf Power's 2015 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, Scherer 3, Scholz 1&2 and Smith 1&2. Oil is also the primary fuel at the Smith A CT unit and as 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 currently 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.

[redacted]

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]

Confirmation, Monitoring, Reporting and Disclosure: The functions of trade confirmation, risk monitoring, risk reporting, and disclosure include the following responsibilities:

[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]

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]

[redacted]

XII. Funding Liquidity

[redacted]

XIII. Operating Procedures and Systems

Processes. [redacted]

Recording Transactions. [redacted]

Contract Administration. [redacted]

Operating Procedures. [redacted]

XIV. Accounting,Tax, and Regulatory Reporting

[redacted]

XV. Legal

[redacted]

[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]

XXII. Terminology

Definitions of terminology used in this RMP are contained in Appendix L.

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:

[redacted]

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):

[redacted]

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:

[redacted]

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:

[redacted]

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

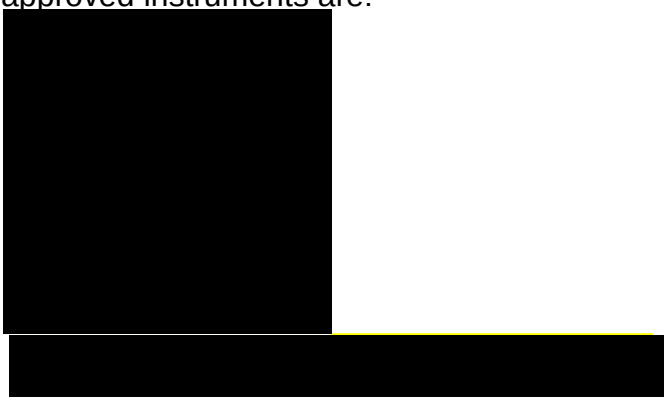
APPROVED COMMODITIES

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)	[redacted]
Southern Power Risk Oversight Committee (SPROC)	[redacted]

Risk Advisory and Controls Committee (RACC)	[redacted]
Southern Company Generation Energy Credit Committee (ECC)	[redacted]
Manager, Risk Control	[redacted]

1

APPENDIX D

AUTHORIZATIONS (continued)

Energy Marketing

Name	Authority
Vice President, Commercial Operations & Services	[redacted]

Vice President, Chief Commercial Officer, SPC	[redacted]
Sr. Vice President, Chief Financial Officer, SPC	[redacted]
	[redacted]

Energy Trading Manager	[redacted]

Manager, SPC Trading and Asset Management	[redacted]
Term Traders	[redacted]
Energy Coordinators	[redacted]
Transmission Project Coordinators and Energy Schedulers	[redacted]

1

APPENDIX D

AUTHORIZATIONS (continued)

SCS Fuel Services

Name	Authority
Vice President, Fuel Services	[redacted]
Gas Services Director	[redacted]
Gas Operations Manager	[redacted]

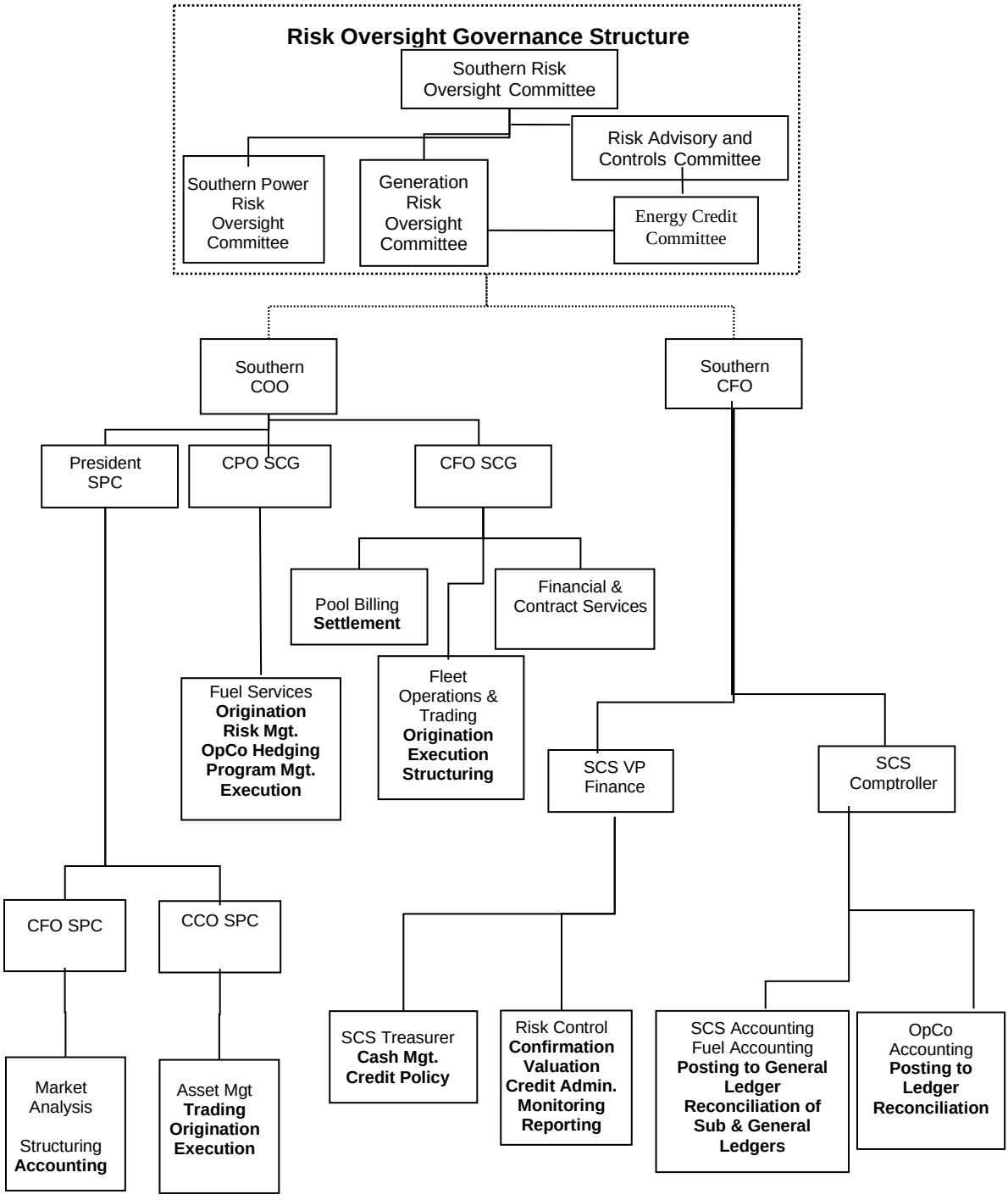
Gas Trading Manager	[redacted]
Natural Gas Trader - Physical	[redacted]
Natural Gas Trader - Financial	[redacted]
Natural Gas Schedulers	[redacted]
Coal Services Director	[redacted]

1
2

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.


Risk Oversight Governance Structure
Southern Risk Oversight Committee
Risk Advisory and Controls Committee
Southern Power Risk Oversight Committee
Generation Risk Oversight Committee
Energy Credit Committee
Southern COO
Southern CFO
President SPC
CPO SCG
CFO SCG
Pool Billing **Settlement**
Financial & Contract Services
Fuel Services **Origination Risk Mgt. OpCo Hedging Program Mgt. Execution**
Fleet Operations & Trading **Origination Execution Structuring**
SCS VP Finance
SCS Comptroller
CFO SPC
CCO SPC
SCS Treasurer **Cash Mgt. Credit Policy**
Risk Control **Confirmation Valuation Credit Admin. Monitoring Reporting**
SCS Accounting Fuel Accounting **Posting to General Ledger Reconciliation of Sub & General Ledgers**
OpCo Accounting **Posting to Ledger Reconciliation**
Market Analysis
Structuring **Accounting**
Asset Mgt **Trading Origination Execution**

1

2

3

APPENDIX F

MARKET RISK MEASUREMENT

Approved Commodities	[redacted]
Electrical Power	[redacted]
Natural Gas	[redacted]
Coal Environmental Products Oil Products RECs	[redacted]

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 * ΔP * 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	[redacted]	[redacted]

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:

$E[\Delta p / p \mid \Delta p / p < \Delta]$ = the Integral of f(x)xdx from negative infinity to Δ

and the expected upward stress is calculated as:

$E[\Delta p / p \mid \Delta p / p > \Delta]$ = the Integral of f(x)xdx from Δ to infinity

where Δ 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	[redacted]
Extreme Event Threshold	[redacted]

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]	[redacted]
Secondary Objectives	[redacted]	[redacted]

		[redacted]
Secondary Objectives	[redacted]	[redacted]

1

2

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]	[redacted]
All positions with mark-to-market changes immediately reflected in income (both primary and secondary activities)	[redacted]	[redacted]

		[redacted]

1

2

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]	[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]	[redacted]
SPC Secondary Objectives	[redacted]	[redacted]
SPC Secondary Objectives	[redacted]	[redacted]

1

Position Classification	Income Change	Notify
All SPC positions with mark-to-market changes immediately reflected in income	[redacted]	[redacted]
All SPC positions with mark-to-market changes immediately reflected in income	[redacted]	[redacted]

2

3

Position Classification	Value-at-Risk	Notify
All SPC positions	[redacted]	[redacted]

4
5

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		[redacted]

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

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

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

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

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

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Generation Energy Credit Committee

Title
Assistant Treasurer, SCS
VP, Fuel Services
VP, Commerical 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 /	X	X							

	NextHour									
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 /				X	X				

	Front Office									
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

1

		Approved Commodities								
		Electricity		Natural Gas						
Title	Application / Role (3)	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 /			(2)						(2)

	Public									
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 .

[redacted]

[redacted]

[redacted]

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

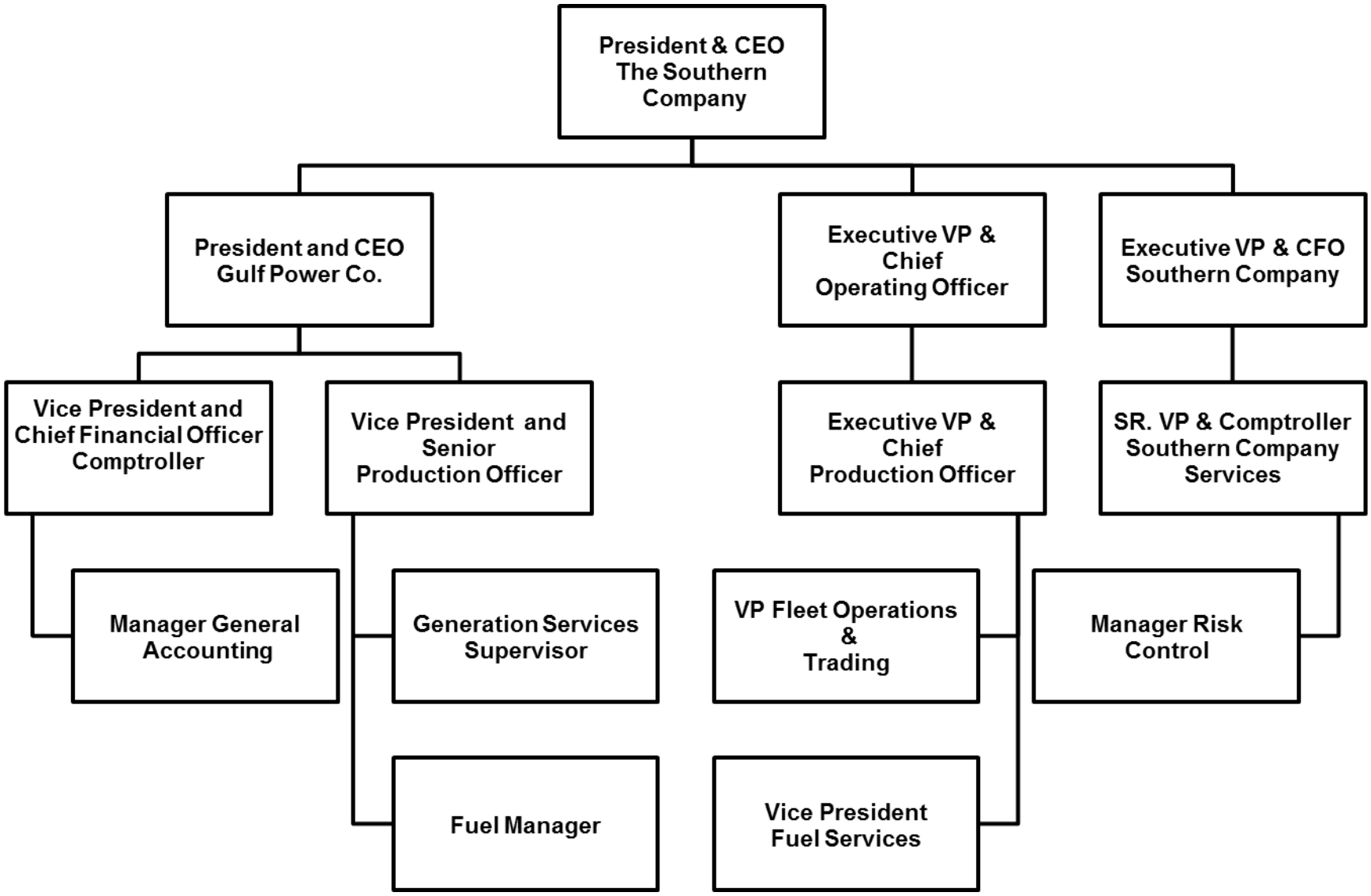


EXHIBIT NO. RWD-1

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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 2013 through December 2013	8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 38
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: C. S. Boyett RWD-1

Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2013 - DECEMBER 2013

1.	Estimated over/(under)-recovery for the period January 2013 - December 2013 (Schedule E-1B, Line 6 + 7 + 8, filed August 2, 2013) approved in FPSC Order No. PSC-13-0665-FOF-EI issued on December 18, 2013)	$ (6,665,066)
2.	Actual over/(under)-recovery for the period January 2013 - December 2013 (December 2013 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Appendix 1)	(11,619,581)
3.	Amount to be refunded/(recovered) in the January 2015 - December 2015 projection period (Line 2 - Line 1)	$ (4,954,515)

Schedule CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2013 - DECEMBER 2013

1. Estimated over/(under)-recovery for the period January 2013 - December 2013 (Schedule CCE-1a, line 1, filed August 2, 2013 and approved in FPSC Order No. PSC-13-0665-FOF-EI issued on December 18, 2013)	$ (2,263,786)
2. Actual over/(under)-recovery for the period January 2013 - December 2013 (Schedule CCA-2, Line 10 + 11 + 14)	(2,925,803)
3. Amount to be refunded/(recovered) in the January 2015 - December 2015 projection period (Line 2 - Line 1)	$ (662,017)

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2013 - DECEMBER 2013

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	IIC Payments / (Receipts) ($)	419,141	(105,345)	341,687	42,050	(4,527)	(2,216)	(3,146)	(3,146)	410,154	17,825	(40,577)	(1,780)	1,070,120
2	Other Capacity Payments / (Receipts)	1,961,029	2,003,882	2,048,096	2,003,745	2,601,116	6,780,108	7,266,443	7,007,226	6,797,704	2,473,170	2,243,716	2,087,604	45,273,839
3	Transmission Revenue ($)	(9,396)	(10,325)	(11,718)	(9,510)	(10,547)	(9,573)	(9,336)	(9,300)	(1,329)	(6,578)	(6,170)	(12,662)	(106,444)
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	2,370,774	1,888,212	2,378,065	2,036,285	2,586,042	6,768,319	7,253,961	6,994,780	7,206,529	2,484,417	2,196,969	2,073,162	46,237,515
5	Jurisdictional %	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
6	Total Jurisdictional Recovery Amount (Line 4 * 5) ($)	2,289,538	1,823,512	2,296,580	1,966,511	2,497,430	6,536,400	7,005,401	6,755,101	6,959,594	2,399,287	2,121,689	2,002,124	44,653,167
7	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	3,089,795	2,775,430	3,144,318	2,852,589	3,479,518	4,343,278	4,362,935	4,439,295	4,078,236	3,224,038	2,893,458	3,990,613	42,673,503
8	True-Up Provision ($)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(945,684)
9	Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	3,010,988	2,696,623	3,065,511	2,773,782	3,400,711	4,264,471	4,284,128	4,360,488	3,999,429	3,145,231	2,814,651	3,911,806	41,727,819
10	Over/(Under) Recovery (Line 9 - 6) ($)	721,450	873,111	768,931	807,271	903,281	(2,271,929)	(2,721,273)	(2,394,613)	(2,960,165)	745,944	692,962	1,909,682	(2,925,348)
11	Interest Provision ($)	(26)	34	100	147	197	137	5	(109)	(228)	(252)	(239)	(221)	(455)
12	Beginning Balance True-Up & Interest Provision ($)	(842,908)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(1,209,823)	(3,525,738)	(6,407,324)	(5,582,825)	(4,811,295)	(842,908)
13	True-Up Collected/(Refunded) ($)	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	945,684
14	Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
15	End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(1,209,823)	(3,525,738)	(6,407,324)	(5,582,825)	(4,811,295)	(2,823,027)	(2,823,027)
	Average Monthly Interest Rate	0.0058%	0.0079%	0.0075%	0.0067%	0.0063%	0.0054%	0.0046%	0.0046%	0.0046%	0.0042%	0.0046%	0.0058%	
	Wall Street Annual Rate 0.05%	0.09%	0.10%	0.08%	0.08%	0.07%	0.06%	0.05%	0.06%	0.05%	0.05%	0.06%	0.08%	
	Average Annual Rate	0.070%	0.095%	0.090%	0.080%	0.075%	0.065%	0.055%	0.055%	0.055%	0.050%	0.055%	0.070%	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2013 - DECEMBER 2013

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1 Beginning True-Up Amount ($)	(842,908)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(1,209,823)	(3,525,738)	(6,407,324)	(5,582,825)	(4,811,295)	
2 Ending True-Up Amount Before Interest ($)	(42,651)	909,241	1,757,013	2,643,191	3,625,426	1,432,501	(1,209,828)	(3,525,629)	(6,407,096)	(5,582,573)	(4,811,056)	(2,822,806)	
3 Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(885,559)	866,564	2,666,288	4,400,304	6,268,764	5,058,124	222,810	(4,735,452)	(9,932,834)	(11,989,897)	(10,393,881)	(7,634,101)	
4 Average True-Up Amount ($)	(442,780)	433,282	1,333,144	2,200,152	3,134,382	2,529,062	111,405	(2,367,726)	(4,966,417)	(5,994,949)	(5,196,941)	(3,817,051)	
5 Interest Rate - First Day of Reporting Business Month	0.05%	0.09%	0.10%	0.08%	0.08%	0.07%	0.06%	0.05%	0.06%	0.05%	0.05%	0.06%	
6 Interest Rate - First Day of Subsequent Business Month	0.09%	0.10%	0.08%	0.08%	0.07%	0.06%	0.05%	0.06%	0.05%	0.05%	0.06%	0.08%	
7 Total Interest Rate (Lines 5 + 6)	0.14%	0.19%	0.18%	0.16%	0.15%	0.13%	0.11%	0.11%	0.11%	0.10%	0.11%	0.14%	
8 Average Interest Rate	0.070%	0.095%	0.090%	0.080%	0.075%	0.065%	0.055%	0.055%	0.055%	0.050%	0.055%	0.070%	
9 Monthly Average Interest Rate (1/12 Of Line 8)	0.0058%	0.0079%	0.0075%	0.0067%	0.0063%	0.0054%	0.0046%	0.0046%	0.0046%	0.0042%	0.0046%	0.0058%	
10 Interest Provision For the Month (Lines 4 X 9) ($)	(26)	34	100	147	197	137	5	(109)	(228)	(252)	(239)	(221)	(455)

Schedule CCA-4
Page 1 of 2

Gulf Power Company
2013 Capacity Contracts

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs (Confidential)			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other (Confidential)			
Alabama Electric Cooperative	11/27/2013	11/29/2013	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2013	6/30/2013	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs
2013

Contract	January MW	January $	February MW	February $ [1]	March MW	March $	April MW	April $	May MW	May $ [1]	June MW	June $ [1]
Southern Intercompany Interchange	177.8	422,287	0.0	(102,074)	370.1	344,833	18.0	45,196	0.0	(1,079)	0.0	8,403
PPAs												
Coral Power,LLC												
Southern Power Company												
Shell Energy N.A. (U.S.), LP												
Other												
Alabama Electric Cooperative	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0
South Carolina Electric & Gas	0.0	0			0.0	0	0.0	0				
South Carolina PSA												
Total		2,380,170		1,898,537		2,389,783		2,045,795		2,596,589		6,777,892

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true up only

Gulf Power Company
2013 Capacity Contracts

Schedule CCA-4
Page 2 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs (Confidential)			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other (Confidential)			
Alabama Electric Cooperative	11/27/2013	11/29/2013	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2013	6/30/2013	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs
2013

Contract	July MW	July $	August MW	August $	September MW	September $	October MW	October $	November MW	November $	December MW	December $ [1]	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	120.0	413,300	58.9	20,971	(83.4)	(36,525)	0.0	1,366	1,116,678
PPAs													
Coral Power,LLC													
Southern Power Company													
Shell Energy N.A. (U.S.), LP													
Total PPAs													45,273,839
Other													
Alabama Electric Cooperative	0.0	0	0.0	0	0.0	0	0.0	0			0.0	0	(906)
South Carolina Electric & Gas	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(7,902)
South Carolina PSA													(37,750)
Total		7,263,297		7,004,080		7,207,858		2,490,995		2,203,139		2,085,824	46,343,959

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true up only

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit RWD-1, Page 7 of 212

APPENDIX 1

SCHEDULES A1 THROUGH A9 AND A12

JANUARY 2013 – DECEMBER 2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

REVISED A-1 and A-2
JANUARY 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2013
CURRENT MONTH

		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)	23,795,767	32,362,324	(8,566,557)	(26.47)	624,359,000	804,247,000	(179,888,000)	(22.37)	3.8112	4.0239	(0.21)	(5.29)
2	Hedging Settlement Costs (A2)	2,013,400	0	2,013,400	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)	6,952	0	6,952	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	25,816,119	32,362,324	(6,546,205)	(20.23)	624,359,000	804,247,000	(179,888,000)	(22.37)	4.1348	4.0239	0.11	2.76
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)	16,459,116	16,706,000	(246,884)	(1.48)	646,771,242	548,860,000	97,911,242	17.84	2.5448	3.0438	(0.50)	(16.39)
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)	628,657	0	628,657	100.00	23,435,000	0	23,435,000	100.00	2.6826	0.0000	2.68	0.00
12	TOTAL COST OF PURCHASED POWER	17,087,773	16,706,000	381,773	2.29	670,206,242	548,860,000	121,346,242	22.11	2.5496	3.0438	(0.49)	(16.24)
13	Total Available MWH (Line 5 + Line 12)	42,903,892	49,068,324	(6,164,432)	(12.56)	1,294,565,242	1,353,107,000	(58,541,758)	(4.33)				
14	Fuel Cost of Economy Sales (A6)	(127,906)	(180,000)	52,094	(28.94)	(5,142,160)	(7,052,000)	1,909,840	(27.08)	(2.4874)	(2.5525)	0.07	2.55
15	Gain on Economy Sales (A6)	(9,801)	(74,000)	64,199	(86.76)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,338,042)	(8,689,000)	350,958	(4.04)	(434,660,661)	(341,838,000)	(92,822,661)	27.15	(1.9183)	(2.5418)	0.62	24.53
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,475,749)	(8,943,000)	467,251	(5.22)	(439,802,821)	(348,890,000)	(90,912,821)	26.06	(1.9272)	(2.5633)	0.64	24.82
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)	34,428,143	40,125,324	(5,697,181)	(14.20)	854,762,421	1,004,217,000	(149,454,579)	(14.88)	4.0278	3.9957	0.03	0.80
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 *	70,485	77,956	(7,471)	(9.58)	1,749,975	1,951,000	(201,025)	(10.30)	4.0278	3.9957	0.03	0.80
22	T & D Losses *	1,978,930	2,133,944	(155,014)	(7.26)	49,131,793	53,406,000	(4,274,207)	(8.00)	4.0278	3.9957	0.03	0.80
23	TERRITORIAL KWH SALES	34,428,143	40,125,324	(5,697,181)	(14.20)	803,880,653	948,860,000	(144,979,347)	(15.28)	4.2827	4.2288	0.05	1.27
24	Wholesale KWH Sales	1,067,136	1,351,701	(284,565)	(21.05)	24,917,444	31,964,000	(7,046,556)	(22.05)	4.2827	4.2288	0.05	1.27
25	Jurisdictional KWH Sales	33,361,007	38,773,623	(5,412,616)	(13.96)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.2827	4.2288	0.05	1.27
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	33,411,049	38,831,783	(5,420,734)	(13.96)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.2892	4.2351	0.05	1.28
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	778,963,209	916,896,000	(137,932,791)	(15.04)	(0.2827)	(0.2402)	(0.04)	17.69
29	TOTAL JURISDICTIONAL FUEL COST	31,208,931	36,629,665	(5,420,734)	(14.80)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.0065	3.9949	0.01	0.29
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0094	3.9978	0.01	0.29
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	778,963,209	916,896,000	(137,932,791)	(15.04)	0.0111	0.0095	0.00	16.84
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0205	4.0073	0.01	0.33
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.021	4.007		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 23,795,767
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	6,952
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,013,400
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	16,459,116
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	628,657
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,475,749)
10	Total Fuel and Net Power Transactions		$ 34,428,143

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2013
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)	23,795,767	32,362,324	(8,566,557)	(26.47)	624,359,000	804,247,000	(179,888,000)	(22.37)	3.8112	4.0239	(0.21)	(5.29)
2	Hedging Settlement Costs (A2)	2,013,400	0	2,013,400	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)	6,952	0	6,952	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	25,816,119	32,362,324	(6,546,205)	(20.23)	624,359,000	804,247,000	(179,888,000)	(22.37)	4.1348	4.0239	0.11	2.76
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)	16,459,116	16,706,000	(246,884)	(1.48)	646,771,242	548,860,000	97,911,242	17.84	2.5448	3.0438	(0.50)	(16.39)
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)	628,657	0	628,657	100.00	23,435,000	0	23,435,000	100.00	2.6826	0.0000	2.68	0.00
12	TOTAL COST OF PURCHASED POWER	17,087,773	16,706,000	381,773	2.29	670,206,242	548,860,000	121,346,242	22.11	2.5496	3.0438	(0.49)	(16.24)
13	Total Available MWH (Line 5 + Line 12)	42,903,892	49,068,324	(6,164,432)	(12.56)	1,294,565,242	1,353,107,000	(58,541,758)	(4.33)				
14	Fuel Cost of Economy Sales (A6)	(127,906)	(180,000)	52,094	(28.94)	(5,142,160)	(7,052,000)	1,909,840	(27.08)	(2.4874)	(2.5525)	0.07	2.55
15	Gain on Economy Sales (A6)	(9,801)	(74,000)	64,199	(86.76)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,338,042)	(8,689,000)	350,958	(4.04)	(434,660,661)	(341,838,000)	(92,822,661)	27.15	(1.9183)	(2.5418)	0.62	24.53
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,475,749)	(8,943,000)	467,251	(5.22)	(439,802,821)	(348,890,000)	(90,912,821)	26.06	(1.9272)	(2.5633)	0.64	24.82
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)	34,428,143	40,125,324	(5,697,181)	(14.20)	854,762,421	1,004,217,000	(149,454,579)	(14.88)	4.0278	3.9957	0.03	0.80
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 *	70,485	77,956	(7,471)	(9.58)	1,749,975	1,951,000	(201,025)	(10.30)	4.0278	3.9957	0.03	0.80
22	T & D Losses *	1,978,930	2,133,944	(155,014)	(7.26)	49,131,793	53,406,000	(4,274,207)	(8.00)	4.0278	3.9957	0.03	0.80
23	TERRITORIAL KWH SALES	34,428,143	40,125,324	(5,697,181)	(14.20)	803,880,653	948,860,000	(144,979,347)	(15.28)	4.2827	4.2288	0.05	1.27
24	Wholesale KWH Sales	1,067,136	1,351,701	(284,565)	(21.05)	24,917,444	31,964,000	(7,046,556)	(22.05)	4.2827	4.2288	0.05	1.27
25	Jurisdictional KWH Sales	33,361,007	38,773,623	(5,412,616)	(13.96)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.2827	4.2288	0.05	1.27
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	33,411,049	38,831,783	(5,420,734)	(13.96)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.2892	4.2351	0.05	1.28
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	778,963,209	916,896,000	(137,932,791)	(15.04)	(0.2827)	(0.2402)	(0.04)	17.69
29	TOTAL JURISDICTIONAL FUEL COST	31,208,931	36,629,665	(5,420,734)	(14.80)	778,963,209	916,896,000	(137,932,791)	(15.04)	4.0065	3.9949	0.01	0.29
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0094	3.9978	0.01	0.29
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	778,963,209	916,896,000	(137,932,791)	(15.04)	0.0111	0.0095	0.00	16.84
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0205	4.0073	0.01	0.33
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.021	4.007		

* 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 2013

		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	23,612,216.88	32,259,621	(8,647,404.12)	(26.81)	23,612,216.88	32,259,621	(8,647,404.12)	(26.81)
1a	Other Generation	183,550.37	102,703	80,847.37	78.72	183,550.37	102,703	80,847.37	78.72
2	Fuel Cost of Power Sold	(8,475,749.46)	(8,943,000)	467,250.54	5.22	(8,475,749.46)	(8,943,000)	467,250.54	5.22
3	Fuel Cost - Purchased Power	16,459,115.59	16,706,000	(246,884.41)	(1.48)	16,459,115.59	16,706,000	(246,884.41)	(1.48)
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	628,657.17	0	628,657.17	100.00	628,657.17	0	628,657.17	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	2,013,400.00	0	2,013,400.00	100.00	2,013,400.00	0	2,013,400.00	100.00
6	Total Fuel & Net Power Transactions	34,421,190.55	40,125,324	(5,704,133.45)	(14.22)	34,421,190.55	40,125,324	(5,704,133.45)	(14.22)
7	AdjustmentsTo Fuel Cost	6,952.10	0	6,952.10	100.00	6,952.10	0	6,952.10	100.00
8	Adj. Total Fuel & Net Power Transactions	34,428,142.65	40,125,324	(5,697,181.35)	(14.20)	34,428,142.65	40,125,324	(5,697,181.35)	(14.20)
B.	*KWH Sales*								
1	Jurisdictional Sales	778,963,209	916,896,000	(137,932,791)	(15.04)	778,963,209	916,896,000	(137,932,791)	(15.04)
2	Non-Jurisdictional Sales	24,917,444	31,964,000	(7,046,556)	(22.05)	24,917,444	31,964,000	(7,046,556)	(22.05)
3	Total Territorial Sales	803,880,653	948,860,000	(144,979,347)	(15.28)	803,880,653	948,860,000	(144,979,347)	(15.28)
4	Juris. Sales as % of Total Terr. Sales	96.9004	96.6313	0.2691	0.28	96.9004	96.6313	0.2691	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: JANUARY 2013

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	29,539,374.46	34,869,555	(5,330,180.42)	(15.29)	29,539,374.46	34,869,555	(5,330,180.42)	(15.29)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	2,202,118.00	2,202,118	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(86,659.00)	(86,659)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	31,654,833.46	36,985,014	(5,330,180.54)	(14.41)	31,654,833.46	36,985,014	(5,330,180.54)	(14.41)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	34,428,142.65	40,125,324	(5,697,181.35)	(14.20)	34,428,142.65	40,125,324	(5,697,181.35)	(14.20)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9004	96.6313	0.2691	0.28	96.9004	96.6313	0.2691	0.28
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	33,411,049.45	38,831,783	(5,420,733.55)	(13.96)	33,411,049.45	38,831,783	(5,420,733.55)	(13.96)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,756,215.99)	(1,846,769)	90,553.01	4.90	(1,756,215.99)	(1,846,769)	90,553.01	4.90
8	Interest Provision for the Month	876.53	1,415	(538.47)	38.05	876.53	1,415	(538.47)	38.05
9	Beginning True-Up & Interest Provision	17,091,723.14	26,425,418	(9,333,694.86)	35.32	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(2,202,118.00)	(2,202,118)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	13,134,265.68	22,377,946	(9,243,680.32)	41.31	13,134,265.68	22,377,946	(9,243,680.32)	41.31
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	13,134,265.68	22,377,946	(9,243,680.32)	41.31	13,134,265.68	22,377,946	(9,243,680.32)	41.31

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	17,091,723.14	26,425,418	(9,333,694.86)	(35.32)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	13,133,389.15	22,376,531	(9,243,141.85)	(41.31)
3	Total of Beginning & Ending True-Up Amts.	30,225,112.29	48,801,949	(18,576,836.71)	(38.07)
4	Average True-Up Amount	15,112,556.15	24,400,975	(9,288,418.85)	(38.07)
	Interest Rate				
5	1st Day of Reporting Business Month	0.05	0.05	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.14	0.14	0.0000	
8	Annual Average Interest Rate	0.07	0.07	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0058	0.0058	0.0000	
10	Interest Provision (D4*D9)	876.53	1,415	(538.47)	(38.05)
	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: JANUARY 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	42,250	67,398	(25,148)	(37.31)	42,250	67,398	(25,148)	(37.31)
2	COAL	14,091,358	21,078,891	(6,987,533)	(33.15)	14,091,358	21,078,891	(6,987,533)	(33.15)
3	GAS	9,558,242	11,156,182	(1,597,940)	(14.32)	9,558,242	11,156,182	(1,597,940)	(14.32)
4	GAS (B.L.)	17,434	0	17,434	100.00	17,434	-	17,434	100.00
5	LANDFILL GAS	63,239	59,853	3,386	5.66	63,239	59,853	3,386	5.66
6	OIL - C.T.	23,244	0	23,244	100.00	23,244	0	23,244	100.00
7	TOTAL ($)	23,795,767	32,362,324	(8,566,557)	(26.47)	23,795,767	32,362,324	(8,566,557)	(26.47)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	284,995	397,809	(112,814)	(28.36)	284,995	397,809	(112,814)	(28.36)
10	GAS	337,120	404,198	(67,078)	(16.60)	337,120	404,198	(67,078)	(16.60)
11	LANDFILL GAS	2,170	2,240	(70)	(3.13)	2,170	2,240	(70)	(3.13)
12	OIL - C.T.	74	0	74	100.00	74	0	74	100.00
13	TOTAL (MWH)	624,359	804,247	(179,888)	(22.37)	624,359	804,247	(179,888)	(22.37)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	339	572	(233)	(40.73)	339	572	(233)	(40.73)
15	COAL (TONS)	135,335	189,802	(54,467)	(28.70)	135,335	189,802	(54,467)	(28.70)
16	GAS (MCF) (1)	2,349,243	2,797,289	(448,046)	(16.02)	2,349,243	2,797,289	(448,046)	(16.02)
17	OIL - C.T. (BBL)	215	0	215	100.00	215	0	215	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,173,845	4,467,071	(1,293,226)	(28.95)	3,173,845	4,467,071	(1,293,226)	(28.95)
19	GAS - Generation (1)	2,384,244	2,737,128	(352,884)	(12.89)	2,384,244	2,737,128	(352,884)	(12.89)
20	OIL - C.T.	1,261	0	1,261	100.00	1,261	0	1,261	100.00
21	TOTAL (MMBTU)	5,559,350	7,204,199	(1,644,849)	(22.83)	5,559,350	7,204,199	(1,644,849)	(22.83)
	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	45.65	49.46	(3.81)	(7.70)	45.65	49.46	(3.81)	(7.70)
24	GAS	53.99	50.26	3.73	7.42	53.99	50.26	3.73	7.42
25	LANDFILL GAS	0.35	0.28	0.07	25.00	0.35	0.28	0.07	25.00
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)	124.63	117.83	6.80	5.77	124.63	117.83	6.80	5.77
29	COAL ($/TON)	104.12	111.06	(6.94)	(6.25)	104.12	111.06	(6.94)	(6.25)
30	GAS ($/MCF) (1)	4.00	3.95	0.05	1.27	4.00	3.95	0.05	1.27
31	OIL - C.T. ($/BBL)	108.11	0.00	108.11	100.00	108.11	0.00	108.11	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.46	4.73	(0.27)	(5.71)	4.46	4.73	(0.27)	(5.71)
33	GAS - Generation (1)	3.93	4.04	(0.11)	(2.72)	3.93	4.04	(0.11)	(2.72)
34	OIL - C.T.	18.43	0.00	18.43	100.00	18.43	0.00	18.43	100.00
35	TOTAL ($/MMBTU)	4.24	4.47	(0.23)	(5.15)	4.24	4.47	(0.23)	(5.15)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,136	11,229	(93)	(0.83)	11,136	11,229	(93)	(0.83)
37	GAS - Generation (1)	7,190	6,820	370	5.43	7,190	6,820	370	5.43
38	OIL - C.T.	17,041	0	17,041	100.00	17,041	0	17,041	100.00
39	TOTAL (BTU/KWH)	9,015	9,015	0	0.00	9,015	9,015	0	0.00
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.97	5.32	(0.35)	(6.58)	4.97	5.32	(0.35)	(6.58)
41	GAS	2.84	2.76	0.08	2.90	2.84	2.76	0.08	2.90
42	LANDFILL GAS	2.91	2.67	0.24	8.99	2.91	2.67	0.24	8.99
43	OIL - C.T.	31.41	0.00	31.41	100.00	31.41	0.00	31.41	100.00
44	TOTAL (¢/KWH)	3.81	4.02	(0.21)	(5.22)	3.81	4.02	(0.21)	(5.22)

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	3,661	6.7	100.0	61.5	10,859	Coal	1,752	11,346	39,753	177,271	4.84	101.18
2				66					Gas-G	704	1,013	713	4,975	7.54	7.07
3									Gas-S	0	1,013	0	0.00		0.00
4									Oil-S	53	138,572	306	6,326		119.36
5	Crist 5		75	32,566	62.6	100.0	66.4	11,070	Coal	15,418	11,691	360,504	1,560,156	4.79	101.19
6				2,357					Gas-G	25,842	1,013	26,178	182,763	7.75	7.07
7									Gas-S	1,464	1,013	1,483	10,354.33		7.07
8									Oil-S	156	138,572	908	18,766		120.29
9	Crist 6		291	(1,641)	(0.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0.00		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		465	198,503	57.7	99.3	58.1	10,916	Coal	92,495	11,713	2,166,796	9,359,632	4.72	101.19
14				997					Gas-G	1,052	1,013	1,066	7,441	0.75	7.07
15									Gas-S	1,001	1,013	1,014	7,080.07		7.07
16									Oil-S	20	138,572	114	2,353		117.65
17	Scholz 1		46	(237)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(184)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	54,573	45.3	100.0	45.3	11,037	Coal	25,670	11,732	602,316	2,780,090	5.09	108.30
22									Oil-S	111	139,719	651	14,806		133.39
23	Smith 2		195	(378)	(0.3)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,719	0	0		0.00
25	Smith 3		584	328,166	75.5	98.1	83.2	7,180	Gas-G	2,319,180	1,016	2,356,287	9,179,512	2.80	3.96
26	Smith A	(2)	40	74	0.2	99.8	33.3	17,041	Oil	215	139,688	1,261	23,244	31.41	108.11
27	Other Generation			5,534									183,550	3.32	0.00
28	Perdido			2,170					Landfill Gas				63,239	2.91	0.00
29	Daniel 1	(1)	255	(1,319)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	140,433	0	0		0.00
31	Daniel 2	(1)	255	(549)	(0.3)	68.6	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,433	0	0		0.00
33	Total		2,489	624,359	33.7	96.2	37.7	9,015				5,559,350	23,581,558	3.78	

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)	
-	Coal Additive	218,268	
	Recoverable Fuel	23,795,767	3.81

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	178	572	(394)	(68.88)	178	572	(394)	(68.88)
3	UNIT COST ($/BBL)	133.28	117.50	15.78	13.43	133.28	117.50	15.78	13.43
4	AMOUNT ($)	23,724	67,208	(43,484)	(64.70)	23,724	67,208	(43,484)	(64.70)
5	*BURNED :*								
6	UNITS (BBL)	376	572	(196)	(34.27)	376	572	(196)	(34.27)
7	UNIT COST ($/BBL)	125.30	117.83	7.47	6.34	125.30	117.83	7.47	6.34
8	AMOUNT ($)	47,114	67,398	(20,284)	(30.10)	47,114	67,398	(20,284)	(30.10)
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,770	7,523	(1,753)	(23.30)	5,770	7,523	(1,753)	(23.30)
11	UNIT COST ($/BBL)	129.57	117.30	12.27	10.46	129.57	117.30	12.27	10.46
12	AMOUNT ($)	747,628	882,474	(134,846)	(15.28)	747,628	882,474	(134,846)	(15.28)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	163,071	127,544	35,527	27.85	163,071	127,544	35,527	27.85
16	UNIT COST ($/TON)	100.73	106.82	(6.09)	(5.70)	100.73	106.82	(6.09)	(5.70)
17	AMOUNT ($)	16,426,795	13,623,647	2,803,148	20.58	16,426,795	13,623,647	2,803,148	20.58
18	*BURNED :*								
19	UNITS (TONS)	135,335	189,802	(54,467)	(28.70)	135,335	189,802	(54,467)	(28.70)
20	UNIT COST ($/TON)	102.54	111.06	(8.52)	(7.67)	102.54	111.06	(8.52)	(7.67)
21	AMOUNT ($)	13,877,149	21,078,891	(7,201,742)	(34.17)	13,877,149	21,078,891	(7,201,742)	(34.17)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	965,944	943,652	22,292	2.36	965,944	943,652	22,292	2.36
24	UNIT COST ($/TON)	105.00	110.25	(5.25)	(4.76)	105.00	110.25	(5.25)	(4.76)
25	AMOUNT ($)	101,428,262	104,038,347	(2,610,085)	(2.51)	101,428,262	104,038,347	(2,610,085)	(2.51)
26	DAYS SUPPLY	46	45	1	2.22				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,386,744	2,737,128	(350,384)	(12.80)	2,386,744	2,737,128	(350,384)	(12.80)
29	UNIT COST ($/MMBTU)	3.90	4.04	(0.14)	(3.47)	3.90	4.04	(0.14)	(3.47)
30	AMOUNT ($)	9,316,407	11,053,479	(1,737,072)	(15.72)	9,316,407	11,053,479	(1,737,072)	(15.72)
31	*BURNED :*								
32	UNITS (MMBTU)	2,386,742	2,737,128	(350,386)	(12.80)	2,386,742	2,737,128	(350,386)	(12.80)
33	UNIT COST ($/MMBTU)	3.94	4.04	(0.10)	(2.48)	3.94	4.04	(0.10)	(2.48)
34	AMOUNT ($)	9,392,127	11,053,479	(1,661,352)	(15.03)	9,392,127	11,053,479	(1,661,352)	(15.03)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	781,308	0	781,308	100.00	781,308	0	781,308	100.00
37	UNIT COST ($/MMBTU)	3.90	0.00	3.90	100.00	3.90	0.00	3.90	100.00
38	AMOUNT ($)	3,043,783	0	3,043,783	100.00	3,043,783	0	3,043,783	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	356	0	356	100.00	356	0	356	100.00
41	UNIT COST ($/BBL)	133.13	0.00	133.13	100.00	133.13	0.00	133.00	100.00
42	AMOUNT ($)	47,394	0	47,394	100.00	47,394	0	47,394	100.00
43	*BURNED :*								
44	UNITS (BBL)	215	0	215	100.00	215	0	215	100.00
45	UNIT COST ($/BBL)	108.11	0.00	108.11	100.00	108.11	0.00	108.11	100.00
46	AMOUNT ($)	23,244	0	23,244	100.00	23,244	0	23,244	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,096	7,143	(1,047)	(14.66)	6,096	7,143	(1,047)	(14.66)
49	UNIT COST ($/BBL)	108.18	105.39	2.79	2.65	108.18	105.39	2.79	2.65
50	AMOUNT ($)	659,464	752,796	(93,332)	(12.40)	659,464	752,796	(93,332)	(12.40)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
						(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH 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		341,838,000	0	341,838,000	2.54	2.92	8,689,000	9,967,000
2	Various	Economy Sales	7,052,000	0	7,052,000	2.55	2.92	180,000	206,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	74,000	74,000
4	TOTAL ESTIMATED SALES		348,890,000	0	348,890,000	2.56	2.94	8,943,000	10,247,000
	ACTUAL								
5	Southern Company Interchange		332,659,914	0	332,659,914	2.54	2.73	8,459,153	9,094,374
6	A.E.C.	External	100,851	0	100,851	3.12	3.99	3,151	4,023
7	AECI	External	216,922	0	216,922	2.52	3.88	5,467	8,421
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	0	0
13	CARGILE	External	377,987	0	377,987	2.40	3.28	9,091	12,412
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.32	2.88	21,661	26,896
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	3,775	0	3,775	2.74	3.40	104	128
19	EAGLE EN	External	29,318	0	29,318	2.56	3.58	750	1,050
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	18,873	0	18,873	2.42	3.47	456	654
22	ENTERGY	External	37,749	0	37,749	2.32	3.80	874	1,434
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	73,923	0	73,923	2.81	3.91	2,079	2,892
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	20,132	0	20,132	2.47	3.03	498	611
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	54,612	0	54,612	2.44	3.82	1,330	2,089
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	18,244	0	18,244	3.45	3.46	630	631
32	NCEMC	External	178,054	0	178,054	2.53	3.20	4,504	5,703
33	NCMPA1	External	0	0	0	0.00	0.00	0	0
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	77,383	0	77,383	2.58	3.79	1,994	2,930
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	1,136,915	0	1,136,915	2.38	3.25	27,016	36,978
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	0	0	0	0.00	0.00	0	0
40	SEC	External	160,115	0	160,115	2.65	2.95	4,241	4,725
41	SEPA	External	469,664	0	469,664	2.54	3.31	11,928	15,569
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	SPP	External	6,174	1	6,173	2.17	1.63	134	101
44	TAL	External	0	0	0	0.00	0.00	0	0
45	TEA	External	659,523	0	659,523	2.53	3.13	16,675	20,612
46	TECO	External	88,770	0	88,770	2.29	3.36	2,036	2,984
47	TENASKA	External	0	0	0	0.00	0.00	0	0
48	TRANSALT	External	0	0	0	0.00	0.00	0	0
49	TVA	External	329,225	0	329,225	2.93	3.93	9,660	12,929
50	UPP	External	0	0	0	0.00	0.00	0	0
51	WRI	External	151,008	0	151,008	2.40	2.84	3,628	4,296
52	Less: Flow-Thru Energy		(4,876,980)	0	(4,876,980)	2.48	2.48	(121,111)	(121,111)
53	SEPA		1,614,624	1,614,624	0	0.00	0.00	0	0
54	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	9,801	9,801
55	Other transactions including adj.		105,263,103	172,455	105,090,648	0.00	0.00	0	0
56	TOTAL ACTUAL SALES		439,802,821	1,787,080	438,015,741	1.93	2.08	8,475,749	9,141,331
57	Difference in Amount		90,912,821	1,787,080	89,125,741	(0.63)	(0.86)	(467,251)	(1,105,669)
58	Difference in Percent		26.06	0.00	25.55	(24.61)	(29.25)	(5.22)	(10.79)

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 54

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

			PERIOD TO DATE						
	(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	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		341,838,000	0	341,838,000	2.54	2.92	8,689,000	9,967,000
2	Various	Economy Sales	7,052,000	0	7,052,000	2.55	2.92	180,000	206,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	74,000	74,000
4	TOTAL ESTIMATED SALES		348,890,000	0	348,890,000	2.56	2.94	8,943,000	10,247,000
	ACTUAL								
5	Southern Company Interchange		332,659,914	0	332,659,914	2.54	2.73	8,459,153	9,094,374
6	A.E.C.	External	100,851	0	100,851	3.12	3.99	3,151	4,023
7	AECI	External	216,922	0	216,922	2.52	3.88	5,467	8,421
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	0	0
13	CARGILE	External	377,987	0	377,987	2.40	3.28	9,091	12,412
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.32	2.88	21,661	26,896
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	3,775	0	3,775	2.74	3.40	104	128
19	EAGLE EN	External	29,318	0	29,318	2.56	3.58	750	1,050
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	18,873	0	18,873	2.42	3.47	456	654
22	ENTERGY	External	37,749	0	37,749	2.32	3.80	874	1,434
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	73,923	0	73,923	2.81	3.91	2,079	2,892
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	20,132	0	20,132	2.47	3.03	498	611
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	54,612	0	54,612	2.44	3.82	1,330	2,089
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	18,244	0	18,244	3.45	3.46	630	631
32	NCEMC	External	178,054	0	178,054	2.53	3.20	4,504	5,703
33	NCMPA1	External	0	0	0	0.00	0.00	0	0
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	77,383	0	77,383	2.58	3.79	1,994	2,930
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	1,136,915	0	1,136,915	2.38	3.25	27,016	36,978
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	0	0	0	0.00	0.00	0	0
40	SEC	External	160,115	0	160,115	2.65	2.95	4,241	4,725
41	SEPA	External	469,664	0	469,664	2.54	3.31	11,928	15,569
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	SPP	External	6,174	1	6,173	2.17	1.63	134	101
44	TAL	External	0	0	0	0.00	0.00	0	0
45	TEA	External	659,523	0	659,523	2.53	3.13	16,675	20,612
46	TECO	External	88,770	0	88,770	2.29	3.36	2,036	2,984
47	TENASKA	External	0	0	0	0.00	0.00	0	0
48	TRANSALT	External	0	0	0	0.00	0.00	0	0
49	TVA	External	329,225	0	329,225	2.93	3.93	9,660	12,929
50	UPP	External	0	0	0	0.00	0.00	0	0
51	WRI	External	151,008	0	151,008	2.40	2.84	3,628	4,296
52	Less: Flow-Thru Energy		(4,876,980)	0	(4,876,980)	2.48	2.48	(121,111)	(121,111)
53	SEPA		1,614,624	1,614,624	0	0.00	0.00	0	0
54	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	9,801	9,801
55	Other transactions including adj.		105,263,103	172,455	105,090,648	0.00	0.00	0	0
56	TOTAL ACTUAL SALES		439,802,821	1,787,080	438,015,741	1.93	2.08	8,475,749	9,141,331
57	Difference in Amount		90,912,821	1,787,080	89,125,741	(0.63)	(0.86)	(467,251)	(1,105,669)
58	Difference in Percent		26.06	0.00	25.55	(24.61)	(29.25)	(5.22)	(10.79)

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 54

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JANUARY 2013

(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 2013

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	15,000	0	0	0	7.74	7.74	1,161
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	23,420,000	0	0	0	2.67	2.67	625,689
6 International Paper	COG 1	0	0	0	0	0.00	0.00	1,807
7 TOTAL		23,435,000	0	0	0	2.68	2.68	628,657

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	15,000	0	0	0	7.74	7.74	1,161
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	23,420,000	0	0	0	2.67	2.67	625,689
6 International Paper	COG 1	0	0	0	0	0.00	0.00	1,807
7 TOTAL		23,435,000	0	0	0	2.68	2.68	628,657

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

	(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	14,031,000	2.97	417,000	14,031,000	2.97	417,000
2	Economy Energy	4,132,000	2.93	121,000	4,132,000	2.93	121,000
3	Other Purchases	530,697,000	3.05	16,168,000	530,697,000	3.05	16,168,000
4	TOTAL ESTIMATED PURCHASES	548,860,000	3.04	16,706,000	548,860,000	3.04	16,706,000
	ACTUAL						
5	Southern Company Interchange	51,879,506	2.75	1,425,095	51,879,506	2.75	1,425,095
6	Non-Associated Companies	38,894,755	0.42	164,189	38,894,755	0.42	164,189
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	485,831,000	3.08	14,983,574	485,831,000	3.08	14,983,574
9	Other Wheeled Energy	5,562,000	0.00	N/A	5,562,000	0.00	N/A
10	Other Transactions	69,480,961	0.03	17,839	69,480,961	0.03	17,839
11	Less: Flow-Thru Energy	(4,876,980)	2.70	(131,581)	(4,876,980)	2.70	(131,581)
12	TOTAL ACTUAL PURCHASES	646,771,242	2.54	16,459,116	646,771,242	2.54	16,459,116
13	Difference in Amount	97,911,242	(0.50)	(246,884)	97,911,242	(0.50)	(246,884)
14	Difference in Percent	17.84	(16.45)	(1.48)	17.84	(16.45)	(1.48)

2013 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	2/18/2000	5 Yr Notice	177.8	422,287											422,287
SUBTOTAL					$ 422,287		$ -		$ -		$ -		$ -		$ -	$ 422,287
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029											1,961,029
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)											(3,146)
SUBTOTAL					$ 1,957,883		$ -		$ -		$ -		$ -		$ -	$ 1,957,883
TOTAL					**$ 2,380,170**		$ -		$ -		$ -		$ -		$ -	**$ 2,380,170**

2013 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	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													422,287
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 422,287
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													1,961,029
2 Other Confidential Agreements	Other	Varies	Varies													(3,146)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,957,883
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 2,380,170

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

FEBRUARY 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2013
CURRENT MONTH

		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)	21,800,766	26,634,277	(4,833,511)	(18.15)	573,478,000	680,555,000	(107,077,000)	(15.73)	3.8015	3.9138	(0.11)	(2.86)
2	Hedging Settlement Costs (A2)	2,166,655	0	2,166,655	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) **	79,735	0	79,735	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	24,047,156	26,634,277	(2,587,121)	(9.71)	573,478,000	680,555,000	(107,077,000)	(15.73)	4.1932	3.9136	0.28	7.14
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)	16,261,330	13,681,000	2,580,330	18.86	684,908,863	447,495,000	237,413,863	53.05	2.3742	3.0572	(0.68)	(22.34)
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)	744,198	0	744,198	100.00	23,306,000	0	23,306,000	100.00	3.1932	0.0000	3.19	0.00
12	TOTAL COST OF PURCHASED POWER	17,005,528	13,681,000	3,324,528	24.30	708,214,863	447,495,000	260,719,863	58.26	2.4012	3.0572	(0.66)	(21.48)
13	Total Available MWH (Line 5 + Line 12)	41,052,684	40,315,277	737,407	1.83	1,281,692,863	1,128,050,000	153,642,863	13.62				
14	Fuel Cost of Economy Sales (A6)	(198,560)	(206,000)	7,440	(3.61)	(7,233,862)	(7,975,000)	741,138	(9.29)	(2.7449)	(2.5831)	(0.16)	(6.26)
15	Gain on Economy Sales (A6)	(25,889)	(53,000)	27,111	(51.15)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(9,843,351)	(6,879,000)	(2,964,351)	43.09	(510,650,921)	(273,819,000)	(236,831,921)	86.49	(1.9276)	(2.5122)	0.58	23.27
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(10,067,800)	(7,138,000)	(2,929,800)	41.05	(517,884,783)	(281,794,000)	(236,090,783)	83.78	(1.9440)	(2.5331)	0.59	23.26
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)	30,984,884	33,177,277	(2,192,393)	(6.61)	763,808,080	846,256,000	(82,447,920)	(9.74)	4.0566	3.9205	0.14	3.47
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 *	70,932	76,097	(5,165)	(6.79)	1,748,553	1,941,000	(192,447)	(9.91)	4.0566	3.9205	0.14	3.47
22	T & D Losses *	1,379,309	1,478,817	(99,308)	(6.72)	34,001,591	37,715,000	(3,713,409)	(9.85)	4.0566	3.9205	0.14	3.47
23	TERRITORIAL KWH SALES	30,984,884	33,177,277	(2,192,393)	(6.61)	728,057,936	806,600,000	(78,542,064)	(9.74)	4.2558	4.1132	0.14	3.47
24	Wholesale KWH Sales	958,208	1,111,804	(153,596)	(13.82)	22,515,414	27,030,000	(4,514,586)	(16.70)	4.2558	4.1132	0.14	3.47
25	Jurisdictional KWH Sales	30,026,676	32,065,473	(2,038,797)	(6.36)	705,542,522	779,570,000	(74,027,478)	(9.50)	4.2558	4.1132	0.14	3.47
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	30,071,716	32,113,571	(2,041,855)	(6.36)	705,542,522	779,570,000	(74,027,478)	(9.50)	4.2622	4.1194	0.14	3.47
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	705,542,522	779,570,000	(74,027,478)	(9.50)	(0.3121)	(0.2825)	(0.03)	10.48
29	TOTAL JURISDICTIONAL FUEL COST	27,869,598	29,911,453	(2,041,855)	(6.83)	705,542,522	779,570,000	(74,027,478)	(9.50)	3.9501	3.8369	0.11	2.95
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9529	3.8397	0.11	2.95
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	705,542,522	779,570,000	(74,027,478)	(9.50)	0.0123	0.0111	0.00	10.81
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9652	3.8508	0.11	2.97
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.965	3.851		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 21,800,766
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	79,735
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,166,655
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	16,261,330
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	744,198
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,067,800)
10	Total Fuel and Net Power Transactions		$ 30,984,884

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2013
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)	45,596,533	58,996,601	(13,400,068)	(22.71)	1,197,837,000	1,484,802,000	(286,965,000)	(19.33)	3.8066	3.9734	(0.17)	(4.20)
2	Hedging Settlement Costs (A2)	4,180,055	0	4,180,055	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) **	86,687	0	86,687	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	49,863,275	58,996,601	(9,133,326)	(15.48)	1,197,837,000	1,484,802,000	(286,965,000)	(19.33)	4.1628	3.9734	0.19	4.77
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)	32,720,446	30,387,000	2,333,446	7.68	1,331,680,105	996,355,000	335,325,105	33.66	2.4571	3.0498	(0.59)	(19.43)
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)	1,372,855	0	1,372,855	100.00	46,741,000	0	46,741,000	100.00	2.9372	0.0000	2.94	0.00
12	TOTAL COST OF PURCHASED POWER	34,093,301	30,387,000	3,706,301	12.20	1,378,421,105	996,355,000	382,066,105	38.35	2.4734	3.0498	(0.58)	(18.90)
13	Total Available MWH (Line 5 + Line 12)	83,956,576	89,383,601	(5,427,025)	(6.07)	2,576,258,105	2,481,157,000	95,101,105	3.83				
14	Fuel Cost of Economy Sales (A6)	(326,466)	(386,000)	59,534	(15.42)	(12,378,022)	(15,027,000)	2,650,978	(17.64)	(2.6379)	(2.5687)	(0.07)	(2.69)
15	Gain on Economy Sales (A6)	(35,690)	(127,000)	91,310	(71.90)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(18,181,393)	(15,568,000)	(2,613,393)	16.79	(945,311,582)	(615,657,000)	(329,654,582)	53.55	(1.9233)	(2.5287)	0.61	23.94
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(18,543,549)	(16,081,000)	(2,462,549)	15.31	(957,687,604)	(630,684,000)	(327,003,604)	51.85	(1.9363)	(2.5498)	0.61	24.06
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)	65,413,027	73,302,601	(7,889,574)	(10.76)	1,618,570,501	1,850,473,000	(231,902,499)	(12.53)	4.0414	3.9613	0.08	2.02
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 *	141,390	154,174	(12,784)	(8.29)	3,498,528	3,892,000	(393,472)	(10.11)	4.0414	3.9613	0.08	2.02
22	T & D Losses *	3,359,753	3,609,576	(249,823)	(6.92)	83,133,384	91,121,000	(7,987,616)	(8.77)	4.0414	3.9613	0.08	2.02
23	TERRITORIAL KWH SALES	65,413,027	73,302,601	(7,889,574)	(10.76)	1,531,938,589	1,755,460,000	(223,521,411)	(12.73)	4.2700	4.1757	0.09	2.26
24	Wholesale KWH Sales	2,025,344	2,463,505	(438,161)	(17.79)	47,432,858	58,994,000	(11,561,142)	(19.60)	4.2699	4.1759	0.09	2.25
25	Jurisdictional KWH Sales	63,387,683	70,839,096	(7,451,413)	(10.52)	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)	4.2700	4.1757	0.09	2.26
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	63,482,765	70,945,354	(7,462,589)	(10.52)	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)	4.2764	4.1819	0.09	2.26
28	TRUE-UP	(4,404,236)	(4,404,236)	0	0.00	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)	(0.2967)	(0.2596)	(0.04)	14.29
29	TOTAL JURISDICTIONAL FUEL COST	59,078,529	66,541,118	(7,462,589)	(11.22)	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)	3.9797	3.9223	0.06	1.46
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9826	3.9251	0.06	1.46
32	GPIF Reward / (Penalty)	173,444	173,444	0	0.00	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)	0.0117	0.0102	0.00	14.71
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9943	3.9353	0.06	1.50
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.994	3.935		

* 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: FEBRUARY 2013

		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	21,601,356.61	26,541,486	(4,940,129.39)	(18.61)	45,213,573.49	58,801,107	(13,587,533.51)	(23.11)
1a	Other Generation	199,409.00	92,791	106,618.00	114.90	382,959.37	195,494	187,465.37	95.89
2	Fuel Cost of Power Sold	(10,067,800.03)	(7,138,000)	(2,929,800.03)	(41.05)	(18,543,549.49)	(16,081,000)	(2,462,549.49)	(15.31)
3	Fuel Cost - Purchased Power	16,261,329.94	13,681,000	2,580,329.94	18.86	32,720,445.53	30,387,000	2,333,445.53	7.68
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	744,198.26	0	744,198.26	100.00	1,372,855.43	0	1,372,855.43	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	2,166,655.00	0	2,166,655.00	100.00	4,180,055.00	0	4,180,055.00	100.00
6	Total Fuel & Net Power Transactions	30,905,148.78	33,177,277	(2,272,128.22)	(6.85)	65,326,339.33	73,302,601	(7,976,261.67)	(10.88)
7	AdjustmentsTo Fuel Cost*	79,735.13	0	79,735.13	100.00	86,687.23	0	86,687.23	100.00
8	Adj. Total Fuel & Net Power Transactions	30,984,883.91	33,177,277	(2,192,393.09)	(6.61)	65,413,026.56	73,302,601	(7,889,574.44)	(10.76)
B.	*KWH Sales*								
1	Jurisdictional Sales	705,542,522	779,570,000	(74,027,478)	(9.50)	1,484,505,731	1,696,466,000	(211,960,269)	(12.49)
2	Non-Jurisdictional Sales	22,515,414	27,030,000	(4,514,586)	(16.70)	47,432,858	58,994,000	(11,561,142)	(19.60)
3	Total Territorial Sales	728,057,936	806,600,000	(78,542,064)	(9.74)	1,531,938,589	1,755,460,000	(223,521,411)	(12.73)
4	Juris. Sales as % of Total Terr. Sales	96.9075	96.6489	0.2586	0.27	96.9037	96.6394	0.2643	0.27

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit RWD-1, Page 30 of 212

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

C. *True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1 Jurisdictional Fuel Revenue	26,749,927.96	29,647,047	(2,897,119.14)	(9.77)	56,289,302.42	64,516,602	(8,227,299.56)	(12.75)
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	4,404,236.00	4,404,236	0.00	0.00
2b Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(173,318.00)	(173,318)	0.00	0.00
3 Juris. Fuel Revenue Applicable to Period	28,865,386.96	31,762,506	(2,897,119.04)	(9.12)	60,520,220.42	68,747,520	(8,227,299.58)	(11.97)
4 Adjusted Total Fuel & Net Power Transactions (Line A8)	30,984,883.91	33,177,277	(2,192,393.09)	(6.61)	65,413,026.56	73,302,601	(7,889,574.44)	(10.76)
5 Juris. Sales % of Total KWH Sales (Line B4)	96.9075	96.6489	0.2586	0.27	96.9037	96.6394	0.2643	0.27
6 Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	30,071,716.39	32,113,571	(2,041,854.61)	(6.36)	63,482,765.84	70,945,354	(7,462,588.16)	(10.52)
7 True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,206,329.43)	(351,065)	(855,264.43)	(243.62)	(2,962,545.42)	(2,197,834)	(764,711.42)	(34.79)
8 Interest Provision for the Month	902.97	1,667	(764.03)	45.83	1,779.50	3,082	(1,302.50)	42.26
9 Beginning True-Up & Interest Provision	13,134,265.68	22,377,946	(9,243,680.32)	41.31	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10 True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(4,404,236.00)	(4,404,236)	0.00	0.00
11 End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	9,726,721.22	19,826,430	(10,099,708.78)	50.94	9,726,721.22	19,826,430	(10,099,708.78)	50.94
12 Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13 End of Period - Total Net True-Up	9,726,721.22	19,826,430	(10,099,708.78)	50.94	9,726,721.22	19,826,430	(10,099,708.78)	50.94

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	13,134,265.68	22,377,946	(9,243,680.32)	(41.31)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	9,725,818.25	19,824,763	(10,098,944.75)	(50.94)
3	Total of Beginning & Ending True-Up Amts.	22,860,083.93	42,202,709	(19,342,625.07)	(45.83)
4	Average True-Up Amount	11,430,041.97	21,101,355	(9,671,313.03)	(45.83)
5	Interest Rate 1st Day of Reporting Business Month	0.09	0.09	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.10	0.10	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)	902.97	1,667	(764.03)	(45.83)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	209,940	67,294	142,646	211.97	252,190	134,692	117,498	87.23
2	COAL	11,093,978	16,510,407	(5,416,429)	(32.81)	25,185,336	37,589,298	(12,403,962)	(33.00)
3	GAS	10,419,732	10,002,548	417,184	4.17	19,977,974	21,158,730	(1,180,756)	(5.58)
4	GAS (B.L.)	-	0	0	0.00	17,434	-	17,434	100.00
5	LANDFILL GAS	58,444	54,028	4,416	8.17	121,683	113,881	7,802	6.85
6	OIL - C.T.	18,672	0	18,672	100.00	41,916	0	41,916	100.00
7	TOTAL ($)	21,800,766	26,634,277	(4,833,511)	(18.15)	45,596,533	58,996,601	(13,400,068)	(22.71)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	212,749	318,498	(105,749)	(33.20)	497,744	716,307	(218,563)	(30.51)
10	GAS	358,648	360,035	(1,387)	(0.39)	695,768	764,233	(68,465)	(8.96)
11	LANDFILL GAS	2,014	2,022	(8)	(0.40)	4,184	4,262	(78)	(1.83)
12	OIL - C.T.	67	0	67	100.00	141	0	141	100.00
13	TOTAL (MWH)	573,478	680,555	(107,077)	(15.73)	1,197,837	1,484,802	(286,965)	(19.33)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,542	572	970	169.58	1,881	1,144	737	64.42
15	COAL (TONS)	105,358	151,611	(46,253)	(30.51)	240,693	341,413	(100,720)	(29.50)
16	GAS (MCF) (1)	2,640,194	2,492,788	147,406	5.91	4,989,437	5,290,077	(300,640)	(5.68)
17	OIL - C.T. (BBL)	173	0	173	100.00	388	0	388	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,415,027	3,577,888	(1,162,861)	(32.50)	5,588,872	8,044,959	(2,456,087)	(30.53)
19	GAS - Generation (1)	2,680,234	2,439,962	240,272	9.85	5,064,478	5,177,090	(112,612)	(2.18)
20	OIL - C.T.	1,013	0	1,013	100.00	2,274	0	2,274	100.00
21	TOTAL (MMBTU)	5,096,274	6,017,850	(921,576)	(15.31)	10,655,624	13,222,049	(2,566,425)	(19.41)
	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	37.10	46.80	(9.70)	(20.73)	41.55	48.24	(6.69)	(13.87)
24	GAS	62.54	52.90	9.64	18.22	58.09	51.47	6.62	12.86
25	LANDFILL GAS	0.35	0.30	0.05	16.67	0.35	0.29	0.06	20.69
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)	136.15	117.65	18.50	15.72	134.07	117.74	16.33	13.87
29	COAL ($/TON)	105.30	108.90	(3.60)	(3.31)	104.64	110.10	(5.46)	(4.96)
30	GAS ($/MCF) (1)	3.87	3.98	(0.11)	(2.76)	3.93	3.96	(0.03)	(0.76)
31	OIL - C.T. ($/BBL)	107.93	0.00	107.93	100.00	108.03	0.00	108.03	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.68	4.63	0.05	1.08	4.55	4.69	(0.14)	(2.99)
33	GAS - Generation (1)	3.81	4.06	(0.25)	(6.16)	3.87	4.05	(0.18)	(4.44)
34	OIL - C.T.	18.43	0.00	18.43	100.00	18.43	0.00	18.43	100.00
35	TOTAL ($/MMBTU)	4.23	4.40	(0.17)	(3.86)	4.23	4.44	(0.21)	(4.73)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,352	11,234	118	1.05	11,228	11,231	(3)	(0.03)
37	GAS - Generation (1)	7,606	6,826	780	11.43	7,404	6,823	581	8.52
38	OIL - C.T.	15,119	0	15,119	100.00	16,128	0	16,128	100.00
39	TOTAL (BTU/KWH)	9,017	8,903	114	1.28	9,016	8,964	52	0.58
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.31	5.20	0.11	2.12	5.11	5.27	(0.16)	(3.04)
41	GAS	2.91	2.78	0.13	4.68	2.87	2.77	0.10	3.61
42	LANDFILL GAS	2.90	2.67	0.23	8.61	2.91	2.67	0.24	8.99
43	OIL - C.T.	27.87	0.00	27.87	100.00	29.73	0.00	29.73	100.00
44	TOTAL (¢/KWH)	3.80	3.91	(0.11)	(2.81)	3.81	3.97	(0.16)	(4.03)

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(742)	0.0	65.2	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	0	1,016	0	0		0.00
4									Oil-S	0	138,572	0	0		0.00
5	Crist 5		75	36,338	74.3	100.0	74.3	10,908	Coal	17,121	11,575	396,360	1,729,301	4.76	101.00
6				1,093					Gas-G	11,708	1,016	11,895	42,941	3.93	3.67
7									Gas-S	0	1,016	0	0		0.00
8									Oil-S	128	138,572	746	15,410		120.39
9	Crist 6		299	(1,414)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		475	129,802	52.7	100.0	52.7	11,262	Coal	62,827	11,634	1,461,857	6,345,688	4.89	101.00
14				38,357					Gas-G	425,146	1,016	431,949	1,559,325	4.07	3.67
15									Gas-S	0	1,016	0	0		0.00
16									Oil-S	20	138,572	114	2,348		117.40
17	Scholz 1		46	(204)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(167)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	49,807	45.8	100.0	45.8	10,998	Coal	24,309	11,267	547,782	2,650,340	5.32	109.03
22									Oil-S	1,085	139,329	6,346	149,587		137.87
23	Smith 2		195	(266)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,329	0	0		0.00
25	Smith 3		584	312,942	79.7	98.1	88.7	7,146	Gas-G	2,203,340	1,015	2,236,390	8,618,057	2.75	3.91
26	Smith A	(2)	40	67	0.2	100.0	75.6	15,119	Oil	173	139,688	1,013	18,672	27.87	107.93
27	Other Generation			6,256									199,409	3.19	0.00
28	Perdido			2,014					Landfill Gas				58,444	2.90	0.00
29	Daniel 1	(1)	255	(64)	0.0	95.5	0.0	0	Coal	1,101	0	0	119,119	0.00	108.19
30									Oil-S	310	140,023	1,822	42,595		137.40
31	Daniel 2	(1)	255	(341)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,023	0	0.00		0.00
33	Total		2,507	573,478	34.0	87.9	37.0	9,017				5,096,274	21,551,236	3.76	

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)	
-	Coal Additive - Crist	270,576	
-	Inventory Adj - Coal, Crist	(28,018)	
-	Inventory Adj - Coal, Smith	11,031	
	Recoverable Fuel	21,800,766	3.80

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	714	572	142	24.83	892	1,144	(252)	(22.03)
3	UNIT COST ($/BBL)	140.97	117.50	23.47	19.97	139.43	117.50	21.93	18.66
4	AMOUNT ($)	100,651	67,208	33,443	49.76	124,375	134,416	(10,041)	(7.47)
5	*BURNED:*								
6	UNITS (BBL)	1,592	572	1,020	178.32	1,968	1,144	824	72.03
7	UNIT COST ($/BBL)	136.17	117.65	18.52	15.74	134.09	117.74	16.35	13.89
8	AMOUNT ($)	216,783	67,294	149,489	222.14	263,897	134,692	129,205	95.93
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,892	7,523	(2,631)	(34.97)	4,892	7,523	(2,631)	(34.97)
11	UNIT COST ($/BBL)	129.09	117.29	11.80	10.06	129.09	117.29	11.80	10.06
12	AMOUNT ($)	631,496	882,388	(250,892)	(28.43)	631,496	882,388	(250,892)	(28.43)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	113,561	143,614	(30,053)	(20.93)	276,632	271,158	5,474	2.02
16	UNIT COST ($/TON)	107.02	104.83	2.19	2.09	103.32	105.76	(2.44)	(2.31)
17	AMOUNT ($)	12,153,754	15,054,509	(2,900,755)	(19.27)	28,580,549	28,678,156	(97,607)	(0.34)
18	*BURNED:*								
19	UNITS (TONS)	105,358	151,611	(46,253)	(30.51)	240,693	341,413	(100,720)	(29.50)
20	UNIT COST ($/TON)	102.77	108.90	(6.13)	(5.63)	102.64	110.10	(7.46)	(6.78)
21	AMOUNT ($)	10,827,460	16,510,407	(5,682,947)	(34.42)	24,704,609	37,589,298	(12,884,689)	(34.28)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	974,146	935,655	38,491	4.11	974,146	935,655	38,491	4.11
24	UNIT COST ($/TON)	105.48	109.64	(4.16)	(3.79)	105.48	109.64	(4.16)	(3.79)
25	AMOUNT ($)	102,754,556	102,582,449	172,107	0.17	102,754,556	102,582,449	172,107	0.17
26	DAYS SUPPLY	46	44	2	4.55				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,670,579	2,439,962	230,617	9.45	5,057,323	5,177,090	(119,767)	(2.31)
29	UNIT COST ($/MMBTU)	3.80	4.06	(0.26)	(6.40)	3.85	4.05	(0.20)	(4.94)
30	AMOUNT ($)	10,150,149	9,909,757	240,392	2.43	19,466,556	20,963,236	(1,496,680)	(7.14)
31	*BURNED:*								
32	UNITS (MMBTU)	2,680,234	2,439,962	240,272	9.85	5,066,976	5,177,090	(110,114)	(2.13)
33	UNIT COST ($/MMBTU)	3.81	4.06	(0.25)	(6.16)	3.87	4.05	(0.18)	(4.44)
34	AMOUNT ($)	10,220,323	9,909,757	310,566	3.13	19,612,450	20,963,236	(1,350,786)	(6.44)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	771,653	0	771,653	100.00	771,653	0	771,653	100.00
37	UNIT COST ($/MMBTU)	3.85	0.00	3.85	100.00	3.85	0.00	3.85	100.00
38	AMOUNT ($)	2,973,609	0	2,973,609	100.00	2,973,609	0	2,973,609	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	356	0	356	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	133.13	0.00	133.00	100.00
42	AMOUNT ($)	0	0	0	0.00	47,394	0	47,394	100.00
43	*BURNED:*								
44	UNITS (BBL)	173	0	173	100.00	388	0	388	100.00
45	UNIT COST ($/BBL)	107.93	0.00	107.93	100.00	108.03	0.00	108.03	100.00
46	AMOUNT ($)	18,672	0	18,672	100.00	41,916	0	41,916	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	5,923	7,143	(1,220)	(17.08)	5,923	7,143	(1,220)	(17.08)
49	UNIT COST ($/BBL)	108.19	105.39	2.80	2.66	108.19	105.39	2.80	2.66
50	AMOUNT ($)	640,792	752,796	(112,004)	(14.88)	640,792	752,796	(112,004)	(14.88)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
						(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH 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		273,819,000	0	273,819,000	2.51	2.84	6,879,000	7,786,000
2	Various	Economy Sales	7,975,000	0	7,975,000	2.58	2.92	206,000	233,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	53,000	53,000
4	TOTAL ESTIMATED SALES		281,794,000	0	281,794,000	2.53	2.86	7,138,000	8,072,000
	ACTUAL								
5	Southern Company Interchange		381,089,087	0	381,089,087	2.63	2.84	10,030,519	10,831,449
6	A.E.C.	External	226,174	0	226,174	2.73	3.63	6,172.27	8,219
7	AECI	External	0	0	0	0.00	0.00	4.90	0
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	AMERENEM	External	0	0	0	0.00	0.00	0.00	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0.00	0
11	BPENERGY	External	0	0	0	0.00	0.00	0.00	0
12	CALPINE	External	0	0	0	0.00	0.00	2,113.88	0
13	CARGILE	External	849,313	0	849,313	2.35	2.95	19,951.96	25,022
14	CITIG	External	0	0	0	0.00	0.00	0.00	0
15	CONSTELL	External	0	0	0	0.00	0.00	82.69	0
16	CPL	External	0	0	0	0.00	0.00	0.00	0
17	DTE	External	0	0	0	0.00	0.00	0.00	0
18	DUKE PWR	External	19,503	0	19,503	2.71	2.27	528.64	443
19	EAGLE EN	External	110,980	0	110,980	2.97	4.14	3,293.95	4,592
20	EASTKY	External	0	0	0	0.00	0.00	0.00	0
21	ENDURE	External	6,103	0	6,103	3.19	4.70	194.60	287
22	ENTERGY	External	18,874	0	18,874	3.28	4.10	618.49	774
23	EXELON	External	635,189	0	635,189	2.45	3.08	15,545.19	19,545
24	FPC	External	0	0	0	0.00	0.00	0.00	0
25	FPL	External	47,185	0	47,185	2.10	3.20	988.56	1,510
26	JARON	External	0	0	0	0.00	0.00	0.00	0
27	JEA	External	0	0	0	0.00	0.00	0.00	0
28	JPMVEC	External	27,432	0	27,432	3.24	4.75	887.81	1,303
29	KEMG	External	0	0	0	0.00	0.00	0.00	0
30	MERRILL	External	0	0	0	0.00	0.00	0.29	0
31	MISO	External	0	0	0	0.00	0.00	0.00	0
32	MORGAN	External	129,478	0	129,478	2.71	3.68	3,512.25	4,761
33	NCEMC	External	54,107	0	54,107	2.54	3.54	1,376.58	1,915
34	NCMPA1	External	0	0	0	0.00	0.00	0.00	0
35	NRG	External	0	0	0	0.00	0.00	2,818.50	0
36	OPC	External	124,256	0	124,256	2.74	3.93	3,404.88	4,888
37	ORLANDO	External	0	0	0	0.00	0.00	0.00	0
38	PJM	External	2,200,530	0	2,200,530	2.73	3.30	60,122.94	72,669
39	REMC	External	0	0	0	0.00	0.00	0.00	0
40	SCE&G	External	639,647	0	639,647	3.12	4.38	19,927.21	28,033
41	SEC	External	44,354	0	44,354	2.87	4.24	1,274.61	1,880
42	SEPA	External	753,384	0	753,384	2.68	3.65	20,154.86	27,491
43	SHELL	External	0	0	0	0.00	0.00	0.00	0
44	SPP	External	0	0	0	0.00	0.00	(0.09)	0
45	TAL	External	0	0	0	0.00	0.00	0.00	0
46	TEA	External	514,882	0	514,882	2.59	3.53	13,314.46	18,185
47	TECO	External	53,917	0	53,917	2.99	4.11	1,614.29	2,213
48	TENASKA	External	0	0	0	0.00	0.00	0.00	0
49	TRANSALT	External	0	0	0	0.00	0.00	0.00	0
50	TVA	External	778,554	0	778,554	2.66	3.90	20,726.19	30,367
51	UPP	External	0	0	0	0.00	0.00	0.00	0
52	WRI	External	0	0	0	0.00	0.00	(69.76)	0
53	Less: Flow-Thru Energy		(7,196,868)	0	(7,196,868)	2.60	2.60	(187,168)	(187,168)
54	SEPA		1,534,280	1,534,280	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	25,889	25,889
56	Other transactions including adj.		135,224,422	129,357,555	5,866,867	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		517,884,783	130,891,835	386,992,948	1.94	2.10	10,067,800	10,898,378
58	Difference in Amount		236,090,783	130,891,835	105,198,948	(0.59)	(0.76)	2,929,800	2,826,378
59	Difference in Percent		83.78	0.00	37.33	(23.32)	(26.57)	41.05	35.01

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 55

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

			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		615,657,000	0	615,657,000	2.53	2.88	15,568,000	17,753,000
2	Various	Economy Sales	15,027,000	0	15,027,000	2.57	2.92	386,000	439,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	127,000	127,000
4	TOTAL ESTIMATED SALES		630,684,000	0	630,684,000	2.55	2.90	16,081,000	18,319,000
	ACTUAL								
5	Southern Company Interchange		713,749,001	0	713,749,001	2.59	2.79	18,489,672	19,925,823
6	A.E.C.	External	327,025	0	327,025	2.85	3.74	9,324	12,242
7	AECI	External	216,922	0	216,922	2.52	3.88	5,472	8,421
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	2,114	0
13	CARGILE	External	1,227,300	0	1,227,300	2.37	3.05	29,042	37,434
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	23,278	0	23,278	2.72	2.45	632	571
19	EAGLE EN	External	140,298	0	140,298	2.88	4.02	4,044	5,641
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	24,976	0	24,976	2.61	3.77	651	941
22	ENTERGY	External	56,623	0	56,623	2.64	3.90	1,493	2,208
23	EXELON	External	635,189	0	635,189	2.45	3.08	15,545	19,545
24	FPC	External	0	0	0	0.00	0.00	0	0
25	FPL	External	121,108	0	121,108	2.53	3.64	3,067	4,402
26	JARON	External	0	0	0	0.00	0.00	0	0
27	JEA	External	0	0	0	0.00	0.00	0	0
28	JPMVEC	External	47,564	0	47,564	2.91	4.02	1,386	1,914
29	KEMG	External	0	0	0	0.00	0.00	0	0
30	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
31	MISO	External	0	0	0	0.00	0.00	0	0
32	MORGAN	External	147,722	0	147,722	2.80	3.65	4,142	5,392
33	NCEMC	External	232,161	0	232,161	2.53	3.28	5,881	7,618
34	NCMPA1	External	0	0	0	0.00	0.00	0	0
35	NRG	External	0	0	0	0.00	0.00	2,819	0
36	OPC	External	201,639	0	201,639	2.68	3.88	5,398	7,818
37	ORLANDO	External	0	0	0	0.00	0.00	0	0
38	PJM	External	3,337,445	0	3,337,445	2.61	3.29	87,139	109,648
39	REMC	External	0	0	0	0.00	0.00	0	0
40	SCE&G	External	639,647	0	639,647	3.12	4.38	19,927	28,033
41	SEC	External	204,469	0	204,469	2.70	3.23	5,515	6,605
42	SEPA	External	1,223,048	0	1,223,048	2.62	3.52	32,083	43,060
43	SHELL	External	0	0	0	0.00	0.00	0	0
44	SPP	External	6,174	0	6,174	2.17	1.63	134	101
45	TAL	External	0	0	0	0.00	0.00	0	0
46	TEA	External	1,174,405	0	1,174,405	2.55	3.30	29,989	38,797
47	TECO	External	142,687	0	142,687	2.56	3.64	3,651	5,197
48	TENASKA	External	0	0	0	0.00	0.00	0	0
49	TRANSALT	External	0	0	0	0.00	0.00	0	0
50	TVA	External	1,107,779	0	1,107,779	2.74	3.91	30,386	43,297
51	UPP	External	0	0	0	0.00	0.00	0	0
52	WRI	External	151,008	0	151,008	2.36	2.84	3,558	4,296
53	Less: Flow-Thru Energy		(12,073,848)	0	(12,073,848)	2.55	2.55	(308,279)	(308,279)
54	SEPA		3,148,904	3,148,904	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	35,690	35,690
56	Other transactions including adj.		240,487,525	129,530,010	110,957,515	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		957,687,604	132,678,914	825,008,690	1.94	2.09	18,543,549	20,039,709
58	Difference in Amount		327,003,604	132,678,914	194,324,690	(0.61)	(0.81)	2,462,549	1,720,709
59	Difference in Percent		51.86	0.00	30.81	(23.92)	(27.93)	15.31	9.39

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 55

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: FEBRUARY 2013

(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 2013

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	1,638,000	0	0	0	7.64	7.64	125,081
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	21,668,000	0	0	0	2.85	2.85	617,665
6	International Paper	COG 1	0	0	0	0	0.00	0.00	1,452
7	TOTAL		23,306,000	0	0	0	3.19	3.19	744,198

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	1,653,000	0	0	0	7.64	7.64	126,243
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	45,088,000	0	0	0	2.76	2.76	1,243,354
6	International Paper	COG 1	0	0	0	0	0.00	0.00	3,258
7	TOTAL		46,741,000	0	0	0	2.94	2.94	1,372,855

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

	(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	16,005,000	2.97	475,000	30,036,000	2.97	892,000
2	Economy Energy	5,477,000	2.85	156,000	9,609,000	2.88	277,000
3	Other Purchases	426,013,000	3.06	13,050,000	956,710,000	3.05	29,218,000
4	TOTAL ESTIMATED PURCHASES	447,495,000	3.06	13,681,000	996,355,000	3.05	30,387,000
	ACTUAL						
5	Southern Company Interchange	24,113,729	2.70	651,782	75,993,235	2.73	2,076,877
6	Non-Associated Companies	44,846,052	1.03	461,097	83,740,807	0.75	625,286
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	514,981,000	2.98	15,329,229	1,000,812,000	3.03	30,312,803
9	Other Wheeled Energy	10,909,000	0.00	N/A	16,471,000	0.00	N/A
10	Other Transactions	97,255,950	0.02	21,616	166,736,911	0.02	39,455
11	Less: Flow-Thru Energy	(7,196,868)	2.81	(202,394)	(12,073,848)	2.77	(333,975)
12	TOTAL ACTUAL PURCHASES	684,908,863	2.37	16,261,330	1,331,680,105	2.46	32,720,446
13	Difference in Amount	237,413,863	(0.69)	2,580,330	335,325,105	(0.59)	2,333,446
14	Difference in Percent	53.05	(22.55)	18.86	33.66	(19.34)	7.68

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2013 Final True-Up Filing
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2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)									320,213
SUBTOTAL					$ 422,287		$ (102,074)		$ -		$ -		$ -		$ -	$ 320,213
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882									3,964,911
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)									(6,417)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ -		$ -		$ -		$ -	$ 3,958,494
TOTAL					**$ 2,380,170**		**$ 1,898,537**		$ -		$ -		$ -		$ -	**$ 4,278,707**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

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2013 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	2/18/2000	5 Yr Notice													320,213
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 320,213
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													3,964,911
2 Other Confidential Agreements	Other	Varies	Varies													(6,417)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 3,958,494
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 4,278,707

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2013 Final True-Up Filing
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

MARCH 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2013
CURRENT MONTH

		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)	24,524,429	24,297,685	226,744	0.93	583,725,000	589,970,000	(6,245,000)	(1.06)	4.2014	4.1185	0.08	2.01
2	Hedging Settlement Costs (A2)	793,231	0	793,231	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) **	13,168	0	13,168	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	25,330,828	24,297,685	1,033,143	4.25	583,725,000	589,970,000	(6,245,000)	(1.06)	4.3395	4.1185	0.22	5.37
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)	18,166,866	16,521,000	1,645,866	9.96	731,487,491	554,952,000	176,535,491	31.81	2.4836	2.9770	(0.49)	(16.57)
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)	940,576	0	940,576	100.00	25,752,000	0	25,752,000	100.00	3.6524	0.0000	3.65	0.00
12	TOTAL COST OF PURCHASED POWER	19,107,442	16,521,000	2,586,442	15.66	757,239,491	554,952,000	202,287,491	36.45	2.5233	2.9770	(0.45)	(15.24)
13	Total Available MWH (Line 5 + Line 12)	44,438,270	40,818,685	3,619,585	8.87	1,340,964,491	1,144,922,000	196,042,491	17.12				
14	Fuel Cost of Economy Sales (A6)	(170,775)	(169,000)	(1,775)	1.05	(5,558,488)	(5,158,000)	599,512	(9.74)	(3.0723)	(2.7444)	(0.33)	(11.95)
15	Gain on Economy Sales (A6)	384	(54,000)	54,384	(100.71)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,677,020)	(8,075,000)	(602,020)	7.46	(477,702,856)	(312,714,000)	(164,988,856)	52.76	(1.8164)	(2.5822)	0.77	29.88
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,847,411)	(8,298,000)	(549,411)	6.62	(483,261,344)	(318,872,000)	(164,389,344)	51.55	(1.8308)	(2.6023)	0.77	29.65
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)	35,590,859	32,520,685	3,070,174	9.44	857,703,147	826,050,000	31,653,147	3.83	4.1496	3.9369	0.21	5.40
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 *	69,335	70,510	(1,175)	(1.67)	1,670,879	1,791,000	(120,121)	(6.71)	4.1496	3.9369	0.21	5.40
22	T & D Losses *	1,598,022	1,414,410	183,612	12.98	38,510,270	35,927,000	2,583,270	7.19	4.1496	3.9369	0.21	5.40
23	TERRITORIAL KWH SALES	35,590,859	32,520,685	3,070,174	9.44	817,521,998	788,332,000	29,189,998	3.70	4.3535	4.1253	0.23	5.53
24	Wholesale KWH Sales	1,060,572	1,106,159	(45,587)	(4.12)	24,361,046	26,814,000	(2,452,954)	(9.15)	4.3536	4.1253	0.23	5.53
25	Jurisdictional KWH Sales	34,530,287	31,414,526	3,115,761	9.92	793,160,952	761,518,000	31,642,952	4.16	4.3535	4.1253	0.23	5.53
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	34,582,082	31,461,648	3,120,434	9.92	793,160,952	761,518,000	31,642,952	4.16	4.3600	4.1314	0.23	5.53
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	793,160,952	761,518,000	31,642,952	4.16	(0.2776)	(0.2892)	0.01	(4.01)
29	TOTAL JURISDICTIONAL FUEL COST	32,379,964	29,259,530	3,120,434	10.66	793,160,952	761,518,000	31,642,952	4.16	4.0824	3.8422	0.24	6.25
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0853	3.8450	0.24	6.25
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	793,160,952	761,518,000	31,642,952	4.16	0.0109	0.0114	(0.00)	(4.39)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0962	3.8564	0.24	6.22
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.096	3.856		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

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SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: MARCH 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 24,524,429
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	13,168
4	Hedging Settlement Costs	Schedule A-2, Line A-5	793,231
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	18,166,866
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	940,576
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,847,411)
10	Total Fuel and Net Power Transactions		$ 35,590,859

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2013
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)	70,120,982	83,294,286	(13,173,324)	(15.82)	1,781,562,000	2,074,772,000	(293,210,000)	(14.13)	3.9359	4.0146	(0.08)	(1.96)
2	Hedging Settlement Costs (A2)	4,973,286	0	4,973,286	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) **	99,855	0	99,855	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	75,194,103	83,294,286	(8,100,183)	(9.72)	1,781,562,000	2,074,772,000	(293,210,000)	(14.13)	4.2207	4.0146	0.21	5.13
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)	50,687,312	46,908,000	3,979,312	8.48	2,063,167,596	1,551,307,000	511,860,596	33.00	2.4565	3.0238	(0.56)	(18.43)
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)	2,313,431	0	2,313,431	100.00	72,493,000	0	72,493,000	100.00	3.1912	0.0000	3.19	0.00
12	TOTAL COST OF PURCHASED POWER	53,200,743	46,908,000	6,292,743	13.42	2,135,660,596	1,551,307,000	584,353,596	37.67	2.4911	3.0238	(0.53)	(17.62)
13	Total Available MWH (Line 5 + Line 12)	128,394,846	130,202,286	(1,807,440)	(1.39)	3,917,222,596	3,626,079,000	291,143,596	8.03				
14	Fuel Cost of Economy Sales (A6)	(497,241)	(555,000)	57,759	(10.41)	(17,934,510)	(21,185,000)	3,250,490	(15.34)	(2.7725)	(2.6198)	(0.15)	(5.83)
15	Gain on Economy Sales (A6)	(35,306)	(181,000)	145,694	(80.49)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(26,858,413)	(23,643,000)	(3,215,413)	13.60	(1,423,014,438)	(928,371,000)	(494,643,438)	53.28	(1.8874)	(2.5467)	0.66	25.89
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(27,390,960)	(24,379,000)	(3,011,960)	12.35	(1,440,948,948)	(949,556,000)	(491,392,948)	51.75	(1.9009)	(2.5674)	0.67	25.96
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)	101,003,886	105,823,286	(4,819,400)	(4.55)	2,476,273,648	2,676,523,000	(200,249,352)	(7.48)	4.0789	3.9538	0.13	3.16
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 *	210,855	224,694	(13,839)	(6.16)	5,169,407	5,683,000	(513,593)	(9.04)	4.0789	3.9538	0.13	3.16
22	T & D Losses *	4,961,723	5,023,224	(61,501)	(1.22)	121,643,654	127,048,000	(5,404,346)	(4.25)	4.0789	3.9538	0.13	3.16
23	TERRITORIAL KWH SALES	101,003,886	105,823,286	(4,819,400)	(4.55)	2,349,460,587	2,543,792,000	(194,331,413)	(7.64)	4.2990	4.1601	0.14	3.34
24	Wholesale KWH Sales	3,085,916	3,569,664	(483,748)	(13.55)	71,793,904	85,808,000	(14,014,096)	(16.33)	4.2983	4.1601	0.14	3.32
25	Jurisdictional KWH Sales	97,917,970	102,253,622	(4,335,652)	(4.24)	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)	4.2990	4.1601	0.14	3.34
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	98,064,847	102,407,002	(4,342,155)	(4.24)	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)	4.3055	4.1663	0.14	3.34
28	TRUE-UP	(6,606,354)	(6,606,354)	0	0.00	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)	(0.2900)	(0.2668)	(0.02)	7.89
29	TOTAL JURISDICTIONAL FUEL COST	91,458,493	95,800,648	(4,342,155)	(4.53)	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)	4.0155	3.8975	0.12	3.03
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0184	3.9003	0.12	3.03
32	GPIF Reward / (Penalty)	260,166	260,166	0	0.00	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)	0.0114	0.0106	0.00	7.55
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0298	3.9109	0.12	3.04
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.030	3.911		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit RWD-1, Page 46 of 212

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

		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	24,302,567.18	24,194,982	107,585.18	0.44	69,516,140.67	82,996,089	(13,479,948.33)	(16.24)
1a	Other Generation	221,861.59	102,703	119,158.59	116.02	604,820.96	298,197	306,623.96	102.83
2	Fuel Cost of Power Sold	(8,847,411.42)	(8,298,000)	(549,411.42)	(6.62)	(27,390,960.91)	(24,379,000)	(3,011,960.91)	(12.35)
3	Fuel Cost - Purchased Power	18,166,866.50	16,521,000	1,645,866.50	9.96	50,887,312.03	46,908,000	3,979,312.03	8.48
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	940,575.93	0	940,575.93	100.00	2,313,431.36	0	2,313,431.36	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	793,231.00	0	793,231.00	100.00	4,973,286.00	0	4,973,286.00	100.00
6	Total Fuel & Net Power Transactions	35,577,690.78	32,520,685	3,057,005.78	9.40	100,904,030.11	105,823,286	(4,919,255.89)	(4.65)
7	Adjustments To Fuel Cost*	13,168.04	0	13,168.04	100.00	99,855.27	0	99,855.27	100.00
8	Adj. Total Fuel & Net Power Transactions	35,590,858.82	32,520,685	3,070,173.82	9.44	101,003,885.38	105,823,286	(4,819,400.62)	(4.55)
B.	*KWH Sales*								
1	Jurisdictional Sales	793,160,952	761,518,000	31,642,952	4.16	2,277,666,683	2,457,984,000	(180,317,317)	(7.34)
2	Non-Jurisdictional Sales	24,361,046	26,814,000	(2,452,954)	(9.15)	71,793,904	85,808,000	(14,014,096)	(16.33)
3	Total Territorial Sales	817,521,998	788,332,000	29,189,998	3.70	2,349,460,587	2,543,792,000	(194,331,413)	(7.64)
4	Juris. Sales as % of Total Terr. Sales	97.0201	96.5986	0.4215	0.44	96.9442	96.6268	0.3174	0.33

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
C.	*True-up Calculation*	ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	Jurisdictional Fuel Revenue	30,090,473.26	28,960,530	1,129,943.72	3.90	86,379,775.68	93,477,132	(7,097,355.84)	(7.59)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	6,606,354.00	6,606,354	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(259,977.00)	(259,977)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	32,205,932.26	31,075,989	1,129,943.26	3.64	92,726,152.68	99,823,509	(7,097,356.32)	(7.11)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	35,590,858.82	32,520,685	3,070,173.82	9.44	101,003,885.38	105,823,286	(4,819,400.62)	(4.55)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.0201	96.5986	0.4215	0.44	96.9442	96.6268	0.3174	0.33
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	34,582,082.25	31,461,648	3,120,434.25	9.92	98,064,848.09	102,407,002	(4,342,153.91)	(4.24)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(2,376,149.99)	(385,659)	(1,990,490.99)	(516.13)	(5,338,695.41)	(2,583,493)	(2,755,202.41)	(106.65)
8	Interest Provision for the Month	557.82	1,390	(832.18)	59.87	2,337.32	4,472	(2,134.68)	47.73
9	Beginning True-Up & Interest Provision	9,726,721.22	19,826,430	(10,099,708.78)	50.94	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(6,606,354.00)	(6,606,354)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	5,149,011.05	17,240,043	(12,091,031.95)	70.13	5,149,011.05	17,240,043	(12,091,031.95)	70.13
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	5,149,011.05	17,240,043	(12,091,031.95)	70.13	5,149,011.05	17,240,043	(12,091,031.95)	70.13

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	9,726,721.22	19,826,430	(10,099,708.78)	(50.94)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	5,148,453.23	17,238,653	(12,090,199.77)	(70.13)
3	Total of Beginning & Ending True-Up Amts.	14,875,174.45	37,065,083	(22,189,908.55)	(59.87)
4	Average True-Up Amount	7,437,587.23	18,532,542	(11,094,954.77)	(59.87)
5	Interest Rate 1st Day of Reporting Business Month	0.10	0.10	0.0000	
6	Interest Rate 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)	557.82	1,390	(832.18)	(59.87)
	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: MARCH 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	317,402	67,247	250,155	371.99	569,592	201,939	367,653	182.06
2	COAL	16,738,493	16,565,746	172,747	1.04	41,923,829	54,155,044	(12,231,215)	(22.59)
3	GAS	7,378,147	7,604,839	(226,692)	(2.98)	27,356,121	28,763,569	(1,407,448)	(4.89)
4	GAS (B.L.)	13,904	0	13,904	100.00	31,338	-	31,338	100.00
5	LANDFILL GAS	59,508	59,853	(345)	(0.58)	181,191	173,734	7,457	4.29
6	OIL - C.T.	16,974	0	16,974	100.00	58,890	0	58,890	100.00
7	TOTAL ($)	24,524,429	24,297,685	226,744	0.93	70,120,962	83,294,286	(13,173,324)	(15.82)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	345,589	320,584	25,005	7.80	843,333	1,036,891	(193,558)	(18.67)
10	GAS	236,030	267,146	(31,116)	(11.65)	931,798	1,031,379	(99,581)	(9.66)
11	LANDFILL GAS	2,052	2,240	(188)	(8.39)	6,236	6,502	(266)	(4.09)
12	OIL - C.T.	54	0	54	100.00	195	0	195	100.00
13	TOTAL (MWH)	583,725	589,970	(6,245)	(1.06)	1,781,562	2,074,772	(293,210)	(14.13)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,356	572	1,784	311.89	4,237	1,716	2,521	146.91
15	COAL (TONS)	163,849	152,128	11,721	7.70	404,542	493,541	(88,999)	(18.03)
16	GAS (MCF) (1)	1,616,202	1,844,101	(227,899)	(12.36)	6,605,639	7,134,178	(528,539)	(7.41)
17	OIL - C.T. (BBL)	157	0	157	100.00	545	0	545	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,818,324	3,594,619	223,705	6.22	9,407,196	11,639,578	(2,232,382)	(19.18)
19	GAS - Generation (1)	1,637,821	1,805,338	(167,517)	(9.28)	6,702,299	6,982,428	(280,129)	(4.01)
20	OIL - C.T.	921	0	921	100.00	3,195	0	3,195	100.00
21	TOTAL (MMBTU)	5,457,066	5,399,957	57,109	1.06	16,112,690	18,622,006	(2,509,316)	(13.48)
	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	54.34	4.86	8.94	47.34	49.98	(2.64)	(5.28)
24	GAS	40.44	45.28	(4.84)	(10.69)	52.30	49.71	2.59	5.21
25	LANDFILL GAS	0.35	0.38	(0.03)	(7.89)	0.35	0.31	0.04	12.90
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)	134.72	117.56	17.16	14.60	134.43	117.68	16.75	14.23
29	COAL ($/TON)	102.16	108.89	(6.73)	(6.18)	103.63	109.73	(6.10)	(5.56)
30	GAS ($/MCF) (1)	4.44	4.07	0.37	9.09	4.05	3.99	0.06	1.50
31	OIL - C.T. ($/BBL)	108.12	0.00	108.12	100.00	108.06	0.00	108.06	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.47	4.63	(0.16)	(3.46)	4.52	4.67	(0.15)	(3.21)
33	GAS - Generation (1)	4.37	4.16	0.21	5.05	3.99	4.08	(0.09)	(2.21)
34	OIL - C.T.	18.43	0.00	18.43	100.00	18.43	0.00	18.43	100.00
35	TOTAL ($/MMBTU)	4.44	4.47	(0.03)	(0.67)	4.30	4.45	(0.15)	(3.37)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,049	11,213	(164)	(1.46)	11,155	11,225	(70)	(0.62)
37	GAS - Generation (1)	7,139	6,831	308	4.51	7,338	6,825	513	7.52
38	OIL - C.T.	17,056	0	17,056	100.00	16,385	0	16,385	100.00
39	TOTAL (BTU/KWH)	9,490	9,233	257	2.78	9,171	9,040	131	1.45
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.94	5.19	(0.25)	(4.82)	5.04	5.24	(0.20)	(3.82)
41	GAS	3.13	2.85	0.28	9.82	2.94	2.79	0.15	5.38
42	LANDFILL GAS	2.90	2.67	0.23	8.61	2.91	2.67	0.24	8.99
43	OIL - C.T.	31.43	0.00	31.43	100.00	30.20	0.00	30.20	100.00
44	TOTAL (¢/KWH)	4.20	4.12	0.08	1.94	3.94	4.01	(0.07)	(1.75)

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(793)	0.0	100.0	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	0	1,016	0	0		0.00
4									Oil-S	0	138,572	0	0		0.00
5	Crist 5		75	36,136	64.9	100.0	64.9	11,160	Coal	17,266	11,678	403,262	1,707,690	4.73	98.90
6				41					Gas-G	4,504	1,016	4,576	23,641	57.66	5.25
7									Gas-S	808	1,016	821	4,240		5.25
8									Oil-S	217	138,572	1,265	26,842		123.70
9	Crist 6		299	(1,579)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		475	178,314	52.2	98.6	52.9	10,689	Coal	81,010	11,764	1,905,997	8,012,298	4.49	98.91
14				5,819					Gas-G	61,302	1,016	62,283	321,737	5.53	5.25
15									Gas-S	1,842	1,016	1,871	9,665		5.25
16									Oil-S	45	138,572	260	5,526		122.80
17	Scholz 1		46	8,129	23.8	100.0	57.0	12,798	Coal	4,597	11,315	104,034	399,705	4.92	86.95
18									Oil-S	38	137,647	220	4,971		130.82
19	Scholz 2		46	(196)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	59,769	49.7	100.0	49.7	10,929	Coal	29,394	11,111	653,197	3,171,406	5.31	107.89
22									Oil-S	394	137,846	2,282	52,656		133.64
23	Smith 2		195	28,459	19.6	99.8	45.5	10,938	Coal	14,667	10,612	311,293	1,582,463	5.56	107.89
24									Oil-S	279	137,846	1,617	37,308		133.72
25	Smith 3		558	223,548	53.9	65.2	84.0	7,027	Gas-G	1,547,746	1,015	1,570,962	6,810,907	3.05	4.40
26	Smith A	(2)	36	54	0.2	100.0	72.3	17,056	Oil	157	139,688	921	16,975	31.44	108.12
27	Other Generation			6,622									221,862	3.35	0.00
28	Perdido			2,052					Landfill Gas				59,506	2.90	0.00
29	Daniel 1	(1)	255	34,304	18.1	98.4	44.1	10,985	Coal	16,867	11,171	376,843	1,832,510	5.34	108.64
30									Oil-S	707	139,799	4,154	97,266		137.58
31	Daniel 2	(1)	255	3,046	1.6	43.2	33.2	15,510	Coal	2,093	11,286	47,243	227,393	7.47	108.64
32									Oil-S	675	139,799	3,965	92,832		137.53
33	Total		2,477	583,725	31.7	85.9	47.9	9,490				5,457,066	24,719,400	4.23	

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.	(4,059)	
-	Coal Additive - Crist	47,726	
709	Inventory Adj - Coal, Scholz	61,625	
(2,754)	Inventory Adj - Coal, Smith	(300,263)	
	Recoverable Fuel	24,524,429	4.20

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	1,964	572	1,392	243.36	2,856	1,716	1,140	66.43
3	UNIT COST ($/BBL)	132.64	117.50	15.14	12.89	134.76	117.50	17.26	14.69
4	AMOUNT ($)	260,500	67,208	193,292	287.60	384,875	201,624	183,251	90.89
5	*BURNED:*								
6	UNITS (BBL)	2,435	572	1,863	325.70	4,403	1,716	2,687	156.59
7	UNIT COST ($/BBL)	134.65	117.56	17.09	14.54	134.40	117.68	16.72	14.21
8	AMOUNT ($)	327,866	67,247	260,619	387.55	591,763	201,939	389,824	193.04
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,421	7,523	(3,102)	(41.23)	4,421	7,523	(3,102)	(41.23)
11	UNIT COST ($/BBL)	127.60	117.29	10.31	8.79	127.60	117.29	10.31	8.79
12	AMOUNT ($)	564,131	882,349	(318,218)	(36.06)	564,131	882,349	(318,218)	(36.06)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	161,628	153,027	8,601	5.62	438,260	424,185	14,075	3.32
16	UNIT COST ($/TON)	98.47	106.08	(7.61)	(7.17)	101.53	105.88	(4.35)	(4.11)
17	AMOUNT ($)	15,914,867	16,232,732	(317,865)	(1.96)	44,495,417	44,910,888	(415,471)	(0.93)
18	*BURNED:*								
19	UNITS (TONS)	163,849	152,128	11,721	7.70	404,542	493,541	(88,999)	(18.03)
20	UNIT COST ($/TON)	101.89	108.89	(7.00)	(6.43)	102.34	109.73	(7.39)	(6.73)
21	AMOUNT ($)	16,694,827	16,565,746	129,081	0.78	41,399,436	54,155,044	(12,755,608)	(23.55)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	971,926	936,554	35,372	3.78	971,926	936,554	35,372	3.78
24	UNIT COST ($/TON)	104.92	109.18	(4.26)	(3.90)	104.92	109.18	(4.26)	(3.90)
25	AMOUNT ($)	101,974,596	102,249,435	(274,839)	(0.27)	101,974,596	102,249,435	(274,839)	(0.27)
26	DAYS SUPPLY	46	44	2	4.55				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	1,640,513	1,805,338	(164,825)	(9.13)	6,697,836	6,982,428	(284,592)	(4.08)
29	UNIT COST ($/MMBTU)	4.60	4.16	0.44	10.58	4.03	4.08	(0.05)	(1.23)
30	AMOUNT ($)	7,542,083	7,502,136	39,947	0.53	27,008,639	28,465,372	(1,456,733)	(5.12)
31	*BURNED:*								
32	UNITS (MMBTU)	1,640,513	1,805,338	(164,825)	(9.13)	6,707,489	6,982,428	(274,939)	(3.94)
33	UNIT COST ($/MMBTU)	4.37	4.16	0.21	5.05	3.99	4.08	(0.09)	(2.21)
34	AMOUNT ($)	7,170,190	7,502,136	(331,946)	(4.42)	26,782,639	28,465,372	(1,682,733)	(5.91)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	771,653	0	771,653	100.00	771,653	0	771,653	100.00
37	UNIT COST ($/MMBTU)	4.34	0.00	4.34	100.00	4.34	0.00	4.34	100.00
38	AMOUNT ($)	3,345,502	0	3,345,502	100.00	3,345,502	0	3,345,502	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	356	0	356	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	133.13	0.00	133.00	100.00
42	AMOUNT ($)	0	0	0	0.00	47,394	0	47,394	100.00
43	*BURNED:*								
44	UNITS (BBL)	157	0	157	100.00	544	0	544	100.00
45	UNIT COST ($/BBL)	108.11	0.00	108.11	100.00	108.25	0.00	108.25	100.00
46	AMOUNT ($)	16,974	0	16,974	100.00	58,890	0	58,890	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	5,766	7,143	(1,377)	(19.28)	5,766	7,143	(1,377)	(19.28)
49	UNIT COST ($/BBL)	108.19	105.39	2.80	2.66	108.19	105.39	2.80	2.66
50	AMOUNT ($)	623,818	752,796	(128,978)	(17.13)	623,818	752,796	(128,978)	(17.13)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6) ¢ / KWH		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) FUEL COST	(b) TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		312,714,000	0	312,714,000	2.58	2.99	8,075,000	9,336,000
2	Various	Economy Sales	6,158,000	0	6,158,000	2.74	3.09	169,000	190,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	54,000	54,000
4	TOTAL ESTIMATED SALES		318,872,000	0	318,872,000	2.60	3.00	8,298,000	9,580,000
	ACTUAL								
5	Southern Company Interchange		297,417,913	0	297,417,913	2.97	3.21	8,842,075	9,532,442
6	A.E.C.	External	292,232	0	292,232	3.02	3.95	8,833.22	11,548
7	AECI	External	0	0	0	0.00	0.00	0.00	0
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	AMERENEM	External	0	0	0	0.00	0.00	0.00	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0.00	0
11	BPENERGY	External	0	0	0	0.00	0.00	0.00	0
12	CALPINE	External	0	0	0	0.00	0.00	0.00	0
13	CARGILE	External	12,834	0	12,834	4.03	4.43	517.23	568
14	CITIG	External	0	0	0	0.00	0.00	0.00	0
15	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
16	CPL	External	0	0	0	0.00	0.00	0.00	0
17	DTE	External	0	0	0	0.00	0.00	0.00	0
18	DUKE PWR	External	14,470	0	14,470	3.34	2.59	482.98	375
19	EAGLE EN	External	243,653	0	243,653	2.68	3.38	6,517.79	8,247
20	EASTKY	External	0	0	0	0.00	0.00	0.00	0
21	ENDURE	External	3,146	0	3,146	3.14	4.70	98.87	148
22	ENTERGY	External	0	0	0	0.00	0.00	0.00	0
23	EXELON	External	12,143	0	12,143	2.34	4.39	284.40	534
24	FPC	External	31,455	0	31,455	2.43	4.00	763.46	1,258
25	FPL	External	56,623	0	56,623	2.80	4.18	1,587.92	2,368
26	JARON	External	0	0	0	0.00	0.00	0.00	0
27	JEA	External	0	0	0	0.00	0.00	0.00	0
28	JPMVEC	External	10,192	0	10,192	3.38	4.17	344.59	425
29	KEMG	External	0	0	0	0.00	0.00	0.00	0
30	MERRILL	External	0	0	0	0.00	0.00	0.00	0
31	MISO	External	0	0	0	0.00	0.00	0.00	0
32	MORGAN	External	600,718	0	600,718	2.85	3.51	17,117.42	21,104
33	NCEMC	External	23,595	0	23,595	2.54	4.05	600.08	956
34	NCMPA1	External	0	0	0	0.00	0.00	0.00	0
35	NRG	External	0	0	0	0.00	0.00	0.00	0
36	OPC	External	221,767	0	221,767	3.38	4.20	7,486.23	9,303
37	ORLANDO	External	0	0	0	0.00	0.00	0.00	0
38	PJM	External	1,822,917	0	1,822,917	2.86	3.33	52,144.25	60,739
39	REMC	External	0	0	0	0.00	0.00	0.00	0
40	SCE&G	External	1,357,714	0	1,357,714	3.56	5.42	48,374.13	73,593
41	SEC	External	113,688	0	113,688	2.98	4.20	3,382.49	4,771
42	SEPA	External	117,961	0	117,961	3.84	4.84	4,526.21	5,704
43	SHELL	External	0	0	0	0.00	0.00	0.00	0
44	SPP	External	0	0	0	0.00	0.00	0.00	0
45	TAL	External	248,226	0	248,226	2.88	3.50	7,153.09	8,699
46	TEA	External	343,446	0	343,446	2.79	3.67	9,578.47	12,598
47	TECO	External	0	0	0	0.00	0.00	0.00	0
48	TENASKA	External	0	0	0	0.00	0.00	0.00	0
49	TRANSALT	External	0	0	0	0.00	0.00	0.00	0
50	TVA	External	31,708	0	31,708	3.10	4.49	982.22	1,422
51	UPP	External	0	0	0	0.00	0.00	0.00	0
52	WRI	External	0	0	0	0.00	0.00	0.00	0
53	Less: Flow-Thru Energy		(5,471,603)	0	(5,471,603)	3.02	3.02	(165,055)	(165,055)
54	SEPA		1,594,296	1,594,296	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(384)	(384)
56	Other transactions including adj.		184,162,250	137,020,904	47,141,346	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		483,261,344	138,615,200	344,646,144	1.83	1.98	8,847,411	9,591,745
58	Difference in Amount		164,389,344	138,615,200	25,774,144	(0.77)	(1.02)	549,411	11,745
59	Difference in Percent		51.55	0.00	8.08	(29.62)	(34.00)	6.62	0.12

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 55

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

			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		928,371,000	0	928,371,000	2.55	2.92	23,643,000	27,089,000
2	Various	Economy Sales	21,185,000	0	21,185,000	2.62	2.97	555,000	629,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	181,000	181,000
4	TOTAL ESTIMATED SALES		949,556,000	0	949,556,000	2.57	2.94	24,379,000	27,899,000
	ACTUAL								
5	Southern Company Interchange		1,011,166,914	0	1,011,166,914	2.70	2.91	27,331,747	29,458,265
6	A.E.C.	External	619,257	0	619,257	2.93	3.84	18,157	23,791
7	AECI	External	216,922	0	216,922	2.52	3.88	5,472	8,421
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	2,114	0
13	CARGILE	External	1,240,134	0	1,240,134	2.38	3.08	29,560	38,002
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,898
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	37,748	0	37,748	2.95	2.51	1,115	948
19	EAGLE EN	External	383,951	0	383,951	2.75	3.62	10,562	13,889
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	28,122	0	28,122	2.67	3.87	750	1,089
22	ENTERGY	External	56,623	0	56,623	2.64	3.90	1,493	2,208
23	EXELON	External	647,332	0	647,332	2.45	3.10	15,830	20,079
24	FPC	External	31,455	0	31,455	2.43	4.00	763	1,258
25	FPL	External	177,731	0	177,731	2.62	3.81	4,655	6,768
26	JARON	External	0	0	0	0.00	0.00	0	0
27	JEA	External	0	0	0	0.00	0.00	0	0
28	JPMVEC	External	57,756	0	57,756	3.00	4.05	1,730	2,339
29	KEMG	External	0	0	0	0.00	0.00	0	0
30	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
31	MISO	External	0	0	0	0.00	0.00	0	0
32	MORGAN	External	748,440	0	748,440	2.84	3.54	21,259	26,496
33	NCEMC	External	255,756	0	255,756	2.53	3.35	6,481	8,574
34	NCMPA1	External	0	0	0	0.00	0.00	0	0
35	NRG	External	0	0	0	0.00	0.00	2,819	0
36	OPC	External	423,406	0	423,406	3.04	4.04	12,885	17,121
37	ORLANDO	External	0	0	0	0.00	0.00	0	0
38	PJM	External	5,160,362	0	5,160,362	2.70	3.30	139,283	170,387
39	REMC	External	0	0	0	0.00	0.00	0	0
40	SCE&G	External	1,997,361	0	1,997,361	3.42	5.09	68,301	101,628
41	SEC	External	318,157	0	318,157	2.80	3.58	8,898	11,375
42	SEPA	External	1,341,009	0	1,341,009	2.73	3.64	36,609	48,763
43	SHELL	External	0	0	0	0.00	0.00	0	0
44	SPP	External	6,174	0	6,174	2.17	1.63	134	101
45	TAL	External	248,226	0	248,226	2.88	3.50	7,153	8,699
46	TEA	External	1,517,851	0	1,517,851	2.61	3.39	39,588	51,396
47	TECO	External	142,687	0	142,687	2.58	3.64	3,651	5,197
48	TENASKA	External	0	0	0	0.00	0.00	0	0
49	TRANSALT	External	0	0	0	0.00	0.00	0	0
50	TVA	External	1,139,487	0	1,139,487	2.75	3.92	31,368	44,719
51	UPP	External	0	0	0	0.00	0.00	0	0
52	WRI	External	151,008	0	151,008	2.36	2.84	3,558	4,296
53	Less: Flow-Thru Energy		(17,545,451)	0	(17,545,451)	2.70	2.70	(473,334)	(473,334)
54	SEPA		4,743,200	4,743,200	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	35,306	35,306
56	Other transactions including adj.		424,649,775	266,550,914	158,098,861	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		1,440,948,948	271,294,114	1,169,654,834	1.90	2.08	27,390,960	29,631,454
58	Difference in Amount		491,392,948	271,294,114	220,098,834	(0.67)	(0.88)	3,011,960	1,732,454
59	Difference in Percent		51.75	0.00	23.18	(26.07)	(29.93)	12.35	6.21

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 55

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MARCH 2013

(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								

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SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

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	2,658,000	0	0	0	7.63	7.63	202,715
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	13
5 Ascend Performance Materials	COG 1	23,094,000	0	0	0	3.18	3.18	733,775
6 International Paper	COG 1	0	0	0	0	0.00	0.00	4,072
7 TOTAL		25,752,000	0	0	0	3.65	3.65	940,576

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	4,311,000	0	0	0	7.63	7.63	328,958
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	13
5 Ascend Performance Materials	COG 1	68,182,000	0	0	0	2.90	2.90	1,977,128
6 International Paper	COG 1	0	0	0	0	0.00	0.00	7,331
7 TOTAL		72,493,000	0	0	0	3.19	3.19	2,313,431

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

	(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	49,179,000	3.27	1,608,000	79,215,000	3.16	2,500,000
2	Economy Energy	4,913,000	3.11	153,000	14,522,000	2.96	430,000
3	Other Purchases	500,860,000	2.95	14,760,000	1,457,570,000	3.02	43,978,000
4	TOTAL ESTIMATED PURCHASES	554,952,000	2.98	16,521,000	1,551,307,000	3.02	46,908,000
	ACTUAL						
5	Southern Company Interchange	39,763,176	3.31	1,316,085	115,756,411	2.93	3,392,962
6	Non-Associated Companies	58,815,101	1.23	721,178	142,555,908	0.94	1,346,464
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	487,131,000	3.34	16,276,750	1,487,943,000	3.13	46,589,553
9	Other Wheeled Energy	48,777,000	0.00	N/A	65,248,000	0.00	N/A
10	Other Transactions	102,472,817	0.03	27,430	269,209,728	0.02	66,885
11	Less: Flow-Thru Energy	(5,471,603)	3.19	(174,577)	(17,545,451)	2.90	(508,552)
12	TOTAL ACTUAL PURCHASES	731,487,491	2.48	18,166,866	2,063,167,596	2.47	50,887,312
13	Difference in Amount	176,535,491	(0.50)	1,645,866	511,860,596	(0.55)	3,979,312
14	Difference in Percent	31.81	(16.78)	9.96	33.00	(18.21)	8.48

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2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833							665,046
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ -		$ -		$ -	$ 665,046
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096							6,013,007
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)							(9,563)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ -		$ -		$ -	$ 6,003,444
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		$ -		$ -		$ -	**$ 6,668,490**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

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2013 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	2/18/2000	5 Yr Notice													665,046
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 665,046
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													6,013,007
2 Other Confidential Agreements	Other	Varies	Varies													(9,563)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 6,003,444
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 6,668,490

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

APRIL 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2013
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	28,070,017	26,293,962	1,776,055	6.75	591,429,000	621,233,000	(29,804,000)	(4.80)	4.7481	4.2325	0.51	12.13
2	Hedging Settlement Costs (A2)	403,524	0	403,524	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) **	16,270	0	16,270	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,489,811	26,293,962	2,195,849	8.35	591,429,000	621,233,000	(29,804,000)	(4.80)	4.8171	4.2325	0.58	13.81
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)	11,459,751	9,344,000	2,115,751	22.64	438,880,483	295,718,000	143,142,483	48.41	2.6113	3.1598	(0.55)	(17.36)
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)	996,576	0	996,576	100.00	21,903,000	0	21,903,000	100.00	4.5500	0.0000	4.55	0.00
12	TOTAL COST OF PURCHASED POWER	12,456,327	9,344,000	3,112,327	33.31	460,783,483	295,718,000	165,065,483	55.81	2.7034	3.1598	(0.46)	(14.44)
13	Total Available MWH (Line 5 + Line 12)	40,946,138	35,637,962	5,308,176	14.89	1,052,192,483	916,951,000	135,241,483	14.75				
14	Fuel Cost of Economy Sales (A6)	(130,573)	(178,000)	47,427	(26.64)	(3,655,509)	(6,045,000)	2,389,491	(39.53)	(3.5720)	(2.9446)	(0.63)	(21.31)
15	Gain on Economy Sales (A6)	(8,782)	(35,000)	26,218	(74.91)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(4,439,680)	(1,700,000)	(2,739,680)	161.16	(246,709,456)	(56,349,000)	(190,360,456)	337.82	(1.7996)	(3.0169)	1.22	40.35
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(4,579,035)	(1,913,000)	(2,666,035)	139.36	(250,364,965)	(62,394,000)	(187,970,965)	301.26	(1.8289)	(3.0660)	1.24	40.35
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)	36,367,103	33,724,962	2,642,141	7.83	801,827,518	854,557,000	(52,729,482)	(6.17)	4.5355	3.9465	0.59	14.92
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 *	76,012	66,183	9,829	14.85	1,675,934	1,677,000	(1,066)	(0.06)	4.5355	3.9465	0.59	14.92
22	T & D Losses *	2,175,078	1,524,099	650,977	42.71	47,956,707	38,619,000	9,337,707	24.18	4.5355	3.9465	0.59	14.92
23	TERRITORIAL KWH SALES	36,367,103	33,724,962	2,642,141	7.83	752,194,877	814,261,000	(62,066,123)	(7.62)	4.8348	4.1418	0.69	16.73
24	Wholesale KWH Sales	1,061,265	1,075,388	(14,123)	(1.31)	21,950,706	25,964,000	(4,013,294)	(15.46)	4.8348	4.1418	0.69	16.73
25	Jurisdictional KWH Sales	35,305,838	32,649,574	2,656,264	8.14	730,244,171	788,297,000	(58,052,829)	(7.36)	4.8348	4.1418	0.69	16.73
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	35,358,797	32,698,548	2,660,249	8.14	730,244,171	788,297,000	(58,052,829)	(7.36)	4.8421	4.1480	0.69	16.73
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	730,244,171	788,297,000	(58,052,829)	(7.36)	(0.3016)	(0.2794)	(0.02)	7.95
29	TOTAL JURISDICTIONAL FUEL COST	33,156,679	30,496,430	2,660,249	8.72	730,244,171	788,297,000	(58,052,829)	(7.36)	4.5405	3.8686	0.67	17.37
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5438	3.8714	0.67	17.37
32	GPIF Reward / (Penalty)	66,722	66,722	0	0.00	730,244,171	788,297,000	(58,052,829)	(7.36)	0.0119	0.0110	0.00	8.18
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5557	3.8824	0.67	17.34
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.556	3.882		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 28,070,017
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	16,270
4	Hedging Settlement Costs	Schedule A-2, Line A-5	403,524
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	11,459,751
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	996,576
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(4,579,035)
10	Total Fuel and Net Power Transactions		$ 36,367,103

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2013
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)	98,190,979	109,588,248	(11,397,269)	(10.40)	2,372,991,000	2,696,005,000	(323,014,000)	(11.98)	4.1379	4.0648	0.07	1.80
2	Hedging Settlement Costs (A2)	5,376,810	0	5,376,810	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) **	116,125	0	116,125	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	103,683,914	109,588,248	(5,904,334)	(5.39)	2,372,991,000	2,696,005,000	(323,014,000)	(11.98)	4.3693	4.0648	0.30	7.49
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)	62,347,063	56,252,000	6,095,063	10.84	2,502,028,079	1,847,025,000	655,003,079	35.46	2.4919	3.0455	(0.55)	(18.18)
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)	3,310,007	0	3,310,007	100.00	94,396,000	0	94,396,000	100.00	3.5065	0.0000	3.51	0.00
12	TOTAL COST OF PURCHASED POWER	65,657,070	56,252,000	9,405,070	16.72	2,596,424,079	1,847,025,000	749,399,079	40.57	2.5287	3.0455	(0.52)	(16.97)
13	Total Available MWH (Line 5 + Line 12)	169,340,984	165,840,248	3,500,736	2.11	4,969,415,079	4,543,030,000	426,385,079	9.39				
14	Fuel Cost of Economy Sales (A6)	(627,814)	(733,000)	105,186	(14.35)	(21,590,019)	(27,230,000)	5,639,981	(20.71)	(2.9079)	(2.6919)	(0.22)	(8.02)
15	Gain on Economy Sales (A6)	(44,088)	(216,000)	171,912	(79.59)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(31,298,093)	(25,343,000)	(5,955,093)	23.50	(1,869,723,894)	(984,720,000)	(885,003,894)	89.86	(1.8744)	(2.5736)	0.70	27.17
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(31,969,995)	(26,292,000)	(5,677,995)	21.60	(1,891,313,913)	(1,011,950,000)	(879,363,913)	87.13	(1.8902)	(2.5982)	0.71	27.25
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)	137,370,989	139,548,248	(2,177,259)	(1.56)	3,276,101,166	3,531,080,000	(252,978,834)	(7.16)	4.1906	3.9520	0.24	6.04
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 *	286,861	290,867	(4,006)	(1.38)	6,845,341	7,360,000	(514,659)	(6.99)	4.1906	3.9520	0.24	6.04
22	T & D Losses *	7,107,273	6,547,160	560,113	8.56	169,600,361	165,667,000	3,933,361	2.37	4.1906	3.9520	0.24	6.04
23	TERRITORIAL KWH SALES	137,370,989	139,548,248	(2,177,259)	(1.56)	3,101,655,464	3,358,053,000	(256,397,536)	(7.64)	4.4290	4.1556	0.27	6.58
24	Wholesale KWH Sales	4,147,181	4,645,052	(497,871)	(10.72)	93,744,610	111,772,000	(18,027,390)	(16.13)	4.4239	4.1558	0.27	6.45
25	Jurisdictional KWH Sales	133,223,808	134,903,196	(1,679,388)	(1.24)	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)	4.4291	4.1556	0.27	6.59
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	133,423,644	135,105,550	(1,681,906)	(1.24)	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)	4.4358	4.1619	0.27	6.58
28	TRUE-UP	(8,808,472)	(8,808,472)	0	0.00	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)	(0.2928)	(0.2713)	(0.02)	7.92
29	TOTAL JURISDICTIONAL FUEL COST	124,615,172	126,297,078	(1,681,906)	(1.33)	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)	4.1430	3.8906	0.25	6.49
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1460	3.8934	0.25	6.49
32	GPIF Reward / (Penalty)	346,888	346,888	0	0.00	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)	0.0115	0.0107	0.00	7.48
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1575	3.9041	0.25	6.49
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.158	3.904		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

	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	27,852,455.30	26,194,563	1,657,892.30	6.33	97,368,595.97	109,190,652	(11,822,056.03)	(10.83)
1a Other Generation	217,561.76	99,399	118,162.76	118.88	822,382.72	397,596	424,786.72	106.84
2 Fuel Cost of Power Sold	(4,579,035.77)	(1,913,000)	(2,666,035.77)	(139.36)	(31,969,996.68)	(26,292,000)	(5,677,996.68)	(21.60)
3 Fuel Cost - Purchased Power	11,459,751.39	9,344,000	2,115,751.39	22.64	62,347,063.42	56,252,000	6,095,063.42	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	996,575.97	0	996,575.97	100.00	3,310,007.33	0	3,310,007.33	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	403,524.00	0	403,524.00	100.00	5,376,810.00	0	5,376,810.00	100.00
6 Total Fuel & Net Power Transactions	36,350,832.65	33,724,962	2,625,870.65	7.79	137,254,862.76	139,548,248	(2,293,385.24)	(1.64)
7 AdjustmentsTo Fuel Cost*	16,269.98	0	16,269.98	100.00	116,125.25	0	116,125.25	100.00
8 Adj. Total Fuel & Net Power Transactions	36,367,102.63	33,724,962	2,642,140.63	7.83	137,370,988.01	139,548,248	(2,177,259.99)	(1.56)
B. *KWH Sales*								
1 Jurisdictional Sales	730,244,171	788,297,000	(58,052,829)	(7.36)	3,007,910,854	3,246,281,000	(238,370,146)	(7.34)
2 Non-Jurisdictional Sales	21,950,706	25,964,000	(4,013,294)	(15.46)	93,744,610	111,772,000	(18,027,390)	(16.13)
3 Total Territorial Sales	752,194,877	814,261,000	(62,066,123)	(7.62)	3,101,655,464	3,358,053,000	(256,397,536)	(7.64)
4 Juris. Sales as % of Total Terr. Sales	97.0818	96.8113	0.2705	0.28	96.9776	96.6715	0.3061	0.32

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

C. True-up Calculation	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1 Jurisdictional Fuel Revenue	27,703,808.92	29,978,935	(2,275,125.99)	(7.59)	114,083,584.60	123,456,066	(9,372,481.83)	(7.59)
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	8,808,472.00	8,808,472	0.00	0.00
2b Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(346,636.00)	(346,636)	0.00	0.00
3 Juris. Fuel Revenue Applicable to Period	29,819,267.92	32,094,394	(2,275,126.08)	(7.09)	122,545,420.60	131,917,902	(9,372,481.40)	(7.10)
4 Adjusted Total Fuel & Net Power Transactions (Line A8)	36,367,102.63	33,724,962	2,642,140.63	7.83	137,370,988.01	139,548,248	(2,177,259.99)	(1.56)
5 Juris. Sales % of Total KWH Sales (Line B4)	97.0818	96.8113	0.2705	0.28	96.9776	96.6715	0.3061	0.32
6 Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	35,358,796.60	32,698,548	2,660,248.60	8.14	133,423,644.69	135,105,550	(1,681,905.31)	(1.24)
7 True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(5,539,528.68)	(604,154)	(4,935,374.68)	(816.91)	(10,878,224.09)	(3,187,647)	(7,690,577.09)	(241.26)
8 Interest Provision for the Month	85.64	1,061	(975.36)	91.93	2,422.96	5,533	(3,110.04)	56.21
9 Beginning True-Up & Interest Provision	5,149,011.05	17,240,043	(12,091,031.95)	70.13	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10 True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(8,808,472.00)	(8,808,472)	0.00	0.00
11 End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(2,592,549.99)	14,434,832	(17,027,381.99)	117.96	(2,592,549.99)	14,434,832	(17,027,381.99)	117.96
12 Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13 End of Period - Total Net True-Up	(2,592,549.99)	14,434,832	(17,027,381.99)	117.96	(2,592,549.99)	14,434,832	(17,027,381.99)	117.96

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	5,149,011.05	17,240,043	(12,091,031.95)	(70.13)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(2,592,635.63)	14,433,771	(17,026,406.63)	(117.96)
3	Total of Beginning & Ending True-Up Amts.	2,556,375.42	31,673,814	(29,117,438.58)	(91.93)
4	Average True-Up Amount	1,278,187.71	15,836,907	(14,558,719.29)	(91.93)
5	Interest Rate 1st Day of Reporting Business Month	0.08	0.08	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.08	0.08	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)	85.64	1,061	(975.36)	(91.93)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	200,571	67,226	133,345	198.35	770,163	269,165	500,998	186.13
2	COAL	19,432,765	16,851,118	2,581,647	15.32	61,356,594	71,006,162	(9,649,568)	(13.59)
3	GAS	8,287,922	9,317,742	(1,029,820)	(11.05)	35,644,043	38,081,311	(2,437,268)	(6.40)
4	GAS (B.L.)	74,805	0	74,805	100.00	106,144	-	106,144	100.00
5	LANDFILL GAS	52,342	57,876	(5,534)	(9.56)	233,533	231,610	1,923	0.83
6	OIL - C.T.	21,611	0	21,611	100.00	80,501	0	80,501	100.00
7	TOTAL ($)	28,070,017	26,293,962	1,776,055	6.75	98,190,979	109,588,248	(11,397,269)	(10.40)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	382,401	332,906	49,495	14.87	1,225,734	1,369,797	(144,063)	(10.52)
10	GAS	207,165	286,161	(78,996)	(27.61)	1,138,963	1,317,540	(178,577)	(13.55)
11	LANDFILL GAS	1,796	2,166	(370)	(17.08)	8,032	8,668	(636)	(7.34)
12	OIL - C.T.	67	0	67	100.00	262	0	262	100.00
13	TOTAL (MWH)	591,429	621,233	(29,804)	(4.80)	2,372,991	2,696,005	(323,014)	(11.98)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,555	572	983	171.85	5,792	2,288	3,504	153.15
15	COAL (TONS)	185,277	159,767	25,510	15.97	589,819	653,308	(63,489)	(9.72)
16	GAS (MCF) (1)	1,522,511	1,979,347	(456,836)	(23.08)	8,128,150	9,113,525	(985,375)	(10.81)
17	OIL - C.T. (BBL)	197	0	197	100.00	742	0	742	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	4,267,898	3,763,951	503,947	13.39	13,675,094	15,403,529	(1,728,435)	(11.22)
19	GAS - Generation (1)	1,538,071	1,938,973	(400,902)	(20.68)	8,240,370	8,921,401	(681,031)	(7.63)
20	OIL - C.T.	1,138	0	1,138	100.00	4,333	0	4,333	100.00
21	TOTAL (MMBTU)	5,807,107	5,702,924	104,183	1.83	21,919,797	24,324,930	(2,405,133)	(9.89)
	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	64.66	53.59	11.07	20.66	51.65	50.81	0.84	1.65
24	GAS	35.03	46.06	(11.03)	(23.95)	48.00	48.87	(0.87)	(1.78)
25	LANDFILL GAS	0.30	0.35	(0.05)	(14.29)	0.34	0.32	0.02	6.25
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)	128.98	117.53	11.45	9.74	132.97	117.64	15.33	13.03
29	COAL ($/TON)	104.88	105.47	(0.59)	(0.56)	104.03	108.69	(4.66)	(4.29)
30	GAS ($/MCF) (1)	5.35	4.66	0.69	14.81	4.30	4.13	0.17	4.12
31	OIL - C.T. ($/BBL)	109.70	0.00	109.70	100.00	108.49	0.00	108.49	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.62	4.49	0.13	2.90	4.55	4.63	(0.08)	(1.73)
33	GAS - Generation (1)	5.25	4.75	0.50	10.53	4.23	4.22	0.01	0.24
34	OIL - C.T.	18.99	0.00	18.99	100.00	18.58	0.00	18.58	100.00
35	TOTAL ($/MMBTU)	4.79	4.58	0.21	4.59	4.43	4.48	(0.05)	(1.12)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,161	11,306	(145)	(1.28)	11,157	11,245	(88)	(0.78)
37	GAS - Generation (1)	7,664	6,842	822	12.01	7,397	6,829	568	8.32
38	OIL - C.T.	16,985	0	16,985	100.00	16,538	0	16,538	100.00
39	TOTAL (BTU/KWH)	9,958	9,254	704	7.61	9,367	9,089	278	3.06
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.15	5.08	0.07	1.38	5.08	5.20	(0.12)	(2.31)
41	GAS	4.00	3.26	0.74	22.70	3.13	2.89	0.24	8.30
42	LANDFILL GAS	2.91	2.67	0.24	8.99	2.91	2.67	0.24	8.99
43	OIL - C.T.	32.26	0.00	32.26	100.00	30.73	0.00	30.73	100.00
44	TOTAL (¢/KWH)	4.75	4.23	0.52	12.29	4.14	4.06	0.08	1.97

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(763)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,014	0	0	0.00	0.00
3									Gas-S	0	1,014	0	0		0.00
4									Oil-S	0	137,552	0	0		0.00
5	Crist 5		75	33,927	62.8	100.0	62.8	11,439	Coal	16,552	11,723	388,082	1,652,587	4.87	99.84
6				-					Gas-G	0	1,014	0	0	0.00	0.00
7									Gas-S	1,251	1,014	1,269	13,077		10.45
8									Oil-S	130	137,552	750	16,029		123.30
9	Crist 6		299	93,076	43.3	98.3	64.9	11,344	Coal	44,845	11,772	1,055,821	4,477,335	4.81	99.84
10				233					Gas-G	2,564	1,014	2,600	26,795	11.50	10.45
11									Gas-S	5,466	1,014	5,544	57,129		10.45
12									Oil-S	5	137,552	28	590		118.00
13	Crist 7		475	65,500	19.4	95.6	52.7	11,327	Coal	31,461	11,791	741,915	3,141,111	4.80	99.84
14				843					Gas-G	9,413	1,014	9,545	98,361	11.67	10.45
15									Gas-S	440	1,014	446	4,599		10.45
16									Oil-S	27	137,552	154	3,282		121.56
17	Scholz 1		46	(220)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(147)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	38,293	32.8	78.0	46.0	11,070	Coal	18,452	11,487	423,916	1,974,090	5.16	106.99
22									Oil-S	284	138,243	1,648	36,965		130.16
23	Smith 2		195	40,486	28.8	94.3	39.3	11,097	Coal	19,602	11,460	449,286	2,097,160	5.18	106.99
24									Oil-S	55	138,243	320	7,170		130.36
25	Smith 3		558	199,607	49.7	65.6	85.6	7,645	Gas-G	1,503,375	1,015	1,525,926	7,945,205	3.98	5.28
26	Smith A	(2)	36	67	0.3	100.0	85.5	16,985	Oil	197	137,322	1,138	21,611	32.26	109.70
27	Other Generation			6,482									217,562	3.36	0.00
28	Perdido			1,796					Landfill Gas				52,342	2.91	0.00
29	Daniel 1	(1)	255	66,200	36.1	99.0	49.6	10,407	Coal	31,428	10,961	688,947	3,435,332	5.19	109.31
30									Oil-S	506	139,381	2,962	65,486		129.42
31	Daniel 2	(1)	255	46,049	25.1	89.4	49.2	10,936	Coal	22,937	10,978	503,596	2,507,238	5.44	109.31
32									Oil-S	549	139,381	3,214	71,050		129.42
33	Total		2,477	591,429	33.2	88.1	56.6	9,958				5,807,107	27,922,106	4.72	

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)	
	Coal Additive - Crist	151,969	
	Recoverable Fuel	28,070,017	4.75

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	1,953	572	1,381	241.43	4,809	2,288	2,521	110.18
3	UNIT COST ($/BBL)	125.25	117.50	7.75	6.60	130.90	117.50	13.40	11.40
4	AMOUNT ($)	244,615	67,208	177,407	263.97	629,490	268,832	360,658	134.16
5	*BURNED:*								
6	UNITS (BBL)	1,612	572	1,040	181.82	6,015	2,288	3,727	162.89
7	UNIT COST ($/BBL)	129.05	117.53	11.52	9.80	132.97	117.64	15.33	13.03
8	AMOUNT ($)	208,032	67,226	140,806	209.45	799,795	269,165	530,630	197.14
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,762	7,523	(2,761)	(36.70)	4,762	7,523	(2,761)	(36.70)
11	UNIT COST ($/BBL)	126.15	117.28	8.87	7.56	126.15	117.28	8.87	7.56
12	AMOUNT ($)	600,713	882,331	(281,618)	(31.92)	600,713	882,331	(281,618)	(31.92)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	127,313	166,525	(39,212)	(23.55)	565,573	590,710	(25,137)	(4.26)
16	UNIT COST ($/TON)	104.30	103.32	0.98	0.95	102.15	105.15	(3.00)	(2.85)
17	AMOUNT ($)	13,278,125	17,204,852	(3,926,727)	(22.82)	57,773,542	62,115,740	(4,342,198)	(6.99)
18	*BURNED:*								
19	UNITS (TONS)	185,277	159,767	25,510	15.97	589,819	653,308	(63,489)	(9.72)
20	UNIT COST ($/TON)	104.09	105.47	(1.38)	(1.31)	102.89	108.69	(5.80)	(5.34)
21	AMOUNT ($)	19,284,854	16,851,118	2,433,736	14.44	60,684,290	71,006,162	(10,321,872)	(14.54)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	913,962	943,312	(29,350)	(3.11)	913,962	943,312	(29,350)	(3.11)
24	UNIT COST ($/TON)	105.00	108.77	(3.77)	(3.47)	105.00	108.77	(3.77)	(3.47)
25	AMOUNT ($)	95,967,867	102,603,169	(6,635,302)	(6.47)	95,967,867	102,603,169	(6,635,302)	(6.47)
26	DAYS SUPPLY	43	45	(2)	(4.44)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	1,566,280	1,938,973	(372,693)	(19.22)	8,264,116	8,921,401	(657,285)	(7.37)
29	UNIT COST ($/MMBTU)	5.70	4.75	0.95	20.00	4.35	4.22	0.13	3.08
30	AMOUNT ($)	8,926,606	9,218,343	(291,737)	(3.16)	35,935,245	37,683,715	(1,748,470)	(4.64)
31	*BURNED:*								
32	UNITS (MMBTU)	1,545,328	1,938,973	(393,645)	(20.30)	8,252,817	8,921,401	(668,584)	(7.49)
33	UNIT COST ($/MMBTU)	5.27	4.75	0.52	10.95	4.23	4.22	0.01	0.24
34	AMOUNT ($)	8,145,166	9,218,343	(1,073,177)	(11.64)	34,927,805	37,683,715	(2,755,910)	(7.31)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	792,605	0	792,605	100.00	792,605	0	792,605	100.00
37	UNIT COST ($/MMBTU)	5.21	0.00	5.21	100.00	5.21	0.00	5.21	100.00
38	AMOUNT ($)	4,126,943	0	4,126,943	100.00	4,126,943	0	4,126,943	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	715	0	715	100.00	1,071	0	1,071	100.00
41	UNIT COST ($/BBL)	120.16	0.00	120.16	100.00	124.47	0.00	124.00	100.00
42	AMOUNT ($)	85,912	0	85,912	100.00	133,306	0	133,306	100.00
43	*BURNED:*								
44	UNITS (BBL)	197	0	197	100.00	741	0	741	100.00
45	UNIT COST ($/BBL)	109.70	0.00	109.70	100.00	108.64	0.00	108.64	100.00
46	AMOUNT ($)	21,611	0	21,611	100.00	80,501	0	80,501	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,284	7,143	(859)	(12.03)	6,284	7,143	(859)	(12.03)
49	UNIT COST ($/BBL)	109.50	105.39	4.11	3.90	109.50	105.39	4.11	3.90
50	AMOUNT ($)	688,119	752,796	(64,677)	(8.59)	688,119	752,796	(64,677)	(8.59)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

			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) FUEL COST ¢ / KWH	(b) TOTAL COST ¢ / KWH	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		56,349,000	0	56,349,000	3.02	3.35	1,700,000	1,886,000
2	Various	Economy Sales	6,045,000	0	6,045,000	2.94	3.28	178,000	198,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	35,000	35,000
4	TOTAL ESTIMATED SALES		62,394,000	0	62,394,000	3.07	3.40	1,913,000	2,119,000
	ACTUAL								
5	Southern Company Interchange		130,037,894	0	130,037,894	3.51	3.64	4,558,361	4,738,712
6	A.E.C.	External	410,501	0	410,501	3.08	3.77	12,647.69	15,460
7	AECI	External	12,771	0	12,771	3.44	4.89	439.62	625
8	AEP	External	0	0	0	0.00	0.00	235.93	0
9	AMERENEM	External	0	0	0	0.00	0.00	0.00	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0.00	0
11	BPENERGY	External	0	0	0	0.00	0.00	0.00	0
12	CALPINE	External	0	0	0	0.00	0.00	0.00	0
13	CARGILE	External	65,808	0	65,808	8.67	3.63	5,708.57	2,391
14	CITIG	External	0	0	0	0.00	0.00	0.00	0
15	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
16	CPL	External	0	0	0	0.00	0.00	0.00	0
17	DTE	External	0	0	0	0.00	0.00	0.00	0
18	DUKE PWR	External	4,404	0	4,404	4.02	2.50	176.87	110
19	EAGLE EN	External	181,143	0	181,143	3.19	3.90	5,776.92	7,064
20	EASTKY	External	0	0	0	0.00	0.00	0.00	0
21	ENDURE	External	0	0	0	0.00	0.00	0.00	0
22	ENTERGY	External	75,495	0	75,495	8.08	4.50	6,100.38	3,397
23	EXELON	External	24,724	0	24,724	4.58	7.01	1,132.71	1,732
24	FPC	External	338,732	0	338,732	3.50	4.73	11,848.76	16,030
25	FPL	External	116,514	0	116,514	3.47	4.70	4,042.38	5,481
26	JARON	External	0	0	0	0.00	0.00	0.00	0
27	JEA	External	0	0	0	0.00	0.00	0.00	0
28	JPMVEC	External	28,627	0	28,627	4.15	6.20	1,186.62	1,774
29	KEMG	External	0	0	0	0.00	0.00	0.00	0
30	MERRILL	External	0	0	0	0.00	0.00	0.00	0
31	MISO	External	0	0	0	0.00	0.00	0.00	0
32	MORGAN	External	274,392	0	274,392	3.34	3.83	9,177.77	10,498
33	NCEMC	External	28,314	0	28,314	4.27	4.10	1,209.66	1,161
34	NCMPA1	External	0	0	0	0.00	0.00	0.00	0
35	NRG	External	0	0	0	0.00	0.00	0.00	0
36	OPC	External	256,064	0	256,064	2.80	3.83	7,177.43	9,794
37	ORLANDO	External	0	0	0	0.00	0.00	0.00	0
38	PJM	External	235,989	0	235,989	4.39	3.67	10,368.56	8,669
39	REMC	External	0	0	0	0.00	0.00	0.00	0
40	SCE&G	External	0	0	0	0.00	0.00	272.20	0
41	SEC	External	195,021	0	195,021	3.94	4.26	7,692.32	8,311
42	SEPA	External	97,648	0	97,648	2.98	3.31	2,907.28	3,237
43	SHELL	External	0	0	0	0.00	0.00	0.00	0
44	SPP	External	0	0	0	0.00	0.00	0.00	0
45	TAL	External	0	0	0	0.00	0.00	2.40	0
46	TEA	External	395,848	0	395,848	2.83	3.87	11,186.86	15,314
47	TECO	External	54,235	0	54,235	3.35	4.39	1,816.54	2,381
48	TENASKA	External	0	0	0	0.00	0.00	0.00	0
49	TRANSALT	External	0	0	0	0.00	0.00	0.00	0
50	TVA	External	859,279	0	859,279	3.43	4.80	29,468.03	41,242
51	UPP	External	0	0	0	0.00	0.00	0.00	0
52	WRI	External	0	0	0	0.00	0.00	0.00	0
53	Less: Flow-Thru Energy		(3,651,105)	0	(3,651,105)	3.25	3.25	(118,681)	(118,681)
54	SEPA		1,725,944	1,725,944	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	8,782	8,782
56	Other transactions including adj		118,596,723	239,276,974	(120,680,251)	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		250,364,965	241,002,918	9,362,047	1.83	1.91	4,579,035	4,774,701
58	Difference in Amount		187,970,965	241,002,918	(53,031,953)	(1.24)	(1.49)	2,666,035	2,655,701
59	Difference in Percent		301.26	0.00	(85.00)	(40.39)	(43.82)	139.36	125.33

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 55

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

			PERIOD TO DATE						
	(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	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		984,720,000	0	984,720,000	2.57	2.94	25,343,000	28,975,000
2	Various	Economy Sales	27,230,000	0	27,230,000	2.69	3.04	733,000	827,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	216,000	216,000
4	TOTAL ESTIMATED SALES		1,011,950,000	0	1,011,950,000	2.60	2.97	26,292,000	30,018,000
	ACTUAL								
5	Southern Company Interchange		1,141,204,808	0	1,141,204,808	2.79	3.00	31,890,108	34,196,977
6	A.E.C.	External	1,029,758	0	1,029,758	2.99	3.81	30,805	39,251
7	AECI	External	229,693	0	229,693	2.57	3.94	5,912	9,046
8	AEP	External	0	0	0	0.00	0.00	236	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	2,114	0
13	CARGILE	External	1,305,942	0	1,305,942	2.70	3.09	35,268	40,393
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,055
19	EAGLE EN	External	565,094	0	565,094	2.89	3.71	16,339	20,953
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	28,122	0	28,122	2.67	3.87	750	1,089
22	ENTERGY	External	132,118	0	132,118	5.75	4.24	7,593	5,606
23	EXELON	External	672,056	0	672,056	2.52	3.25	16,962	21,811
24	FPC	External	370,187	0	370,187	3.41	4.67	12,612	17,288
25	FPL	External	294,245	0	294,245	2.96	4.16	8,697	12,249
26	JARON	External	0	0	0	0.00	0.00	0	0
27	JEA	External	0	0	0	0.00	0.00	0	0
28	JPMVEC	External	86,383	0	86,383	3.38	4.76	2,917	4,113
29	KEMG	External	0	0	0	0.00	0.00	0	0
30	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
31	MISO	External	0	0	0	0.00	0.00	0	0
32	MORGAN	External	1,022,832	0	1,022,832	2.98	3.62	30,437	36,994
33	NCEMC	External	284,070	0	284,070	2.71	3.43	7,691	9,735
34	NCMPA1	External	0	0	0	0.00	0.00	0	0
35	NRG	External	0	0	0	0.00	0.00	2,819	0
36	OPC	External	679,470	0	679,470	2.95	3.96	20,062	26,915
37	ORLANDO	External	0	0	0	0.00	0.00	0	0
38	PJM	External	5,396,351	0	5,396,351	2.77	3.32	149,650	179,058
39	REMC	External	0	0	0	0.00	0.00	0	0
40	SCE&G	External	1,997,361	0	1,997,361	3.43	5.09	68,574	101,626
41	SEC	External	513,178	0	513,178	3.23	3.84	16,590	19,686
42	SEPA	External	1,438,657	0	1,438,657	2.75	3.61	39,517	52,000
43	SHELL	External	0	0	0	0.00	0.00	0	0
44	SPP	External	6,174	0	6,174	2.17	1.63	134	101
45	TAL	External	248,226	0	248,226	2.88	3.50	7,155	8,699
46	TEA	External	1,913,699	0	1,913,699	2.65	3.49	50,754	66,710
47	TECO	External	196,922	0	196,922	2.78	3.85	5,467	7,578
48	TENASKA	External	0	0	0	0.00	0.00	0	0
49	TRANSALT	External	0	0	0	0.00	0.00	0	0
50	TVA	External	1,998,766	0	1,998,766	3.04	4.30	60,836	85,962
51	UPP	External	0	0	0	0.00	0.00	0	0
52	WRI	External	151,008	0	151,008	2.36	2.84	3,558	4,296
53	Less: Flow-Thru Energy		(21,196,556)	0	(21,196,556)	2.79	2.79	(592,015)	(592,015)
54	SEPA		6,469,144	6,469,144	0	0.00	0.00	0	0
55	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	44,088	44,088
56	Other transactions including adj.		543,246,498	505,827,888	37,418,610	0.00	0.00	0	0
57	TOTAL ACTUAL SALES		1,691,313,913	512,297,032	1,179,016,881	1.89	2.03	31,969,995	34,406,155
58	Difference in Amount		679,363,913	512,297,032	167,066,881	(0.71)	(0.94)	5,677,995	4,388,155
59	Difference in Percent		67.13	0.00	16.51	(27.31)	(31.65)	21.60	14.62

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 55

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: APRIL 2013

(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								

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SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

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	4,959,000	0	0	0	7.63	7.63	378,597
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	1
5 Ascend Performance Materials	COG 1	16,622,000	0	0	0	3.69	3.69	614,130
6 International Paper	COG 1	322,000	0	0	0	1.19	1.19	3,847
7 TOTAL		21,903,000	0	0	0	4.55	4.55	996,576

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	9,270,000	0	0	0	7.63	7.63	707,555
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	15
5 Ascend Performance Materials	COG 1	84,804,000	0	0	0	3.06	3.06	2,591,259
6 International Paper	COG 1	322,000	0	0	0	3.47	3.47	11,178
7 TOTAL		94,396,000	0	0	0	3.51	3.51	3,310,007

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

	(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	114,227,000	3.39	3,868,000	193,442,000	3.29	6,368,000
2	Economy Energy	4,891,000	3.35	164,000	19,413,000	3.06	594,000
3	Other Purchases	176,600,000	3.01	5,312,000	1,634,170,000	3.02	49,290,000
4	TOTAL ESTIMATED PURCHASES	295,718,000	3.16	9,344,000	1,847,025,000	3.05	56,252,000
	ACTUAL						
5	Southern Company Interchange	103,056,122	3.64	3,746,558	218,812,533	3.26	7,139,520
6	Non-Associated Companies	50,847,095	1.41	715,301	193,403,003	1.07	2,061,765
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	196,795,000	3.61	7,111,796	1,684,738,000	3.19	53,701,349
9	Other Wheeled Energy	14,476,000	0.00	N/A	79,724,000	0.00	N/A
10	Other Transactions	77,337,371	0.02	13,371	346,547,099	0.02	80,256
11	Less: Flow-Thru Energy	(3,651,105)	3.49	(127,275)	(21,196,556)	3.00	(635,827)
12	TOTAL ACTUAL PURCHASES	438,860,483	2.61	11,459,751	2,502,028,079	2.49	62,347,063
13	Difference in Amount	143,142,483	(0.55)	2,115,751	655,003,079	(0.56)	6,095,063
14	Difference in Percent	48.41	(17.41)	22.64	35.46	(18.36)	10.84

2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196					710,242
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ -		$ -	$ 710,242
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744					8,016,751
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)					(12,709)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ -		$ -	$ 8,004,042
TOTAL					$ 2,380,170		$ 1,898,537		$ 2,389,783		$ 2,045,794		$ -		$ -	$ 8,714,284

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

2013 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L) JUL		(M) AUG		(N) SEP		(O) OCT		(P) NOV		(O) DEC		(R) YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													710,242
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 710,242
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													6,016,751
2 Other Confidential Agreements	Other	Varies	Varies													(12,709)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 6,004,042
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 8,714,284

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

MAY 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2013
CURRENT MONTH

		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)	26,467,509	25,174,667	1,292,842	5.14	627,519,000	643,537,000	(16,018,000)	(2.49)	4.2178	3.9119	0.31	7.82
2	Hedging Settlement Costs (A2)	493,084	0	493,084	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) **	(9,789)	0	(9,789)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	26,950,804	25,174,667	1,776,137	7.06	627,519,000	643,537,000	(16,018,000)	(2.49)	4.2948	3.9119	0.38	9.79
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)	16,278,229	15,569,000	709,229	4.56	574,136,272	520,811,000	53,325,272	10.24	2.8353	2.9894	(0.15)	(5.15)
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)	895,427	0	895,427	100.00	21,895,000	0	21,895,000	100.00	4.0896	0.0000	4.09	0.00
12	TOTAL COST OF PURCHASED POWER	17,173,656	15,569,000	1,604,656	10.31	596,031,272	520,811,000	75,220,272	14.44	2.8813	2.9894	(0.11)	(3.62)
13	Total Available MWH (Line 5 + Line 12)	44,124,460	40,743,667	3,380,793	8.30	1,223,550,272	1,164,348,000	59,202,272	5.08				
14	Fuel Cost of Economy Sales (A6)	(400,097)	(260,000)	(140,097)	53.88	(13,071,538)	(6,613,000)	(6,458,538)	97.66	(3.0608)	(3.9316)	0.87	22.15
15	Gain on Economy Sales (A6)	(52,332)	(56,000)	3,668	(6.55)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(4,922,235)	(3,217,000)	(1,705,235)	53.01	(259,546,886)	(101,304,000)	(158,242,886)	156.21	(1.8965)	(3.1756)	1.28	40.28
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(5,374,664)	(3,533,000)	(1,841,664)	52.13	(272,618,424)	(107,917,000)	(164,701,424)	152.62	(1.9715)	(3.2738)	1.30	39.78
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)	38,749,786	37,210,667	1,539,129	4.14	950,931,848	1,056,431,000	(105,499,152)	(9.99)	4.0749	3.5223	0.55	15.69
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 *	62,186	58,717	3,469	5.91	1,526,068	1,667,000	(140,932)	(8.45)	4.0749	3.5223	0.55	15.69
22	T & D Losses *	1,657,653	2,060,883	(403,210)	(19.57)	40,679,611	58,509,000	(17,829,389)	(30.47)	4.0749	3.5223	0.55	15.69
23	TERRITORIAL KWH SALES	38,749,786	37,210,667	1,539,129	4.14	908,726,169	996,255,000	(87,528,831)	(8.79)	4.2642	3.7351	0.53	14.17
24	Wholesale KWH Sales	1,082,320	1,162,685	(80,365)	(6.91)	25,381,308	31,129,000	(5,747,692)	(18.46)	4.2642	3.7351	0.53	14.17
25	Jurisdictional KWH Sales	37,667,476	36,047,982	1,619,494	4.49	883,344,861	965,126,000	(81,781,139)	(8.47)	4.2642	3.7351	0.53	14.17
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	37,723,977	36,102,054	1,621,923	4.49	883,344,861	965,126,000	(81,781,139)	(8.47)	4.2706	3.7407	0.53	14.17
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	883,344,861	965,126,000	(81,781,139)	(8.47)	(0.2493)	(0.2282)	(0.02)	9.25
29	TOTAL JURISDICTIONAL FUEL COST	35,521,859	33,899,936	1,621,923	4.78	883,344,861	965,126,000	(81,781,139)	(8.47)	4.0213	3.5125	0.51	14.49
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0242	3.5150	0.51	14.49
32	GPIF Reward / (Penalty)	66,722	66,722	0	0.00	883,344,861	965,126,000	(81,781,139)	(8.47)	0.0098	0.0090	0.00	8.89
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0340	3.5240	0.51	14.47
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.034	3.524		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 26,467,509
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	(9,789)
4	Hedging Settlement Costs	Schedule A-2, Line A-5	493,084
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	16,278,229
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	895,427
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(5,374,664)
10	Total Fuel and Net Power Transactions		$ 38,749,796

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2013
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)	124,658,488	134,762,915	(10,104,427)	(7.50)	3,000,510,000	3,339,542,000	(339,032,000)	(10.15)	4.1546	4.0354	0.12	2.95
2	Hedging Settlement Costs (A2)	5,869,894	0	5,869,894	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) **	106,336	0	106,336	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	130,634,718	134,762,915	(4,128,197)	(3.08)	3,000,510,000	3,339,542,000	(339,032,000)	(10.15)	4.3538	4.0354	0.32	7.89
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)	78,825,292	71,821,000	6,804,292	9.47	3,076,164,351	2,367,836,000	708,328,351	29.91	2.5560	3.0332	(0.48)	(15.73)
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)	4,205,434	0	4,205,434	100.00	116,291,000	0	116,291,000	100.00	3.8163	0.0000	3.62	0.00
12	TOTAL COST OF PURCHASED POWER	82,830,726	71,821,000	11,009,726	15.33	3,192,455,351	2,367,836,000	824,619,351	34.83	2.5946	3.0332	(0.44)	(14.46)
13	Total Available MWH (Line 5 + Line 12)	213,465,444	206,583,915	6,881,529	3.33	6,192,965,351	5,707,378,000	485,587,351	8.51				
14	Fuel Cost of Economy Sales (A6)	(1,027,911)	(993,000)	(34,911)	3.52	(34,861,557)	(33,843,000)	(818,557)	2.42	(2.9656)	(2.9341)	(0.03)	(1.07)
15	Gain on Economy Sales (A6)	(96,420)	(272,000)	175,580	(64.55)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(36,220,328)	(28,560,000)	(7,660,328)	26.82	(1,929,270,780)	(1,086,024,000)	(843,246,780)	77.65	(1.8774)	(2.6298)	0.75	28.61
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(37,344,659)	(29,825,000)	(7,519,659)	25.21	(1,963,932,337)	(1,119,867,000)	(844,065,337)	75.37	(1.9015)	(2.6633)	0.76	28.60
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)	176,120,785	176,758,915	(638,130)	(0.36)	4,229,033,014	4,587,511,000	(358,477,986)	(7.81)	4.1646	3.8530	0.31	8.09
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 *	348,636	347,810	826	0.24	8,371,409	9,027,000	(655,591)	(7.26)	4.1646	3.8530	0.31	8.09
22	T & D Losses *	8,757,320	8,637,501	119,819	1.39	210,279,972	224,176,000	(13,896,028)	(6.20)	4.1646	3.8530	0.31	8.09
23	TERRITORIAL KWH SALES	176,120,785	176,758,915	(638,130)	(0.36)	4,010,381,633	4,354,308,000	(343,926,367)	(7.90)	4.3916	4.0594	0.33	8.18
24	Wholesale KWH Sales	5,229,501	5,807,737	(578,236)	(9.96)	119,125,918	142,901,000	(23,775,082)	(16.64)	4.3899	4.0642	0.33	8.01
25	Jurisdictional KWH Sales	170,891,284	170,951,178	(59,894)	(0.04)	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)	4.3917	4.0592	0.33	8.19
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	171,147,621	171,207,604	(59,983)	(0.04)	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)	4.3983	4.0653	0.33	8.19
28	TRUE-UP	(11,010,590)	(11,010,590)	0	0.00	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)	(0.2830)	(0.2614)	(0.02)	8.28
29	TOTAL JURISDICTIONAL FUEL COST	160,137,031	160,197,014	(59,983)	(0.04)	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)	4.1153	3.8039	0.31	8.19
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1183	3.8066	0.31	8.19
32	GPIF Reward / (Penalty)	433,610	433,610	0	0.00	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)	0.0111	0.0103	0.00	7.77
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1294	3.8169	0.31	8.19
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.129	3.817		

* 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 2013

		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	26,252,165.97	24,969,477	1,282,688.97	5.14	123,620,761.94	134,160,129	(10,539,367.06)	(7.86)
1a	Other Generation	215,342.86	205,190	10,152.86	4.95	1,037,725.58	602,786	434,939.58	72.15
2	Fuel Cost of Power Sold	(5,374,663.85)	(3,533,000)	(1,841,663.85)	(52.13)	(37,344,660.53)	(29,825,000)	(7,519,660.53)	(25.21)
3	Fuel Cost - Purchased Power	16,278,229.43	15,569,000	709,229.43	4.56	78,625,292.85	71,821,000	6,804,292.85	9.47
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	895,426.55	0	895,426.55	100.00	4,205,433.88	0	4,205,433.88	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	493,084.00	0	493,084.00	100.00	5,869,894.00	0	5,869,894.00	100.00
6	Total Fuel & Net Power Transactions	38,759,584.96	37,210,667	1,548,917.96	4.16	176,014,447.72	176,758,915	(744,467.28)	(0.42)
7	AdjustmentsTo Fuel Cost*	(9,788.63)	0	(9,788.63)	100.00	106,336.62	0	106,336.62	100.00
8	Adj. Total Fuel & Net Power Transactions	38,749,796.33	37,210,667	1,539,129.33	4.14	176,120,784.34	176,758,915	(638,130.66)	(0.36)
B.	*KWH Sales*								
1	Jurisdictional Sales	883,344,861	965,126,000	(81,781,139)	(8.47)	3,891,255,715	4,211,407,000	(320,151,285)	(7.60)
2	Non-Jurisdictional Sales	25,381,308	31,129,000	(5,747,692)	(18.46)	119,125,918	142,901,000	(23,775,082)	(16.64)
3	Total Territorial Sales	908,726,169	996,255,000	(87,528,831)	(8.79)	4,010,381,633	4,354,308,000	(343,926,367)	(7.90)
4	Juris. Sales as % of Total Terr. Sales	97.2069	96.8754	0.3315	0.34	97.0296	96.7182	0.3114	0.32

**(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 2013

C.	True-up Calculation	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	33,545,795.79	36,703,742	(3,157,945.99)	(8.60)	147,629,380.39	160,159,808	(12,530,427.82)	(7.82)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	11,010,590.00	11,010,590	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(433,295.00)	(433,295)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	35,681,254.79	38,819,201	(3,157,946.21)	(8.14)	158,206,675.39	170,737,103	(12,530,427.61)	(7.34)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	38,749,796.33	37,210,667	1,539,129.33	4.14	176,120,784.34	176,758,915	(638,130.66)	(0.36)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2069	96.8754	0.3315	0.34	97.0296	96.7182	0.3114	0.32
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	37,723,976.98	36,102,054	1,621,922.98	4.49	171,147,621.67	171,207,604	(59,982.33)	(0.04)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(2,062,722.19)	2,717,147	(4,779,869.19)	175.92	(12,940,946.28)	(470,500)	(12,470,446.28)	(2,650.47)
8	Interest Provision for the Month	(297.67)	926	(1,223.67)	132.15	2,125.29	6,459	(4,333.71)	67.10
9	Beginning True-Up & Interest Provision	(2,592,549.99)	14,434,832	(17,027,381.99)	117.96	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(11,010,590.00)	(11,010,590)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(6,857,687.85)	14,950,787	(21,808,474.85)	145.87	(6,857,687.85)	14,950,787	(21,808,474.85)	145.87
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	(6,857,687.85)	14,950,787	(21,808,474.85)	145.87	(6,857,687.85)	14,950,787	(21,808,474.85)	145.87

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

		CURRENT MONTH			
		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(2,592,549.99)	14,434,832	(17,027,381.99)	(117.96)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(6,857,390.18)	14,949,861	(21,807,251.18)	(145.87)
3	Total of Beginning & Ending True-Up Amts.	(9,449,940.17)	29,384,693	(38,834,633.17)	(132.16)
4	Average True-Up Amount	(4,724,970.09)	14,692,347	(19,417,317.09)	(132.16)
	Interest Rate				
5	1st Day of Reporting Business Month	0.08	0.08	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.07	0.07	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)	(297.67)	926	(1,223.67)	(132.15)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	109,031	67,216	41,815	62.21	879,194	336,381	542,813	161.37
2	COAL	15,021,429	13,110,913	1,910,516	14.57	76,378,023	84,117,075	(7,739,052)	(9.20)
3	GAS	11,221,480	11,927,687	(706,207)	(5.92)	46,865,523	50,008,998	(3,143,475)	(6.29)
4	GAS (B.L.)	31,203	0	31,203	100.00	137,347	-	137,347	100.00
5	LANDFILL GAS	63,553	59,853	3,700	6.18	297,087	291,463	5,624	1.93
6	OIL - C.T.	20,813	8,998	11,815	131.31	101,314	8,998	92,316	1,025.96
7	TOTAL ($)	26,467,509	25,174,667	1,292,842	5.14	124,658,488	134,782,915	(10,104,427)	(7.50)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	335,012	259,692	75,320	29.00	1,560,746	1,629,489	(68,743)	(4.22)
10	GAS	290,294	381,605	(91,311)	(23.93)	1,429,257	1,699,145	(269,888)	(15.88)
11	LANDFILL GAS	2,152	2,240	(88)	(3.93)	10,184	10,908	(724)	(6.64)
12	OIL - C.T.	81	0	81	100.00	323	0	323	100.00
13	TOTAL (MWH)	627,519	643,537	(16,018)	(2.49)	3,000,510	3,339,542	(339,032)	(10.15)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	845	572	273	47.73	6,637	2,860	3,777	132.08
15	COAL (TONS)	145,535	124,207	21,328	17.17	735,354	777,515	(42,161)	(5.42)
16	GAS (MCF) (1)	2,035,339	2,627,224	(591,885)	(22.53)	10,163,489	11,740,749	(1,577,260)	(13.43)
17	OIL - C.T. (BBL)	188	85	103	121.18	930	85	845	994.12
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,694,825	2,915,450	779,375	26.73	17,369,919	18,318,979	(949,060)	(5.18)
19	GAS - Generation (1)	2,007,507	2,574,480	(566,973)	(22.02)	10,247,877	11,495,881	(1,248,004)	(10.86)
20	OIL - C.T.	1,086	499	587	117.64	5,419	499	4,920	985.97
21	TOTAL (MMBTU)	5,703,418	5,490,429	212,989	3.88	27,623,215	29,815,359	(2,192,144)	(7.35)
	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	53.39	40.35	13.04	32.32	52.02	48.79	3.23	6.62
24	GAS	46.26	59.30	(13.04)	(21.99)	47.63	50.88	(3.25)	(6.39)
25	LANDFILL GAS	0.34	0.35	(0.01)	(2.86)	0.34	0.33	0.01	3.03
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)	129.03	117.51	11.52	9.80	132.47	117.62	14.85	12.63
29	COAL ($/TON)	103.22	105.56	(2.34)	(2.22)	103.87	108.19	(4.32)	(3.99)
30	GAS ($/MCF) (1)	5.42	4.46	0.96	21.52	4.52	4.21	0.31	7.36
31	OIL - C.T. ($/BBL)	110.71	105.86	4.85	4.58	108.94	105.86	3.08	2.91
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.10	4.52	(0.42)	(9.29)	4.46	4.61	(0.15)	(3.25)
33	GAS - Generation (1)	5.46	4.55	0.93	20.44	4.47	4.30	0.17	3.95
34	OIL - C.T.	19.16	18.03	1.13	6.27	18.70	18.03	0.67	3.72
35	TOTAL ($/MMBTU)	4.59	4.54	0.05	1.10	4.46	4.49	(0.03)	(0.67)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,029	11,227	(198)	(1.76)	11,129	11,242	(113)	(1.01)
37	GAS - Generation (1)	7,074	6,849	225	3.29	7,331	8,833	498	7.29
38	OIL - C.T.	17,803	0	17,803	100.00	16,777	0	16,777	100.00
39	TOTAL (BTU/KWH)	9,216	8,638	578	6.69	9,335	9,003	332	3.69
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.53	5.07	(0.54)	(10.65)	4.98	5.18	(0.22)	(4.25)
41	GAS	3.87	3.13	0.74	23.64	3.28	2.94	0.34	11.56
42	LANDFILL GAS	2.95	2.67	0.28	10.49	2.92	2.67	0.25	9.36
43	OIL - C.T.	34.12	0.00	34.12	100.00	31.37	0.00	31.37	100.00
44	TOTAL (¢/KWH)	4.22	3.91	0.31	7.93	4.15	4.04	0.11	2.72

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(878)	0.0	100.0	0.0	0	Coal	0.0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,013	0	0	0.00	0.00
3									Gas-S	0	1,013	0	0		0.00
4									Oil-S	0	137,552	0	0		0.00
5	Crist 5		75	39,632	72.8	100.0	72.8	10,963	Coal	18,540	11,717	434,467	1,860,201	4.69	100.33
6				1,001					Gas-G	10,817	1,013	10,958	151,377	15.12	13.99
7									Gas-S	2,230	1,013	2,259	31,203		13.99
8									Oil-S	78	137,552	446	9,647		123.68
9	Crist 6		299	(2,430)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0		0.00
12									Oil-S	0	137,552	0	0		0.00
13	Crist 7		475	192,625	54.5	99.8	54.5	10,712	Coal	87,864	11,742	2,063,427	8,815,903	4.58	100.34
14				0					Gas-G	0	1,013	0	0	0.00	0.00
15									Gas-S	0	1,013	0	0		0.00
16									Oil-S	10	137,552	58	1,259		125.90
17	Schoiz 1		46	(231)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,847	0	0		0.00
19	Schoiz 2		46	(158)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,847	0	0		0.00
21	Smith 1		162	57,214	47.5	100.0	47.5	10,823	Coal	26,846	11,620	619,246	2,825,076	4.94	106.02
22									Oil-S	78	138,243	453	10,168		130.36
23	Smith 2		195	(731)	0.0	74.2	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,243	0	0		0.00
25	Smith 3		558	282,805	68.1	98.0	83.1	7,060	Gas-G	2,022,292	1,016	1,996,549	10,960,834	3.88	5.42
26	Smith A	(2)	36	61	0.2	100.0	82.9	17,803	Oil	188	137,322	1,086	20,813	34.12	110.71
27	Other Generation			6,488									215,343	3.32	0.00
28	Perdido			2,152					Landfill Gas				63,553	2.95	0.00
29	Daniel 1	(1)	255	9,715	5.1	87.2	40.4	13,768	Coal	5,939	11,282	133,758	663,398	6.73	110.02
30									Oil-S	332	138,434	1,933	43,030		129.61
31	Daniel 2	(1)	255	40,254	21.2	82.0	47.6	10,850	Coal	19,625	11,128	436,762	2,159,234	5.36	110.02
32									Oil-S	347	138,434	2,018	44,928		129.48
33	Total		2,477	627,519	34.1	94.3	44.7	9,216				5,703,418	27,865,967	4.44	

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)	
	Coal Additive - Crist	117,276	
(13,079)	Inventory Adjustment - Daniel	(1,405,600)	
	Inventory Adjustment - Gas Smith	(106,075)	
	Recoverable Fuel	26,467,509	4.22

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	0	572	(572)	(100.00)	4,809	2,860	1,949	68.15
3	UNIT COST ($/BBL)	0.00	117.50	(117.50)	(100.00)	131.73	117.50	14.23	12.11
4	AMOUNT ($)	3,976	67,208	(63,232)	(94.08)	633,466	336,040	297,426	88.51
5	*BURNED:*								
6	UNITS (BBL)	881	572	309	54.02	6,896	2,860	4,036	141.12
7	UNIT COST ($/BBL)	129.10	117.51	11.59	9.86	132.47	117.62	14.85	12.63
8	AMOUNT ($)	113,739	67,216	46,523	69.21	913,534	336,381	577,153	171.58
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	3,881	7,523	(3,642)	(48.41)	3,881	7,523	(3,642)	(48.41)
11	UNIT COST ($/BBL)	126.50	117.28	9.22	7.86	126.50	117.28	9.22	7.86
12	AMOUNT ($)	490,950	882,323	(391,373)	(44.36)	490,950	882,323	(391,373)	(44.36)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	174,655	133,795	40,860	30.54	740,228	724,505	15,723	2.17
16	UNIT COST ($/TON)	103.74	108.77	(5.03)	(4.62)	102.53	105.82	(3.29)	(3.11)
17	AMOUNT ($)	18,118,769	14,553,396	3,565,373	24.50	75,892,311	76,669,136	(776,825)	(1.01)
18	*BURNED:*								
19	UNITS (TONS)	145,535	124,207	21,328	17.17	735,354	777,515	(42,161)	(5.42)
20	UNIT COST ($/TON)	102.44	105.56	(3.12)	(2.96)	102.80	108.19	(5.39)	(4.98)
21	AMOUNT ($)	14,908,212	13,110,913	1,797,299	13.71	75,592,502	84,117,075	(8,524,573)	(10.13)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	943,082	952,900	(9,818)	(1.03)	943,082	952,900	(9,818)	(1.03)
24	UNIT COST ($/TON)	105.16	109.19	(4.03)	(3.69)	105.16	109.19	(4.03)	(3.69)
25	AMOUNT ($)	99,178,424	104,045,652	(4,867,228)	(4.68)	99,178,424	104,045,652	(4,867,228)	(4.68)
26	DAYS SUPPLY	45	45	0	0.00				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,062,896	2,574,480	(511,584)	(19.87)	10,327,012	11,495,881	(1,168,869)	(10.17)
29	UNIT COST ($/MMBTU)	5.54	4.55	0.99	21.76	4.59	4.30	0.29	6.74
30	AMOUNT ($)	11,422,098	11,722,497	(300,399)	(2.56)	47,357,343	49,406,212	(2,048,869)	(4.15)
31	*BURNED:*								
32	UNITS (MMBTU)	2,009,766	2,574,480	(564,714)	(21.94)	10,262,583	11,495,881	(1,233,298)	(10.73)
33	UNIT COST ($/MMBTU)	5.49	4.55	0.94	20.66	4.48	4.30	0.18	4.19
34	AMOUNT ($)	11,037,340	11,722,497	(685,157)	(5.84)	45,965,145	49,406,212	(3,441,067)	(6.96)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	845,735	0	845,735	100.00	845,735	0	845,735	100.00
37	UNIT COST ($/MMBTU)	5.33	0.00	5.33	100.00	5.33	0.00	5.33	100.00
38	AMOUNT ($)	4,511,701	0	4,511,701	100.00	4,511,701	0	4,511,701	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	85	(85)	(100.00)	1,071	85	986	1,160.00
41	UNIT COST ($/BBL)	0.00	117.93	(117.93)	(100.00)	130.55	117.93	13.00	11.02
42	AMOUNT ($)	6,513	10,024	(3,511)	(35.03)	139,819	10,024	129,795	1,294.84
43	*BURNED:*								
44	UNITS (BBL)	188	85	103	121.18	930	85	845	994.12
45	UNIT COST ($/BBL)	110.71	105.86	4.85	4.58	108.94	105.86	3.08	2.91
46	AMOUNT ($)	20,813	8,998	11,815	131.31	101,314	8,998	92,316	1,025.98
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,096	7,143	(1,047)	(14.66)	6,096	7,143	(1,047)	(14.66)
49	UNIT COST ($/BBL)	110.53	105.54	4.99	4.73	110.53	105.54	4.99	4.73
50	AMOUNT ($)	673,819	753,822	(80,003)	(10.61)	673,819	753,822	(80,003)	(10.61)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

				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		101,304,000	0	101,304,000	3.16	3.51	3,217,000	3,556,000
2	Various	Economy Sales	6,613,000	0	6,613,000	3.93	4.16	260,000	275,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	56,000	56,000
4	TOTAL ESTIMATED SALES		107,917,000	0	107,917,000	3.27	3.60	3,533,000	3,887,000
	ACTUAL								
5	Southern Company Interchange		178,154,417	0	178,154,417	3.01	3.14	5,299,485	5,524,583
6	A.E.C.	External	2,427,480	0	2,427,480	2.94	3.64	71,263.32	88,371
7	AECI	External	0	0	0	0.00	0.00	0.00	0
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	AMERENEM	External	0	0	0	0.00	0.00	0.00	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0.00	0
11	BPENERGY	External	0	0	0	0.00	0.00	0.00	0
12	CALPINE	External	0	0	0	0.00	0.00	0.00	0
13	CARGILE	External	1,868,847	0	1,868,847	2.93	3.38	54,678.64	63,101
14	CITIG	External	0	0	0	0.00	0.00	0.00	0
15	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
16	CPL	External	0	0	0	0.00	0.00	0.00	0
17	DTE	External	0	0	0	0.00	0.00	0.00	0
18	DUKE PWR	External	0	0	0	0.00	0.00	0.00	0
19	EAGLE EN	External	502,066	0	502,066	2.60	3.46	13,052.09	17,396
20	EASTKY	External	0	0	0	0.00	0.00	0.00	0
21	ENDURE	External	45,049	0	45,049	3.73	4.87	1,682.48	2,196
22	ENTERGY	External	0	0	0	0.00	0.00	0.00	0
23	EXELON	External	2,112,405	0	2,112,405	3.03	3.40	63,961.99	71,830
24	FPC	External	144,698	0	144,698	3.03	3.97	4,390.56	5,741
25	FPL	External	0	0	0	0.00	0.00	0.00	0
26	JARON	External	0	0	0	0.00	0.00	0.00	0
27	JEA	External	0	0	0	0.00	0.00	0.00	0
28	JPMVEC	External	805,309	0	805,309	3.19	3.68	25,697.80	29,632
29	KEMG	External	0	0	0	0.00	0.00	0.00	0
30	MERRILL	External	0	0	0	0.00	0.00	0.00	0
31	MISO	External	315	0	315	2.70	2.76	8.52	9
32	MORGAN	External	89,087	0	89,087	7.02	3.57	6,256.66	3,177
33	NCEMC	External	50,964	0	50,964	3.29	4.56	1,675.57	2,323
34	NCMPA1	External	0	0	0	0.00	0.00	0.00	0
35	NRG	External	0	0	0	0.00	0.00	1,925.14	0
36	OGE	External	1,260	1	1,259	3.01	3.00	37.94	38
37	OPC	External	307,049	0	307,049	3.22	3.94	9,894.54	12,104
38	ORLANDO	External	17,619	0	17,619	3.57	5.40	628.33	951
39	PJM	External	1,940,976	0	1,940,976	3.22	4.01	62,482.47	77,886
40	REMC	External	0	0	0	0.00	0.00	0.00	0
41	SCE&G	External	352,320	0	352,320	3.18	4.67	11,203.71	18,458
42	SEC	External	203,833	0	203,833	2.79	3.64	5,679.82	7,427
43	SEPA	External	0	0	0	0.00	0.00	0.00	0
44	SHELL	External	0	0	0	0.00	0.00	0.00	0
45	SPP	External	0	0	0	0.00	0.00	0.00	0
46	TAL	External	272,431	0	272,431	3.24	4.00	8,833.66	10,899
47	TEA	External	869,724	0	869,724	2.77	3.75	24,077.07	32,602
48	TECO	External	122,619	0	122,619	3.76	6.00	4,618.41	7,357
49	TENASKA	External	0	0	0	0.00	0.00	0.00	0
50	TRANSALT	External	0	0	0	0.00	0.00	0.00	0
51	TVA	External	264,243	0	264,243	3.13	4.03	8,267.68	10,682
52	UPP	External	0	0	0	0.00	0.00	0.00	0
53	WRI	External	673,244	0	673,244	2.94	3.53	19,782.72	23,775
54	Less: Flow-Thru Energy		(12,945,083)	0	(12,945,083)	2.91	2.91	(377,250)	(377,250)
55	SEPA		2,230,272	2,230,272	0	0.00	0.00	0	0
56	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	52,332	52,332
57	Other transactions including adj.		94,107,280	113,746,348	(19,639,068)	0.00	0.00	0	0
58	TOTAL ACTUAL SALES		272,618,424	115,976,619	156,641,805	1.97	2.07	5,374,664	5,631,257
59	Difference in Amount		164,701,424	115,976,619	48,724,805	(1.30)	(1.53)	1,841,664	1,744,257
60	Difference in Percent		152.62	0.00	45.15	(39.78)	(42.50)	52.13	44.87

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 56

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

			PERIOD TO DATE						
	(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	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,086,024,000	0	1,086,024,000	2.63	3.00	28,560,000	32,531,000
2	Various	Economy Sales	33,843,000	0	33,843,000	2.93	3.26	993,000	1,102,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	272,000	272,000
4	TOTAL ESTIMATED SALES		1,119,867,000	0	1,119,867,000	2.66	3.03	29,825,000	33,905,000
	ACTUAL								
5	Southern Company Interchange		1,317,359,225	0	1,317,359,225	2.82	3.02	37,189,593	39,721,560
6	A.E.C.	External	3,457,238	0	3,457,238	2.95	3.69	102,068	127,622
7	AECI	External	229,693	0	229,693	2.57	3.94	5,912	9,048
8	AEP	External	0	0	0	0.00	0.00	236	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	2,114	0
13	CARGILE	External	3,174,789	0	3,174,789	2.83	3.26	89,947	103,493
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,898
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,056
19	EAGLE EN	External	1,067,160	0	1,067,160	2.75	3.59	29,391	38,349
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	73,171	0	73,171	3.32	4.49	2,432	3,285
22	ENTERGY	External	132,118	0	132,118	5.75	4.24	7,593	5,606
23	EXELON	External	2,784,461	0	2,784,461	2.91	3.36	80,924	93,640
24	FPC	External	514,885	0	514,885	3.30	4.47	17,003	23,029
25	FPL	External	294,245	0	294,245	2.96	4.16	8,697	12,249
26	JARON	External	0	0	0	0.00	0.00	0	0
27	JEA	External	0	0	0	0.00	0.00	0	0
28	JPMVEC	External	891,692	0	891,692	3.21	3.78	28,615	33,745
29	KEMG	External	0	0	0	0.00	0.00	0	0
30	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
31	MISO	External	315	0	315	2.70	2.76	9	9
32	MORGAN	External	1,111,919	0	1,111,919	3.30	3.61	36,694	40,171
33	NCEMC	External	335,034	0	335,034	2.80	3.60	9,366	12,057
34	NCMPA1	External	0	0	0	0.00	0.00	0	0
35	NRG	External	0	0	0	0.00	0.00	4,744	0
36	OGE	External	1,260	1	1,259	3.01	3.00	38	38
37	OPC	External	986,519	0	986,519	3.04	3.96	29,957	39,019
38	ORLANDO	External	17,619	0	17,619	3.57	5.40	628	951
39	PJM	External	7,337,327	0	7,337,327	2.89	3.50	212,133	256,942
40	REMC	External	0	0	0	0.00	0.00	0	0
41	SCE&G	External	2,349,681	0	2,349,681	3.40	5.03	79,777	118,084
42	SEC	External	717,011	0	717,011	3.11	3.78	22,270	27,113
43	SEPA	External	1,438,657	0	1,438,657	2.75	3.61	39,517	52,000
44	SHELL	External	0	0	0	0.00	0.00	0	0
45	SPP	External	6,174	0	6,174	2.17	1.63	134	101
46	TAL	External	520,657	0	520,657	3.07	3.76	15,989	19,588
47	TEA	External	2,783,423	0	2,783,423	2.69	3.57	74,831	99,312
48	TECO	External	319,541	0	319,541	3.16	4.67	10,084	14,935
49	TENASKA	External	0	0	0	0.00	0.00	0	0
50	TRANSALT	External	0	0	0	0.00	0.00	0	0
51	TVA	External	2,263,009	0	2,263,009	3.05	4.27	69,104	96,624
52	UPP	External	0	0	0	0.00	0.00	0	0
53	WRI	External	824,252	0	824,252	2.83	3.41	23,340	28,071
54	Less: Flow-Thru Energy		(34,141,639)	0	(34,141,639)	2.84	2.84	(969,265)	(969,265)
55	SEPA		8,699,416	8,699,416	0	0.00	0.00	0	0
56	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	96,420	96,420
57	Other transactions including adj.		637,353,778	619,574,234	17,779,544	0.00	0.00	0	0
58	TOTAL ACTUAL SALES		1,963,932,337	628,273,651	1,335,658,686	1.90	2.04	37,344,659	40,037,412
59	Difference in Amount		844,065,337	628,273,651	215,791,686	(0.76)	(0.99)	7,519,659	6,132,412
60	Difference in Percent		75.37	0.00	19.27	(28.57)	(32.67)	25.21	18.09

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 56

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MAY 2013

(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								

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SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

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	4,984,000	0	0	0	7.63	7.63	380,497
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	16,714,000	0	0	0	3.05	3.05	509,291
6 International Paper	COG 1	197,000	0	0	0	2.86	2.86	5,638
7 TOTAL		21,895,000	0	0	0	4.09	4.09	895,427

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	14,254,000	0	0	0	7.63	7.63	1,088,052
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	15
5 Ascend Performance Materials	COG 1	101,518,000	0	0	0	3.05	3.05	3,100,550
6 International Paper	COG 1	519,000	0	0	0	3.24	3.24	16,816
7 TOTAL		116,291,000	0	0	0	3.62	3.62	4,205,434

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

	(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	60,904,000	4.22	2,571,000	254,346,000	3.51	8,939,000
2	Economy Energy	4,594,000	4.40	202,000	24,007,000	3.32	796,000
3	Other Purchases	455,313,000	2.81	12,796,000	2,089,483,000	2.97	62,086,000
4	TOTAL ESTIMATED PURCHASES	520,811,000	2.99	15,569,000	2,367,836,000	3.03	71,821,000
	ACTUAL						
5	Southern Company Interchange	114,386,091	3.19	3,652,263	333,198,624	3.24	10,791,783
6	Non-Associated Companies	43,062,035	0.34	145,735	236,465,038	0.93	2,207,500
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	368,879,000	3.49	12,862,707	2,053,617,000	3.24	66,564,056
9	Other Wheeled Energy	8,146,000	0.00	N/A	87,870,000	0.00	N/A
10	Other Transactions	52,608,229	0.04	21,493	399,155,328	0.03	101,749
11	Less: Flow-Thru Energy	(12,945,083)	3.12	(403,969)	(34,141,639)	3.05	(1,039,796)
12	TOTAL ACTUAL PURCHASES	574,136,272	2.84	16,278,229	3,076,164,351	2.56	78,625,292
13	Difference in Amount	53,325,272	(0.15)	709,229	708,328,351	(0.47)	6,804,292
14	Difference in Percent	10.24	(5.02)	4.56	29.91	(15.51)	9.47

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SCHEDULE A-12
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2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)			709,163
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)		$ -	$ 709,163
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116			10,617,867
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)			(16,157)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ -	$ 10,601,710
TOTAL					$ 2,380,170		$ 1,898,537		$ 2,389,783		$ 2,045,794		$ 2,596,589		$ -	$ 11,310,873

(1) February's Southern intercompany interchange reserve sharing charge consists of prior month true-up only

2013 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	2/18/2000	5 Yr Notice													709,163
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 709,163
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													10,617,867
2 Other Confidential Agreements	Other	Varies	Varies													(16,157)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 10,601,710
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 11,310,873

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

JUNE 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2013
CURRENT MONTH

		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)	40,837,373	32,196,519	8,440,854	26.22	871,952,000	779,157,000	92,795,000	11.91	4.6805	4.1322	0.53	12.78
2	Hedging Settlement Costs (A2)	916,010	0	916,010	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) **	15,968	0	15,968	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	41,569,351	32,196,519	9,372,832	29.11	871,952,000	779,157,000	92,795,000	11.91	4.7674	4.1322	0.64	15.37
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)	17,819,494	18,420,000	(600,506)	(4.35)	682,699,707	617,799,000	64,900,707	10.51	2.5809	2.9816	(0.40)	(13.44)
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)	851,224	0	851,224	100.00	17,483,000	0	17,483,000	100.00	4.8689	0.0000	4.87	0.00
12	TOTAL COST OF PURCHASED POWER	18,670,718	18,420,000	50,718	0.28	700,182,707	617,799,000	82,383,707	13.34	2.6380	2.9816	(0.34)	(11.52)
13	Total Available MWH (Line 5 + Line 12)	60,040,069	50,616,519	9,423,550	18.62	1,572,134,707	1,396,956,000	175,178,707	12.54				
14	Fuel Cost of Economy Sales (A6)	(105,111)	(190,000)	84,889	(44.68)	(2,799,259)	(4,749,000)	1,949,741	(41.06)	(3.7550)	(4.0008)	0.25	6.14
15	Gain on Economy Sales (A6)	14,588	(95,000)	109,588	(115.36)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,207,997)	(4,149,000)	(4,058,997)	97.83	(397,151,331)	(140,200,000)	(256,951,331)	183.27	(2.0667)	(2.9593)	0.89	30.16
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,298,520)	(4,434,000)	(3,864,520)	87.16	(399,950,590)	(144,949,000)	(255,001,590)	175.93	(2.0749)	(3.0590)	0.98	32.17
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)	51,741,549	46,182,519	5,559,030	12.04	1,172,184,117	1,252,007,000	(79,822,883)	(6.38)	4.4141	3.6887	0.73	19.67
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 *	72,148	65,364	6,784	10.38	1,634,495	1,772,000	(137,505)	(7.76)	4.4141	3.6887	0.73	19.67
22	T & D Losses *	2,751,976	3,068,371	(316,395)	(10.31)	62,345,125	83,183,000	(20,837,875)	(25.05)	4.4141	3.6887	0.73	19.67
23	TERRITORIAL KWH SALES	51,741,549	46,182,519	5,559,030	12.04	1,108,204,497	1,167,052,000	(58,847,503)	(5.04)	4.6690	3.9572	0.71	17.99
24	Wholesale KWH Sales	1,379,016	1,353,658	25,360	1.87	29,535,898	34,207,000	(4,671,302)	(13.66)	4.6690	3.9572	0.71	17.99
25	Jurisdictional KWH Sales	50,362,533	44,828,863	5,533,670	12.34	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	4.6690	3.9572	0.71	17.99
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	50,438,077	44,896,106	5,541,971	12.34	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	4.6760	3.9631	0.71	17.99
28	TRUE-UP	(2,202,118)	(2,202,116)	0	0.00	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	(0.2042)	(0.1944)	(0.01)	5.04
29	TOTAL JURISDICTIONAL FUEL COST	48,235,959	42,693,988	5,541,971	12.98	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	4.4718	3.7687	0.70	18.66
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4750	3.7714	0.70	18.68
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	0.0080	0.0077	0.00	3.90
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4830	3.7791	0.70	18.63
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.483	3.779		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 40,637,373
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	15,968
4	Hedging Settlement Costs	Schedule A-2, Line A-5	916,010
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	17,619,494
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	851,224
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,298,520)
10	Total Fuel and Net Power Transactions		$ 51,741,549

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2013
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)	185,295,861	188,959,434	(1,663,573)	(1.00)	3,872,462,000	4,118,699,000	(246,237,000)	(5.98)	4.2685	4.0537	0.21	5.30
2	Hedging Settlement Costs (A2)	6,785,904	0	6,785,904	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) **	122,304	0	122,304	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	172,204,069	166,959,434	5,244,635	3.14	3,872,462,000	4,118,699,000	(246,237,000)	(5.98)	4.4469	4.0537	0.39	9.70
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)	96,244,786	90,241,000	6,003,786	6.65	3,758,864,058	2,985,635,000	773,229,058	25.90	2.5605	3.0225	(0.46)	(15.29)
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)	5,056,658	0	5,056,658	100.00	133,774,000	0	133,774,000	100.00	3.7800	0.0000	3.78	0.00
12	TOTAL COST OF PURCHASED POWER	101,301,444	90,241,000	11,060,444	12.26	3,892,638,058	2,985,635,000	907,003,058	30.38	2.6024	3.0225	(0.42)	(13.90)
13	Total Available MWH (Line 5 + Line 12)	273,505,513	257,200,434	16,305,079	6.34	7,765,100,058	7,104,334,000	660,766,058	9.30				
14	Fuel Cost of Economy Sales (A6)	(1,133,022)	(1,183,000)	49,978	(4.22)	(37,460,816)	(38,592,000)	1,131,184	(2.93)	(3.0246)	(3.0654)	0.04	1.33
15	Gain on Economy Sales (A6)	(81,832)	(367,000)	285,168	(77.70)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(44,428,325)	(32,709,000)	(11,719,325)	35.83	(2,326,422,111)	(1,226,224,000)	(1,100,198,111)	89.72	(1.9097)	(2.6675)	0.76	28.41
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(45,643,179)	(34,259,000)	(11,384,179)	33.23	(2,363,882,927)	(1,264,816,000)	(1,099,066,927)	86.90	(1.9309)	(2.7086)	0.78	28.71
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)	227,862,334	222,941,434	4,920,900	2.21	5,401,217,131	5,839,518,000	(438,300,869)	(7.51)	4.2187	3.8178	0.40	10.50
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 *	422,119	412,284	9,835	2.39	10,005,904	10,799,000	(793,096)	(7.34)	4.2187	3.8178	0.40	10.50
22	T & D Losses *	11,501,235	11,734,352	(233,117)	(1.99)	272,625,097	307,359,000	(34,733,903)	(11.30)	4.2187	3.8178	0.40	10.50
23	TERRITORIAL KWH SALES	227,862,334	222,941,434	4,920,900	2.21	5,118,588,130	5,521,360,000	(402,773,870)	(7.29)	4.4517	4.0378	0.41	10.25
24	Wholesale KWH Sales	6,808,517	7,161,393	(552,876)	(7.72)	148,681,616	177,108,000	(28,448,384)	(16.06)	4.4453	4.0435	0.40	9.94
25	Jurisdictional KWH Sales	221,253,817	215,780,041	5,473,776	2.54	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)	4.4519	4.0378	0.41	10.26
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	221,565,698	216,103,710	5,461,988	2.54	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)	4.4585	4.0437	0.41	10.26
28	TRUE-UP	(13,212,708)	(13,212,708)	0	0.00	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)	(0.2659)	(0.2472)	(0.02)	7.56
29	TOTAL JURISDICTIONAL FUEL COST	208,372,990	202,891,002	5,481,988	2.70	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)	4.1926	3.7965	0.40	10.43
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1956	3.7992	0.40	10.43
32	GPIF Reward / (Penalty)	520,332	520,332	0	0.00	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)	0.0105	0.0097	0.00	8.25
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2061	3.8089	0.40	10.43
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.206	3.809		

* 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 2013

		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	40,413,751.45	31,997,937	8,415,814.45	26.30	164,034,513.39	166,158,066	(2,123,552.61)	(1.28)
1a	Other Generation	223,621.47	198,582	25,039.47	12.61	1,261,347.05	801,368	459,979.05	57.40
2	Fuel Cost of Power Sold	(8,298,519.65)	(4,434,000)	(3,864,519.65)	(87.16)	(45,643,180.18)	(34,259,000)	(11,384,180.18)	(33.23)
3	Fuel Cost - Purchased Power	17,619,494.27	18,420,000	(800,505.73)	(4.35)	96,244,787.12	90,241,000	6,003,787.12	6.65
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	851,224.12	0	851,224.12	100.00	5,056,658.00	0	5,056,658.00	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	916,010.00	0	916,010.00	100.00	6,785,904.00	0	6,785,904.00	100.00
6	Total Fuel & Net Power Transactions	51,725,581.66	46,182,519	5,543,062.66	12.00	227,740,029.38	222,941,434	4,798,595.38	2.15
7	AdjustmentsTo Fuel Cost*	15,967.75	0	15,967.75	100.00	122,304.37	0	122,304.37	100.00
8	Adj. Total Fuel & Net Power Transactions	51,741,549.41	46,182,519	5,559,030.41	12.04	227,862,333.75	222,941,434	4,920,899.75	2.21
B.	*KWH Sales*								
1	Jurisdictional Sales	1,078,668,799	1,132,845,000	(54,176,201)	(4.78)	4,969,924,514	5,344,252,000	(374,327,486)	(7.00)
2	Non-Jurisdictional Sales	29,535,698	34,207,000	(4,671,302)	(13.66)	148,661,616	177,108,000	(28,446,384)	(16.06)
3	Total Territorial Sales	1,108,204,497	1,167,052,000	(58,847,503)	(5.04)	5,118,586,130	5,521,360,000	(402,773,870)	(7.29)
4	Juris. Sales as % of Total Terr. Sales	97.3348	97.0689	0.2659	0.27	97.0957	96.7923	0.3034	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: JUNE 2013

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	40,974,608.87	43,082,095	(2,107,486.48)	(4.89)	188,603,989.26	203,241,904	(14,637,914.30)	(7.20)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	13,212,708.00	13,212,708	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(519,954.00)	(519,954)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	43,090,067.87	45,197,554	(2,107,486.13)	(4.66)	201,296,743.26	215,934,658	(14,637,914.74)	(6.78)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	51,741,549.41	46,182,519	5,559,030.41	12.04	227,862,333.75	222,941,434	4,920,899.75	2.21
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3348	97.0689	0.2659	0.27	97.0957	96.7923	0.3034	0.31
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	50,438,077.44	44,896,106	5,541,971.44	12.34	221,585,699.11	216,103,710	5,481,989.11	2.54
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(7,348,009.57)	301,448	(7,649,457.57)	2,537.57	(20,288,955.85)	(169,052)	(20,119,903.85)	(11,901.61)
8	Interest Provision for the Month	(628.17)	756	(1,384.17)	183.09	1,497.12	7,215	(5,717.88)	79.25
9	Beginning True-Up & Interest Provision	(6,857,687.85)	14,950,787	(21,808,474.85)	145.87	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(13,212,708.00)	(13,212,708)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(16,408,443.59)	13,050,873	(29,459,316.59)	225.73	(16,408,443.59)	13,050,873	(29,459,316.59)	225.73
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	(16,408,443.59)	13,050,873	(29,459,316.59)	225.73	(16,408,443.59)	13,050,873	(29,459,316.59)	225.73

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2013

		CURRENT MONTH			
		$		DIFFERENCE	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	Beginning True-Up Amount (C9)	(6,857,687.85)	14,950,787	(21,808,474.85)	(145.87)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(16,407,815.42)	13,050,117	(29,457,932.42)	(225.73)
3	Total of Beginning & Ending True-Up Amts.	(23,265,503.27)	28,000,904	(51,266,407.27)	(183.09)
4	Average True-Up Amount	(11,632,751.64)	14,000,452	(25,633,203.64)	(183.09)
5	Interest Rate 1st Day of Reporting Business Month	0.07	0.07	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.06	0.06	0.0000	
7	Total (D5+D6)	0.13	0.13	0.0000	
8	Annual Average Interest Rate	0.07	0.07	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0054	0.0054	0.0000	
10	Interest Provision (D4*D9)	(628.17)	756	(1,384.17)	(183.09)
	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: JUNE 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
	FUEL COST-NET GEN.($)	ACTUAL (1)	EST. (2)	AMOUNT (3)	% (4)	ACTUAL (5)	EST. (6)	AMOUNT (7)	% (8)
1	LIGHTER OIL (B.L.)	155,555	67,212	88,343	131.44	1,034,749	403,593	631,156	156.38
2	COAL	29,763,111	20,547,892	9,215,219	44.85	106,141,134	104,664,967	1,476,167	1.41
3	GAS	10,501,521	11,482,735	(981,214)	(8.55)	57,387,043	61,491,733	(4,124,690)	(6.71)
4	GAS (B.L.)	143,481	0	143,481	100.00	280,828	-	280,828	100.00
5	LANDFILL GAS	59,830	57,876	1,954	3.38	356,917	349,339	7,578	2.17
6	OIL - C.T.	13,875	40,804	(26,929)	(66.00)	115,189	49,802	65,387	131.29
7	TOTAL ($)	40,637,373	32,196,519	8,440,854	26.22	165,295,860	166,959,434	(1,663,574)	(1.00)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	598,151	419,014	179,137	42.75	2,158,897	2,048,503	110,394	5.39
10	GAS	271,781	357,753	(85,972)	(24.03)	1,701,038	2,056,898	(355,860)	(17.30)
11	LANDFILL GAS	1,984	2,166	(182)	(8.40)	12,168	13,074	(906)	(6.93)
12	OIL - C.T.	36	224	(188)	(83.93)	359	224	135	60.27
13	TOTAL (MWH)	871,952	779,157	92,795	11.91	3,872,462	4,118,699	(246,237)	(5.98)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,241	572	669	116.96	7,878	3,432	4,446	129.55
15	COAL (TONS)	283,844	198,429	85,415	43.05	1,019,198	975,944	43,254	4.43
16	GAS (MCF) (1)	1,938,257	2,465,562	(527,305)	(21.39)	12,101,746	14,206,311	(2,104,565)	(14.81)
17	OIL - C.T. (BBL)	126	384	(258)	(67.19)	1,056	469	587	125.16
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	6,511,202	4,615,686	1,895,516	41.07	23,881,121	22,934,665	946,456	4.13
19	GAS - Generation (1)	1,950,805	2,418,012	(467,207)	(19.32)	12,198,682	13,913,893	(1,715,211)	(12.33)
20	OIL - C.T.	724	2,251	(1,527)	(67.84)	6,143	2,750	3,393	123.38
21	TOTAL (MMBTU)	8,462,731	7,035,949	1,426,782	20.28	36,085,946	36,851,308	(765,362)	(2.08)
	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	68.60	53.77	14.83	27.58	55.75	49.73	6.02	12.11
24	GAS	31.17	45.92	(14.75)	(32.12)	43.93	49.94	(6.01)	(12.03)
25	LANDFILL GAS	0.23	0.28	(0.05)	(17.86)	0.31	0.32	(0.01)	(3.13)
26	OIL - C.T.	0.00	0.03	(0.03)	(100.00)	0.01	0.01	0.00	0.00
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)	125.33	117.50	7.83	6.66	131.34	117.60	13.74	11.68
29	COAL ($/TON)	104.86	103.55	1.31	1.27	104.14	107.24	(3.10)	(2.89)
30	GAS ($/MCF) (1)	5.38	4.58	0.80	17.47	4.66	4.27	0.39	9.13
31	OIL - C.T. ($/BBL)	110.12	106.26	3.86	3.63	109.08	106.19	2.89	2.72
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.62	4.47	0.15	3.36	4.50	4.58	(0.08)	(1.75)
33	GAS - Generation (1)	5.27	4.67	0.60	12.85	4.60	4.36	0.24	5.50
34	OIL - C.T.	19.16	18.13	1.03	5.68	18.75	18.11	0.64	3.53
35	TOTAL ($/MMBTU)	4.77	4.54	0.23	5.07	4.54	4.50	0.04	0.89
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,886	11,016	(130)	(1.18)	11,062	11,196	(134)	(1.20)
37	GAS - Generation (1)	7,349	6,865	484	7.05	7,334	6,839	495	7.24
38	OIL - C.T.	20,111	10,049	10,062	100.13	17,111	12,277	4,834	39.37
39	TOTAL (BTU/KWH)	9,799	9,120	679	7.45	9,440	9,025	415	4.60
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.03	4.92	0.11	2.24	4.98	5.13	(0.15)	(2.92)
41	GAS	3.86	3.21	0.65	20.25	3.37	2.99	0.38	12.71
42	LANDFILL GAS	3.02	2.67	0.35	13.11	2.93	2.67	0.26	9.74
43	OIL - C.T.	38.54	18.22	20.32	111.53	32.09	22.23	9.86	44.35
44	TOTAL (¢/KWH)	4.66	4.13	0.53	12.83	4.27	4.05	0.22	5.43

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	16,879	32.6	100.0	54.6	11,322	Coal	8,289.0	11,528	191,112	826,494	4.90	99.71
2				713					Gas-G	7,981	1,014	8,072	62,920	8.82	7.90
3									Gas-S	1,479	1,014	1,500	11,692		7.91
4									Oil-S	126	137,552	729	15,762		125.10
5	Crist 5		75	19,661	36.6	91.4	63.4	11,385	Coal	9,572	11,691	223,844	954,551	4.86	99.72
6				99					Gas-G	1,114	1,014	1,130	8,807	8.90	7.91
7									Gas-S	0	1,014	0	0		0.00
8									Oil-S	92	137,552	534	11,554		125.59
9	Crist 6		299	53,758	25.0	76.0	57.2	11,747	Coal	27,737	11,384	631,514	2,765,627	5.14	99.71
10				5					Gas-G	55	1,014	56	437	8.75	7.95
11									Gas-S	16,674	1,014	16,907	131,789		7.90
12									Oil-S	34	137,552	196	4,244		124.82
13	Crist 7		475	198,703	58.1	100.0	58.1	10,717	Coal	91,681	11,614	2,129,565	9,141,439	4.60	99.71
14				90					Gas-G	948	1,014	961	7,491	8.32	7.90
15									Gas-S	0	1,014	0	0		0.00
16									Oil-S	29	137,552	170	3,675		126.72
17	Scholz 1		46	2,378	7.2	99.8	38.4	14,274	Coal	1,465	11,571	33,914	127,418	5.36	86.97
18									Oil-S	17	137,647	98	2,205		129.71
19	Scholz 2		46	3,221	9.7	100.0	52.9	13,907	Coal	1,925	11,636	44,795	167,357	5.20	86.94
20									Oil-S	24	137,647	133	3,000		125.00
21	Smith 1		162	64,545	55.3	100.0	55.3	10,876	Coal	30,199	11,623	702,001	3,177,932	4.92	105.23
22									Oil-S	89	138,176	517	11,191		125.74
23	Smith 2		195	41,570	29.6	97.2	41.4	11,146	Coal	19,992	11,588	463,325	2,103,791	5.06	105.23
24									Oil-S	410	138,176	2,378	51,460		125.51
25	Smith 3		556	264,554	66.1	87.0	77.7	7,335	Gas-G	1,910,026	1,016	1,940,586	10,198,244	3.85	5.34
26	Smith A	(2)	32	36	0.2	89.5	75.0	20,111	Oil	126	137,322	724	13,875	38.54	110.12
27	Other Generation			6,320									223,621	3.54	0.00
28	Perdido			1,984					Landfill Gas				59,830	3.02	0.00
29	Daniel 1	(1)	255	96,718	52.7	98.7	53.1	10,417	Coal	45,352	11,107	1,007,477	5,020,605	5.19	110.70
30									Oil-S	146	137,591	844	18,234		124.89
31	Daniel 2	(1)	255	100,720	54.9	97.9	55.2	10,505	Coal	47,632	11,107	1,058,064	5,272,953	5.24	110.70
32									Oil-S	274	137,591	1,585	34,231		124.93
33	Total		2,471	871,952	49.0	93.2	59.9	9,799				8,462,731	40,432,429	4.64	

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)	
	Coal Additive - Crist	209,003	
	Recoverable Fuel	40,637,373	4.66

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	1,974	572	1,402	245.10	6,783	3,432	3,351	97.64
3	UNIT COST ($/BBL)	122.67	117.50	5.17	4.40	129.09	117.50	11.59	9.86
4	AMOUNT ($)	242,151	67,208	174,943	260.30	875,617	403,248	472,369	117.14
5	*BURNED:*								
6	UNITS (BBL)	1,302	572	730	127.62	8,198	3,432	4,766	138.87
7	UNIT COST ($/BBL)	125.41	117.50	7.91	6.73	131.35	117.60	13.75	11.69
8	AMOUNT ($)	163,285	67,212	96,073	142.94	1,076,819	403,593	673,226	166.81
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,553	7,523	(2,970)	(39.48)	4,553	7,523	(2,970)	(39.48)
11	UNIT COST ($/BBL)	125.15	117.28	7.87	6.71	125.15	117.28	7.87	6.71
12	AMOUNT ($)	569,816	882,319	(312,503)	(35.42)	569,816	882,319	(312,503)	(35.42)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	156,445	172,204	(15,759)	(9.15)	896,673	896,709	(36)	0.00
16	UNIT COST ($/TON)	101.22	101.95	(0.73)	(0.72)	102.30	105.08	(2.78)	(2.65)
17	AMOUNT ($)	15,835,755	17,556,989	(1,721,234)	(9.80)	91,728,066	94,226,125	(2,498,059)	(2.65)
18	*BURNED:*								
19	UNITS (TONS)	283,844	198,429	85,415	43.05	1,019,198	975,944	43,254	4.43
20	UNIT COST ($/TON)	104.14	103.55	0.59	0.57	103.17	107.24	(4.07)	(3.80)
21	AMOUNT ($)	29,558,167	20,547,892	9,010,275	43.85	105,150,669	104,664,967	485,702	0.46
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	815,682	926,675	(110,993)	(11.98)	815,682	926,675	(110,993)	(11.98)
24	UNIT COST ($/TON)	104.77	109.05	(4.28)	(3.92)	104.77	109.05	(4.28)	(3.92)
25	AMOUNT ($)	85,456,013	101,054,749	(15,598,736)	(15.44)	85,456,013	101,054,749	(15,598,736)	(15.44)
26	DAYS SUPPLY	39	44	(5)	(11.36)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	1,973,145	2,418,012	(444,867)	(18.40)	12,300,157	13,913,893	(1,613,736)	(11.60)
29	UNIT COST ($/MMBTU)	5.26	4.67	0.59	12.63	4.69	4.36	0.33	7.57
30	AMOUNT ($)	10,374,888	11,284,153	(909,265)	(8.06)	57,732,231	60,690,365	(2,958,134)	(4.87)
31	*BURNED:*								
32	UNITS (MMBTU)	1,969,213	2,418,012	(448,799)	(18.56)	12,231,796	13,913,893	(1,682,097)	(12.09)
33	UNIT COST ($/MMBTU)	5.29	4.67	0.62	13.28	4.61	4.36	0.25	5.73
34	AMOUNT ($)	10,421,380	11,284,153	(862,773)	(7.65)	56,386,525	60,690,365	(4,303,840)	(7.09)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	849,667	0	849,667	100.00	849,667	0	849,667	100.00
37	UNIT COST ($/MMBTU)	5.26	0.00	5.26	100.00	5.26	0.00	5.26	100.00
38	AMOUNT ($)	4,465,209	0	4,465,209	100.00	4,465,209	0	4,465,209	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	(126)	384	(510)	(132.81)	945	469	476	101.49
41	UNIT COST ($/BBL)	110.12	117.69	(7.57)	(6.43)	133.27	117.73	16.00	13.59
42	AMOUNT ($)	(13,875)	45,192	(59,067)	(130.70)	125,944	55,216	70,728	128.09
43	*BURNED:*								
44	UNITS (BBL)	126	384	(258)	(67.19)	1,056	469	587	125.16
45	UNIT COST ($/BBL)	110.12	106.26	3.86	3.63	109.08	106.19	2.89	2.72
46	AMOUNT ($)	13,875	40,804	(26,929)	(66.00)	115,189	49,802	65,387	131.29
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	5,845	7,143	(1,298)	(18.17)	5,845	7,143	(1,298)	(18.17)
49	UNIT COST ($/BBL)	110.53	106.15	4.38	4.13	110.53	106.15	4.38	4.13
50	AMOUNT ($)	646,069	758,210	(112,141)	(14.79)	646,069	758,210	(112,141)	(14.79)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2013

			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		140,200,000	0	140,200,000	2.96	3.27	4,149,000	4,581,000
2	Various	Economy Sales	4,749,000	0	4,749,000	4.00	4.19	190,000	199,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	95,000	95,000
4	TOTAL ESTIMATED SALES		144,949,000	0	144,949,000	3.06	3.36	4,434,000	4,875,000
	ACTUAL								
5	Southern Company Interchange		227,488,407	0	227,488,407	3.65	3.86	8,307,793	8,787,173
6	A.E.C.	External	327,786	0	327,786	3.38	3.82	11,068.48	12,516
7	AECI	External	0	0	0	0.00	0.00	0.00	0
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	CALPINE	External	0	0	0	0.00	0.00	0.00	0
10	CARGILE	External	9,688	0	9,688	3.13	4.05	303.44	392
11	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
12	DUKE PWR	External	0	0	0	0.00	0.00	0.00	0
13	EAGLE EN	External	9,877	0	9,877	3.82	4.08	377.55	403
14	ENDURE	External	0	0	0	0.00	0.00	14.26	0
15	ENTERGY	External	0	0	0	0.00	0.00	0.00	0
16	EXELON	External	12,583	0	12,583	33.26	4.80	4,185.59	604
17	FPC	External	174,581	0	174,581	3.41	4.31	5,959.60	7,517
18	FPL	External	84,245	0	84,245	3.67	4.44	3,091.76	3,739
19	JPMVEC	External	0	0	0	0.00	0.00	(8.63)	0
20	MERRILL	External	0	0	0	0.00	0.00	0.00	0
21	MISO	External	0	0	0	0.00	0.00	(0.18)	0
22	MORGAN	External	16,673	0	16,673	2.95	3.79	491.71	631
23	NCEMC	External	31,460	0	31,460	4.22	4.72	1,329.15	1,485
24	NRG	External	0	0	0	0.00	0.00	0.00	0
25	OGE	External	0	0	0	0.00	0.00	(0.02)	0
26	OPC	External	66,059	0	66,059	2.89	3.93	1,906.74	2,597
27	ORLANDO	External	0	0	0	0.00	0.00	0.00	0
28	PJM	External	283,302	0	283,302	4.02	4.98	11,393.44	14,116
29	SCE&G	External	191,631	0	191,631	4.30	4.98	8,241.56	9,535
30	SEC	External	236,102	0	236,102	3.87	4.18	9,136.42	9,868
31	SEPA	External	181,180	0	181,180	2.54	2.79	4,594.09	5,053
32	SPP	External	0	0	0	0.00	0.00	8.23	0
33	TAL	External	333,128	0	333,128	3.88	5.69	12,918.77	18,944
34	TEA	External	336,535	0	336,535	3.51	4.71	11,801.73	15,852
35	TECO	External	8,808	0	8,808	3.53	4.40	310.91	388
36	TVA	External	495,621	0	495,621	3.63	5.11	17,983.74	25,310
37	WRI	External	0	0	0	0.00	0.00	2.57	0
38	Less: Flow-Thru Energy		(2,795,295)	0	(2,795,295)	3.57	3.57	(99,796)	(99,796)
39	SEPA		1,585,584	1,585,584	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(14,588)	(14,588)
41	Other transactions including adj.		170,872,635	157,952,241	12,920,394	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		399,950,590	159,537,825	240,412,765	2.07	2.20	8,298,520	8,816,327
43	Difference in Amount		255,001,590	159,537,825	95,463,765	(0.99)	(1.16)	3,864,520	3,941,327
44	Difference in Percent		175.93	0.00	65.86	(32.35)	(34.52)	87.16	80.85

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: JUNE 2013

				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		1,226,224,000	0	1,226,224,000	2.67	3.03	32,709,000	37,112,000
2	Various	Economy Sales	38,592,000	0	38,592,000	3.07	3.37	1,183,000	1,301,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	367,000	367,000
4	TOTAL ESTIMATED SALES		1,264,816,000	0	1,264,816,000	2.71	3.07	34,259,000	38,780,000
	ACTUAL								
5	Southern Company Interchange		1,544,847,632	0	1,544,847,632	2.95	3.14	45,497,386	48,508,733
6	A.E.C.	External	3,785,024	0	3,785,024	2.99	3.70	113,136	140,138
7	AECI	External	229,693	0	229,693	2.57	3.94	5,912	9,046
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	0	0	0	0.00	0.00	2,114	0
10	CARGILE	External	3,184,477	0	3,184,477	2.83	3.26	90,250	103,886
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,056
13	EAGLE EN	External	1,077,037	0	1,077,037	2.76	3.60	29,768	38,752
14	ENDURE	External	73,171	0	73,171	3.34	4.49	2,446	3,285
15	ENTERGY	External	132,118	0	132,118	5.75	4.24	7,593	5,606
16	EXELON	External	2,797,044	0	2,797,044	3.04	3.37	85,110	94,244
17	FPC	External	689,466	0	689,466	3.33	4.43	22,962	30,545
18	FPL	External	378,490	0	378,490	3.11	4.22	11,789	15,987
19	JPMVEC	External	891,692	0	891,692	3.21	3.78	28,606	33,745
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	315	0	315	2.65	2.76	8	9
22	MORGAN	External	1,128,592	0	1,128,592	3.29	3.62	37,186	40,803
23	NCEMC	External	366,494	0	366,494	2.92	3.69	10,695	13,542
24	NRG	External	0	0	0	0.00	0.00	4,744	0
25	OGE	External	1,260	0	1,260	3.01	3.00	38	38
26	OPC	External	1,052,578	0	1,052,578	3.03	3.95	31,863	41,616
27	ORLANDO	External	17,619	0	17,619	3.57	5.40	628	951
28	PJM	External	7,620,629	0	7,620,629	2.93	3.56	223,526	271,058
29	SCE&G	External	2,541,312	0	2,541,312	3.46	5.02	88,019	127,618
30	SEC	External	953,113	0	953,113	3.30	3.88	31,406	36,981
31	SEPA	External	1,619,837	0	1,619,837	2.72	3.52	44,111	57,053
32	SPP	External	6,174	0	6,174	2.30	1.63	142	101
33	TAL	External	853,785	0	853,785	3.39	4.51	28,908	38,532
34	TEA	External	3,119,958	0	3,119,958	2.78	3.69	86,633	115,165
35	TECO	External	328,349	0	328,349	3.17	4.67	10,395	15,323
36	TVA	External	2,758,630	0	2,758,630	3.16	4.42	87,087	121,933
37	WRI	External	824,252	0	824,252	2.83	3.41	23,343	28,071
38	Less: Flow-Thru Energy		(36,936,934)	0	(36,936,934)	2.89	2.89	(1,069,061)	(1,069,061)
39	SEPA		10,285,000	10,285,000	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	81,832	81,832
41	Other transactions including adj.		808,226,413	777,526,475	30,699,938	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		2,363,882,927	787,811,475	1,576,071,452	1.93	2.07	45,643,179	48,853,738
43	Difference in Amount		1,099,066,927	787,811,475	311,255,452	(0.78)	(1.00)	11,384,179	10,073,738
44	Difference in Percent		86.90	0.00	24.61	(28.78)	(32.57)	33.23	25.98

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: JUNE 2013

(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 2013

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	5,531,000	0	0	0	7.63	7.63	422,291
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	32
5	Ascend Performance Materials	COG 1	11,849,000	0	0	0	3.58	3.58	424,239
6	International Paper	COG 1	103,000	0	0	0	4.53	4.53	4,662
7	TOTAL		17,483,000	0	0	0	4.87	4.87	851,224

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	19,785,000	0	0	0	7.63	7.63	1,510,344
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	47
5	Ascend Performance Materials	COG 1	113,367,000	0	0	0	3.11	3.11	3,524,789
6	International Paper	COG 1	622,000	0	0	0	3.45	3.45	21,479
7	TOTAL		133,774,000	0	0	0	3.78	3.78	5,056,658

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2013

	(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	58,085,000	5.21	3,027,000	312,431,000	3.83	11,966,000
2	Economy Energy	2,685,000	4.39	118,000	26,692,000	3.42	914,000
3	Other Purchases	557,029,000	2.74	15,275,000	2,646,512,000	2.92	77,361,000
4	TOTAL ESTIMATED PURCHASES	617,799,000	2.98	18,420,000	2,985,635,000	3.02	90,241,000
	ACTUAL						
5	Southern Company Interchange	30,609,715	3.41	1,044,491	363,808,339	3.25	11,836,274
6	Non-Associated Companies	76,304,663	1.18	902,601	312,769,701	0.99	3,110,101
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	454,477,000	3.48	15,800,392	2,508,094,000	3.28	82,364,448
9	Other Wheeled Energy	41,896,000	0.00	N/A	129,766,000	0.00	N/A
10	Other Transactions	82,207,624	(0.03)	(21,686)	481,362,952	0.02	80,063
11	Less: Flow-Thru Energy	(2,795,295)	3.80	(106,304)	(36,936,934)	3.10	(1,146,100)
12	TOTAL ACTUAL PURCHASES	682,699,707	2.58	17,619,494	3,758,864,058	2.56	96,244,786
13	Difference in Amount	64,900,707	(0.40)	(800,506)	773,229,058	(0.46)	6,003,786
14	Difference in Percent	10.51	(13.42)	(4.35)	25.90	(15.23)	6.65

2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	SUBTOTAL $
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		**$ 2,045,794**		**$ 2,596,589**		**$ 6,777,892**	**$ 18,088,765**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

SCHEDULE A-12
PAGE 2 OF 2

2013 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	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													717,566
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													17,397,975
2 Other Confidential Agreements	Other	Varies	Varies													(26,776)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 17,371,199
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 18,088,765

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

JULY 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2013
CURRENT MONTH

		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)	42,481,217	43,478,416	(1,017,199)	(2.34)	933,979,000	1,012,129,000	(78,150,000)	(7.72)	4.5463	4.2957	0.25	5.83
2	Hedging Settlement Costs (A2)	1,893,990	0	1,893,990	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) **	(11,432)	0	(11,432)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	44,143,775	43,478,416	665,359	1.53	933,979,000	1,012,129,000	(78,150,000)	(7.72)	4.7264	4.2957	0.43	10.03
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)	18,329,136	21,784,000	(3,454,864)	(15.86)	693,843,115	638,908,000	54,935,115	8.60	2.6417	3.4096	(0.77)	(22.52)
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)	715,856	0	715,856	100.00	17,468,000	0	17,468,000	100.00	4.0934	0.0000	4.09	0.00
12	TOTAL COST OF PURCHASED POWER	19,044,992	21,784,000	(2,739,008)	(12.57)	711,331,115	638,908,000	72,423,115	11.34	2.6774	3.4096	(0.73)	(21.47)
13	Total Available MWH (Line 5 + Line 12)	63,188,767	65,262,416	(2,073,649)	(3.18)	1,645,310,115	1,651,037,000	(5,726,885)	(0.35)				
14	Fuel Cost of Economy Sales (A6)	(130,232)	(186,000)	55,768	(29.98)	(3,824,063)	(4,339,000)	714,937	(16.48)	(3.5935)	(4.2867)	0.69	16.17
15	Gain on Economy Sales (A6)	(18,557)	(78,000)	61,443	(78.77)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(10,038,023)	(14,392,000)	4,353,977	(30.25)	(459,174,442)	(318,178,000)	(140,996,442)	44.31	(2.1861)	(4.5233)	2.34	51.67
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(10,184,812)	(14,656,000)	4,471,188	(30.51)	(462,798,505)	(322,517,000)	(140,281,505)	43.50	(2.2007)	(4.5443)	2.34	51.57
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)	53,003,955	50,606,416	2,397,539	4.74	1,182,511,610	1,328,520,000	(146,008,390)	(10.99)	4.4823	3.8092	0.67	17.67
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 *	79,634	69,518	10,316	14.84	1,781,096	1,825,000	(43,904)	(2.41)	4.4823	3.8092	0.67	17.67
22	T & D Losses *	2,758,173	3,576,382	(820,209)	(22.93)	61,490,141	93,868,000	(32,397,859)	(34.51)	4.4823	3.8092	0.67	17.67
23	TERRITORIAL KWH SALES	53,003,955	50,606,416	2,397,539	4.74	1,118,240,373	1,232,807,000	(113,566,627)	(9.21)	4.7357	4.1050	0.63	15.36
24	Wholesale KWH Sales	1,399,464	1,413,336	(13,872)	(0.98)	29,550,909	34,430,000	(4,879,091)	(14.17)	4.7358	4.1050	0.63	15.37
25	Jurisdictional KWH Sales	51,604,491	49,193,080	2,411,411	4.90	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	4.7357	4.1050	0.63	15.36
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	51,681,896	49,266,870	2,415,026	4.90	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	4.7428	4.1111	0.63	15.37
28	TRUE-UP	(2,202,116)	(2,202,118)	0	0.00	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	(0.2021)	(0.1838)	(0.02)	9.96
29	TOTAL JURISDICTIONAL FUEL COST	49,479,780	47,064,752	2,415,028	5.13	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	4.5407	3.9273	0.61	15.62
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5440	3.9301	0.61	15.62
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	0.0080	0.0072	0.00	11.11
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5520	3.9373	0.61	15.61
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.552	3.937		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 42,461,217
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	(11,432)
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,693,990
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	18,329,136
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	715,856
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,184,812)
10	Total Fuel and Net Power Transactions		$ 53,003,955

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2013
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)	207,757,078	210,437,850	(2,680,772)	(1.27)	4,806,441,000	5,130,828,000	(324,387,000)	(6.32)	4.3225	4.1014	0.22	5.39
2	Hedging Settlement Costs (A2)	8,479,894	0	8,479,894	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) **	110,872	0	110,872	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	216,347,844	210,437,850	5,909,994	2.81	4,806,441,000	5,130,828,000	(324,387,000)	(6.32)	4.5012	4.1014	0.40	9.75
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)	114,573,922	112,025,000	2,548,922	2.28	4,452,707,173	3,624,543,000	828,164,173	22.85	2.5731	3.0907	(0.52)	(16.75)
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)	5,772,514	0	5,772,514	100.00	151,262,000	0	151,262,000	100.00	3.8162	0.0000	3.82	0.00
12	TOTAL COST OF PURCHASED POWER	120,346,436	112,025,000	8,321,436	7.43	4,603,969,173	3,624,543,000	979,426,173	27.02	2.6140	3.0907	(0.48)	(15.42)
13	Total Available MWH (Line 5 + Line 12)	336,694,280	322,462,850	14,231,430	4.41	9,410,410,173	8,755,371,000	655,039,173	7.48				
14	Fuel Cost of Economy Sales (A6)	(1,263,255)	(1,369,000)	105,745	(7.72)	(41,084,679)	(42,931,000)	1,846,121	(4.30)	(3.0747)	(3.1688)	0.11	3.56
15	Gain on Economy Sales (A6)	(96,389)	(445,000)	348,611	(77.89)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(54,466,348)	(47,101,000)	(7,365,348)	15.64	(2,785,596,553)	(1,544,402,000)	(1,241,194,553)	80.37	(1.9553)	(3.0498)	1.09	35.89
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(55,827,992)	(48,915,000)	(6,912,992)	14.13	(2,826,681,432)	(1,587,333,000)	(1,239,348,432)	78.08	(1.9750)	(3.0816)	1.11	35.91
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)	280,866,288	273,547,850	7,318,438	2.68	6,583,728,741	7,188,038,000	(584,309,259)	(8.15)	4.2661	3.8162	0.45	11.79
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 *	502,845	481,757	21,088	4.38	11,787,000	12,624,000	(837,000)	(6.63)	4.2661	3.8162	0.45	11.79
22	T & D Losses *	14,253,690	15,312,388	(1,058,698)	(6.91)	334,115,238	401,247,000	(67,131,762)	(16.73)	4.2661	3.8162	0.45	11.79
23	TERRITORIAL KWH SALES	280,686,289	273,547,850	7,318,439	2.68	6,237,826,503	6,754,167,000	(516,340,497)	(7.64)	4.5026	4.0501	0.45	11.17
24	Wholesale KWH Sales	8,007,981	8,574,729	(566,748)	(6.61)	178,212,525	211,538,000	(33,325,475)	(15.75)	4.4935	4.0535	0.44	10.85
25	Jurisdictional KWH Sales	272,658,308	264,973,121	7,685,187	2.98	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)	4.5029	4.0499	0.45	11.19
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	273,267,596	265,370,580	7,897,016	2.98	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)	4.5097	4.0580	0.45	11.19
28	TRUE-UP	(15,414,826)	(15,414,826)	0	0.00	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)	(0.2644)	(0.2358)	(0.02)	7.96
29	TOTAL JURISDICTIONAL FUEL COST	257,852,770	249,955,754	7,897,016	3.16	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)	4.2553	3.8204	0.43	11.36
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2584	3.8232	0.44	11.36
32	GPIF Reward / (Penalty)	807,054	807,054	0	0.00	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)	0.0100	0.0093	0.00	7.53
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2684	3.8325	0.44	11.37
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.268	3.833		

* 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: JULY 2013

		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	42,290,147.97	43,191,597	(901,449.03)	(2.09)	206,324,661.97	209,349,663	(3,025,001.03)	(1.44)
1a	Other Generation	171,068.92	286,819	(115,750.08)	(40.36)	1,432,415.97	1,088,187	344,228.97	31.63
2	Fuel Cost of Power Sold	(10,184,811.61)	(14,656,000)	4,471,188.39	30.51	(55,827,991.79)	(48,915,000)	(6,912,991.79)	(14.13)
3	Fuel Cost - Purchased Power	18,329,135.73	21,784,000	(3,454,864.27)	(15.86)	114,573,921.85	112,025,000	2,548,921.85	2.28
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	715,855.91	0	715,855.91	100.00	5,772,513.91	0	5,772,513.91	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,693,990.00	0	1,693,990.00	100.00	8,479,894.00	0	8,479,894.00	100.00
6	Total Fuel & Net Power Transactions	53,015,386.92	50,606,416	2,408,970.92	4.76	280,755,415.91	273,547,850	7,207,565.91	2.63
7	AdjustmentsTo Fuel Cost*	(11,432.02)	0	(11,432.02)	100.00	110,872.35	0	110,872.35	100.00
8	Adj. Total Fuel & Net Power Transactions	53,003,954.90	50,606,416	2,397,538.90	4.74	280,866,288.26	273,547,850	7,318,438.26	2.68
B.	*KWH Sales*								
1	Jurisdictional Sales	1,089,689,464	1,198,377,000	(108,687,536)	(9.07)	6,059,613,978	6,542,629,000	(483,015,022)	(7.38)
2	Non-Jurisdictional Sales	29,550,909	34,430,000	(4,879,091)	(14.17)	178,212,525	211,538,000	(33,325,475)	(15.75)
3	Total Territorial Sales	1,119,240,373	1,232,807,000	(113,566,627)	(9.21)	6,237,826,503	6,754,167,000	(516,340,497)	(7.64)
4	Juris. Sales as % of Total Terr. Sales	97.3597	97.2072	0.1525	0.16	97.1430	96.8680	0.2750	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: JULY 2013

C.	*True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	41,392,283.97	45,574,277	(4,181,993.34)	(9.18)	229,996,273.23	248,816,181	(18,819,907.64)	(7.56)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	15,414,826.00	15,414,826	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(606,613.00)	(606,613)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	43,507,742.97	47,689,736	(4,181,993.03)	(8.77)	244,804,486.23	263,624,394	(18,819,907.77)	(7.14)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	53,003,954.90	50,606,416	2,397,538.90	4.74	280,866,288.65	273,547,850	7,318,438.65	2.68
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3597	97.2072	0.1525	0.16	97.1430	96.8680	0.2750	0.28
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	51,681,898.22	49,266,870	2,415,028.22	4.90	273,267,597.33	265,370,580	7,897,017.33	2.98
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(8,174,155.25)	(1,577,134)	(6,597,021.25)	(418.29)	(28,463,111.10)	(1,746,186)	(26,716,925.10)	(1,530.02)
8	Interest Provision for the Month	(382.31)	513	(895.31)	174.52	1,114.81	7,728	(6,613.19)	85.57
9	Beginning True-Up & Interest Provision	(16,408,443.59)	13,050,873	(29,459,316.59)	225.73	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(15,414,826.00)	(15,414,826)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(26,785,099.15)	9,272,134	(36,057,233.15)	388.88	(26,785,099.15)	9,272,134	(36,057,233.15)	388.88
12	Adjustment	26,571,082.26	0	26,571,082.26	100.00	26,571,082.26	0	26,571,082.26	100.00
13	End of Period - Total Net True-Up	(214,016.89)	9,272,134	(9,486,150.89)	102.31	(214,016.89)	9,272,134	(9,486,150.89)	102.31

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

		CURRENT MONTH			
		$		DIFFERENCE	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	(16,408,443.59)	13,050,873	(29,459,316.59)	(225.73)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(213,634.58)	9,271,621	(9,485,255.58)	(102.30)
3	Total of Beginning & Ending True-Up Amts.	(16,622,078.17)	22,322,494	(38,944,572.17)	(174.46)
4	Average True-Up Amount	(8,311,039.09)	11,161,247	(19,472,286.09)	(174.46)
	Interest Rate				
5	1st Day of Reporting Business Month	0.06	0.06	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.05	0.05	0.0000	
7	Total (D5+D6)	0.11	0.11	0.0000	
8	Annual Average Interest Rate	0.06	0.06	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0046	0.0046	0.0000	
10	Interest Provision (D4*D9)	(382.31)	513	(895.31)	(174.52)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	115,492	138,937	(23,445)	(16.87)	1,150,241	542,530	607,711	112.01
2	COAL	30,605,834	31,004,467	(398,633)	(1.29)	136,746,968	135,669,434	1,077,534	0.79
3	GAS	11,584,533	12,261,473	(676,940)	(5.52)	68,951,577	73,753,206	(4,801,629)	(6.51)
4	GAS (B.L.)	83,159	0	83,159	100.00	363,987	-	363,987	100.00
5	LANDFILL GAS	62,369	56,112	6,257	11.15	419,288	405,451	13,835	3.41
6	OIL - C.T.	9,829	17,427	(7,598)	(43.60)	125,019	67,229	57,790	85.96
7	TOTAL ($)	42,461,217	43,478,416	(1,017,199)	(2.34)	207,757,078	210,437,850	(2,680,772)	(1.27)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	615,776	654,428	(38,652)	(5.91)	2,774,673	2,702,931	71,742	2.65
10	GAS	316,143	355,537	(39,394)	(11.08)	2,017,181	2,412,435	(395,254)	(16.38)
11	LANDFILL GAS	2,048	2,100	(52)	(2.48)	14,216	15,174	(958)	(6.31)
12	OIL - C.T.	12	64	(52)	(81.25)	371	288	83	28.82
13	TOTAL (MWH)	933,979	1,012,129	(78,150)	(7.72)	4,806,441	5,130,828	(324,387)	(6.32)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	902	1,094	(192)	(17.55)	8,780	4,526	4,254	93.99
15	COAL (TONS)	293,402	299,919	(6,517)	(2.17)	1,312,600	1,275,863	36,737	2.88
16	GAS (MCF) (1)	2,265,805	2,441,784	(175,979)	(7.21)	14,387,551	16,848,095	(2,280,544)	(13.70)
17	OIL - C.T. (BBL)	88	154	(66)	(42.86)	1,144	623	521	83.63
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	14,704,973	7,068,370	7,638,603	108.04	38,586,094	30,003,035	8,583,059	28.61
19	GAS - Generation (1)	2,293,945	2,515,037	(221,092)	(8.79)	14,492,627	16,428,930	(1,936,303)	(11.79)
20	OIL - C.T.	515	900	(385)	(42.78)	6,658	3,650	3,008	82.41
21	TOTAL (MMBTU)	16,999,433	9,584,307	7,415,126	77.37	53,085,379	46,435,615	6,649,764	14.32
	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	65.93	64.65	1.28	1.98	57.72	52.67	5.05	9.59
24	GAS	33.85	35.13	(1.28)	(3.64)	41.97	47.02	(5.05)	(10.74)
25	LANDFILL GAS	0.22	0.21	0.01	4.76	0.30	0.30	0.00	0.00
26	OIL - C.T.	0.00	0.01	(0.01)	(100.00)	0.01	0.01	0.00	0.00
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)	128.02	127.00	1.02	0.80	131.00	119.87	11.13	9.29
29	COAL ($/TON)	104.31	103.38	0.93	0.90	104.18	106.34	(2.16)	(2.03)
30	GAS ($/MCF) (1)	5.07	4.94	0.13	2.63	4.72	4.37	0.35	8.01
31	OIL - C.T. ($/BBL)	111.70	113.16	(1.46)	(1.29)	109.28	107.91	1.37	1.27
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	2.09	4.41	(2.32)	(52.61)	3.58	4.54	(0.96)	(21.15)
33	GAS - Generation (1)	4.98	4.79	0.19	3.97	4.66	4.43	0.23	5.19
34	OIL - C.T.	19.09	19.36	(0.27)	(1.39)	18.78	18.42	0.36	1.95
35	TOTAL ($/MMBTU)	2.48	4.51	(2.03)	(45.01)	3.88	4.50	(0.62)	(13.78)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	23,880	10,801	13,079	121.09	13,907	11,100	2,807	25.29
37	GAS - Generation (1)	7,369	7,189	180	2.50	7,339	6,890	449	6.52
38	OIL - C.T.	42,917	14,063	28,854	205.18	17,946	12,674	5,272	41.60
39	TOTAL (BTU/KWH)	18,336	9,543	8,793	92.14	11,177	9,127	2,050	22.46
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.00	4.76	0.24	5.04	4.98	5.04	(0.06)	(1.19)
41	GAS	3.66	3.45	0.21	6.09	3.42	3.06	0.36	11.76
42	LANDFILL GAS	3.05	2.67	0.38	14.23	2.95	2.67	0.28	10.49
43	OIL - C.T.	81.91	27.23	54.68	200.81	33.70	23.34	10.36	44.39
44	TOTAL (¢/KWH)	4.55	4.30	0.25	5.81	4.32	4.10	0.22	5.37

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	7,751	13.9	100.0	54.5	11,824	Coal	3,993.0	11,476	91,646	394,646	5.09	98.83
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	484	1,018	492	5,044		10.42
4									Oil-S	102	137,922	588	12,904		126.51
5	Crist 5		75	27,889	50.0	100.0	65.4	10,822	Coal	13,142	11,483	301,828	1,298,933	4.66	98.84
6				-					Gas-G	0	1,016	0	0	0.00	0.00
7									Gas-S	1,500	1,016	1,524	15,621		10.41
8									Oil-S	101	137,922	582	12,781		126.54
9	Crist 6		299	141,165	63.8	100.0	63.8	10,523	Coal	64,292	11,552	1,485,420	6,354,389	4.50	98.84
10				755					Gas-G	7,817	1,016	7,942	81,395	10.78	10.41
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	7	137,922	38	844		120.57
13	Crist 7		475	156,749	44.4	95.4	54.1	10,944	Coal	74,867	11,457	1,715,513	7,399,543	4.72	98.84
14				0					Gas-G	0	1,016	0	0	0.00	0.00
15									Gas-S	6,001	1,016	6,097	62,494		10.41
16									Oil-S	48	137,922	281	6,168		128.50
17	Scholz 1		46	(234)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(178)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	57,056	47.3	99.6	47.5	10,959	Coal	27,078	11,546	625,293	2,848,993	4.99	105.21
22									Oil-S	203	138,574	1,181	26,053		128.34
23	Smith 2		195	52,945	36.5	95.0	38.4	11,260	Coal	25,945	11,489	596,154	2,729,702	5.16	105.21
24									Oil-S	417	138,574	2,435	53,730		128.85
25	Smith 3		556	310,540	75.1	99.4	87.1	7,361	Gas-G	2,250,003	1,016	2,286,003	11,332,070	3.65	5.04
26	Smith A	(2)	32	12	0.1	89.7	35.7	42,917	Oil	88	139,136	515	9,829	81.91	111.69
27	Other Generation			4,848									171,069	3.53	0.00
28	Perdido			2,048					Landfill Gas				62,389	3.05	0.00
29	Daniel 1	(1)	255	88,630	46.7	100.0	46.7	10,662	Coal	43,137	10,953	944,931	4,811,603	5.43	111.54
30									Oil-S	2	137,894	12	271		135.50
31	Daniel 2	(1)	255	84,003	44.3	100.0	44.3	106,316	Coal	40,948	109,052	8,930,833	4,567,434	5.44	111.54
32				-					Oil-S	22	137,894	125	2,740		124.55
33	Total		2,471	933,979	50.8	98.4	57.4	18,338				16,999,433	42,260,625	4.52	

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)	
	Coal Additive - Crist	204,651	
	Recoverable Fuel	42,461,217	4.55

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	2,557	1,091	1,466	134.37	9,340	4,523	4,817	106.50
3	UNIT COST ($/BBL)	131.43	126.29	5.14	4.07	129.73	119.62	10.11	8.45
4	AMOUNT ($)	336,076	137,767	198,289	143.91	1,211,693	541,035	670,658	123.96
5	*BURNED:*								
6	UNITS (BBL)	985	1,094	(109)	(9.96)	9,183	4,526	4,657	102.89
7	UNIT COST ($/BBL)	128.04	127.00	1.04	0.82	131.00	119.87	11.13	9.29
8	AMOUNT ($)	126,117	138,937	(12,820)	(9.23)	1,202,936	542,530	660,406	121.73
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	6,125	4,550	1,575	34.62	6,125	4,550	1,575	34.62
11	UNIT COST ($/BBL)	127.31	124.98	2.33	1.86	127.31	124.98	2.33	1.86
12	AMOUNT ($)	779,775	568,666	211,109	37.12	779,775	568,666	211,109	37.12
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	161,262	212,300	(51,038)	(24.04)	1,057,935	1,109,009	(51,074)	(4.61)
16	UNIT COST ($/TON)	101.86	102.44	(0.58)	(0.57)	102.23	104.57	(2.34)	(2.24)
17	AMOUNT ($)	16,425,989	21,748,002	(5,322,013)	(24.47)	108,154,055	115,974,127	(7,820,072)	(6.74)
18	*BURNED:*								
19	UNITS (TONS)	293,402	299,919	(6,517)	(2.17)	1,312,600	1,275,863	36,737	2.88
20	UNIT COST ($/TON)	103.63	103.38	0.25	0.24	103.27	106.34	(3.07)	(2.89)
21	AMOUNT ($)	30,405,242	31,004,467	(599,225)	(1.93)	135,555,911	135,669,434	(113,523)	(0.08)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	683,542	726,063	(44,521)	(6.11)	683,542	728,063	(44,521)	(6.11)
24	UNIT COST ($/TON)	104.57	104.66	(0.09)	(0.09)	104.57	104.66	(0.09)	(0.09)
25	AMOUNT ($)	71,476,760	76,199,548	(4,722,788)	(6.20)	71,476,760	76,199,548	(4,722,788)	(6.20)
26	DAYS SUPPLY	32	35	(3)	(8.57)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,302,057	2,515,037	(212,980)	(8.47)	14,602,214	16,428,930	(1,826,716)	(11.12)
29	UNIT COST ($/MMBTU)	4.88	4.76	0.12	2.52	4.72	4.42	0.30	6.79
30	AMOUNT ($)	11,243,345	11,974,654	(731,309)	(6.11)	68,975,576	72,665,019	(3,689,443)	(5.08)
31	*BURNED:*								
32	UNITS (MMBTU)	2,302,057	2,515,037	(212,980)	(8.47)	14,533,853	16,428,930	(1,895,077)	(11.53)
33	UNIT COST ($/MMBTU)	4.99	4.76	0.23	4.83	4.67	4.42	0.25	5.66
34	AMOUNT ($)	11,496,623	11,974,654	(478,031)	(3.99)	67,883,148	72,665,019	(4,781,871)	(6.58)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	849,667	0	849,667	100.00	849,667	0	849,667	100.00
37	UNIT COST ($/MMBTU)	4.96	0.00	4.96	100.00	4.96	0.00	4.96	100.00
38	AMOUNT ($)	4,211,930	0	4,211,930	100.00	4,211,930	0	4,211,930	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	361	154	207	134.42	1,308	623	683	109.63
41	UNIT COST ($/BBL)	127.38	126.49	0.89	0.70	131.65	119.90	12.00	10.01
42	AMOUNT ($)	45,985	19,480	26,505	136.06	171,929	74,696	97,233	130.17
43	*BURNED:*								
44	UNITS (BBL)	88	154	(66)	(42.86)	1,144	623	521	83.63
45	UNIT COST ($/BBL)	111.69	113.16	(1.47)	(1.30)	109.28	107.91	1.37	1.27
46	AMOUNT ($)	9,829	17,427	(7,598)	(43.60)	125,018	67,229	57,789	85.96
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,118	5,845	273	4.67	6,118	5,845	273	4.67
49	UNIT COST ($/BBL)	111.51	110.88	0.63	0.57	111.51	110.88	0.63	0.57
50	AMOUNT ($)	682,225	648,122	34,103	5.26	682,225	648,122	34,103	5.26
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
		TYPE	TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	TOTAL
	SOLD TO	AND SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJ.	COST $
	ESTIMATED								
1	Southern Company Interchange		318,178,000	0	318,178,000	4.52	4.76	14,392,000	15,154,000
2	Various	Economy Sales	4,339,000	0	4,339,000	4.29	4.56	186,000	198,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	78,000	78,000
4	TOTAL ESTIMATED SALES		322,517,000	0	322,517,000	4.54	4.78	14,656,000	15,430,000
	ACTUAL								
5	Southern Company Interchange		318,748,219	0	318,748,219	3.19	3.38	10,158,480	10,765,218
6	A.E.C.	External	125,827	0	125,827	3.16	3.99	3,978.45	5,027
7	AECI	External	50,331	0	50,331	3.28	4.94	1,648.70	2,485
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	CALPINE	External	0	0	0	0.00	0.00	0.00	0
10	CARGILE	External	232,142	0	232,142	2.55	3.05	5,920.00	7,079
11	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
12	DUKE PWR	External	0	0	0	0.00	0.00	0.00	0
13	EAGLE EN	External	67,568	0	67,568	3.99	5.35	2,694.74	3,617
14	ENDURE	External	0	0	0	0.00	0.00	0.00	0
15	ENTERGY	External	75,498	0	75,498	3.22	5.20	2,429.32	3,926
16	EXELON	External	45,611	0	45,611	3.31	4.26	1,511.28	1,943
17	FPC	External	59,770	0	59,770	3.13	3.95	1,869.55	2,361
18	FPL	External	0	0	0	0.00	0.00	44.97	0
19	JPMVEC	External	0	0	0	0.00	0.00	0.00	0
20	MERRILL	External	0	0	0	0.00	0.00	0.00	0
21	MISO	External	0	0	0	0.00	0.00	0.00	0
22	MORGAN	External	6,292	0	6,292	2.78	3.40	174.85	214
23	NCEMC	External	251,049	0	251,049	3.33	4.01	8,360.15	10,059
24	NRG	External	6,291	0	6,291	2.59	3.50	163.19	220
25	OGE	External	0	0	0	0.00	0.00	0.00	0
26	OPC	External	18,874	0	18,874	3.18	4.07	599.50	768
27	ORLANDO	External	0	0	0	0.00	0.00	0.00	0
28	PJM	External	1,006,245	0	1,006,245	4.29	5.55	43,152.52	55,841
29	SCE&G	External	206,351	0	206,351	3.31	6.04	6,828.74	12,457
30	SEC	External	113,868	0	113,868	3.00	3.95	3,412.16	4,494
31	SEPA	External	28,813	0	28,813	3.37	5.00	971.15	1,440
32	SPP	External	0	0	0	0.00	0.00	0.00	0
33	TAL	External	0	0	0	0.00	0.00	0.00	0
34	TEA	External	541,928	0	541,928	3.69	5.74	19,987.44	31,122
35	TECO	External	0	0	0	0.00	0.00	0.00	0
36	TVA	External	483,298	0	483,298	3.23	4.47	15,625.88	21,583
37	WRI	External	304,307	0	304,307	3.57	4.00	10,859.72	12,172
38	Less: Flow-Thru Energy		(3,605,568)	0	(3,605,566)	3.34	3.34	(120,457)	(120,457)
39	SEPA		2,799,458	2,799,456	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	16,557	16,557
41	Other transactions including adj.		141,232,333	143,963,765	(2,731,432)	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		462,798,505	146,763,221	316,035,284	2.20	2.34	10,184,812	10,821,567
43	Difference in Amount		140,281,505	146,763,221	(6,481,716)	(2.34)	(2.44)	(4,471,188)	(4,608,433)
44	Difference in Percent		43.50	0.00	(2.01)	(51.54)	(51.05)	(30.51)	(29.87)

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 40

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

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		1,544,402,000	0	1,544,402,000	3.05	3.38	47,101,000	52,266,000
2	Various	Economy Sales	42,931,000	0	42,931,000	3.19	3.49	1,369,000	1,499,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	445,000	445,000
4	TOTAL ESTIMATED SALES		1,587,333,000	0	1,587,333,000	3.08	3.42	48,915,000	54,210,000
	ACTUAL								
5	Southern Company Interchange		1,863,595,851	0	1,863,595,851	2.99	3.18	55,655,866	59,273,951
6	A.E.C.	External	3,910,851	0	3,910,851	2.99	3.71	117,115	145,165
7	AECI	External	280,024	0	280,024	2.70	4.12	7,560	11,531
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	0	0	0	0.00	0.00	2,114	0
10	CARGILE	External	3,416,619	0	3,416,619	2.81	3.25	96,170	110,964
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,056
13	EAGLE EN	External	1,144,605	0	1,144,605	2.84	3.70	32,463	42,369
14	ENDURE	External	73,171	0	73,171	3.34	4.49	2,446	3,285
15	ENTERGY	External	207,616	0	207,616	4.83	4.59	10,022	9,531
16	EXELON	External	2,842,655	0	2,842,655	3.05	3.38	86,621	96,187
17	FPC	External	749,236	0	749,236	3.31	4.39	24,832	32,906
18	FPL	External	378,490	0	378,490	3.13	4.22	11,834	15,987
19	JPMVEC	External	891,692	0	891,692	3.21	3.78	28,606	33,745
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	315	0	315	2.65	2.76	8	9
22	MORGAN	External	1,134,884	0	1,134,884	3.29	3.61	37,360	41,016
23	NCEMC	External	617,543	0	617,543	3.09	3.82	19,056	23,601
24	NRG	External	6,291	0	6,291	78.00	3.50	4,907	220
25	OGE	External	1,260	0	1,260	3.01	3.00	38	38
26	OPC	External	1,071,452	0	1,071,452	3.03	3.96	32,463	42,384
27	ORLANDO	External	17,619	0	17,619	3.57	5.40	628	951
28	PJM	External	8,626,874	0	8,826,874	3.09	3.79	266,678	328,899
29	SCE&G	External	2,747,663	0	2,747,663	3.45	5.10	94,848	140,075
30	SEC	External	1,066,981	0	1,066,981	3.26	3.89	34,818	41,475
31	SEPA	External	1,648,650	0	1,648,650	2.73	3.55	45,082	58,493
32	SPP	External	6,174	0	6,174	2.30	1.63	142	101
33	TAL	External	853,785	0	853,785	3.39	4.51	28,908	38,532
34	TEA	External	3,661,886	0	3,661,886	2.91	3.99	106,821	146,286
35	TECO	External	328,349	0	328,349	3.17	4.67	10,395	15,323
36	TVA	External	3,241,928	0	3,241,928	3.17	4.43	102,713	143,516
37	WRI	External	1,128,559	0	1,128,559	3.03	3.57	34,203	40,243
38	Less: Flow-Thru Energy		(40,542,500)	0	(40,542,500)	2.93	2.93	(1,189,518)	(1,189,518)
39	SEPA		13,084,456	13,084,456	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	98,389	98,389
41	Other transactions including adj.		949,458,746	921,490,240	27,968,506	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		2,826,681,432	934,574,696	1,892,106,736	1.98	2.11	55,827,992	59,675,305
43	Difference in Amount		1,239,348,432	934,574,696	304,773,736	(1.10)	(1.31)	6,912,992	5,465,305
44	Difference in Percent		78.08	0.00	19.20	(35.71)	(38.30)	14.13	10.08

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 40

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JULY 2013

(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								

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2013 Final True-Up Filing
Exhibit RWD-1, Page 123 of 212

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

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	3,439,000	0	0	0	7.64	7.64	262,575
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	13,966,000	0	0	0	3.23	3.23	450,676
6 International Paper	COG 1	83,000	0	0	0	3.14	3.14	2,605
7 TOTAL		17,488,000	0	0	0	4.09	4.09	715,856

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	23,224,000	0	0	0	7.63	7.63	1,772,918
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	47
5 Ascend Performance Materials	COG 1	127,333,000	0	0	0	3.12	3.12	3,975,465
6 International Paper	COG 1	705,000	0	0	0	3.42	3.42	24,083
7 TOTAL		151,262,000	0	0	0	3.82	3.82	5,772,514

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2013

	(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	5,166,000	4.10	212,000	317,597,000	3.83	12,178,000
2	Economy Energy	2,878,000	5.14	148,000	29,570,000	3.59	1,062,000
3	Other Purchases	630,864,000	3.40	21,424,000	3,277,376,000	3.01	98,785,000
4	TOTAL ESTIMATED PURCHASES	638,908,000	3.41	21,784,000	3,624,543,000	3.09	112,025,000
	ACTUAL						
5	Southern Company Interchange	44,100,420	3.34	1,473,589	407,908,759	3.26	13,309,863
6	Non-Associated Companies	62,896,164	0.63	395,170	375,665,865	0.93	3,505,271
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	494,594,000	3.35	16,586,965	3,002,688,000	3.30	98,951,413
9	Other Wheeled Energy	24,304,000	0.00	N/A	154,070,000	0.00	N/A
10	Other Transactions	71,554,097	0.00	2,081	552,917,049	0.01	82,144
11	Less: Flow-Thru Energy	(3,605,566)	3.57	(128,669)	(40,542,500)	3.14	(1,274,769)
12	TOTAL ACTUAL PURCHASES	693,843,115	2.64	18,329,136	4,452,707,173	2.57	114,573,922
13	Difference in Amount	54,935,115	(0.77)	(3,454,864)	828,164,173	(0.52)	2,548,922
14	Difference in Percent	8.60	(22.58)	(15.86)	22.85	(16.83)	2.28

2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,267	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,267		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					$ 2,380,170		$ 1,898,537		$ 2,389,783		$ 2,045,794		$ 2,596,589		$ 6,777,892	$ 18,088,765

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

2013 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	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -		$ -		$ -		$ -		$ -		$ -	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443											24,664,418
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)											(29,922)
SUBTOTAL					$ 7,263,297		$ -		$ -		$ -		$ -		$ -	$ 24,634,496
TOTAL					**$ 7,263,297**		**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 25,352,062**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

August 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2013
CURRENT MONTH

		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)	34,516,338	39,805,899	(5,289,561)	(13.29)	797,972,000	933,250,000	(135,278,000)	(14.50)	4.3255	4.2653	0.06	1.41
2	Hedging Settlement Costs (A2)	2,385,644	0	2,385,644	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) **	44,251	0	44,251	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	36,946,233	39,805,899	(2,859,666)	(7.18)	797,972,000	933,250,000	(135,278,000)	(14.50)	4.6300	4.2653	0.36	8.55
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)	17,700,713	22,937,000	(5,236,287)	(22.83)	761,700,475	663,438,000	98,262,475	14.81	2.3238	3.4573	(1.13)	(32.79)
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)	862,376	0	862,376	100.00	21,727,000	0	21,727,000	100.00	3.9691	0.0000	3.97	0.00
12	TOTAL COST OF PURCHASED POWER	18,563,089	22,937,000	(4,373,911)	(19.07)	783,427,475	663,438,000	119,989,475	18.09	2.3695	3.4573	(1.09)	(31.46)
13	Total Available MWH (Line 5 + Line 12)	55,509,322	62,742,899	(7,233,577)	(11.53)	1,581,399,475	1,596,688,000	(15,288,525)	(0.96)				
14	Fuel Cost of Economy Sales (A6)	(118,809)	(243,000)	124,191	(51.11)	(3,925,799)	(5,755,000)	1,829,201	(31.78)	(3.0264)	(4.2224)	1.20	28.33
15	Gain on Economy Sales (A6)	7,607	(66,000)	73,607	(111.53)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(5,419,703)	(13,200,000)	7,780,297	(58.94)	(371,916,202)	(280,190,000)	(91,726,202)	32.74	(1.4572)	(4.7111)	3.25	69.07
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(5,530,905)	(13,509,000)	7,978,095	(59.06)	(375,842,001)	(285,945,000)	(89,897,001)	31.44	(1.4716)	(4.7243)	3.25	68.85
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)	49,978,417	49,233,899	744,518	1.51	1,205,557,474	1,310,743,000	(105,185,526)	(8.02)	4.1457	3.7562	0.39	10.37
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 *	70,037	78,692	(8,655)	(11.00)	1,689,399	2,095,000	(405,601)	(19.36)	4.1457	3.7562	0.39	10.37
22	T & D Losses *	2,449,531	3,459,535	(1,010,004)	(29.19)	59,086,059	92,102,000	(33,015,941)	(35.85)	4.1457	3.7562	0.39	10.37
23	TERRITORIAL KWH SALES	49,978,416	49,233,899	744,518	1.51	1,144,782,016	1,216,546,000	(71,763,984)	(5.90)	4.3658	4.0470	0.32	7.88
24	Wholesale KWH Sales	1,342,120	1,409,173	(67,053)	(4.76)	30,742,395	34,820,000	(4,077,605)	(11.71)	4.3657	4.0470	0.32	7.87
25	Jurisdictional KWH Sales	48,636,296	47,824,726	811,570	1.70	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	4.3658	4.0470	0.32	7.88
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	48,709,250	47,896,463	812,787	1.70	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	4.3723	4.0531	0.32	7.88
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	(0.1977)	(0.1863)	(0.01)	6.12
29	TOTAL JURISDICTIONAL FUEL COST	46,507,132	45,694,345	812,787	1.78	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	4.1746	3.8668	0.31	7.96
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1776	3.8696	0.31	7.96
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	0.0078	0.0073	0.00	6.85
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1854	3.8769	0.31	7.96
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.185	3.877		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 34,516,338
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	44,251
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,385,644
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	17,700,713
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	862,376
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(5,530,905)
10	Total Fuel and Net Power Transactions		$ 49,978,417

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2013
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)	242,273,416	250,243,749	(7,970,333)	(3.19)	5,604,413,000	6,064,078,000	(459,665,000)	(7.58)	4.3229	4.1267	0.20	4.75
2	Hedging Settlement Costs (A2)	10,865,538	0	10,865,538	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) **	155,123	0	155,123	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	253,294,077	250,243,749	3,050,328	1.22	5,604,413,000	6,064,078,000	(459,665,000)	(7.58)	4.5195	4.1267	0.39	9.52
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)	132,274,635	134,962,000	(2,687,365)	(1.99)	5,214,407,648	4,287,981,000	926,426,648	21.61	2.5367	3.1474	(0.61)	(19.40)
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)	6,634,890	0	6,634,890	100.00	172,989,000	0	172,989,000	100.00	3.8354	0.0000	3.84	0.00
12	TOTAL COST OF PURCHASED POWER	138,909,525	134,962,000	3,947,525	2.92	5,387,396,648	4,287,981,000	1,099,415,648	25.64	2.5784	3.1474	(0.57)	(18.08)
13	Total Available MWH (Line 5 + Line 12)	392,203,602	385,205,749	6,997,853	1.82	10,991,809,648	10,352,059,000	639,750,648	6.18				
14	Fuel Cost of Economy Sales (A6)	(1,382,064)	(1,612,000)	229,936	(14.26)	(45,010,678)	(48,686,000)	3,675,322	(7.55)	(3.0705)	(3.3110)	0.24	7.26
15	Gain on Economy Sales (A6)	(90,782)	(511,000)	420,218	(82.23)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(59,886,051)	(60,301,000)	414,949	(0.69)	(3,157,512,755)	(1,824,592,000)	(1,332,920,755)	73.05	(1.8966)	(3.3049)	1.41	42.61
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(61,358,897)	(62,424,000)	1,065,103	(1.71)	(3,202,523,433)	(1,873,278,000)	(1,329,245,433)	70.96	(1.9160)	(3.3323)	1.42	42.50
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)	330,844,705	322,781,749	8,062,956	2.50	7,789,286,215	8,478,781,000	(689,494,785)	(8.13)	4.2474	3.8069	0.44	11.57
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 *	572,397	560,338	12,059	2.15	13,476,399	14,719,000	(1,242,601)	(8.44)	4.2474	3.8069	0.44	11.57
22	T & D Losses *	16,700,832	18,781,303	(2,080,471)	(11.08)	393,201,297	493,349,000	(100,147,703)	(20.30)	4.2474	3.8069	0.44	11.57
23	TERRITORIAL KWH SALES	330,844,705	322,781,749	8,062,956	2.50	7,382,608,519	7,970,713,000	(588,104,481)	(7.38)	4.4814	4.0496	0.43	10.66
24	Wholesale KWH Sales	9,350,101	9,983,902	(633,801)	(6.35)	208,954,920	246,358,000	(37,403,080)	(15.18)	4.4747	4.0526	0.42	10.42
25	Jurisdictional KWH Sales	321,494,604	312,797,847	8,696,757	2.78	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)	4.4816	4.0495	0.43	10.67
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	321,976,848	313,267,043	8,709,805	2.78	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)	4.4883	4.0556	0.43	10.67
28	TRUE-UP	(17,616,944)	(17,616,944)	0	0.00	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)	(0.2456)	(0.2281)	(0.02)	7.67
29	TOTAL JURISDICTIONAL FUEL COST	304,359,904	295,650,099	8,709,805	2.95	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)	4.2427	3.8275	0.42	10.85
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2458	3.8303	0.42	10.85
32	GPIF Reward / (Penalty)	693,776	693,776	0	0.00	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)	0.0097	0.0090	0.00	7.78
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2555	3.8393	0.42	10.84
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.256	3.839		

* 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 2013

		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	34,305,237.09	39,519,080	(5,213,842.91)	(13.19)	240,629,899.06	248,868,743	(8,238,843.94)	(3.31)
1a	Other Generation	211,100.43	286,819	(75,718.57)	(26.40)	1,643,516.40	1,375,006	268,510.40	19.53
2	Fuel Cost of Power Sold	(5,530,904.85)	(13,509,000)	7,978,095.15	59.06	(61,358,896.64)	(62,424,000)	1,065,103.36	1.71
3	Fuel Cost - Purchased Power	17,700,713.30	22,937,000	(5,236,286.70)	(22.83)	132,274,635.15	134,962,000	(2,687,364.85)	(1.99)
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	862,375.59	0	862,375.59	100.00	6,634,889.50	0	6,634,889.50	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	2,385,644.00	0	2,385,644.00	100.00	10,865,538.00	0	10,865,538.00	100.00
6	Total Fuel & Net Power Transactions	49,934,165.56	49,233,899	700,266.56	1.42	330,689,581.47	322,781,749	7,907,832.47	2.45
7	AdjustmentsTo Fuel Cost*	44,250.72	0	44,250.72	100.00	155,123.07	0	155,123.07	100.00
8	Adj. Total Fuel & Net Power Transactions	49,978,416.28	49,233,899	744,517.28	1.51	330,844,704.54	322,781,749	8,062,955.54	2.50
B.	*KWH Sales*								
1	Jurisdictional Sales	1,114,039,621	1,181,726,000	(67,686,379)	(5.73)	7,173,653,599	7,724,355,000	(550,701,401)	(7.13)
2	Non-Jurisdictional Sales	30,742,395	34,820,000	(4,077,605)	(11.71)	208,954,920	246,358,000	(37,403,080)	(15.18)
3	Total Territorial Sales	1,144,782,016	1,216,546,000	(71,763,984)	(5.90)	7,382,608,519	7,970,713,000	(588,104,481)	(7.38)
4	Juris. Sales as % of Total Terr. Sales	97.3146	97.1378	0.1768	0.18	97.1696	96.9092	0.2604	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: AUGUST 2013

C.	*True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	42,296,529.87	**44,903,982**	(2,607,452.14)	(5.81)	272,292,803.10	293,720,163	(21,427,359.78)	(7.30)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	**2,202,118**	0.00	0.00	17,616,944.00	17,616,944	0.00	0.00
2b	Incentive Provision	(86,659.00)	**(86,659)**	0.00	0.00	(693,272.00)	(693,272)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	44,411,988.87	**47,019,441**	(2,607,452.13)	(5.55)	289,216,475.10	310,643,835	(21,427,359.90)	(6.90)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	49,978,416.28	49,233,899	744,517.28	1.51	330,844,704.93	322,781,749	8,062,955.93	2.50
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3146	97.1378	0.1768	0.18	97.1696	96.9092	0.2604	0.27
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	48,709,250.33	47,896,463	812,787.33	1.70	321,976,847.66	313,267,043	8,709,804.66	2.78
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(4,297,261.46)	(877,022)	(3,420,239.46)	(389.98)	(32,760,372.56)	(2,623,208)	(30,137,164.56)	(1,148.87)
8	Interest Provision for the Month	(159.33)	356	(515.33)	144.76	955.48	8,084	(7,128.52)	88.18
9	Beginning True-Up & Interest Provision	(214,016.89)	9,272,134	(9,486,150.89)	102.31	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(17,616,944.00)	(17,616,944)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(6,713,555.68)	6,193,350	(12,906,905.68)	208.40	(33,284,637.94)	6,193,350	(39,477,987.94)	637.43
12	Adjustment		0	0.00	0.00	26,571,082.26	0	26,571,082.26	100.00
13	End of Period - Total Net True-Up	(6,713,555.68)	6,193,350	(12,906,905.68)	208.40	(6,713,555.68)	6,193,350	(12,906,905.68)	208.40

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(214,016.89)	9,272,134	(9,486,150.89)	(102.31)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(6,713,396.35)	6,192,994	(12,906,390.35)	(208.40)
3	Total of Beginning & Ending True-Up Amts.	(6,927,413.24)	15,465,128	(22,392,541.24)	(144.79)
4	Average True-Up Amount	(3,463,706.62)	7,732,564	(11,196,270.62)	(144.79)
	Interest Rate				
5	1st Day of Reporting Business Month	0.05	0.05	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.06	0.06	0.0000	
7	Total (D5+D6)	0.11	0.11	0.0000	
8	Annual Average Interest Rate	0.06	0.06	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0046	0.0046	0.0000	
10	Interest Provision (D4*D9)	(159.33)	356	(515.33)	(144.76)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	148,335	138,719	9,616	6.93	1,298,577	681,249	617,328	90.62
2	COAL	22,699,868	27,286,890	(4,587,022)	(16.81)	159,446,836	162,956,324	(3,509,488)	(2.15)
3	GAS	11,448,690	12,315,454	(866,764)	(7.04)	80,400,267	86,068,660	(5,668,393)	(6.59)
4	GAS (B.L.)	144,315	0	144,315	100.00	508,302	-	508,302	100.00
5	LANDFILL GAS	60,257	56,112	4,145	7.39	479,544	461,563	17,981	3.90
6	OIL - C.T.	14,871	8,724	6,147	70.46	139,890	75,953	63,937	84.18
7	TOTAL ($)	34,516,338	39,805,899	(5,289,561)	(13.29)	242,273,415	250,243,749	(7,970,334)	(3.19)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	459,726	571,743	(112,017)	(19.59)	3,234,399	3,274,674	(40,275)	(1.23)
10	GAS	336,237	359,375	(23,138)	(6.44)	2,353,418	2,771,810	(418,392)	(15.09)
11	LANDFILL GAS	1,965	2,100	(135)	(6.43)	16,181	17,274	(1,093)	(6.33)
12	OIL - C.T.	44	32	12	37.50	415	320	95	29.69
13	TOTAL (MWH)	797,972	933,250	(135,278)	(14.50)	5,604,413	6,064,078	(459,665)	(7.58)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,117	1,094	23	2.10	9,897	5,620	4,277	76.10
15	COAL (TONS)	223,324	260,595	(37,271)	(14.30)	1,535,924	1,536,458	(534)	(0.03)
16	GAS (MCF) (1)	2,372,788	2,470,947	(98,159)	(3.97)	16,740,339	19,119,042	(2,378,703)	(12.44)
17	OIL - C.T. (BBL)	133	77	56	72.73	1,277	700	577	82.43
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,111,777	6,154,866	(1,043,089)	(16.95)	43,697,871	36,157,901	7,539,970	20.85
19	GAS - Generation (1)	2,401,078	2,545,076	(143,998)	(5.66)	16,893,705	18,974,006	(2,080,301)	(10.96)
20	OIL - C.T.	776	450	326	72.44	7,434	4,100	3,334	81.32
21	TOTAL (MMBTU)	7,513,631	8,700,392	(1,186,761)	(13.64)	60,599,010	55,136,007	5,463,003	9.91
	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	57.60	61.26	(3.66)	(5.97)	57.71	54.00	3.71	6.87
24	GAS	42.14	38.51	3.63	9.43	41.99	45.71	(3.72)	(8.14)
25	LANDFILL GAS	0.25	0.23	0.02	8.70	0.29	0.28	0.01	3.57
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.01	0.00	0.00
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)	132.82	126.80	6.02	4.75	131.21	121.22	9.99	8.24
29	COAL ($/TON)	101.65	104.71	(3.06)	(2.92)	103.81	106.06	(2.25)	(2.12)
30	GAS ($/MCF) (1)	4.80	4.87	(0.07)	(1.44)	4.73	4.43	0.30	6.77
31	OIL - C.T. ($/BBL)	111.82	113.30	(1.48)	(1.31)	109.55	108.50	1.05	0.97
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.50	4.46	0.04	0.90	3.69	4.53	(0.84)	(18.54)
33	GAS - Generation (1)	4.68	4.73	(0.05)	(1.06)	4.66	4.46	0.20	4.48
34	OIL - C.T.	19.16	19.39	(0.23)	(1.19)	18.82	18.53	0.29	1.57
35	TOTAL ($/MMBTU)	4.56	4.54	0.02	0.44	3.96	4.51	(0.55)	(12.20)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,119	10,765	354	3.29	13,510	11,042	2,468	22.35
37	GAS - Generation (1)	7,275	7,196	79	1.10	7,330	6,930	400	5.77
38	OIL - C.T.	17,636	14,063	3,573	25.41	17,913	12,813	5,100	39.80
39	TOTAL (BTU/KWH)	9,513	9,401	112	1.19	10,939	9,169	1,770	19.30
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.00	4.80	0.20	4.17	4.99	5.00	(0.01)	(0.20)
41	GAS	3.40	3.43	(0.03)	(0.87)	3.42	3.11	0.31	9.97
42	LANDFILL GAS	3.07	2.67	0.40	14.98	2.96	2.67	0.29	10.86
43	OIL - C.T.	33.80	27.26	6.54	23.99	33.71	23.74	9.97	42.00
44	TOTAL (¢/KWH)	4.33	4.27	0.06	1.41	4.32	4.13	0.19	4.60

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(825)	0.0	100.0	0.0	0	Coal	0.0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	0	1,015	0	0		0.00
4									Oil-S	0	137,922	0	0		0.00
5	Crist 5		75	36,297	65.0	100.0	65.1	11,168	Coal	17,229	11,764	405,352	1,661,444	4.58	96.43
6				-					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	0	1,015	0	0		0.00
8									Oil-S	130	137,922	750	16,466		126.66
9	Crist 6		299	12,457	5.6	100.0	50.2	12,573	Coal	6,841	11,447	156,622	659,733	5.30	96.44
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	4,398	1,015	4,464	66,653		15.16
12									Oil-S	1	137,922	6	127		127.00
13	Crist 7		475	198,531	56.2	100.0	58.2	11,151	Coal	93,931	11,784	2,213,794	9,058,422	4.56	96.44
14				0					Gas-G	0	1,015	0	0	0.00	0.00
15									Gas-S	5,124	1,015	5,201	77,662		15.16
16									Oil-S	24	137,922	138	3,036		126.50
17	Scholz 1		46	(235)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(165)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	50,926	42.3	91.8	49.0	10,892	Coal	24,641	11,255	554,664	2,535,493	4.98	102.90
22									Oil-S	359	138,902	2,096	48,215		134.30
23	Smith 2		195	41,962	28.9	93.7	43.7	11,500	Coal	22,445	10,750	482,559	2,309,508	5.50	102.90
24									Oil-S	542	138,902	3,159	72,645		134.03
25	Smith 3		556	330,024	79.8	99.5	92.6	7,275	Gas-G	2,363,266	1,016	2,401,078	11,237,590	3.41	4.76
26	Smith A	(2)	32	44	0.2	99.7	78.6	17,636	Oil	133	138,520	776	14,871	33.80	111.81
27	Other Generation			6,213									211,100	3.40	0.00
28	Perdido			1,965					Landfill Gas				60,257	3.07	0.00
29	Daniel 1	(1)	255	37,335	19.7	94.6	44.6	10,533	Coal	17,861	11,009	393,245	1,969,319	5.27	110.26
30									Oil-S	60	138,363	351	7,682		128.03
31	Daniel 2	(1)	255	83,443	44.0	100.0	44.0	10,658	Coal	40,377	11,013	889,368	4,451,958	5.34	110.26
32									Oil-S	1	138,363	8	165		165.00
33	Total		2,471	797,972	43.4	98.3	56.9	9,513				7,513,631	34,462,346	4.32	

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)	
	Coal Additive - Crist	116,462	
	Inventory Adj - Smith	(6,984)	
	Inventory Adj - Daniel	(51,427)	
	Recoverable Fuel	34,516,338	4.33

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,235	1,091	144	13.20	10,575	5,614	4,961	88.37
3	UNIT COST ($/BBL)	135.05	126.29	8.76	6.94	130.35	120.92	9.43	7.80
4	AMOUNT ($)	166,786	137,787	28,999	21.05	1,378,479	678,822	699,657	103.07
5	*BURNED :*								
6	UNITS (BBL)	1,177	1,094	83	7.59	10,360	5,620	4,740	84.34
7	UNIT COST ($/BBL)	132.91	126.80	6.11	4.82	131.21	121.22	9.99	8.24
8	AMOUNT ($)	156,439	138,719	17,720	12.77	1,359,375	681,249	678,126	99.54
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	6,182	4,547	1,635	35.96	6,182	4,547	1,635	35.96
11	UNIT COST ($/BBL)	127.81	124.86	2.95	2.36	127.81	124.86	2.95	2.36
12	AMOUNT ($)	790,121	567,734	222,387	39.17	790,121	567,734	222,387	39.17
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	213,147	196,500	16,647	8.47	1,271,082	1,305,509	(34,427)	(2.64)
16	UNIT COST ($/TON)	93.88	105.13	(11.25)	(10.70)	100.83	104.66	(3.83)	(3.66)
17	AMOUNT ($)	20,010,303	20,657,223	(646,920)	(3.13)	128,164,358	136,631,350	(8,466,992)	(6.20)
18	*BURNED :*								
19	UNITS (TONS)	223,324	260,595	(37,271)	(14.30)	1,535,924	1,536,458	(534)	(0.03)
20	UNIT COST ($/TON)	101.14	104.71	(3.57)	(3.41)	102.96	106.06	(3.10)	(2.92)
21	AMOUNT ($)	22,587,465	27,286,890	(4,699,425)	(17.22)	158,143,376	162,956,324	(4,812,948)	(2.95)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	673,365	663,968	9,397	1.42	673,365	663,968	9,397	1.42
24	UNIT COST ($/TON)	102.32	104.78	(2.46)	(2.35)	102.32	104.78	(2.46)	(2.35)
25	AMOUNT ($)	68,899,598	69,569,881	(670,283)	(0.96)	68,899,598	69,569,881	(670,283)	(0.96)
26	DAYS SUPPLY	32	32	0	0.00				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,410,743	2,545,076	(134,333)	(5.28)	17,012,957	18,974,006	(1,961,049)	(10.34)
29	UNIT COST ($/MMBTU)	4.62	4.73	(0.11)	(2.33)	4.71	4.46	0.25	5.61
30	AMOUNT ($)	11,146,609	12,048,308	(901,699)	(7.48)	80,122,185	84,713,327	(4,591,142)	(5.42)
31	*BURNED :*								
32	UNITS (MMBTU)	2,410,743	2,545,076	(134,333)	(5.28)	16,944,596	18,974,006	(2,029,410)	(10.70)
33	UNIT COST ($/MMBTU)	4.72	4.73	(0.01)	(0.21)	4.68	4.46	0.22	4.93
34	AMOUNT ($)	11,381,905	12,028,635	(646,730)	(5.38)	79,265,053	84,693,654	(5,428,601)	(6.41)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	849,667	978,750	(129,083)	(13.19)	(129,083)	0	(129,083)	100.00
37	UNIT COST ($/MMBTU)	4.68	4.36	0.32	7.34	2.24	0.00	2.24	100.00
38	AMOUNT ($)	3,976,634	4,265,295	(288,661)	(6.77)	(288,661)	0	(288,661)	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	77	(77)	(100.00)	1,306	700	606	86.57
41	UNIT COST ($/BBL)	0.00	126.49	(126.49)	(100.00)	131.65	120.62	11.00	9.12
42	AMOUNT ($)	0	9,740	(9,740)	(100.00)	171,929	84,436	87,493	103.62
43	*BURNED :*								
44	UNITS (BBL)	133	77	56	72.73	1,277	700	577	82.43
45	UNIT COST ($/BBL)	111.81	113.30	(1.49)	(1.32)	109.55	108.50	1.05	0.97
46	AMOUNT ($)	14,871	8,724	6,147	70.46	139,889	75,953	63,936	84.18
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	5,984	5,845	139	2.38	5,984	5,845	139	2.38
49	UNIT COST ($/BBL)	111.52	111.06	0.46	0.41	111.52	111.06	0.46	0.41
50	AMOUNT ($)	667,353	649,138	18,215	2.81	667,353	649,138	18,215	2.81
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2013

			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		280,190,000	0	280,190,000	4.71	4.99	13,200,000	13,990,000
2	Various	Economy Sales	5,755,000	0	5,755,000	4.22	4.50	243,000	259,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	66,000	66,000
4	TOTAL ESTIMATED SALES		285,945,000	0	285,945,000	4.72	5.01	13,509,000	14,315,000
	ACTUAL								
5	Southern Company Interchange		169,998,838	0	169,998,838	3.26	2.92	5,536,513	4,968,534
6	A.E.C.	External	17,302	0	17,302	3.87	5.09	669.19	881
7	AECI	External	12,582	0	12,582	1.67	2.80	209.87	352
8	AEP	External	0	0	0	0.00	0.00	0.00	0
9	CALPINE	External	0	0	0	0.00	0.00	0.00	0
10	CARGILE	External	0	0	0	0.00	0.00	0.00	0
11	CONSTELL	External	0	0	0	0.00	0.00	0.00	0
12	DUKE PWR	External	0	0	0	0.00	0.00	0.00	0
13	EAGLE EN	External	44,857	0	44,857	2.61	3.63	1,169.63	1,630
14	ENDURE	External	0	0	0	0.00	0.00	0.00	0
15	ENTERGY	External	14,407	0	14,407	3.23	6.20	465.30	893
16	EXELON	External	30,514	0	30,514	2.58	3.55	787.97	1,084
17	FPC	External	142,182	0	142,182	1.93	3.27	2,738.58	4,648
18	FPL	External	63,482	0	63,482	2.24	3.27	1,424.63	2,076
19	JPMVEC	External	10,381	0	10,381	3.65	4.15	379.38	431
20	MERRILL	External	0	0	0	0.00	0.00	0.00	0
21	MISO	External	0	0	0	0.00	0.00	0.00	0
22	MORGAN	External	127,397	0	127,397	2.21	2.62	2,815.46	3,338
23	NCEMC	External	0	0	0	0.00	0.00	(11.77)	0
24	NRG	External	0	0	0	0.00	0.00	0.00	0
25	OGE	External	0	0	0	0.00	0.00	0.00	0
26	OPC	External	51,904	0	51,904	2.78	3.51	1,443.55	1,823
27	ORLANDO	External	17,300	0	17,300	3.34	4.90	578.53	848
28	PJM	External	156,026	0	156,026	3.01	3.49	4,693.14	5,446
29	SCE&G	External	71,724	0	71,724	2.28	3.40	1,637.56	2,439
30	SEC	External	267,006	0	267,006	2.43	3.09	6,495.73	8,254
31	SEPA	External	0	0	0	0.00	0.00	0.00	0
32	SPP	External	0	0	0	0.00	0.00	0.00	0
33	TAL	External	34,602	0	34,602	3.76	4.69	1,302.25	1,623
34	TEA	External	2,611,414	0	2,611,414	3.18	4.17	83,086.41	108,927
35	TECO	External	56,622	0	56,622	3.81	4.00	2,159.95	2,265
36	TVA	External	180,497	0	180,497	3.54	4.30	6,389.28	7,767
37	WRI	External	15,600	0	15,600	2.40	2.50	374.47	390
38	Less: Flow-Thru Energy		(3,868,673)	0	(3,868,673)	3.02	3.02	(116,810)	(116,810)
39	SEPA		1,997,952	1,997,952	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(7,607)	(7,607)
41	Other transactions including adj.		203,788,085	162,441,881	41,346,204	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		375,842,001	164,439,833	211,402,168	1.47	1.33	5,530,905	5,006,838
43	Difference in Amount		89,897,001	164,439,833	(74,542,832)	(3.25)	(3.68)	(7,978,095)	(9,308,162)
44	Difference in Percent		31.44	0.00	(26.07)	(68.86)	(73.45)	(59.06)	(65.02)

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: AUGUST 2013

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		1,824,592,000	0	1,824,592,000	3.30	3.63	60,301,000	66,256,000
2	Various	Economy Sales	48,686,000	0	48,686,000	3.31	3.61	1,612,000	1,758,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	511,000	511,000
4	TOTAL ESTIMATED SALES		1,873,278,000	0	1,873,278,000	3.33	3.66	62,424,000	68,525,000
	ACTUAL								
5	Southern Company Interchange		2,033,594,689	0	2,033,594,689	3.01	3.16	61,192,379	64,242,485
6	A.E.C.	External	3,928,153	0	3,928,153	3.00	3.72	117,784	146,046
7	AECI	External	292,606	0	292,606	2.66	4.06	7,770	11,883
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	0	0	0	0.00	0.00	2,114	0
10	CARGILE	External	3,416,619	0	3,416,619	2.81	3.25	96,170	110,964
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,056
13	EAGLE EN	External	1,189,462	0	1,189,462	2.83	3.70	33,633	43,999
14	ENDURE	External	73,171	0	73,171	3.34	4.49	2,446	3,285
15	ENTERGY	External	222,023	0	222,023	4.72	4.70	10,488	10,425
16	EXELON	External	2,873,169	0	2,873,169	3.04	3.39	87,409	97,271
17	FPC	External	891,418	0	891,418	3.09	4.21	27,571	37,554
18	FPL	External	441,972	0	441,972	3.00	4.09	13,259	18,063
19	JPMVEC	External	902,073	0	902,073	3.21	3.79	28,985	34,176
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	315	0	315	2.65	2.76	8	9
22	MORGAN	External	1,262,281	0	1,262,281	3.18	3.51	40,176	44,354
23	NCEMC	External	617,543	0	617,543	3.08	3.82	19,044	23,601
24	NRG	External	6,291	0	6,291	78.00	3.50	4,907	220
25	OGE	External	1,260	0	1,260	3.01	3.00	38	38
26	OPC	External	1,123,356	0	1,123,356	3.02	3.94	33,906	44,206
27	ORLANDO	External	34,919	0	34,919	3.46	5.15	1,207	1,799
28	PJM	External	8,782,900	0	8,782,900	3.09	3.78	271,372	332,345
29	SCE&G	External	2,819,387	0	2,819,387	3.42	5.05	96,485	142,514
30	SEC	External	1,333,987	0	1,333,987	3.10	3.73	41,314	49,729
31	SEPA	External	1,648,650	0	1,648,650	2.73	3.55	45,082	58,493
32	SPP	External	6,174	0	6,174	2.30	1.63	142	101
33	TAL	External	888,387	0	888,387	3.40	4.52	30,210	40,155
34	TEA	External	6,273,300	0	6,273,300	3.02	4.07	189,707	255,213
35	TECO	External	384,971	0	384,971	3.26	4.57	12,555	17,588
36	TVA	External	3,422,425	0	3,422,425	3.19	4.42	109,103	151,283
37	WRI	External	1,144,159	0	1,144,159	3.02	3.55	34,577	40,633
38	Less: Flow-Thru Energy		(44,411,173)	0	(44,411,173)	2.94	2.94	(1,306,328)	(1,306,328)
39	SEPA		15,082,408	15,082,408	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	90,782	90,782
41	Other transactions including adj.		1,153,246,831	1,083,932,121	69,314,710	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		3,202,523,433	1,099,014,529	2,103,508,904	1.92	2.02	61,358,897	64,682,143
43	Difference in Amount		1,329,245,433	1,099,014,529	230,230,904	(1.41)	(1.64)	(1,065,103)	(3,842,857)
44	Difference in Percent		70.96	0.00	12.29	(42.34)	(44.81)	(1.71)	(5.61)

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: AUGUST 2013

(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 2013

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	4,119,000	0	0	0	7.63	7.63	314,463
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	17,603,000	0	0	0	3.11	3.11	547,662
6 International Paper	COG 1	5,000	0	0	0	5.00	5.00	250
7 TOTAL		21,727,000	0	0	0	3.97	3.97	862,376

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	27,343,000	0	0	0	7.63	7.63	2,087,381
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	47
5 Ascend Performance Materials	COG 1	144,936,000	0	0	0	3.12	3.12	4,523,126
6 International Paper	COG 1	710,000	0	0	0	3.43	3.43	24,334
7 TOTAL		172,989,000	0	0	0	3.84	3.84	6,634,890

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2013

	(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	11,252,000	3.95	445,000	328,849,000	3.84	12,623,000
2	Economy Energy	3,378,000	5.30	179,000	32,948,000	3.77	1,241,000
3	Other Purchases	648,808,000	3.44	22,313,000	3,926,184,000	3.08	121,098,000
4	TOTAL ESTIMATED PURCHASES	663,438,000	3.46	22,937,000	4,287,981,000	3.15	134,962,000
	ACTUAL						
5	Southern Company Interchange	36,233,874	2.54	919,116	444,142,633	3.20	14,228,979
6	Non-Associated Companies	57,592,962	5.93	3,413,869	433,258,827	1.60	6,919,140
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	512,377,000	2.63	13,478,925	3,515,065,000	3.20	112,430,338
9	Other Wheeled Energy	59,378,000	0.00	N/A	213,448,000	0.00	N/A
10	Other Transactions	99,987,312	0.01	13,669	652,904,361	0.01	95,813
11	Less: Flow-Thru Energy	(3,868,673)	3.23	(124,866)	(44,411,173)	3.15	(1,399,635)
12	TOTAL ACTUAL PURCHASES	761,700,475	2.32	17,700,713	5,214,407,648	2.54	132,274,635
13	Difference in Amount	98,262,475	(1.14)	(5,236,287)	926,426,648	(0.61)	(2,687,365)
14	Difference in Percent	14.81	(32.95)	(22.83)	21.61	(19.37)	(1.99)

2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		**$ 2,045,794**		**$ 2,596,589**		**$ 6,777,892**	**$ 18,088,765**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

SCHEDULE A-12
PAGE 2 OF 2

2013 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	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -		$ -		$ -		$ -		$ -	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,225									31,671,643
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)									(33,068)
SUBTOTAL					$ 7,263,297		$ 7,004,079		$ -		$ -		$ -		$ -	$ 31,638,575
TOTAL					**$ 7,263,297**		**$ 7,004,079**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 32,356,141**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

September 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2013
CURRENT MONTH

		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)	26,160,169	38,603,142	(12,442,973)	(32.23)	671,871,000	891,783,000	(219,912,000)	(24.66)	3.8936	4.3288	(0.44)	(10.05)
2	Hedging Settlement Costs (A2)	1,541,155	0	1,541,155	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) **	21,507	0	21,507	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	27,722,831	38,603,142	(10,880,311)	(28.19)	671,871,000	891,783,000	(219,912,000)	(24.66)	4.1262	4.3288	(0.20)	(4.68)
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)	15,667,156	16,031,000	(363,844)	(2.27)	622,649,677	433,175,000	189,474,677	43.74	2.5162	3.7008	(1.18)	(32.01)
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)	852,491	0	852,491	100.00	21,034,000	0	21,034,000	100.00	4.0529	0.0000	4.05	0.00
12	TOTAL COST OF PURCHASED POWER	16,519,647	16,031,000	488,647	3.05	643,683,677	433,175,000	210,508,677	48.60	2.5664	3.7008	(1.13)	(30.65)
13	Total Available MWH (Line 5 + Line 12)	44,242,478	54,634,142	(10,391,664)	(19.02)	1,315,554,677	1,324,958,000	(9,403,323)	(0.71)				
14	Fuel Cost of Economy Sales (A6)	(131,189)	(187,000)	55,811	(29.85)	(3,860,255)	(4,272,000)	411,745	(9.64)	(3.3985)	(4.3773)	0.98	22.36
15	Gain on Economy Sales (A6)	1,588	(57,000)	58,588	(102.79)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(956,753)	(7,713,000)	6,756,247	(87.60)	(195,642,790)	(183,312,000)	(12,330,790)	6.73	(0.4890)	(4.2076)	3.72	88.38
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(1,086,354)	(7,957,000)	6,870,646	(86.35)	(199,503,045)	(187,584,000)	(11,919,045)	6.35	(0.5445)	(4.2418)	3.70	87.16
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)	43,156,124	46,677,142	(3,521,018)	(7.54)	1,116,051,632	1,137,374,000	(21,322,368)	(1.87)	3.8669	4.1039	(0.24)	(5.77)
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 *	64,460	75,922	(11,462)	(15.10)	1,666,973	1,850,000	(183,027)	(9.89)	3.8669	4.1039	(0.24)	(5.77)
22	T & D Losses *	2,471,919	2,876,834	(404,915)	(14.08)	63,925,082	70,100,000	(6,174,918)	(8.81)	3.8669	4.1039	(0.24)	(5.77)
23	TERRITORIAL KWH SALES	43,156,125	46,677,142	(3,521,018)	(7.54)	1,050,459,577	1,065,424,000	(14,964,423)	(1.40)	4.1083	4.3811	(0.27)	(6.23)
24	Wholesale KWH Sales	1,161,374	1,335,993	(174,619)	(13.07)	28,268,462	30,495,000	(2,226,538)	(7.30)	4.1084	4.3810	(0.27)	(6.22)
25	Jurisdictional KWH Sales	41,994,751	45,341,149	(3,346,398)	(7.38)	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	4.1083	4.3811	(0.27)	(6.23)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	42,057,743	45,409,161	(3,351,418)	(7.38)	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	4.1145	4.3877	(0.27)	(6.23)
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	(0.2154)	(0.2128)	(0.00)	1.22
29	TOTAL JURISDICTIONAL FUEL COST	39,855,625	43,207,043	(3,351,418)	(7.76)	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	3.8991	4.1749	(0.28)	(6.61)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9019	4.1779	(0.28)	(6.61)
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	0.0085	0.0084	0.00	1.19
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9104	4.1863	(0.28)	(6.59)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.910	4.186		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 26,160,169
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	21,507
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,541,155
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	15,667,156
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	852,491
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(1,086,354)
10	Total Fuel and Net Power Transactions		$ 43,156,124

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2013
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)	268,433,585	288,846,891	(20,413,306)	(7.07)	6,276,284,000	6,955,861,000	(679,577,000)	(9.77)	4.2770	4.1526	0.12	3.00
2	Hedging Settlement Costs (A2)	12,406,693	0	12,406,693	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) **	176,630	0	176,630	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	281,016,908	288,846,891	(7,829,983)	(2.71)	6,276,284,000	6,955,861,000	(679,577,000)	(9.77)	4.4774	4.1526	0.32	7.82
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)	147,941,791	150,993,000	(3,051,209)	(2.02)	5,837,057,325	4,721,156,000	1,115,901,325	23.64	2.5345	3.1982	(0.66)	(20.75)
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)	7,487,381	0	7,487,381	100.00	194,023,000	0	194,023,000	100.00	3.8590	0.0000	3.86	0.00
12	TOTAL COST OF PURCHASED POWER	155,429,172	150,993,000	4,436,172	2.94	6,031,080,325	4,721,156,000	1,309,924,325	27.75	2.5771	3.1982	(0.62)	(19.42)
13	Total Available MWH (Line 5 + Line 12)	436,446,080	439,839,891	(3,393,811)	(0.77)	12,307,364,325	11,677,017,000	630,347,325	5.40				
14	Fuel Cost of Economy Sales (A6)	(1,513,253)	(1,799,000)	285,747	(15.88)	(48,870,933)	(52,958,000)	4,087,067	(7.72)	(3.0964)	(3.3970)	0.30	8.85
15	Gain on Economy Sales (A6)	(89,194)	(568,000)	478,806	(84.30)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(60,842,804)	(68,014,000)	7,171,196	(10.54)	(3,353,155,545)	(2,007,904,000)	(1,345,251,545)	67.00	(1.8145)	(3.3873)	1.57	46.43
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(62,445,251)	(70,381,000)	7,935,749	(11.28)	(3,402,026,478)	(2,060,862,000)	(1,341,164,478)	65.08	(1.8355)	(3.4151)	1.58	46.25
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)	374,000,829	369,458,891	4,541,938	1.23	8,905,337,847	9,616,155,000	(710,817,153)	(7.39)	4.1997	3.8421	0.36	9.31
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 *	635,976	636,598	(622)	(0.10)	15,143,372	16,569,000	(1,425,628)	(8.60)	4.1997	3.8421	0.36	9.31
22	T & D Losses *	19,197,937	21,648,274	(2,450,337)	(11.32)	457,126,379	563,449,000	(106,322,621)	(18.87)	4.1997	3.8421	0.36	9.31
23	TERRITORIAL KWH SALES	374,000,830	369,458,891	4,541,939	1.23	8,433,068,096	9,036,137,000	(603,068,904)	(6.67)	4.4349	4.0887	0.35	8.47
24	Wholesale KWH Sales	10,511,475	11,319,895	(808,420)	(7.14)	237,223,382	276,853,000	(39,629,618)	(14.31)	4.4310	4.0888	0.34	8.37
25	Jurisdictional KWH Sales	363,489,355	358,138,996	5,350,359	1.49	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)	4.4350	4.0887	0.35	8.47
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	364,034,590	358,676,204	5,358,386	1.49	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)	4.4417	4.0948	0.35	8.47
28	TRUE-UP	(19,819,062)	(19,819,062)	0	0.00	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)	(0.2418)	(0.2263)	(0.02)	6.85
29	TOTAL JURISDICTIONAL FUEL COST	344,215,528	338,857,142	5,358,386	1.58	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)	4.1999	3.8685	0.33	8.57
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2029	3.8713	0.33	8.57
32	GPIF Reward / (Penalty)	780,498	780,498	0	0.00	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)	0.0095	0.0089	0.00	6.74
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2124	3.8802	0.33	8.56
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.212	3.880		

* 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 2013

		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	25,996,852.54	38,325,558	(12,328,705.46)	(32.17)	266,626,751.60	287,194,301	(20,567,549.40)	(7.16)
1a	Other Generation	163,316.14	277,584	(114,267.86)	(41.17)	1,806,832.54	1,652,590	154,242.54	9.33
2	Fuel Cost of Power Sold	(1,086,353.65)	(7,957,000)	6,870,646.35	86.35	(62,445,250.29)	(70,381,000)	7,935,749.71	11.28
3	Fuel Cost - Purchased Power	15,667,156.19	16,031,000	(363,843.81)	(2.27)	147,941,791.34	150,993,000	(3,051,208.66)	(2.02)
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	852,491.31	0	852,491.31	100.00	7,487,380.81	0	7,487,380.81	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,541,155.00	0	1,541,155.00	100.00	12,406,693.00	0	12,406,693.00	100.00
6	Total Fuel & Net Power Transactions	43,134,617.53	46,677,142	(3,542,524.47)	(7.59)	373,824,199.00	369,458,891	4,365,308.00	1.18
7	AdjustmentsTo Fuel Cost*	21,507.35	0	21,507.35	100.00	176,630.42	0	176,630.42	100.00
8	Adj. Total Fuel & Net Power Transactions	43,156,124.88	46,677,142	(3,521,017.12)	(7.54)	374,000,829.42	369,458,891	4,541,938.42	1.23
B.	*KWH Sales*								
1	Jurisdictional Sales	1,022,191,115	1,034,929,000	(12,737,885)	(1.23)	8,195,844,714	8,759,284,000	(563,439,286)	(6.43)
2	Non-Jurisdictional Sales	28,268,462	30,495,000	(2,226,538)	(7.30)	237,223,382	276,853,000	(39,629,618)	(14.31)
3	Total Territorial Sales	1,050,459,577	1,065,424,000	(14,964,423)	(1.40)	8,433,068,096	9,036,137,000	(603,068,904)	(6.67)
4	Juris. Sales as % of Total Terr. Sales	97.3089	97.1378	0.1711	0.18	97.1870	96.9362	0.2508	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 2013

C.	*True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	38,813,674.44	39,325,896	(512,221.07)	(1.30)	311,106,477.54	333,046,058	(21,939,580.85)	(6.59)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	19,819,062.00	19,819,062	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(779,931.00)	(779,931)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	40,929,133.44	41,441,355	(512,221.56)	(1.24)	330,145,608.54	352,085,189	(21,939,580.46)	(6.23)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	43,156,124.88	46,677,142	(3,521,017.12)	(7.54)	374,000,829.81	369,458,891	4,541,938.81	1.23
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3089	97.1378	0.1711	0.18	97.1870	96.9362	0.2508	0.26
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	42,057,742.53	45,409,161	(3,351,418.47)	(7.38)	364,034,590.19	358,676,204	5,358,386.19	1.49
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,128,609.09)	(3,967,806)	2,839,196.91	71.56	(33,888,981.65)	(6,591,014)	(27,297,967.65)	(414.17)
8	Interest Provision for the Month	(385.43)	143	(528.43)	369.53	570.05	8,227	(7,656.95)	93.07
9	Beginning True-Up & Interest Provision	(6,713,555.68)	6,193,350	(12,906,905.68)	208.40	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(19,819,062.00)	(19,819,062)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(10,044,668.20)	23,569	(10,068,237.20)	42,718.13	(36,615,750.46)	23,569	(36,639,319.46)	155,455.55
12	Adjustment		0	0.00	0.00	26,571,082.26	0	26,571,082.26	100.00
13	End of Period - Total Net True-Up	(10,044,668.20)	23,569	(10,068,237.20)	42,718.13	(10,044,668.20)	23,569	(10,068,237.20)	42,718.13

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	(6,713,555.68)	6,193,350	(12,906,905.68)	(208.40)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(10,044,282.77)	23,426	(10,067,708.77)	(42,976.64)
3	Total of Beginning & Ending True-Up Amts.	(16,757,838.45)	6,216,776	(22,974,614.45)	(369.56)
4	Average True-Up Amount	(8,378,919.23)	3,108,388	(11,487,307.23)	(369.56)
5	Interest Rate 1st Day of Reporting Business Month	0.06	0.06	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.05	0.05	0.0000	
7	Total (D5+D6)	0.11	0.11	0.0000	
8	Annual Average Interest Rate	0.06	0.06	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0046	0.0046	0.0000	
10	Interest Provision (D4*D9)	(385.43)	143	(528.43)	(369.53)
	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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	115,018	138,589	(23,571)	(17.01)	1,413,595	819,838	593,757	72.42
2	COAL	14,642,830	26,560,450	(11,917,620)	(44.87)	174,089,667	189,516,774	(15,427,107)	(8.14)
3	GAS	11,180,922	11,849,835	(668,913)	(5.64)	91,581,189	97,918,495	(6,337,306)	(6.47)
4	GAS (B.L.)	160,772	0	160,772	100.00	669,074	-	669,074	100.00
5	LANDFILL GAS	55,552	54,268	1,284	2.37	535,096	515,831	19,265	3.73
6	OIL - C.T.	5,074	0	5,074	100.00	144,964	75,953	69,011	90.86
7	TOTAL ($)	26,160,169	38,603,142	(12,442,973)	(32.23)	268,433,585	288,846,891	(20,413,306)	(7.07)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	345,022	544,785	(199,763)	(36.67)	3,579,421	3,819,459	(240,038)	(6.28)
10	GAS	325,014	344,967	(19,953)	(5.78)	2,678,432	3,116,777	(438,345)	(14.06)
11	LANDFILL GAS	1,804	2,031	(227)	(11.18)	17,985	19,305	(1,320)	(6.84)
12	OIL - C.T.	31	0	31	100.00	446	320	126	39.38
13	TOTAL (MWH)	671,871	891,783	(219,912)	(24.66)	6,276,284	6,955,861	(679,577)	(9.77)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	873	1,094	(221)	(20.20)	10,770	6,714	4,056	60.41
15	COAL (TONS)	151,199	249,570	(98,371)	(39.42)	1,687,123	1,786,028	(98,905)	(5.54)
16	GAS (MCF) (1)	2,303,544	2,368,540	(64,996)	(2.74)	19,043,883	21,487,582	(2,443,699)	(11.37)
17	OIL - C.T. (BBL)	46	0	46	100.00	1,323	700	623	89.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,761,214	5,841,596	(2,080,382)	(35.61)	47,459,085	41,999,497	5,459,588	13.00
19	GAS - Generation (1)	2,329,692	2,439,596	(109,904)	(4.51)	19,223,397	21,413,602	(2,190,205)	(10.23)
20	OIL - C.T.	265	0	265	100.00	7,699	4,100	3,599	87.78
21	TOTAL (MMBTU)	6,091,171	8,281,192	(2,190,021)	(26.45)	66,690,181	63,417,199	3,272,982	5.16
	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	51.36	61.09	(9.73)	(15.93)	57.02	54.91	2.11	3.84
24	GAS	48.37	38.68	9.69	25.05	42.68	44.81	(2.13)	(4.75)
25	LANDFILL GAS	0.27	0.23	0.04	17.39	0.29	0.28	0.01	3.57
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)	131.73	126.68	5.05	3.99	131.25	122.11	9.14	7.49
29	COAL ($/TON)	96.84	106.42	(9.58)	(9.00)	103.19	106.11	(2.92)	(2.75)
30	GAS ($/MCF) (1)	4.85	4.89	(0.04)	(0.82)	4.75	4.48	0.27	6.03
31	OIL - C.T. ($/BBL)	110.30	0.00	110.30	100.00	109.57	108.50	1.07	0.99
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.97	4.57	(0.60)	(13.13)	3.71	4.53	(0.82)	(18.10)
33	GAS - Generation (1)	4.73	4.74	(0.01)	(0.21)	4.67	4.50	0.17	3.78
34	OIL - C.T.	19.17	0.00	19.17	100.00	18.83	18.53	0.30	1.62
35	TOTAL ($/MMBTU)	4.26	4.62	(0.36)	(7.79)	3.99	4.52	(0.53)	(11.73)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,901	10,723	178	1.66	13,259	10,996	2,263	20.58
37	GAS - Generation (1)	7,270	7,187	83	1.15	7,323	6,958	365	5.25
38	OIL - C.T.	8,539	0	8,539	100.00	17,262	12,813	4,449	34.72
39	TOTAL (BTU/KWH)	9,153	9,366	(213)	(2.27)	10,748	9,195	1,553	16.89
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.32	4.90	(0.58)	(11.84)	4.92	4.98	(0.06)	(1.20)
41	GAS	3.44	3.44	0.00	0.00	3.42	3.14	0.28	8.92
42	LANDFILL GAS	3.08	2.67	0.41	15.36	2.98	2.67	0.31	11.61
43	OIL - C.T.	16.37	0.00	16.37	100.00	32.50	23.74	8.76	36.90
44	TOTAL (¢/KWH)	3.89	4.33	(0.44)	(10.16)	4.28	4.15	0.13	3.13

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(629)	0.0	100.0	0.0	0	Coal	0.0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	0	1,015	0	0		0.00
4									Oil-S	0	137,922	0	0		0.00
5	Crist 5		75	32,010	59.3	100.0	59.3	11,355	Coal	15,436	11,774	363,479	1,481,292	4.63	95.96
6				-					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	0	1,015	0	0		0.00
8									Oil-S	154	137,922	894	19,610		127.34
9	Crist 6		299	116,636	54.2	100.0	54.2	10,679	Coal	52,958	11,760	1,245,562	5,082,087	4.36	95.96
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	6,354	1,015	6,449	79,835		12.56
12									Oil-S	0	137,922	0	0		0.00
13	Crist 7		475	112,489	32.9	54.1	60.8	10,677	Coal	51,564	11,646	1,201,034	4,948,376	4.40	95.97
14				0					Gas-G	0	1,015	0	0	0.00	0.00
15									Gas-S	6,441	1,015	6,538	80,937		12.57
16									Oil-S	14	137,922	79	1,726		123.29
17	Scholz 1		46	(225)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(157)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	45,271	38.8	79.2	49.0	10,873	Coal	21,275	11,568	492,218	2,172,706	4.80	102.12
22									Oil-S	261	138,506	1,520	35,091		134.45
23	Smith 2		195	29,986	21.4	62.0	38.9	11,351	Coal	14,647	11,619	340,372	1,495,843	4.99	102.12
24									Oil-S	293	138,506	1,705	39,377		134.39
25	Smith 3		556	320,439	80.0	96.9	94.5	7,270	Gas-G	2,290,749	1,017	2,329,692	11,017,606	3.44	4.81
26	Smith A	(2)	32	31	0.1	93.5	45.8	8,548	Oil	46	138,520	265	5,074	16.37	110.30
27	Other Generation			4,575									163,316	3.57	0.00
28	Perdido			1,804					Landfill Gas				55,552	3.08	0.00
29	Daniel 1	(1)	255	(1,092)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	13,844	0	11		0.00
31	Daniel 2	(1)	255	10,733	5.8	100.0	44.3	9,436	Coal	4,559	11,108	101,276	505,335	4.71	110.84
32									Oil-S	151	13,844	88	19,203		127.17
33	Total		2,471	671,871	37.8	86.0	52.7	9,153				6,091,171	27,202,977	4.05	

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)	
	Coal Additive - Crist	(88,000)	
(9,240)	Inventory Adj - Smith	(950,749)	
	Recoverable Fuel	26,160,169	3.89

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	541	1,091	(550)	(50.41)	11,116	6,705	4,411	65.79
3	UNIT COST ($/BBL)	134.60	126.29	8.31	6.58	130.56	121.79	8.77	7.20
4	AMOUNT ($)	72,817	137,787	(64,970)	(47.15)	1,451,296	816,609	634,687	77.72
5	*BURNED:*								
6	UNITS (BBL)	911	1,094	(183)	(16.73)	11,271	6,714	4,557	67.87
7	UNIT COST ($/BBL)	131.79	126.68	5.11	4.03	131.26	122.11	9.15	7.49
8	AMOUNT ($)	120,057	138,589	(18,532)	(13.37)	1,479,432	819,838	659,594	80.45
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,813	4,544	1,269	27.93	5,813	4,544	1,269	27.93
11	UNIT COST ($/BBL)	127.80	124.76	3.04	2.44	127.80	124.76	3.04	2.44
12	AMOUNT ($)	742,881	566,932	175,949	31.04	742,881	566,932	175,949	31.04
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	150,669	166,500	(15,831)	(9.51)	1,421,751	1,472,009	(50,258)	(3.41)
16	UNIT COST ($/TON)	99.72	108.55	(8.83)	(8.13)	100.71	105.10	(4.39)	(4.18)
17	AMOUNT ($)	15,024,991	18,073,338	(3,048,347)	(16.87)	143,189,349	154,704,688	(11,515,339)	(7.44)
18	*BURNED:*								
19	UNITS (TONS)	151,199	249,570	(98,371)	(39.42)	1,687,123	1,786,028	(98,905)	(5.54)
20	UNIT COST ($/TON)	97.45	106.42	(8.97)	(8.43)	102.47	106.11	(3.64)	(3.43)
21	AMOUNT ($)	14,734,889	26,560,450	(11,825,561)	(44.52)	172,878,265	189,516,774	(16,638,509)	(8.78)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	672,835	580,898	91,937	15.83	672,835	580,898	91,937	15.83
24	UNIT COST ($/TON)	102.83	105.15	(2.32)	(2.21)	102.83	105.15	(2.32)	(2.21)
25	AMOUNT ($)	69,189,700	61,082,769	8,106,931	13.27	69,189,700	61,082,769	8,106,931	13.27
26	DAYS SUPPLY	32	28	4	14.29				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,342,679	2,406,971	(64,292)	(2.67)	19,355,636	21,380,977	(2,025,341)	(9.47)
29	UNIT COST ($/MMBTU)	4.79	4.74	0.05	1.05	4.72	4.50	0.22	4.89
30	AMOUNT ($)	11,219,999	11,411,057	(191,058)	(1.67)	91,342,184	96,124,384	(4,782,200)	(4.98)
31	*BURNED:*								
32	UNITS (MMBTU)	2,342,679	2,439,596	(96,917)	(3.97)	19,287,275	21,413,602	(2,126,327)	(9.93)
33	UNIT COST ($/MMBTU)	4.77	4.74	0.03	0.63	4.69	4.50	0.19	4.22
34	AMOUNT ($)	11,178,378	11,572,251	(393,873)	(3.40)	90,443,431	96,265,905	(5,822,474)	(6.05)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	849,667	946,125	(96,458)	(10.20)	(96,458)	0	(96,458)	100.00
37	UNIT COST ($/MMBTU)	4.73	4.34	0.39	8.99	0.89	0.00	0.89	100.00
38	AMOUNT ($)	4,018,255	4,104,101	(85,846)	(2.09)	(85,846)	0	(85,846)	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	1,306	700	606	86.57
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	131.65	120.62	11.00	9.12
42	AMOUNT ($)	0	0	0	0.00	171,929	84,436	87,493	103.62
43	*BURNED:*								
44	UNITS (BBL)	46	0	46	100.00	1,323	700	623	89.00
45	UNIT COST ($/BBL)	110.30	0.00	110.30	100.00	109.57	108.50	1.07	0.99
46	AMOUNT ($)	5,074	0	5,074	100.00	144,963	75,953	69,010	90.86
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	5,939	5,845	94	1.61	5,939	5,845	94	1.61
49	UNIT COST ($/BBL)	111.51	111.06	0.45	0.41	111.51	111.06	0.45	0.41
50	AMOUNT ($)	662,279	649,138	13,141	2.02	662,279	649,138	13,141	2.02
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			CURRENT MONTH						
	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		183,312,000	0	183,312,000	4.21	4.51	7,713,000	8,263,000
2	Various	Economy Sales	4,272,000	0	4,272,000	4.38	4.63	187,000	198,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	57,000	57,000
4	TOTAL ESTIMATED SALES		187,584,000	0	187,584,000	4.24	4.54	7,957,000	8,518,000
	ACTUAL								
5	Southern Company Interchange		34,256,047	0	34,256,047	3.17	2.82	1,086,625	967,606
6	A.E.C.	External	289,287	0	289,287	2.68	3.42	7,756.22	9,891
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	CALPINE	External	0	0	0	0.00	0.00	0	0
10	CARGILE	External	66,003	0	66,003	2.73	3.11	1,801	2,055
11	CONSTELL	External	0	0	0	0.00	0.00	0	0
12	DUKE PWR	External	0	0	0	0.00	0.00	0	0
13	EAGLE EN	External	50,080	0	50,080	3.67	4.94	1,838	2,471
14	ENDURE	External	36,551	0	36,551	4.85	7.33	1,771	2,678
15	ENTERGY	External	50,332	0	50,332	3.04	4.40	1,532	2,215
16	EXELON	External	333,451	0	333,451	2.15	2.35	7,156	7,820
17	FPC	External	74,862	0	74,862	4.89	4.10	3,661	3,069
18	FPL	External	108,210	0	108,210	3.25	4.58	3,520	4,953
19	JPMVEC	External	32,401	0	32,401	4.11	5.30	1,332	1,716
20	MERRILL	External	0	0	0	0.00	0.00	0	0
21	MISO	External	0	0	0	0.00	0.00	0	0
22	MORGAN	External	18,561	0	18,561	9.23	3.87	1,714	718
23	NCEMC	External	0	0	0	0.00	0.00	0	0
24	NRG	External	0	0	0	0.00	0.00	0	0
25	OGE	External	0	0	0	0.00	0.00	0	0
26	OPC	External	23,593	0	23,593	3.45	4.98	815	1,175
27	ORLANDO	External	0	0	0	0.00	0.00	0	0
28	PJM	External	305,185	0	305,185	4.25	5.73	12,978	17,482
29	SCE&G	External	0	0	0	0.00	0.00	0	0
30	SEC	External	88,074	0	88,074	3.31	3.26	2,917	2,873
31	SEPA	External	298,280	0	298,280	2.37	2.68	7,074	7,996
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	0	0	0	0.00	0.00	0	0
34	TEA	External	2,040,085	0	2,040,085	3.60	4.51	73,507	92,017
35	TECO	External	10,698	0	10,698	2.52	2.73	269	293
36	TVA	External	34,602	0	34,602	4.47	5.60	1,547	1,938
37	WRI	External	0	0	0	0.00	0.00	0.00	0
38	Less: Flow-Thru Energy		(3,860,255)	0	(3,860,255)	3.36	3.36	(129,872)	(129,872)
39	SEPA		1,039,632	1,039,632	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(1,588)	(1,588)
41	Other transactions including adj.		164,207,366	153,039,538	11,167,828	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		199,503,045	154,079,170	45,423,875	0.54	0.50	1,086,354	999,094
43	Difference in Amount		11,919,045	154,079,170	(142,160,125)	(3.70)	(4.04)	(6,870,646)	(7,518,906)
44	Difference in Percent		6.35	0.00	(75.78)	(87.26)	(88.99)	(86.35)	(88.27)

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 40

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2013

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		2,007,904,000	0	2,007,904,000	3.39	3.71	68,014,000	74,519,000
2	Various	Economy Sales	52,958,000	0	52,958,000	3.40	3.69	1,799,000	1,956,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	568,000	568,000
4	TOTAL ESTIMATED SALES		2,060,862,000	0	2,060,862,000	3.42	3.74	70,381,000	77,043,000
	ACTUAL								
5	Southern Company Interchange		2,067,850,736	0	2,067,850,736	3.01	3.15	62,279,004	65,210,091
6	A.E.C.	External	4,217,440	0	4,217,440	2.98	3.70	125,540	155,936
7	AECI	External	292,606	0	292,606	2.66	4.06	7,770	11,883
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	0	0	0	0.00	0.00	2,114	0
10	CARGILE	External	3,482,622	0	3,482,622	2.81	3.25	97,972	113,019
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	42,152	0	42,152	3.07	2.51	1,292	1,056
13	EAGLE EN	External	1,239,542	0	1,239,542	2.86	3.75	35,471	46,471
14	ENDURE	External	109,722	0	109,722	3.84	5.43	4,218	5,963
15	ENTERGY	External	272,355	0	272,355	4.41	4.64	12,020	12,639
16	EXELON	External	3,206,620	0	3,206,620	2.95	3.28	94,565	105,091
17	FPC	External	966,280	0	966,280	3.23	4.20	31,232	40,624
18	FPL	External	550,182	0	550,182	3.05	4.18	16,779	23,016
19	JPMVEC	External	934,474	0	934,474	3.24	3.84	30,317	35,892
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	315	0	315	2.65	2.76	8	9
22	MORGAN	External	1,280,842	0	1,280,842	3.27	3.52	41,890	45,072
23	NCEMC	External	617,543	0	617,543	3.08	3.82	19,044	23,601
24	NRG	External	6,291	0	6,291	78.00	3.50	4,907	220
25	OGE	External	1,260	0	1,260	3.01	3.00	38	38
26	OPC	External	1,146,949	0	1,146,949	3.03	3.96	34,721	45,381
27	ORLANDO	External	34,919	0	34,919	3.46	5.15	1,207	1,799
28	PJM	External	9,088,085	0	9,088,085	3.13	3.85	284,349	349,827
29	SCE&G	External	2,819,387	0	2,819,387	3.42	5.05	96,485	142,514
30	SEC	External	1,422,061	0	1,422,061	3.11	3.70	44,231	52,602
31	SEPA	External	1,946,930	0	1,946,930	2.68	3.42	52,156	66,489
32	SPP	External	6,174	0	6,174	2.30	1.63	142	101
33	TAL	External	888,387	0	888,387	3.40	4.52	30,210	40,155
34	TEA	External	8,313,385	0	8,313,385	3.17	4.18	263,214	347,230
35	TECO	External	395,669	0	395,669	3.24	4.52	12,824	17,880
36	TVA	External	3,457,027	0	3,457,027	3.20	4.43	110,650	153,221
37	WRI	External	1,144,159	0	1,144,159	3.02	3.55	34,577	40,633
38	Less: Flow-Thru Energy		(48,271,428)	0	(48,271,428)	2.98	2.98	(1,436,200)	(1,436,200)
39	SEPA		16,122,040	16,122,040	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	89,194	89,194
41	Other transactions including adj.		1,317,454,197	1,236,971,659	80,482,538	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		3,402,026,478	1,253,093,699	2,148,932,779	1.84	1.93	62,445,250	65,681,237
43	Difference in Amount		1,341,164,478	1,253,093,699	88,070,779	(1.58)	(1.81)	(7,935,750)	(11,361,763)
44	Difference in Percent		65.08	0.00	4.27	(46.20)	(48.40)	(11.28)	(14.75)

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: SEPTEMBER 2013

(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 2013

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	3,914,000	0	0	0	7.64	7.64	298,845
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	16
5	Ascend Performance Materials	COG 1	16,991,000	0	0	0	3.23	3.23	549,407
6	International Paper	COG 1	129,000	0	0	0	3.27	3.27	4,223
7	TOTAL		21,034,000	0	0	0	4.05	4.05	852,491

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	31,257,000	0	0	0	7.63	7.63	2,386,226
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	63
5	Ascend Performance Materials	COG 1	161,927,000	0	0	0	3.13	3.13	5,072,533
6	International Paper	COG 1	839,000	0	0	0	3.40	3.40	28,557
7	TOTAL		194,023,000	0	0	0	3.86	3.86	7,487,381

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2013

	(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	101,050,000	4.22	4,263,000	429,899,000	3.93	16,886,000
2	Economy Energy	2,474,000	5.30	131,000	35,422,000	3.87	1,372,000
3	Other Purchases	329,651,000	3.53	11,637,000	4,255,835,000	3.12	132,735,000
4	TOTAL ESTIMATED PURCHASES	433,175,000	3.70	16,031,000	4,721,156,000	3.20	150,993,000
	ACTUAL						
5	Southern Company Interchange	174,329,928	3.32	5,795,162	618,472,561	3.24	20,024,141
6	Non-Associated Companies	64,927,238	1.02	663,269	498,186,065	1.52	7,582,409
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	264,240,000	3.53	9,334,717	3,779,305,000	3.22	121,765,055
9	Other Wheeled Energy	34,812,000	0.00	N/A	248,260,000	0.00	N/A
10	Other Transactions	88,200,766	0.01	12,743	741,105,127	0.01	108,556
11	Less: Flow-Thru Energy	(3,860,255)	3.59	(138,735)	(48,271,428)	3.19	(1,538,370)
12	TOTAL ACTUAL PURCHASES	622,649,677	2.52	15,667,156	5,837,057,325	2.53	147,941,791
13	Difference in Amount	189,474,677	(1.18)	(363,844)	1,115,901,325	(0.67)	(3,051,209)
14	Difference in Percent	43.74	(31.89)	(2.27)	23.64	(20.94)	(2.02)

2013 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C) JAN		(D) FEB		(E) MAR		(F) APR		(G) MAY		(H) JUN		(I)
	CONTRACT	TERM														SUBTOTAL
A. CONTRACT/COUNTERPARTY	TYPE	Start	End	MW	$	MW	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		**$ 2,045,794**		**$ 2,596,589**		**$ 6,777,892**	**$ 18,088,765**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

2013 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	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -	120	$ 413,300		$ -		$ -		$ -	$ 1,130,866
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,225	Varies	6,797,704							38,469,347
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)							(36,214)
SUBTOTAL					$ 7,263,297		$ 7,004,079		$ 6,794,558		$ -		$ -		$ -	$ 38,433,133
TOTAL					**$ 7,263,297**		**$ 7,004,079**		**$ 7,207,858**		$ -		$ -		$ -	**$ 39,563,999**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

October 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2013
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	28,246,455	29,717,615	(1,471,160)	(4.95)	713,533,000	675,501,000	38,032,000	5.63	3.9587	4.3993	(0.44)	(10.02)
2	Hedging Settlement Costs (A2)	1,306,667	0	1,306,667	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) **	13,707	0	13,707	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	29,566,829	29,717,615	(150,786)	(0.51)	713,533,000	675,501,000	38,032,000	5.63	4.1437	4.3993	(0.26)	(5.81)
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)	18,769,201	15,756,000	3,013,201	19.12	720,623,160	480,159,000	240,464,160	50.08	2.6046	3.2814	(0.68)	(20.63)
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)	832,351	0	832,351	100.00	22,669,000	0	22,669,000	100.00	3.6718	0.0000	3.67	0.00
12	TOTAL COST OF PURCHASED POWER	19,601,552	15,756,000	3,845,552	24.41	743,292,160	480,159,000	263,133,160	54.80	2.6371	3.2814	(0.64)	(19.63)
13	Total Available MWH (Line 5 + Line 12)	49,168,381	45,473,615	3,694,766	8.13	1,456,825,160	1,155,660,000	301,165,160	26.06				
14	Fuel Cost of Economy Sales (A6)	(237,024)	(235,000)	(2,024)	0.86	(7,938,856)	(6,747,000)	(1,191,856)	17.66	(2.9856)	(3.4850)	0.50	14.28
15	Gain on Economy Sales (A6)	(23,521)	(32,000)	8,479	(26.50)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(11,371,493)	(6,338,000)	(5,033,493)	79.42	(523,033,717)	(205,646,000)	(317,387,717)	154.34	(2.1741)	(3.0820)	0.91	29.46
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(11,632,038)	(6,605,000)	(5,027,038)	76.11	(530,972,573)	(212,393,000)	(318,579,573)	150.00	(2.1907)	(3.1098)	0.92	29.55
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)	37,536,343	38,868,615	(1,332,272)	(3.43)	925,852,587	943,267,000	(17,414,413)	(1.85)	4.0542	4.1206	(0.07)	(1.61)
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 *	66,411	66,960	(549)	(0.82)	1,638,088	1,625,000	13,088	0.81	4.0542	4.1206	(0.07)	(1.61)
22	T & D Losses *	1,780,961	2,056,303	(275,342)	(13.39)	43,928,792	49,903,000	(5,974,208)	(11.97)	4.0542	4.1206	(0.07)	(1.61)
23	TERRITORIAL KWH SALES	37,536,344	38,868,615	(1,332,272)	(3.43)	880,285,707	891,739,000	(11,453,293)	(1.28)	4.2641	4.3587	(0.09)	(2.17)
24	Wholesale KWH Sales	1,020,238	1,147,596	(127,358)	(11.10)	23,925,987	26,329,000	(2,403,013)	(9.13)	4.2641	4.3587	(0.09)	(2.17)
25	Jurisdictional KWH Sales	36,516,106	37,721,019	(1,204,913)	(3.19)	856,359,720	865,410,000	(9,050,280)	(1.05)	4.2641	4.3587	(0.09)	(2.17)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	36,570,880	37,777,601	(1,206,721)	(3.19)	856,359,720	865,410,000	(9,050,280)	(1.05)	4.2705	4.3653	(0.09)	(2.17)
28	TRUE-UP	(2,202,118)	(2,202,118)	0	0.00	856,359,720	865,410,000	(9,050,280)	(1.05)	(0.2571)	(0.2545)	(0.00)	1.02
29	TOTAL JURISDICTIONAL FUEL COST	34,368,762	35,575,483	(1,206,721)	(3.39)	856,359,720	865,410,000	(9,050,280)	(1.05)	4.0134	4.1108	(0.10)	(2.37)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0163	4.1138	(0.10)	(2.37)
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	856,359,720	865,410,000	(9,050,280)	(1.05)	0.0101	0.0100	0.00	1.00
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0264	4.1238	(0.10)	(2.36)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.026	4.124		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 28,246,455
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	13,707
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,306,667
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	18,769,201
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	832,351
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(11,632,038)
10	Total Fuel and Net Power Transactions		$ 37,536,343

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2013
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)	296,680,040	318,564,506	(21,884,466)	(6.87)	6,989,817,000	7,631,362,000	(641,545,000)	(8.41)	4.2445	4.1744	0.07	1.68
2	Hedging Settlement Costs (A2)	13,713,360	0	13,713,360	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) **	190,337	0	190,337	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	310,583,737	318,564,506	(7,980,769)	(2.51)	6,989,817,000	7,631,362,000	(641,545,000)	(8.41)	4.4434	4.1744	0.27	6.44
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)	166,710,992	166,749,000	(38,008)	(0.02)	6,557,680,485	5,201,315,000	1,356,365,485	26.08	2.5422	3.2059	(0.66)	(20.70)
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)	8,319,732	0	8,319,732	100.00	216,692,000	0	216,692,000	100.00	3.8394	0.0000	3.84	0.00
12	TOTAL COST OF PURCHASED POWER	175,030,724	166,749,000	8,281,724	4.97	6,774,372,485	5,201,315,000	1,573,057,485	30.24	2.5837	3.2059	(0.62)	(19.41)
13	Total Available MWH (Line 5 + Line 12)	485,614,461	485,313,506	300,955	0.06	13,764,189,485	12,832,677,000	931,512,485	7.26				
14	Fuel Cost of Economy Sales (A6)	(1,750,277)	(2,034,000)	283,723	(13.95)	(56,809,789)	(59,705,000)	2,895,211	(4.85)	(3.0809)	(3.4067)	0.33	9.56
15	Gain on Economy Sales (A6)	(112,715)	(600,000)	487,285	(81.21)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(72,214,296)	(74,352,000)	2,137,704	(2.88)	(3,876,189,262)	(2,213,550,000)	(1,662,639,262)	75.11	(1.8630)	(3.3589)	1.50	44.54
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(74,077,288)	(76,986,000)	2,908,712	(3.78)	(3,932,999,051)	(2,273,255,000)	(1,659,744,051)	73.01	(1.8835)	(3.3866)	1.50	44.38
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)	411,537,173	408,327,506	3,209,667	0.79	9,831,190,434	10,559,422,000	(728,231,566)	(6.90)	4.1860	3.8669	0.32	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 *	702,472	703,544	(1,072)	(0.15)	16,781,460	18,194,000	(1,412,540)	(7.76)	4.1860	3.8669	0.32	8.25
22	T & D Losses *	20,974,169	23,717,708	(2,743,539)	(11.57)	501,055,171	613,352,000	(112,296,829)	(18.31)	4.1860	3.8669	0.32	8.25
23	TERRITORIAL KWH SALES	411,537,174	408,327,506	3,209,668	0.79	9,313,353,803	9,927,876,000	(614,522,197)	(6.19)	4.4188	4.1129	0.31	7.44
24	Wholesale KWH Sales	11,531,713	12,467,491	(935,778)	(7.51)	261,149,369	303,182,000	(42,032,631)	(13.86)	4.4158	4.1122	0.30	7.38
25	Jurisdictional KWH Sales	400,005,461	395,860,015	4,145,446	1.05	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)	4.4189	4.1130	0.31	7.44
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	400,605,470	396,453,805	4,151,665	1.05	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)	4.4255	4.1191	0.31	7.44
28	TRUE-UP	(22,021,180)	(22,021,180)	0	0.00	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)	(0.2433)	(0.2288)	(0.01)	6.34
29	TOTAL JURISDICTIONAL FUEL COST	378,584,290	374,432,625	4,151,665	1.11	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)	4.1822	3.8903	0.29	7.50
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1852	3.8931	0.29	7.50
32	GPIF Reward / (Penalty)	867,220	867,220	0	0.00	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)	0.0096	0.0090	0.00	6.67
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1948	3.9021	0.29	7.50
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.195	3.902		

* 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 2013

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	28,036,792.63	29,526.224	(1,489,431.37)	(5.04)	294,663,544.23	316,720,525	(22,056,980.77)	(6.96)
1a	Other Generation	209,662.77	191,391	18,271.77	9.55	2,016,495.31	1,843,981	172,514.31	9.36
2	Fuel Cost of Power Sold	(11,632,037.63)	(6,605,000)	(5,027,037.63)	(76.11)	(74,077,287.92)	(76,986,000)	2,908,712.08	3.78
3	Fuel Cost - Purchased Power	18,769,200.75	15,756,000	3,013,200.75	19.12	166,710,992.09	166,749,000	(38,007.91)	(0.02)
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	832,350.78	0	832,350.78	100.00	8,319,731.59	0	8,319,731.59	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,306,667.00	0	1,306,667.00	100.00	13,713,360.00	0	13,713,360.00	100.00
6	Total Fuel & Net Power Transactions	37,522,636.30	38,868,615	(1,345,978.70)	(3.46)	411,346,835.30	408,327,506	3,019,329.30	0.74
7	AdjustmentsTo Fuel Cost*	13,707.49	0	13,707.49	100.00	190,337.91	0	190,337.91	100.00
8	Adj. Total Fuel & Net Power Transactions	37,536,343.79	38,868,615	(1,332,271.21)	(3.43)	411,537,173.21	408,327,506	3,209,667.21	0.79
B.	*KWH Sales*								
1	Jurisdictional Sales	856,359,720	865,410,000	(9,050,280)	(1.05)	9,052,204,434	9,624,694,000	(572,489,566)	(5.95)
2	Non-Jurisdictional Sales	23,925,987	26,329,000	(2,403,013)	(9.13)	261,149,369	303,182,000	(42,032,631)	(13.86)
3	Total Territorial Sales	880,285,707	891,739,000	(11,453,293)	(1.28)	9,313,353,803	9,927,876,000	(614,522,197)	(6.19)
4	Juris. Sales as % of Total Terr. Sales	97.2820	97.0475	0.2345	0.24	97.1960	96.9462	0.2498	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: OCTOBER 2013

C. *True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1 Jurisdictional Fuel Revenue	32,483,350.58	32,884,404	(401,053.31)	(1.22)	343,589,828.12	365,930,462	(22,340,634.16)	(6.11)
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	22,021,180.00	22,021,180	0.00	0.00
2b Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(866,590.00)	(866,590)	0.00	0.00
3 Juris. Fuel Revenue Applicable to Period	34,598,809.58	34,999,863	(401,053.42)	(1.15)	364,744,418.12	387,085,052	(22,340,633.88)	(5.77)
4 Adjusted Total Fuel & Net Power Transactions (Line A8)	37,536,343.79	38,868,615	(1,332,271.21)	(3.43)	411,537,173.60	408,327,506	3,209,667.60	0.79
5 Juris. Sales % of Total KWH Sales (Line B4)	97.2820	97.0475	0.2345	0.24	97.1960	96.9462	0.2498	0.26
6 Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	36,570,880.12	37,777,601	(1,206,720.88)	(3.19)	400,605,470.31	396,453,805	4,151,665.31	1.05
7 True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,972,070.54)	(2,777,738)	805,667.46	29.00	(35,861,052.19)	(9,368,752)	(26,492,300.19)	(282.77)
8 Interest Provision for the Month	(509.53)	(104)	(405.53)	(389.93)	60.52	8,123	(8,062.48)	99.25
9 Beginning True-Up & Interest Provision	(10,044,668.20)	23,569	(10,068,237.20)	42,718.13	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10 True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(22,021,180.00)	(22,021,180)	0.00	0.00
11 End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(14,219,366.27)	(4,956,391)	(9,262,975.27)	(186.89)	(40,790,448.53)	(4,956,391)	(35,834,057.53)	(722.99)
12 Adjustment		0	0.00	0.00	26,571,082.26	0	26,571,082.26	100.00
13 End of Period - Total Net True-Up	(14,219,366.27)	(4,956,391)	(9,262,975.27)	(186.89)	(14,219,366.27)	(4,956,391)	(9,262,975.27)	(186.89)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	(10,044,668.20)	23,569	(10,068,237.20)	(42,718.13)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(14,218,856.74)	(4,956,287)	(9,262,569.74)	186.89
3	Total of Beginning & Ending True-Up Amts.	(24,263,524.94)	(4,932,718)	(19,330,806.94)	391.89
4	Average True-Up Amount	(12,131,762.47)	(2,466,359)	(9,665,403.47)	391.89
5	Interest Rate 1st Day of Reporting Business Month	0.05	0.05	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.05	0.05	0.0000	
7	Total (D5+D6)	0.10	0.10	0.0000	
8	Annual Average Interest Rate	0.05	0.05	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0042	0.0042	0.0000	
10	Interest Provision (D4*D9)	(509.53)	(104)	(405.53)	389.93
	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: OCTOBER 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	157,051	138,490	18,561	13.40	1,570,646	958,328	612,318	63.89
2	COAL	15,416,939	19,718,648	(4,301,709)	(21.82)	189,506,605	209,235,422	(19,728,817)	(9.43)
3	GAS	12,329,461	9,804,365	2,525,096	25.75	103,910,649	107,722,860	(3,812,211)	(3.54)
4	GAS (B.L.)	254,888	0	254,888	100.00	923,962	-	923,962	100.00
5	LANDFILL GAS	54,872	56,112	(1,240)	(2.21)	589,969	571,943	18,026	3.15
6	OIL - C.T.	33,245	0	33,245	100.00	178,209	75,953	102,256	134.63
7	TOTAL ($)	28,246,455	29,717,615	(1,471,160)	(4.95)	296,680,040	318,564,506	(21,884,466)	(6.87)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	347,319	403,247	(55,928)	(13.87)	3,926,740	4,222,706	(295,966)	(7.01)
10	GAS	364,382	270,154	94,228	34.88	3,042,814	3,386,931	(344,117)	(10.16)
11	LANDFILL GAS	1,769	2,100	(331)	(15.76)	19,754	21,405	(1,651)	(7.71)
12	OIL - C.T.	63	0	63	100.00	509	320	189	59.06
13	TOTAL (MWH)	713,533	675,501	38,032	5.63	6,989,817	7,631,362	(641,545)	(8.41)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,218	1,094	124	11.33	11,988	7,808	4,180	53.53
15	COAL (TONS)	157,108	186,124	(29,016)	(15.59)	1,844,231	1,972,152	(127,921)	(6.49)
16	GAS (MCF) (1)	2,560,426	1,825,897	734,529	40.23	21,604,309	23,313,479	(1,709,170)	(7.33)
17	OIL - C.T. (BBL)	298	0	298	100.00	1,621	700	921	131.57
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,810,980	4,424,493	(613,513)	(13.87)	51,270,066	46,423,990	4,846,076	10.44
19	GAS - Generation (1)	2,567,464	1,880,674	686,790	36.52	21,790,861	23,294,276	(1,503,415)	(6.45)
20	OIL - C.T.	1,734	0	1,734	100.00	9,433	4,100	5,333	130.07
21	TOTAL (MMBTU)	6,380,179	6,305,167	75,012	1.19	73,070,360	69,722,366	3,347,994	4.80
	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	48.67	59.70	(11.03)	(18.48)	56.18	55.33	0.85	1.54
24	GAS	51.07	39.99	11.08	27.71	43.53	44.38	(0.85)	(1.92)
25	LANDFILL GAS	0.25	0.31	(0.06)	(19.35)	0.28	0.28	0.00	0.00
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.01	0.00	0.00
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)	128.99	126.59	2.40	1.90	131.02	122.74	8.28	6.75
29	COAL ($/TON)	98.13	105.94	(7.81)	(7.37)	102.76	106.09	(3.33)	(3.14)
30	GAS ($/MCF) (1)	4.83	5.26	(0.43)	(8.17)	4.76	4.54	0.22	4.85
31	OIL - C.T. ($/BBL)	111.56	0.00	111.56	100.00	109.94	108.50	1.44	1.33
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.15	4.49	(0.34)	(7.57)	3.74	4.53	(0.79)	(17.44)
33	GAS - Generation (1)	4.72	5.11	(0.39)	(7.63)	4.68	4.55	0.13	2.86
34	OIL - C.T.	19.17	0.00	19.17	100.00	18.89	18.53	0.36	1.94
35	TOTAL ($/MMBTU)	4.39	4.67	(0.28)	(6.00)	4.02	4.53	(0.51)	(11.26)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,973	10,972	1	0.01	13,057	10,994	2,063	18.76
37	GAS - Generation (1)	7,167	7,112	55	0.77	7,304	6,964	340	4.88
38	OIL - C.T.	27,530	0	27,530	100.00	18,533	12,813	5,720	44.64
39	TOTAL (BTU/KWH)	9,042	9,443	(401)	(4.25)	10,574	9,213	1,361	14.77
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.56	4.92	(0.36)	(7.32)	4.89	4.98	(0.09)	(1.81)
41	GAS	3.38	3.63	(0.25)	(6.89)	3.41	3.18	0.23	7.23
42	LANDFILL GAS	3.10	2.67	0.43	16.10	2.99	2.67	0.32	11.99
43	OIL - C.T.	52.77	0.00	52.77	100.00	35.01	23.74	11.27	47.47
44	TOTAL (¢/KWH)	3.96	4.40	(0.44)	(10.00)	4.24	4.17	0.07	1.68

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 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	(588)	0.0	100.0	0.0	0	Coal	0.0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	0	1,016	0	0		0.00
4									Oil-S	0	137,922	0	0		0.00
5	Crist 5		75	33,907	60.8	99.4	61.1	10,877	Coal	15,634	11,795	368,805	1,501,591	4.43	96.05
6				-					Gas-G	0	1,016	0	0	0.00	0.00
7									Gas-S	434	1,016	441	2,885		6.65
8									Oil-S	120	137,922	695	15,242		127.02
9	Crist 6		299	13,619	6.1	100.0	52.9	10,212	Coal	5,909	11,768	139,074	567,541	4.17	96.05
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	37,925	1,016	38,532	252,003		6.64
12									Oil-S	0	137,922	0	0		0.00
13	Crist 7		475	196,453	55.6	100.0	55.6	10,547	Coal	87,447	11,847	2,071,974	8,399,035	4.28	96.05
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	14	137,922	83	1,827		130.50
17	Scholz 1		46	(222)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(156)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	55,176	45.8	100.0	45.8	10,916	Coal	26,003	11,581	602,288	2,652,871	4.81	102.02
22									Oil-S	139	138,605	806	18,372		132.17
23	Smith 2		195	25,943	17.9	100.0	45.0	11,040	Coal	12,328	11,616	286,412	1,257,745	4.85	102.02
24									Oil-S	256	138,605	1,488	33,908		132.45
25	Smith 3		558	358,249	86.3	99.4	101.1	7,167	Gas-G	2,522,067	1,018	2,567,466	12,119,798	3.38	4.81
26	Smith A	(2)	36	63	0.2	97.2	57.6	27,524	Oil	298	138,520	1,734	33,245	52.77	111.56
27	Other Generation			6,133									209,663	3.42	0.00
28	Perdido			1,769					Landfill Gas				54,872	3.10	0.00
29	Daniel 1	(1)	255	16,195	8.5	100.0	38.1	12,440	Coal	9,034	11,151	201,473	971,837	6.00	107.58
30									Oil-S	270	138,243	1,570	34,421		127.49
31	Daniel 2	(1)	255	6,992	3.7	89.2	37.0	13,574	Coal	4,308	11,017	94,908	463,381	6.63	107.56
32									Oil-S	419	138,243	2,430	53,281		127.16
33	Total		2,477	713,533	38.7	98.7	56.8	9,042				6,380,179	28,643,518	4.01	

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)	
(3,556)	Inventory Adj - Daniel	(393,004)	
	Recoverable Fuel	28,246,455	3.96

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	367	1,091	(724)	(66.36)	11,483	7,796	3,687	47.29
3	UNIT COST ($/BBL)	130.49	126.29	4.20	3.33	130.56	122.42	8.14	6.65
4	AMOUNT ($)	47,888	137,787	(89,899)	(65.24)	1,499,184	954,396	544,788	57.08
5	*BURNED:*								
6	UNITS (BBL)	1,246	1,094	152	13.89	12,517	7,808	4,709	60.31
7	UNIT COST ($/BBL)	129.05	126.59	2.46	1.94	131.04	122.74	8.30	6.76
8	AMOUNT ($)	160,793	138,490	22,303	16.10	1,640,225	958,328	681,897	71.15
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,934	4,541	393	8.65	4,934	4,541	393	8.65
11	UNIT COST ($/BBL)	127.68	124.69	2.99	2.40	127.68	124.69	2.99	2.40
12	AMOUNT ($)	629,976	566,229	63,747	11.26	629,976	566,229	63,747	11.26
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	177,825	158,771	19,054	12.00	1,599,576	1,630,780	(31,204)	(1.91)
16	UNIT COST ($/TON)	94.41	109.92	(15.51)	(14.11)	100.01	105.57	(5.56)	(5.27)
17	AMOUNT ($)	16,788,077	17,452,372	(664,295)	(3.81)	159,977,426	172,157,060	(12,179,634)	(7.07)
18	*BURNED:*								
19	UNITS (TONS)	157,108	186,124	(29,016)	(15.59)	1,844,231	1,972,152	(127,921)	(6.49)
20	UNIT COST ($/TON)	98.16	105.94	(7.78)	(7.34)	102.10	106.09	(3.99)	(3.76)
21	AMOUNT ($)	15,420,997	19,718,648	(4,297,651)	(21.79)	188,299,262	209,235,422	(20,936,160)	(10.01)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	693,552	553,545	140,007	25.29	693,552	553,545	140,007	25.29
24	UNIT COST ($/TON)	101.73	106.25	(4.52)	(4.25)	101.73	106.25	(4.52)	(4.25)
25	AMOUNT ($)	70,556,780	58,816,493	11,740,287	19.96	70,556,780	58,816,493	11,740,287	19.96
26	DAYS SUPPLY	33	26	7	26.92				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,554,949	1,848,049	706,900	38.25	21,910,585	23,229,026	(1,318,441)	(5.68)
29	UNIT COST ($/MMBTU)	4.75	5.11	(0.36)	(7.05)	4.72	4.54	0.18	3.96
30	AMOUNT ($)	12,124,262	9,447,702	2,676,560	28.33	103,466,446	105,572,086	(2,105,640)	(1.99)
31	*BURNED:*								
32	UNITS (MMBTU)	2,606,437	1,880,674	725,763	38.59	21,893,712	23,294,276	(1,400,564)	(6.01)
33	UNIT COST ($/MMBTU)	4.75	5.11	(0.36)	(7.05)	4.70	4.55	0.15	3.30
34	AMOUNT ($)	12,374,686	9,612,974	2,761,712	28.73	102,818,117	105,878,879	(3,060,762)	(2.89)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	798,179	913,500	(115,321)	(12.62)	(115,321)	0	(115,321)	100.00
37	UNIT COST ($/MMBTU)	4.72	4.31	0.41	9.51	1.48	0.00	1.48	100.00
38	AMOUNT ($)	3,767,830	3,938,829	(170,999)	(4.34)	(170,999)	0	(170,999)	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	1,306	700	606	86.57
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	131.65	120.62	11.00	9.12
42	AMOUNT ($)	0	0	0	0.00	171,929	84,436	87,493	103.62
43	*BURNED:*								
44	UNITS (BBL)	298	0	298	100.00	1,621	700	921	131.57
45	UNIT COST ($/BBL)	111.56	0.00	111.56	100.00	109.94	108.50	1.44	1.33
46	AMOUNT ($)	33,245	0	33,245	100.00	178,208	75,953	102,255	134.63
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	5,641	5,845	(204)	(3.49)	5,641	5,845	(204)	(3.49)
49	UNIT COST ($/BBL)	111.51	111.06	0.45	0.41	111.51	111.06	0.45	0.41
50	AMOUNT ($)	629,034	649,138	(20,104)	(3.10)	629,034	649,138	(20,104)	(3.10)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

			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		205,646,000	0	205,646,000	3.08	3.44	6,338,000	7,067,000
2	Various	Economy Sales	6,747,000	0	6,747,000	3.48	3.78	235,000	255,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	32,000	32,000
4	TOTAL ESTIMATED SALES		212,393,000	0	212,393,000	3.11	3.46	6,605,000	7,354,000
	ACTUAL								
5	Southern Company Interchange		390,280,632	0	390,280,632	2.97	3.17	11,597,754	12,371,088
6	A.E.C.	External	445,172	0	445,172	3.05	3.67	13,568	16,337
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	CALPINE	External	5,662	0	5,662	2.83	3.90	160	221
10	CARGILE	External	874,183	0	874,183	2.76	2.77	24,110	24,255
11	CONSTELL	External	0	0	0	0.00	0.00	0	0
12	DUKE PWR	External	205,853	0	205,853	2.99	3.82	6,158	7,864
13	EAGLE EN	External	352,691	0	352,691	2.67	3.10	9,413	10,948
14	ENDURE	External	0	0	0	0.00	0.00	0	0
15	ENTERGY	External	1,115,144	0	1,115,144	3.90	6.64	43,533	74,099
16	EXELON	External	535,897	0	535,897	2.87	2.79	15,398	14,934
17	FPC	External	0	0	0	0.00	0.00	0	0
18	FPL	External	133,753	0	133,753	3.19	4.14	4,262	5,538
19	JPMVEC	External	64,990	0	64,990	7.02	3.94	4,564	2,559
20	MERRILL	External	0	0	0	0.00	0.00	0	0
21	MISO	External	0	0	0	0.00	0.00	0	0
22	MORGAN	External	1,388,088	0	1,388,088	2.41	2.66	33,461	36,921
23	NCEMC	External	71,727	0	71,727	3.89	4.33	2,788	3,103
24	NCMPA1	External	80,223	0	80,223	3.61	4.09	2,894	3,284
25	NRG	External	0	0	0	0.00	0.00	1,252	0
26	OGE	External	0	0	0	0.00	0.00	0	0
27	OPC	External	55,051	0	55,051	2.52	3.41	1,388	1,878
28	ORLANDO	External	0	0	0	0.00	0.00	0	0
29	PJM	External	565,091	0	565,091	3.04	3.92	17,200	22,133
30	SCE&G	External	0	0	0	0.00	0.00	0	0
31	SEC	External	164,200	0	164,200	3.09	3.88	5,069	6,365
32	SEPA	External	772,146	0	772,146	2.46	2.87	19,008	22,147
33	SPP	External	0	0	0	0.00	0.00	0	0
34	TAL	External	54,109	0	54,109	2.57	3.46	1,386	1,874
35	TEA	External	708,018	0	708,018	2.96	3.75	20,952	26,528
36	TECO	External	0	0	0	0.00	0.00	0	0
37	TVA	External	61,970	0	61,970	2.62	3.09	1,623	1,913
38	UPP	External	0	0	0	0.00	0.00	1,321	0
39	WRI	External	284,888	0	284,888	2.64	2.59	7,514	7,393
40	Less: Flow-Thru Energy		(7,885,947)	0	(7,885,947)	2.87	2.87	(226,261)	(226,261)
41	SEPA		1,070,608	1,070,608	0	0.00	0.00	0	0
42	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	23,521	23,521
43	Other transactions including adj.		139,568,424	136,362,757	3,205,667	0.00	0.00	0	0
44	TOTAL ACTUAL SALES		530,972,573	137,433,365	393,539,208	2.19	2.34	11,632,038	12,435,118
45	Difference in Amount		318,579,573	137,433,365	181,146,208	(0.92)	(1.12)	5,027,038	5,081,118
46	Difference in Percent		150.00	0.00	85.29	(29.58)	(32.37)	76.11	69.09

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 42

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

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		2,213,550,000	0	2,213,550,000	3.36	3.69	74,352,000	81,586,000
2	Various	Economy Sales	59,705,000	0	59,705,000	3.41	3.70	2,034,000	2,211,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	600,000	600,000
4	TOTAL ESTIMATED SALES		2,273,255,000	0	2,273,255,000	3.39	3.71	76,986,000	84,397,000
	ACTUAL								
5	Southern Company Interchange		2,458,131,368	0	2,458,131,368	3.01	3.16	73,876,758	77,581,179
6	A.E.C.	External	4,662,612	0	4,662,612	2.98	3.69	139,109	172,274
7	AECI	External	292,606	0	292,606	2.66	4.06	7,770	11,883
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	5,662	0	5,662	40.16	3.90	2,274	221
10	CARGILE	External	4,356,805	0	4,356,805	2.80	3.15	122,082	137,274
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	248,005	0	248,005	3.00	3.60	7,450	8,920
13	EAGLE EN	External	1,592,233	0	1,592,233	2.82	3.61	44,884	57,418
14	ENDURE	External	109,722	0	109,722	3.84	5.43	4,218	5,963
15	ENTERGY	External	1,387,499	0	1,387,499	4.00	6.25	55,553	86,738
16	EXELON	External	3,742,517	0	3,742,517	2.94	3.21	109,963	120,025
17	FPC	External	966,280	0	966,280	3.23	4.20	31,232	40,624
18	FPL	External	683,935	0	683,935	3.08	4.17	21,041	28,554
19	JPMVEC	External	999,464	0	999,464	3.49	3.85	34,881	38,452
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	315	0	315	2.65	2.76	8	9
22	MORGAN	External	2,668,930	0	2,668,930	2.82	3.07	75,350	81,993
23	NCEMC	External	689,270	0	689,270	3.17	3.87	21,832	26,704
24	NCMPA1	External	80,223	0	80,223	3.61	4.09	2,894	3,284
25	NRG	External	6,291	0	6,291	97.90	3.50	6,159	220
26	OGE	External	1,260	0	1,260	3.01	3.00	38	38
27	OPC	External	1,202,000	0	1,202,000	3.00	3.93	36,108	47,259
28	ORLANDO	External	34,919	0	34,919	3.46	5.15	1,207	1,799
29	PJM	External	9,653,176	0	9,653,176	3.12	3.85	301,550	371,959
30	SCE&G	External	2,819,387	0	2,819,387	3.42	5.05	96,485	142,514
31	SEC	External	1,586,261	0	1,586,261	3.11	3.72	49,300	58,966
32	SEPA	External	2,719,076	0	2,719,076	2.62	3.26	71,164	88,636
33	SPP	External	6,174	0	6,174	2.30	1.63	142	101
34	TAL	External	942,496	0	942,496	3.35	4.46	31,598	42,029
35	TEA	External	9,021,403	0	9,021,403	3.15	4.14	284,166	373,759
36	TECO	External	395,669	0	395,669	3.24	4.52	12,824	17,880
37	TVA	External	3,518,997	0	3,518,997	3.19	4.41	112,273	155,133
38	UPP	External	0	0	0	0.00	0.00	1,321	0
39	WRI	External	1,429,047	0	1,429,047	2.95	3.36	42,091	48,026
40	Less: Flow-Thru Energy		(56,157,375)	0	(56,157,375)	2.96	2.96	(1,662,461)	(1,662,461)
41	SEPA		17,192,648	17,192,648	0	0.00	0.00	0	0
42	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	112,715	112,715
43	Other transactions including adj.		1,457,022,621	1,373,334,416	83,688,205	0.00	0.00	0	0
44	TOTAL ACTUAL SALES		3,932,999,051	1,390,527,064	2,542,471,987	1.88	1.99	74,077,288	78,116,356
45	Difference in Amount		1,659,744,051	1,390,527,064	289,216,987	(1.51)	(1.72)	(2,908,712)	(6,280,644)
46	Difference in Percent		73.01	0.00	11.84	(44.54)	(46.38)	(3.78)	(7.44)

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 42

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: OCTOBER 2013

(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								

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SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

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	2,271,000	0	0	0	7.64	7.64	173,419
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	6
5 Ascend Performance Materials	COG 1	20,390,000	0	0	0	3.23	3.23	658,619
6 International Paper	COG 1	8,000	0	0	0	3.84	3.84	307
7 TOTAL		22,669,000	0	0	0	3.67	3.67	832,351

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	33,528,000	0	0	0	7.63	7.63	2,559,645
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	69
5 Ascend Performance Materials	COG 1	182,317,000	0	0	0	3.14	3.14	5,731,152
6 International Paper	COG 1	847,000	0	0	0	3.41	3.41	28,864
7 TOTAL		216,692,000	0	0	0	3.84	3.84	8,319,732

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2013

	(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	55,706,000	4.09	2,279,000	485,605,000	3.95	19,165,000
2	Economy Energy	2,704,000	3.99	108,000	38,126,000	3.88	1,480,000
3	Other Purchases	421,749,000	3.17	13,369,000	4,677,584,000	3.12	146,104,000
4	TOTAL ESTIMATED PURCHASES	480,159,000	3.28	15,756,000	5,201,315,000	3.21	166,749,000
	ACTUAL						
5	Southern Company Interchange	51,864,280	2.70	1,402,239	670,336,841	3.20	21,426,380
6	Non-Associated Companies	42,845,880	(26.58)	(11,386,650)	541,031,945	(0.70)	(3,804,241)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	523,114,000	5.54	28,985,550	4,302,419,000	3.50	150,750,605
9	Other Wheeled Energy	33,251,000	0.00	N/A	281,511,000	0.00	N/A
10	Other Transactions	77,433,947	0.01	11,556	818,539,074	0.01	120,112
11	Less: Flow-Thru Energy	(7,885,947)	3.09	(243,494)	(56,157,375)	3.17	(1,781,864)
12	TOTAL ACTUAL PURCHASES	720,623,160	2.60	18,769,201	6,557,680,485	2.54	166,710,992
13	Difference in Amount	240,464,160	(0.68)	3,013,201	1,356,365,485	(0.67)	(38,008)
14	Difference in Percent	50.08	(20.73)	19.12	26.08	(20.87)	(0.02)

2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		**$ 2,045,794**		**$ 2,596,589**		**$ 6,777,892**	**$ 18,088,765**

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

2013 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	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -	120	$ 413,300	58.9	$ 20,971		$ -		$ -	$ 1,151,837
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,225	Varies	6,797,704	Varies	2,473,170					40,942,517
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)					(39,360)
SUBTOTAL					$ 7,263,297		$ 7,004,079		$ 6,794,558		$ 2,470,024		$ -		$ -	$ 40,903,157
TOTAL					**$ 7,263,297**		**$ 7,004,079**		**$ 7,207,858**		**$ 2,490,995**		$ -		$ -	**$ 42,054,994**

Docket No. 140001-EI
2013 Final True-Up Filing
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

November 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2013
CURRENT MONTH

		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)	26,750,341	24,205,809	2,544,532	10.51	670,928,000	593,044,000	77,884,000	13.13	3.9871	4.0816	(0.09)	(2.32)
2	Hedging Settlement Costs (A2)	1,348,136	0	1,348,136	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) **	(1,129)	0	(1,129)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,097,348	24,205,809	3,891,539	16.08	670,928,000	593,044,000	77,884,000	13.13	4.1878	4.0816	0.11	2.60
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)	19,712,063	16,659,000	3,053,063	18.33	778,636,451	529,871,000	248,765,451	46.95	2.5316	3.1440	(0.61)	(19.48)
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)	889,274	0	669,274	100.00	24,068,000	0	24,068,000	100.00	3.6948	0.0000	3.69	0.00
12	TOTAL COST OF PURCHASED POWER	20,601,337	16,659,000	3,942,337	23.66	802,704,451	529,871,000	272,833,451	51.49	2.5665	3.1440	(0.58)	(18.37)
13	Total Available MWH (Line 5 + Line 12)	48,698,885	40,864,809	7,833,878	19.17	1,473,632,451	1,122,915,000	350,717,451	31.23				
14	Fuel Cost of Economy Sales (A6)	(348,353)	(219,000)	(129,353)	59.07	(12,930,695)	(7,930,000)	(5,000,695)	63.06	(2.6940)	(2.7617)	0.07	2.45
15	Gain on Economy Sales (A6)	(39,339)	(26,000)	(13,339)	51.30	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(13,906,604)	(7,417,000)	(6,489,604)	87.50	(657,493,080)	(281,608,000)	(375,885,080)	133.48	(2.1151)	(2.6338)	0.52	19.69
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(14,294,296)	(7,662,000)	(6,632,296)	86.56	(670,423,775)	(289,538,000)	(380,885,775)	131.55	(2.1321)	(2.6463)	0.51	19.43
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)	34,404,389	33,202,809	1,201,580	3.62	803,208,676	833,377,000	(30,168,324)	(3.62)	4.2834	3.9841	0.30	7.51
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 *	67,753	59,522	8,231	13.83	1,581,758	1,494,000	87,758	5.87	4.2834	3.9841	0.30	7.51
22	T & D Losses *	1,504,609	1,764,916	(260,307)	(14.75)	35,126,509	44,299,000	(9,172,491)	(20.71)	4.2834	3.9841	0.30	7.51
23	TERRITORIAL KWH SALES	34,404,389	33,202,809	1,201,580	3.62	766,500,409	787,584,000	(21,083,591)	(2.68)	4.4885	4.2158	0.27	6.47
24	Wholesale KWH Sales	1,036,433	1,044,826	(8,393)	(0.80)	23,090,567	24,784,000	(1,693,433)	(6.83)	4.4886	4.2157	0.27	6.47
25	Jurisdictional KWH Sales	33,367,956	32,157,983	1,209,973	3.76	743,409,842	762,800,000	(19,390,158)	(2.54)	4.4885	4.2158	0.27	6.47
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	33,418,008	32,206,220	1,211,788	3.76	743,409,842	762,800,000	(19,390,158)	(2.54)	4.4952	4.2221	0.27	6.47
28	TRUE-UP	(2,202,116)	(2,202,118)	0	0.00	743,409,842	762,800,000	(19,390,158)	(2.54)	(0.2962)	(0.2887)	(0.01)	2.60
29	TOTAL JURISDICTIONAL FUEL COST	31,215,890	30,004,102	1,211,788	4.04	743,409,842	762,800,000	(19,390,158)	(2.54)	4.1990	3.9334	0.27	6.75
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2020	3.9362	0.27	6.75
32	GPIF Reward / (Penalty)	86,722	86,722	0	0.00	743,409,842	762,800,000	(19,390,158)	(2.54)	0.0117	0.0114	0.00	2.63
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2137	3.9476	0.27	6.74
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.214	3.948		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 26,750,341
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	(1,129)
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,348,136
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	19,712,063
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	889,274
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(14,294,296)
10	Total Fuel and Net Power Transactions		$ 34,404,389

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2013
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)	323,430,381	342,770,315	(19,339,934)	(5.64)	7,660,745,000	8,224,406,000	(563,661,000)	(6.85)	4.2219	4.1677	0.05	1.30
2	Hedging Settlement Costs (A2)	15,061,496	0	15,061,496	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) **	189,208	0	189,208	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	336,681,085	342,770,315	(4,089,230)	(1.19)	7,660,745,000	8,224,406,000	(563,661,000)	(6.85)	4.4210	4.1677	0.25	6.08
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)	166,423,055	163,408,000	3,015,055	1.84	7,336,316,936	5,731,186,000	1,605,130,936	28.01	2.5411	3.2002	(0.66)	(20.60)
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)	9,209,006	0	9,209,006	100.00	240,760,000	0	240,760,000	100.00	3.8250	0.0000	3.83	0.00
12	TOTAL COST OF PURCHASED POWER	195,632,061	163,408,000	12,224,061	6.66	7,577,076,936	5,731,186,000	1,845,890,936	32.21	2.5819	3.2002	(0.62)	(19.32)
13	Total Available MWH (Line 5 + Line 12)	534,313,146	526,178,315	8,134,831	1.55	15,237,821,936	13,955,592,000	1,282,229,936	9.19				
14	Fuel Cost of Economy Sales (A6)	(2,098,630)	(2,253,000)	154,370	(6.85)	(69,740,484)	(67,635,000)	(2,105,484)	3.11	(3.0092)	(3.3311)	0.32	9.66
15	Gain on Economy Sales (A6)	(152,054)	(626,000)	473,946	(75.71)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(66,120,900)	(61,769,000)	(4,351,900)	5.32	(4,533,682,342)	(2,495,158,000)	(2,038,524,342)	81.70	(1.8996)	(3.2771)	1.38	42.03
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(68,371,584)	(64,848,000)	(3,723,584)	4.40	(4,603,422,826)	(2,562,793,000)	(2,040,629,826)	79.63	(1.9197)	(3.3030)	1.38	41.88
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)	445,941,562	441,530,315	4,411,247	1.00	10,634,399,110	11,392,799,000	(758,399,890)	(6.66)	4.1934	3.8755	0.32	8.20
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 *	770,043	763,008	7,035	0.92	18,363,216	19,688,000	(1,324,782)	(6.73)	4.1934	3.8755	0.32	8.20
22	T & D Losses *	22,484,243	25,487,265	(3,003,022)	(11.78)	536,161,680	657,651,000	(121,489,320)	(18.47)	4.1934	3.8755	0.32	8.20
23	TERRITORIAL KWH SALES	445,941,563	441,530,315	4,411,248	1.00	10,079,854,212	10,715,460,000	(635,605,788)	(5.93)	4.4241	4.1205	0.30	7.37
24	Wholesale KWH Sales	12,568,146	13,512,317	(944,171)	(6.99)	284,239,936	327,966,000	(43,726,064)	(13.33)	4.4217	4.1200	0.30	7.32
25	Jurisdictional KWH Sales	433,373,417	426,017,998	5,365,419	1.25	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)	4.4242	4.1205	0.30	7.37
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	434,023,479	426,660,025	5,363,454	1.25	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)	4.4308	4.1267	0.30	7.37
28	TRUE-UP	(24,223,298)	(24,223,298)	0	0.00	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)	(0.2473)	(0.2332)	(0.01)	6.05
29	TOTAL JURISDICTIONAL FUEL COST	409,800,181	404,436,727	5,363,454	1.33	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)	4.1835	3.8935	0.29	7.45
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1865	3.8963	0.29	7.45
32	GPIF Reward / (Penalty)	953,942	953,942	0	0.00	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)	0.0097	0.0092	0.00	5.43
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1962	3.9055	0.29	7.44
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.196	3.906		

* 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 2013

		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	26,527,636.04	24,020,574	2,507,062.04	10.44	321,191,180.27	340,741,099	(19,549,918.73)	(5.74)
1a	Other Generation	222,704.96	185,235	37,469.96	20.23	2,239,200.27	2,029,216	209,984.27	10.35
2	Fuel Cost of Power Sold	(14,294,296.50)	(7,662,000)	(6,632,296.50)	(86.56)	(88,371,584.42)	(84,648,000)	(3,723,584.42)	(4.40)
3	Fuel Cost - Purchased Power	19,712,063.15	16,659,000	3,053,063.15	18.33	186,423,055.24	183,408,000	3,015,055.24	1.64
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	889,273.50	0	889,273.50	100.00	9,209,005.09	0	9,209,005.09	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	1,348,136.00	0	1,348,136.00	100.00	15,061,496.00	0	15,061,496.00	100.00
6	Total Fuel & Net Power Transactions	34,405,517.15	33,202,809	1,202,708.15	3.62	445,752,352.45	441,530,315	4,222,037.45	0.96
7	AdjustmentsTo Fuel Cost*	(1,128.50)	0	(1,128.50)	100.00	189,209.41	0	189,209.41	100.00
8	Adj. Total Fuel & Net Power Transactions	34,404,388.65	33,202,809	1,201,579.65	3.62	445,941,561.86	441,530,315	4,411,246.86	1.00
B.	*KWH Sales*								
1	Jurisdictional Sales	743,409,842	762,800,000	(19,390,158)	(2.54)	9,795,614,276	10,387,494,000	(591,879,724)	(5.70)
2	Non-Jurisdictional Sales	23,090,567	24,784,000	(1,693,433)	(6.83)	284,239,936	327,966,000	(43,726,064)	(13.33)
3	Total Territorial Sales	766,500,409	787,584,000	(21,083,591)	(2.68)	10,079,854,212	10,715,460,000	(635,605,788)	(5.93)
4	Juris. Sales as % of Total Terr. Sales	96.9875	96.8532	0.1343	0.14	97.1801	96.9393	0.2408	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: NOVEMBER 2013

C.	*True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	28,149,267.79	28,985,363	(836,095.55)	(2.88)	371,739,095.91	394,915,826	(23,176,729.71)	(5.87)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,118.00	2,202,118	0.00	0.00	24,223,298.00	24,223,298	0.00	0.00
2b	Incentive Provision	(86,659.00)	(86,659)	0.00	0.00	(953,249.00)	(953,249)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	30,264,726.79	31,100,822	(836,095.21)	(2.69)	395,009,144.91	418,185,875	(23,176,730.09)	(5.54)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	34,404,388.65	33,202,809	1,201,579.65	3.62	445,941,562.25	441,530,316	4,411,247.25	1.00
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9875	96.8532	0.1343	0.14	97.1801	96.9393	0.2408	0.25
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	33,418,008.38	32,206,220	1,211,788.38	3.76	434,023,478.69	428,660,025	5,363,453.69	1.25
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(3,153,281.59)	(1,105,398)	(2,047,883.59)	(185.26)	(39,014,333.78)	(10,474,150)	(28,540,183.78)	(272.48)
8	Interest Provision for the Month	(777.27)	(304)	(473.27)	(155.68)	(716.75)	7,819	(8,535.75)	109.17
9	Beginning True-Up & Interest Provision	(14,219,366.27)	(4,956,391)	(9,262,975.27)	(186.89)	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,118.00)	(2,202,118)	0.00	0.00	(24,223,298.00)	(24,223,298)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(19,575,543.13)	(8,264,211)	(11,311,332.13)	(136.87)	(46,146,625.39)	(8,264,211)	(37,882,414.39)	(458.39)
12	Adjustment		0	0.00	0.00	26,571,082.26	0	26,571,082.26	100.00
13	End of Period - Total Net True-Up	(19,575,543.13)	(8,264,211)	(11,311,332.13)	(136.87)	(19,575,543.13)	(8,264,211)	(11,311,332.13)	(136.87)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

		CURRENT MONTH			
		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(14,219,366.27)	(4,956,391)	(9,262,975.27)	186.89
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(19,574,765.86)	(8,263,907)	(11,310,858.86)	136.87
3	Total of Beginning & Ending True-Up Amts.	(33,794,132.13)	(13,220,298)	(20,573,834.13)	155.62
4	Average True-Up Amount	(16,897,066.07)	(6,610,149)	(10,286,917.07)	155.62
5	Interest Rate 1st Day of Reporting Business Month	0.05	0.05	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.06	0.06	0.0000	
7	Total (D5+D6)	0.11	0.11	0.0000	
8	Annual Average Interest Rate	0.06	0.06	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0046	0.0046	0.0000	
10	Interest Provision (D4*D9)	(777.27)	(304)	(473.27)	155.68
	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: NOVEMBER 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	114,634	134,445	(19,811)	(14.74)	1,685,280	1,092,773	592,507	54.22
2	COAL	17,004,332	12,744,995	4,259,337	33.42	206,510,937	221,980,417	(15,469,480)	(6.97)
3	GAS	9,451,739	11,272,101	(1,820,362)	(16.15)	113,362,388	118,994,961	(5,632,573)	(4.73)
4	GAS (B.L.)	120,206	0	120,206	100.00	1,044,168	-	1,044,168	100.00
5	LANDFILL GAS	54,113	54,268	(155)	(0.29)	644,083	626,211	17,872	2.85
6	OIL - C.T.	5,315	0	5,315	100.00	183,524	75,953	107,571	141.63
7	TOTAL ($)	26,750,341	24,205,809	2,544,532	10.51	323,430,381	342,770,315	(19,339,934)	(5.64)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	358,455	264,797	93,658	35.37	4,285,195	4,487,503	(202,308)	(4.51)
10	GAS	310,692	326,216	(15,524)	(4.76)	3,353,506	3,713,147	(359,641)	(9.69)
11	LANDFILL GAS	1,762	2,031	(269)	(13.24)	21,516	23,436	(1,920)	(8.19)
12	OIL - C.T.	19	0	19	100.00	528	320	208	65.00
13	TOTAL (MWH)	670,928	593,044	77,884	13.13	7,660,745	8,224,406	(563,661)	(6.85)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	904	1,063	(159)	(14.96)	12,891	8,871	4,020	45.32
15	COAL (TONS)	171,066	122,384	48,682	39.78	2,015,297	2,094,536	(79,239)	(3.78)
16	GAS (MCF) (1)	2,096,045	2,204,437	(108,392)	(4.92)	23,700,354	25,517,916	(1,817,562)	(7.12)
17	OIL - C.T. (BBL)	47	0	47	100.00	1,668	700	968	138.29
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,645,707	2,962,447	683,260	23.06	54,915,773	49,386,437	5,529,336	11.20
19	GAS - Generation (1)	2,134,187	2,270,570	(136,383)	(6.01)	23,925,048	25,564,846	(1,639,798)	(6.41)
20	OIL - C.T.	275	0	275	100.00	9,708	4,100	5,608	136.78
21	TOTAL (MMBTU)	5,780,169	5,233,017	547,152	10.46	78,850,529	74,955,383	3,895,146	5.20
	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	53.43	44.65	8.78	19.66	55.93	54.56	1.37	2.51
24	GAS	46.31	55.01	(8.70)	(15.82)	43.78	45.15	(1.37)	(3.03)
25	LANDFILL GAS	0.26	0.34	(0.08)	(23.53)	0.28	0.28	0.00	0.00
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
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)	126.87	126.48	0.39	0.31	130.73	123.18	7.55	6.13
29	COAL ($/TON)	99.40	104.14	(4.74)	(4.55)	102.47	105.98	(3.51)	(3.31)
30	GAS ($/MCF) (1)	4.46	5.03	(0.57)	(11.33)	4.73	4.58	0.15	3.28
31	OIL - C.T. ($/BBL)	113.09	0.00	113.09	100.00	110.03	108.50	1.53	1.41
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.73	4.35	0.38	8.74	3.81	4.52	(0.71)	(15.71)
33	GAS - Generation (1)	4.32	4.88	(0.56)	(11.48)	4.64	4.58	0.06	1.31
34	OIL - C.T.	19.31	0.00	19.31	100.00	18.90	18.53	0.37	2.00
35	TOTAL ($/MMBTU)	4.58	4.58	0.00	0.00	4.07	4.54	(0.47)	(10.35)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,171	11,188	(1,017)	(9.09)	12,815	11,005	1,810	16.45
37	GAS - Generation (1)	7,024	7,080	(56)	(0.79)	7,278	6,974	304	4.36
38	OIL - C.T.	14,484	0	14,484	100.00	18,387	12,813	5,574	43.50
39	TOTAL (BTU/KWH)	8,727	8,938	(211)	(2.36)	10,412	9,193	1,219	13.26
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.81	4.86	(0.05)	(1.03)	4.88	4.97	(0.09)	(1.81)
41	GAS	3.04	3.46	(0.42)	(12.14)	3.38	3.20	0.18	5.63
42	LANDFILL GAS	3.07	2.67	0.40	14.98	2.99	2.67	0.32	11.99
43	OIL - C.T.	27.98	0.00	27.98	100.00	34.76	23.74	11.02	46.42
44	TOTAL (¢/KWH)	3.99	4.08	(0.09)	(2.21)	4.22	4.17	0.05	1.20

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: NOVEMBER 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	13,933	25.8	100.0	58.2	11,931	Coal	7,027.0	11,829	166,236	676,359	4.85	96.25
2				0					Gas-G	0	1,018	0	0	0.00	0.00
3									Gas-S	1,645	1,018	1,675	119,778		72.81
4									Oil-S	70	137,922	407	8,926		127.51
5	Crist 5		75	16,437	30.4	75.2	57.8	0	Coal	0	11,905	0	0	0.00	0.00
6				-					Gas-G	0	1,018	0	0	0.00	0.00
7									Gas-S	3	1,018	3	214		71.32
8									Oil-S	0	137,922	0	0		0.00
9	Crist 6		299	(1,815)	0.0	100.0	0.0	0	Coal	7,440	0	0	716,211	0.00	96.26
10				0					Gas-G	0	1,018	0	0	0.00	0.00
11									Gas-S	3	1,018	3	214		71.32
12									Oil-S	10	137,922	58	1,222		122.20
13	Crist 7		475	181,469	53.0	100.0	53.0	10,571	Coal	80,963	11,847	1,918,353	7,793,286	4.29	96.26
14				0					Gas-G	0	1,018	0	0	0.00	0.00
15									Gas-S	0	1,018	0	0		0.00
16									Oil-S	54	137,922	315	6,921		128.17
17	Scholz 1		46	(217)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(142)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	59,017	50.5	100.0	50.5	10,595	Coal	29,044	10,765	625,307	2,901,423	4.92	99.90
22									Oil-S	104	139,145	606	13,271		127.61
23	Smith 2		195	16,178	11.5	100.0	48.4	11,284	Coal	9,061	10,073	182,545	905,197	5.60	99.90
24									Oil-S	376	139,145	2,194	48,081		127.88
25	Smith 3		558	303,826	75.5	91.0	87.1	7,024	Gas-G	2,094,394	1,019	2,134,187	9,229,034	3.04	4.41
26	Smith A	(2)	36	19	0.1	93.9	53.8	14,474	Oil	47	139,202	275	5,315	27.97	113.09
27	Other Generation			6,866									222,705	3.24	0.00
28	Perdido			1,762					Landfill Gas				54,113	3.07	0.00
29	Daniel 1	(1)	255	66,604	36.2	99.8	59.9	10,070	Coal	34,131	9,826	670,719	3,652,101	5.48	107.00
30									Oil-S	29	138,414	169	3,622		124.90
31	Daniel 2	(1)	255	6,991	3.8	100.0	36.2	10,814	Coal	3,400	11,118	75,601	363,814	5.20	107.00
32									Oil-S	261	138,414	1,518	32,592		124.87
33	Total		2,477	670,928	37.6	97.1	51.1	8,727				5,780,169	26,754,400	3.99	

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	26,750,341	3.99

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	1,802	1,063	739	69.52	13,285	8,859	4,426	49.96
3	UNIT COST ($/BBL)	122.24	126.33	(4.09)	(3.24)	129.43	122.89	6.54	5.32
4	AMOUNT ($)	220,282	134,284	85,998	64.04	1,719,466	1,088,680	630,786	57.94
5	*BURNED:*								
6	UNITS (BBL)	933	1,063	(130)	(12.23)	13,450	8,871	4,579	51.62
7	UNIT COST ($/BBL)	126.95	126.48	0.47	0.37	130.76	123.18	7.58	6.15
8	AMOUNT ($)	118,445	134,445	(16,000)	(11.90)	1,758,670	1,092,773	665,897	60.94
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,803	4,541	1,262	27.79	5,803	4,541	1,262	27.79
11	UNIT COST ($/BBL)	126.11	124.66	1.45	1.16	126.11	124.66	1.45	1.16
12	AMOUNT ($)	731,813	566,068	165,745	29.28	731,813	566,068	165,745	29.28
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	138,905	146,500	(7,595)	(5.18)	1,738,481	1,777,280	(38,799)	(2.18)
16	UNIT COST ($/TON)	96.36	111.66	(15.30)	(13.70)	99.72	106.07	(6.35)	(5.99)
17	AMOUNT ($)	13,384,201	16,357,555	(2,973,354)	(18.18)	173,361,627	188,514,615	(15,152,988)	(8.04)
18	*BURNED:*								
19	UNITS (TONS)	171,066	122,384	48,682	39.78	2,015,297	2,094,536	(79,239)	(3.78)
20	UNIT COST ($/TON)	99.43	104.14	(4.71)	(4.52)	101.87	105.98	(4.11)	(3.88)
21	AMOUNT ($)	17,008,391	12,744,995	4,263,396	33.45	205,307,653	221,980,417	(16,672,764)	(7.51)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	661,391	577,661	83,730	14.49	661,391	577,661	83,730	14.49
24	UNIT COST ($/TON)	101.20	108.07	(6.87)	(6.36)	101.20	108.07	(6.87)	(6.36)
25	AMOUNT ($)	66,932,589	62,429,053	4,503,536	7.21	66,932,589	62,429,053	4,503,536	7.21
26	DAYS SUPPLY	31	28	3	10.71				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,135,868	2,270,570	(134,702)	(5.93)	24,046,453	25,499,596	(1,453,143)	(5.70)
29	UNIT COST ($/MMBTU)	4.23	4.92	(0.69)	(14.02)	4.68	4.58	0.10	2.18
30	AMOUNT ($)	9,033,039	11,165,427	(2,132,388)	(19.10)	112,499,485	116,737,513	(4,238,028)	(3.63)
31	*BURNED:*								
32	UNITS (MMBTU)	2,135,868	2,270,570	(134,702)	(5.93)	24,029,580	25,564,846	(1,535,266)	(6.01)
33	UNIT COST ($/MMBTU)	4.38	4.88	(0.50)	(10.25)	4.67	4.58	0.09	1.97
34	AMOUNT ($)	9,349,241	11,086,866	(1,737,625)	(15.67)	112,167,358	116,965,745	(4,798,387)	(4.10)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	798,179	913,500	(115,321)	(12.62)	(115,321)	0	(115,321)	100.00
37	UNIT COST ($/MMBTU)	4.32	4.40	(0.08)	(1.82)	4.91	0.00	4.91	100.00
38	AMOUNT ($)	3,451,629	4,017,390	(565,761)	(14.08)	(565,761)	0	(565,761)	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	712	0	712	100.00	2,018	700	1,318	188.29
41	UNIT COST ($/BBL)	124.08	0.00	124.08	100.00	128.97	120.62	8.00	6.63
42	AMOUNT ($)	88,342	0	88,342	100.00	260,271	84,436	175,835	208.25
43	*BURNED:*								
44	UNITS (BBL)	47	0	47	100.00	1,668	700	968	138.29
45	UNIT COST ($/BBL)	113.09	0.00	113.09	100.00	110.03	108.50	1.53	1.41
46	AMOUNT ($)	5,315	0	5,315	100.00	183,523	75,953	107,570	141.63
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,306	5,845	461	7.89	6,306	5,845	461	7.89
49	UNIT COST ($/BBL)	112.92	111.06	1.86	1.67	112.92	111.06	1.86	1.67
50	AMOUNT ($)	712,061	649,138	62,923	9.69	712,061	649,138	62,923	9.69
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

			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		281,608,000	0	281,608,000	2.63	2.91	7,417,000	8,203,000
2	Various	Economy Sales	7,930,000	0	7,930,000	2.76	3.06	219,000	243,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	26,000	26,000
4	TOTAL ESTIMATED SALES		289,538,000	0	289,538,000	2.65	2.93	7,662,000	8,472,000
	ACTUAL								
5	Southern Company Interchange		513,060,486	0	513,060,486	2.77	2.97	14,228,025	15,251,044
6	A.E.C.	External	1,580,696	0	1,580,696	2.92	3.67	46,233	57,940
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	CALPINE	External	7,424	0	7,424	15.56	5.33	1,157	396
10	CARGILE	External	916,634	0	916,634	2.20	2.65	20,202	24,334
11	CONSTELL	External	0	0	0	0.00	0.00	0	0
12	DUKE PWR	External	270,404	0	270,404	2.30	2.28	6,210	6,159
13	EAGLE EN	External	699,429	0	699,429	2.14	2.61	14,992	18,245
14	ENDURE	External	9,437	0	9,437	2.38	3.43	225	324
15	ENTERGY	External	78,642	0	78,642	3.08	5.27	2,422	4,143
16	EXELON	External	2,486,883	0	2,486,883	2.61	3.11	64,845	77,438
17	FPC	External	113,247	0	113,247	3.55	4.00	4,019	4,530
18	FPL	External	162,882	0	162,882	2.54	3.80	4,141	6,188
19	JPMVEC	External	35,924	0	35,924	15.85	6.09	5,695	2,187
20	MERRILL	External	0	0	0	0.00	0.00	0	0
21	MISO	External	62,659	0	62,659	3.13	4.63	1,960	2,900
22	MORGAN	External	959,745	0	959,745	2.22	2.71	21,331	26,005
23	NCEMC	External	11,325	0	11,325	2.54	3.66	288	414
24	NCMPA1	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	12,482	0
26	OGE	External	0	0	0	0.00	0.00	0	0
27	OPC	External	480,000	0	480,000	2.82	3.63	13,547	17,412
28	ORLANDO	External	62,912	0	62,912	3.17	4.30	1,993	2,705
29	PJM	External	819,577	0	819,577	2.85	3.50	23,349	28,701
30	SCE&G	External	44,037	0	44,037	3.24	4.00	1,429	1,762
31	SEC	External	9,437	0	9,437	3.23	4.40	305	415
32	SEPA	External	1,725,610	0	1,725,610	2.27	2.91	39,150	50,155
33	SPP	External	0	0	0	0.00	0.00	0	0
34	TAL	External	1,573	0	1,573	2.12	2.90	33	46
35	TEA	External	1,140,487	0	1,140,487	2.51	3.49	28,579	39,831
36	TECO	External	358,103	0	358,103	2.67	3.45	9,556	12,352
37	TENASKA	External	9,437	0	9,437	2.91	4.53	275	428
38	TVA	External	200,501	0	200,501	3.00	4.17	6,008	8,363
39	UPP	External	0	0	0	0.00	0.00	0	0
40	WRI	External	683,690	0	683,690	2.82	2.81	17,928	19,191
41	Less: Flow-Thru Energy		(12,632,671)	0	(12,632,671)	2.54	2.54	(321,421)	(321,421)
42	SEPA		846,032	846,032	0	0.00	0.00	0	0
43	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	39,339	39,339
44	Other transactions including adj.		156,219,233	115,332,091	40,887,142	0.00	0.00	0	0
45	TOTAL ACTUAL SALES		670,423,775	116,178,123	554,245,652	2.13	2.29	14,294,298	15,342,188
46	Difference in Amount		380,885,775	116,178,123	284,707,652	(0.52)	(0.64)	6,632,298	6,870,188
47	Difference in Percent		131.55	0.00	91.42	(19.62)	(21.84)	86.56	81.09

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 43

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

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		2,495,158,000	0	2,495,158,000	3.28	3.60	81,769,000	89,789,000
2	Various	Economy Sales	67,635,000	0	67,635,000	3.33	3.63	2,253,000	2,454,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	626,000	626,000
4	TOTAL ESTIMATED SALES		2,562,793,000	0	2,562,793,000	3.30	3.62	84,648,000	92,869,000
	ACTUAL								
5	Southern Company Interchange		2,971,191,854	0	2,971,191,854	2.97	3.12	88,104,783	92,832,223
6	A.E.C.	External	6,243,308	0	6,243,308	2.97	3.69	185,341	230,214
7	AECI	External	292,606	0	292,606	2.66	4.06	7,770	11,883
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	13,086	0	13,086	26.22	4.71	3,431	617
10	CARGILE	External	5,273,439	0	5,273,439	2.70	3.06	142,283	161,609
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	518,409	0	518,409	2.63	2.91	13,659	15,079
13	EAGLE EN	External	2,291,662	0	2,291,662	2.61	3.30	59,878	75,663
14	ENDURE	External	119,159	0	119,159	3.73	5.28	4,442	6,287
15	ENTERGY	External	1,466,141	0	1,466,141	3.95	6.20	57,975	90,881
16	EXELON	External	6,229,400	0	6,229,400	2.81	3.17	174,808	197,463
17	FPC	External	1,079,527	0	1,079,527	3.27	4.18	35,251	45,153
18	FPL	External	846,817	0	846,817	2.97	4.10	25,182	34,742
19	JPMVEC	External	1,035,388	0	1,035,388	3.92	3.92	40,578	40,638
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	62,974	0	62,974	3.13	4.62	1,969	2,908
22	MORGAN	External	3,626,675	0	3,626,675	2.66	2.96	96,681	107,998
23	NCEMC	External	700,595	0	700,595	3.16	3.87	22,119	27,117
24	NCMPA1	External	80,223	0	80,223	3.61	4.09	2,894	3,284
25	NRG	External	6,291	0	6,291	296.31	3.50	18,641	220
26	OGE	External	1,260	0	1,260	3.01	3.00	38	38
27	OPC	External	1,682,000	0	1,682,000	2.95	3.84	49,655	64,671
28	ORLANDO	External	97,831	0	97,831	3.27	4.60	3,200	4,504
29	PJM	External	10,472,753	0	10,472,753	3.10	3.83	324,898	400,660
30	SCE&G	External	2,863,424	0	2,863,424	3.42	5.04	97,914	144,275
31	SEC	External	1,595,698	0	1,595,698	3.11	3.72	49,605	59,382
32	SEPA	External	4,444,686	0	4,444,686	2.48	3.12	110,314	138,790
33	SPP	External	6,174	0	6,174	2.30	1.63	142	101
34	TAL	External	944,069	0	944,069	3.35	4.46	31,632	42,074
35	TEA	External	10,161,890	0	10,161,890	3.08	4.07	312,745	413,590
36	TECO	External	753,772	0	753,772	2.97	4.01	22,380	30,232
37	TENASKA	External	9,437	0	9,437	2.91	4.53	275	428
38	TVA	External	3,719,498	0	3,719,498	3.16	4.40	118,281	163,497
39	UPP	External	0	0	0	0.00	0.00	1,321	0
40	WRI	External	2,112,737	0	2,112,737	2.84	3.18	60,020	67,217
41	Less: Flow-Thru Energy		(68,790,046)	0	(68,790,046)	2.88	2.88	(1,983,882)	(1,983,882)
42	SEPA		18,038,680	18,038,680	0	0.00	0.00	0	0
43	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	152,054	152,054
44	Other transactions including adj.		1,813,241,854	1,488,666,507	124,575,347	0.00	0.00	0	0
45	TOTAL ACTUAL SALES		4,603,422,826	1,506,705,187	3,096,717,639	1.92	2.03	88,371,584	93,458,542
46	Difference in Amount		2,040,629,826	1,506,705,187	533,924,639	(1.38)	(1.59)	3,723,584	589,542
47	Difference in Percent		79.63	0.00	20.83	(41.82)	(43.92)	4.40	0.63

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 43

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: NOVEMBER 2013

(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 2013

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	3,697,000	0	0	0	7.64	7.64	282,289
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	6
5 Ascend Performance Materials	COG 1	20,324,000	0	0	0	2.98	2.98	605,288
6 International Paper	COG 1	47,000	0	0	0	3.60	3.60	1,690
7 TOTAL		24,068,000	0	0	0	3.69	3.69	889,274

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	37,225,000	0	0	0	7.63	7.63	2,841,934
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	75
5 Ascend Performance Materials	COG 1	202,641,000	0	0	0	3.13	3.13	6,336,440
6 International Paper	COG 1	894,000	0	0	0	3.42	3.42	30,554
7 TOTAL		240,760,000	0	0	0	3.82	3.82	9,209,005

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

	(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	23,810,000	3.32	790,000	509,415,000	3.92	19,955,000
2	Economy Energy	4,375,000	3.22	141,000	42,501,000	3.81	1,621,000
3	Other Purchases	501,686,000	3.14	15,728,000	5,179,270,000	3.12	161,832,000
4	TOTAL ESTIMATED PURCHASES	529,871,000	3.14	16,659,000	5,731,186,000	3.20	183,408,000
	ACTUAL						
5	Southern Company Interchange	87,186,066	3.31	2,885,910	757,522,907	3.21	24,312,290
6	Non-Associated Companies	39,917,555	29.74	11,872,209	580,949,500	1.39	8,067,968
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	549,615,000	0.96	5,271,335	4,852,034,000	3.22	156,021,940
9	Other Wheeled Energy	67,793,000	0.00	N/A	349,304,000	0.00	N/A
10	Other Transactions	46,757,501	0.06	28,139	865,296,575	0.02	148,251
11	Less: Flow-Thru Energy	(12,632,671)	2.74	(345,530)	(68,790,046)	3.09	(2,127,394)
12	TOTAL ACTUAL PURCHASES	778,636,451	2.53	19,712,063	7,336,316,936	2.54	186,423,055
13	Difference in Amount	248,765,451	(0.61)	3,053,063	1,605,130,936	(0.66)	3,015,055
14	Difference in Percent	46.95	(19.43)	18.33	28.01	(20.63)	1.64

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2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					$ 2,380,170		$ 1,898,537		$ 2,389,783		$ 2,045,794		$ 2,596,589		$ 6,777,892	$ 18,088,765

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

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2013 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	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -	120	$ 413,300	58.9	$ 20,971	-83.14	$ (36,525)		$ -	$ 1,115,312
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,225	Varies	6,797,704	Varies	2,473,170	Varies	2,243,716			43,186,233
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(4,052)			(43,412)
SUBTOTAL					$ 7,263,297		$ 7,004,079		$ 6,794,558		$ 2,470,024		$ 2,239,664		$ -	$ 43,142,821
TOTAL					**$ 7,263,297**		**$ 7,004,079**		**$ 7,207,858**		**$ 2,490,995**		**$ 2,203,139**		**$ -**	**$ 44,258,133**

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SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: NOVEMBER 2013

(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 2013

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	3,697,000	0	0	0	7.64	7.64	282,289
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	6
5 Ascend Performance Materials	COG 1	20,324,000	0	0	0	2.98	2.98	605,288
6 International Paper	COG 1	47,000	0	0	0	3.60	3.60	1,690
7 TOTAL		24,068,000	0	0	0	3.69	3.69	889,274

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	37,225,000	0	0	0	7.63	7.63	2,841,934
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	1
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	75
5 Ascend Performance Materials	COG 1	202,641,000	0	0	0	3.13	3.13	6,336,440
6 International Paper	COG 1	894,000	0	0	0	3.42	3.42	30,554
7 TOTAL		240,760,000	0	0	0	3.82	3.82	9,209,005

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2013

	(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	23,810,000	3.32	790,000	509,415,000	3.92	19,955,000
2	Economy Energy	4,375,000	3.22	141,000	42,501,000	3.81	1,621,000
3	Other Purchases	501,686,000	3.14	15,728,000	5,179,270,000	3.12	161,832,000
4	TOTAL ESTIMATED PURCHASES	529,871,000	3.14	16,659,000	5,731,186,000	3.20	183,408,000
	ACTUAL						
5	Southern Company Interchange	87,186,066	3.31	2,885,910	757,522,907	3.21	24,312,290
6	Non-Associated Companies	39,917,555	29.74	11,872,209	580,949,500	1.39	8,067,968
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	549,615,000	0.96	5,271,335	4,852,034,000	3.22	156,021,940
9	Other Wheeled Energy	67,793,000	0.00	N/A	349,304,000	0.00	N/A
10	Other Transactions	46,757,501	0.06	28,139	865,296,575	0.02	148,251
11	Less: Flow-Thru Energy	(12,632,671)	2.74	(345,530)	(68,790,046)	3.09	(2,127,394)
12	TOTAL ACTUAL PURCHASES	778,636,451	2.53	19,712,063	7,336,316,936	2.54	186,423,055
13	Difference in Amount	248,765,451	(0.61)	3,053,063	1,605,130,936	(0.66)	3,015,055
14	Difference in Percent	46.95	(19.43)	18.33	28.01	(20.63)	1.64

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2013 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	$ [1]	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,744	Varies	2,601,116	Varies	6,780,108	17,397,975
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,598		$ 2,597,668		$ 6,769,489	$ 17,371,199
TOTAL					$ 2,380,170		$ 1,898,537		$ 2,389,783		$ 2,045,794		$ 2,596,589		$ 6,777,892	$ 18,088,765

(1) February's Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

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2013 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	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -	120	$ 413,300	58.9	$ 20,971	-83.14	$ (36,525)		$ -	$ 1,115,312
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,225	Varies	6,797,704	Varies	2,473,170	Varies	2,243,716			43,186,233
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(4,052)			(43,412)
SUBTOTAL					$ 7,263,297		$ 7,004,079		$ 6,794,558		$ 2,470,024		$ 2,239,664		$ -	$ 43,142,821
TOTAL					**$ 7,263,297**		**$ 7,004,079**		**$ 7,207,858**		**$ 2,490,995**		**$ 2,203,139**		**$ -**	**$ 44,258,133**

Docket No. 140001-EI
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

December 2013

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2013
CURRENT MONTH

		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)	20,655,061	29,074,110	(8,419,049)	(28.96)	493,305,000	702,626,000	(209,321,000)	(29.79)	4.1871	4.1379	0.05	1.19
2	Hedging Settlement Costs (A2)	(406,630)	0	(406,630)	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) **	7,705	0	7,705	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	20,256,136	29,074,110	(8,817,974)	(30.33)	493,305,000	702,626,000	(209,321,000)	(29.79)	4.1062	4.1379	(0.03)	(0.77)
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)	20,101,745	18,753,000	1,348,745	7.19	693,559,511	566,319,000	127,240,511	22.47	2.8983	3.3114	(0.41)	(12.48)
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)	951,974	0	951,974	100.00	25,188,000	0	25,188,000	100.00	3.7795	0.0000	3.78	0.00
12	TOTAL COST OF PURCHASED POWER	21,053,719	18,753,000	2,300,719	12.27	718,747,511	566,319,000	152,428,511	26.92	2.9292	3.3114	(0.38)	(11.54)
13	Total Available MWH (Line 5 + Line 12)	41,309,855	47,827,110	(6,517,255)	(13.63)	1,212,052,511	1,268,945,000	(56,892,489)	(4.48)				
14	Fuel Cost of Economy Sales (A6)	(332,555)	(269,000)	(63,555)	23.63	(11,690,747)	(8,633,000)	(3,057,747)	35.42	(2.8446)	(3.1160)	0.27	8.71
15	Gain on Economy Sales (A6)	(42,676)	(65,000)	22,324	(34.34)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(5,948,367)	(9,182,000)	3,233,633	(35.22)	(303,502,784)	(320,944,000)	17,441,216	(5.43)	(1.9599)	(2.8609)	0.90	31.49
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(6,323,598)	(9,516,000)	3,192,402	(33.55)	(315,193,531)	(329,577,000)	14,383,469	(4.36)	(2.0063)	(2.8873)	0.88	30.51
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)	34,986,257	38,311,110	(3,324,853)	(8.68)	896,858,980	939,368,000	(42,509,020)	(4.53)	3.9010	4.0784	(0.18)	(4.35)
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 *	71,874	74,308	(2,434)	(3.28)	1,842,445	1,822,000	20,445	1.12	3.9010	4.0784	(0.18)	(4.35)
22	T & D Losses *	1,760,367	2,294,712	(534,345)	(23.29)	45,126,044	56,265,000	(11,138,956)	(19.80)	3.9010	4.0784	(0.18)	(4.35)
23	TERRITORIAL KWH SALES	34,986,258	38,311,110	(3,324,853)	(8.68)	849,890,491	881,281,000	(31,390,509)	(3.56)	4.1166	4.3472	(0.23)	(5.30)
24	Wholesale KWH Sales	1,054,486	1,258,980	(204,494)	(16.24)	25,616,104	28,961,000	(3,344,896)	(11.55)	4.1165	4.3472	(0.23)	(5.31)
25	Jurisdictional KWH Sales	33,931,772	37,052,130	(3,120,358)	(8.42)	824,274,387	852,320,000	(28,045,613)	(3.29)	4.1166	4.3472	(0.23)	(5.30)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	33,982,670	37,107,708	(3,125,038)	(8.42)	824,274,387	852,320,000	(28,045,613)	(3.29)	4.1227	4.3537	(0.23)	(5.31)
28	TRUE-UP	(2,202,120)	(2,202,120)	0	0.00	824,274,387	852,320,000	(28,045,613)	(3.29)	(0.2672)	(0.2584)	(0.01)	3.41
29	TOTAL JURISDICTIONAL FUEL COST	31,780,550	34,905,588	(3,125,038)	(8.95)	824,274,387	852,320,000	(28,045,613)	(3.29)	3.8555	4.0953	(0.24)	(5.86)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8583	4.0982	(0.24)	(5.85)
32	GPIF Reward / (Penalty)	86,718	86,718	0	0.00	824,274,387	852,320,000	(28,045,613)	(3.29)	0.0105	0.0102	0.00	2.94
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8688	4.1084	(0.24)	(5.83)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.869	4.108		

* 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 2013

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 20,655,061
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	7,705
4	Hedging Settlement Costs	Schedule A-2, Line A-5	(406,630)
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	20,101,745
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	951,974
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(6,323,598)
10	Total Fuel and Net Power Transactions		$ 34,986,257

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2013
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)	344,085,442	371,844,425	(27,758,983)	(7.47)	8,154,050,000	8,927,032,000	(772,982,000)	(8.66)	4.2198	4.1654	0.05	1.31
2	Hedging Settlement Costs (A2)	14,654,866	0	14,654,866	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) **	196,913	0	196,913	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	358,937,221	371,844,425	(12,907,204)	(3.47)	8,154,050,000	8,927,032,000	(772,982,000)	(8.66)	4.4020	4.1654	0.24	5.68
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	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)	206,524,800	202,161,000	4,363,800	2.16	8,029,876,447	6,297,505,000	1,732,371,447	27.51	2.5720	3.2102	(0.64)	(19.88)
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)	10,160,978	0	10,160,978	100.00	265,948,000	0	265,948,000	100.00	3.8207	0.0000	3.82	0.00
12	TOTAL COST OF PURCHASED POWER	216,685,778	202,161,000	14,524,778	7.18	8,295,824,447	6,297,505,000	1,998,319,447	31.73	2.6120	3.2102	(0.60)	(18.63)
13	Total Available MWH (Line 5 + Line 12)	575,622,999	574,005,425	1,617,574	0.28	16,449,874,447	15,224,537,000	1,225,337,447	8.05				
14	Fuel Cost of Economy Sales (A6)	(2,431,185)	(2,522,000)	90,815	(3.60)	(81,431,231)	(76,268,000)	(5,163,231)	6.77	(2.9856)	(3.3068)	0.32	9.71
15	Gain on Economy Sales (A6)	(194,730)	(691,000)	496,270	(71.82)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(92,069,267)	(90,951,000)	(1,118,267)	1.23	(4,837,185,126)	(2,816,102,000)	(2,021,083,126)	71.77	(1.9034)	(3.2297)	1.33	41.07
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(94,695,182)	(94,164,000)	(531,182)	0.56	(4,918,616,357)	(2,892,370,000)	(2,026,246,357)	70.05	(1.9252)	(3.2556)	1.33	40.86
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)	480,927,817	479,841,425	1,086,392	0.23	11,531,258,090	12,332,167,000	(800,908,910)	(6.49)	4.1706	3.8910	0.28	7.19
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 *	842,697	836,954	5,743	0.69	20,205,663	21,510,000	(1,304,337)	(6.06)	4.1706	3.8910	0.28	7.19
22	T & D Losses *	24,244,020	27,778,472	(3,534,452)	(12.72)	581,307,724	713,916,000	(132,608,276)	(18.57)	4.1706	3.8910	0.28	7.19
23	TERRITORIAL KWH SALES	480,927,821	479,841,425	1,086,396	0.23	10,929,744,703	11,596,741,000	(666,996,297)	(5.75)	4.4002	4.1377	0.26	6.34
24	Wholesale KWH Sales	13,622,632	14,771,297	(1,148,665)	(7.78)	309,856,040	356,927,000	(47,070,960)	(13.19)	4.3964	4.1385	0.26	6.23
25	Jurisdictional KWH Sales	467,305,189	465,070,128	2,235,061	0.48	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)	4.4003	4.1377	0.26	6.35
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	468,006,149	465,767,733	2,238,416	0.48	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)	4.4069	4.1439	0.26	6.35
28	TRUE-UP	(26,425,418)	(26,425,418)	0	0.00	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)	(0.2488)	(0.2351)	(0.01)	5.83
29	TOTAL JURISDICTIONAL FUEL COST	441,580,731	439,342,315	2,238,416	0.51	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)	4.1581	3.9088	0.25	6.38
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1611	3.9116	0.25	6.38
32	GPIF Reward / (Penalty)	1,040,660	1,040,660	0	0.00	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)	0.0098	0.0093	0.00	5.38
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1709	3.9209	0.25	6.38
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.171	3.921		

* 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 2013

		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	20,435,934.54	28,882,719	(8,446,784.46)	(29.25)	341,627,114.81	369,623,818	(27,996,703.19)	(7.57)
1a	Other Generation	219,126.70	191,391	27,735.70	14.49	2,458,326.97	2,220,607	237,719.97	10.71
2	Fuel Cost of Power Sold	(6,323,597.48)	(9,516,000)	3,192,402.52	33.55	(94,695,181.90)	(94,164,000)	(531,181.90)	(0.56)
3	Fuel Cost - Purchased Power	20,101,744.63	18,753,000	1,348,744.63	7.19	206,524,799.87	202,161,000	4,363,799.87	2.16
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	951,974.39	0	951,974.39	100.00	10,160,978.48	0	10,160,978.48	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	(406,630.00)	0	(406,630.00)	100.00	14,654,866.00	0	14,654,866.00	100.00
6	Total Fuel & Net Power Transactions	34,978,552.78	38,311,110	(3,332,557.22)	(8.70)	480,730,904.23	479,841,425	889,479.23	0.19
7	AdjustmentsTo Fuel Cost*	7,705.22	0	7,705.22	100.00	196,912.63	0	196,912.63	100.00
8	Adj. Total Fuel & Net Power Transactions	34,986,258.00	38,311,110	(3,324,852.00)	(8.68)	480,927,816.86	479,841,425	1,086,391.86	0.23
B.	*KWH Sales*								
1	Jurisdictional Sales	824,274,387	852,320,000	(28,045,613)	(3.29)	10,619,888,663	11,239,814,000	(619,925,337)	(5.52)
2	Non-Jurisdictional Sales	25,616,104	28,961,000	(3,344,896)	(11.55)	309,856,040	356,927,000	(47,070,960)	(13.19)
3	Total Territorial Sales	849,890,491	881,281,000	(31,390,509)	(3.56)	10,929,744,703	11,596,741,000	(666,996,297)	(5.75)
4	Juris. Sales as % of Total Terr. Sales	96.9860	96.7138	0.2722	0.28	97.1650	96.9222	0.2428	0.25

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
C.	*True-up Calculation*	ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	Jurisdictional Fuel Revenue	32,692,774.49	32,387,002	305,772.81	0.94	404,431,870.40	427,302,827	(22,870,956.89)	(5.35)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	2,202,120.00	2,202,120	0.00	0.00	26,425,418.00	26,425,418	0.00	0.00
2b	Incentive Provision	(86,662.00)	(86,662)	0.00	0.00	(1,039,911.00)	(1,039,911)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	34,808,232.49	34,502,460	305,772.49	0.89	429,817,377.40	452,688,334	(22,870,956.60)	(5.05)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	34,986,256.00	38,311,110	(3,324,852.00)	(8.68)	480,927,820.25	479,841,425	1,086,395.25	0.23
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9860	96.7138	0.2722	0.28	97.1650	96.9222	0.2428	0.25
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	33,962,669.84	37,107,708	(3,125,038.16)	(8.42)	468,006,148.53	465,767,733	2,238,415.53	0.48
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	825,562.65	(2,605,248)	3,430,810.65	131.69	(38,188,771.13)	(13,079,398)	(25,109,373.13)	(191.98)
8	Interest Provision for the Month	(1,175.30)	(619)	(556.30)	(89.87)	(1,892.05)	7,200	(9,092.05)	126.28
9	Beginning True-Up & Interest Provision	(19,575,543.13)	(8,264,211)	(11,311,332.13)	(136.87)	17,091,723.14	26,425,418	(9,333,694.86)	35.32
10	True-Up Collected / (Refunded)	(2,202,120.00)	(2,202,120)	0.00	0.00	(26,425,418.00)	(26,425,418)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(20,953,275.78)	(13,072,198)	(7,881,077.78)	(60.29)	(47,524,358.04)	(13,072,198)	(34,452,160.04)	(263.55)
12	Adjustment	0.00	0	0.00	0.00	26,571,082.26	0	26,571,082.26	100.00
13	End of Period - Total Net True-Up	(20,953,275.78)	(13,072,198)	(7,881,077.78)	(60.29)	(20,953,275.78)	(13,072,198)	(7,881,077.78)	(60.29)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

		CURRENT MONTH			
		$		DIFFERENCE	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	(19,575,543.13)	(8,264,211)	(11,311,332.13)	136.87
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(20,952,100.48)	(13,071,579)	(7,880,521.48)	60.29
3	Total of Beginning & Ending True-Up Amts.	(40,527,643.61)	(21,335,790)	(19,191,853.61)	89.95
4	Average True-Up Amount	(20,263,821.81)	(10,667,895)	(9,595,926.81)	89.95
5	Interest Rate 1st Day of Reporting Business Month	0.06	0.06	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.08	0.08	0.0000	
7	Total (D5+D6)	0.14	0.14	0.0000	
8	Annual Average Interest Rate	0.07	0.07	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0058	0.0058	0.0000	
10	Interest Provision (D4*D9)	(1,175.30)	(619)	(556.30)	89.87
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit RWD-1, Page 202 of 212

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	115,361	103,416	11,945	11.55	1,800,641	1,196,189	604,452	50.53
2	COAL	12,060,084	16,428,286	(4,368,202)	(26.59)	218,571,021	238,408,703	(19,837,682)	(8.32)
3	GAS	8,403,576	12,486,296	(4,082,720)	(32.70)	121,765,965	131,481,257	(9,715,293)	(7.39)
4	GAS (B.L.)	10,903	0	10,903	100.00	1,055,071	-	1,055,071	100.00
5	LANDFILL GAS	55,558	56,112	(554)	(0.99)	699,640	682,323	17,317	2.54
6	OIL - C.T.	9,579	0	9,579	100.00	193,104	75,953	117,151	154.24
7	TOTAL ($)	20,655,061	29,074,110	(8,419,049)	(28.96)	344,085,442	371,844,425	(27,758,983)	(7.47)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	254,676	340,147	(85,471)	(25.13)	4,539,871	4,827,650	(287,779)	(5.96)
10	GAS	236,713	360,379	(123,666)	(34.32)	3,590,219	4,073,526	(483,307)	(11.86)
11	LANDFILL GAS	1,888	2,100	(212)	(10.10)	23,404	25,536	(2,132)	(8.35)
12	OIL - C.T.	28	0	28	100.00	556	320	236	73.75
13	TOTAL (MWH)	493,305	702,626	(209,321)	(29.79)	8,154,050	8,927,032	(772,982)	(8.66)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	920	817	103	12.61	13,811	9,688	4,123	42.56
15	COAL (TONS)	119,615	156,826	(37,211)	(23.73)	2,134,912	2,251,362	(116,450)	(5.17)
16	GAS (MCF) (1)	1,638,267	2,437,745	(799,478)	(32.80)	25,338,621	27,955,661	(2,617,040)	(9.36)
17	OIL - C.T. (BBL)	85	0	85	100.00	1,753	700	1,053	150.43
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,762,873	3,771,542	(1,008,669)	(26.74)	57,678,646	53,157,979	4,520,667	8.50
19	GAS - Generation (1)	1,667,192	2,510,877	(843,685)	(33.60)	25,592,240	28,075,723	(2,483,483)	(8.85)
20	OIL - C.T.	496	0	496	100.00	10,204	4,100	6,104	148.88
21	TOTAL (MMBTU)	4,430,561	6,282,419	(1,851,858)	(29.48)	83,281,090	81,237,802	2,043,288	2.52
	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	51.62	48.41	3.21	6.63	55.67	54.07	1.60	2.96
24	GAS	47.99	51.29	(3.30)	(6.43)	44.03	45.63	(1.60)	(3.51)
25	LANDFILL GAS	0.38	0.30	0.08	26.67	0.29	0.29	0.00	0.00
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.01	0.00	0.00
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)	125.41	126.58	(1.17)	(0.92)	130.38	123.47	6.91	5.60
29	COAL ($/TON)	100.82	104.75	(3.93)	(3.75)	102.38	105.90	(3.52)	(3.32)
30	GAS ($/MCF) (1)	5.00	5.04	(0.04)	(0.79)	4.75	4.62	0.13	2.81
31	OIL - C.T. ($/BBL)	112.70	0.00	112.70	100.00	110.16	108.50	1.66	1.53
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.41	4.38	0.03	0.68	3.84	4.51	(0.67)	(14.86)
33	GAS - Generation (1)	4.91	4.90	0.01	0.20	4.66	4.60	0.06	1.30
34	OIL - C.T.	19.31	0.00	19.31	100.00	18.92	18.53	0.39	2.10
35	TOTAL ($/MMBTU)	4.60	4.59	0.01	0.22	4.09	4.54	(0.45)	(9.91)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,849	11,088	(239)	(2.16)	12,705	11,011	1,694	15.38
37	GAS - Generation (1)	7,243	7,080	163	2.30	7,276	6,979	297	4.26
38	OIL - C.T.	17,714	0	17,714	100.00	18,353	12,813	5,540	43.24
39	TOTAL (BTU/KWH)	9,137	9,042	95	1.05	10,335	9,178	1,157	12.61
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.79	4.86	(0.07)	(1.44)	4.88	4.96	(0.08)	(1.61)
41	GAS	3.55	3.46	0.09	2.60	3.39	3.23	0.16	4.95
42	LANDFILL GAS	2.94	2.67	0.27	10.11	2.99	2.67	0.32	11.99
43	OIL - C.T.	34.21	0.00	34.21	100.00	34.73	23.74	10.99	46.29
44	TOTAL (¢/KWH)	4.19	4.14	0.05	1.21	4.22	4.17	0.05	1.20

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: DECEMBER 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(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	26,034	46.7	100.0	70.4	10,698	Coal	11,825.0	11,776	278,511	1,141,436	4.38	96.53
2				0					Gas-G	0	1,013	0	0	0.00	0.00
3									Gas-S	98	1,013	99	2,045		20.87
4									Oil-S	52	137,922	304	6,665		128.17
5	Crist 5		75	33,394	59.8	100.0	63.6	11,418	Coal	16,148	11,806	381,287	1,558,677	4.67	96.52
6				-					Gas-G	0	1,013	0	0	0.00	0.00
7									Gas-S	100	1,013	101	2,088		20.88
8									Oil-S	68	137,922	395	8,676		127.59
9	Crist 6		299	(1,714)	0.0	87.9	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0		0.00
12									Oil-S	0	137,922	0	0		0.00
13	Crist 7		475	84,162	23.8	54.7	51.5	10,406	Coal	37,059	11,816	875,772	3,577,071	4.25	96.52
14				0					Gas-G	6,334	1,013	6,416	132,123	0.00	20.86
15									Gas-S	324	1,013	329	6,769		20.89
16									Oil-S	62	137,922	352	7,702		124.23
17	Scholz 1		46	(213)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(150)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	27,577	22.9	78.9	45.9	10,988	Coal	12,477	12,143	303,015	1,242,242	4.50	99.56
22									Oil-S	45	139,479	265	5,803		128.96
23	Smith 2		195	(723)	0.0	89.5	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,479	0	0		0.00
25	Smith 3		584	230,188	53.0	72.3	80.0	7,215	Gas-G	1,631,411	1,018	1,660,777	8,052,326	3.50	4.94
26	Smith A	(2)	40	28	0.1	100.0	66.7	17,714	Oil	85	139,202	496	9,579	34.21	112.69
27	Other Generation			6,525									219,127	3.36	0.00
28	Perdido			1,888					Landfill Gas				55,558	2.94	0.00
29	Daniel 1	(1)	255	21,169	11.2	63.9	50.2	10,763	Coal	10,410	10,943	227,833	1,116,367	5.27	107.24
30									Oil-S	335	139,773	1,969	41,852		124.93
31	Daniel 2	(1)	255	65,140	34.3	73.2	53.1	10,601	Coal	31,696	10,893	690,539	3,428,350	5.26	108.16
32									Oil-S	358	139,773	2,101	44,663		124.76
33	Total		2,507	493,305	26.4	75.0	47.0	9,137				4,430,561	20,659,120	4.19	

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	20,655,061	4.19

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	190	815	(625)	(76.69)	13,476	9,674	3,802	39.30
3	UNIT COST ($/BBL)	128.81	126.49	2.32	1.83	129.41	123.19	6.22	5.05
4	AMOUNT ($)	24,473	103,092	(78,619)	(76.26)	1,743,939	1,191,772	552,167	46.33
5	*BURNED:*								
6	UNITS (BBL)	941	817	124	15.18	14,392	9,688	4,704	48.55
7	UNIT COST ($/BBL)	125.50	126.58	(1.08)	(0.85)	130.40	123.47	6.93	5.61
8	AMOUNT ($)	118,100	103,416	14,684	14.20	1,876,770	1,196,189	680,581	56.90
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,052	4,539	513	11.30	5,052	4,539	513	11.30
11	UNIT COST ($/BBL)	126.32	124.64	1.68	1.35	126.32	124.64	1.68	1.35
12	AMOUNT ($)	638,187	565,744	72,443	12.80	638,187	565,744	72,443	12.80
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	168,153	166,927	1,226	0.73	1,906,634	1,944,207	(37,573)	(1.93)
16	UNIT COST ($/TON)	99.81	109.64	(9.83)	(8.97)	99.73	106.38	(6.65)	(6.25)
17	AMOUNT ($)	16,783,727	18,301,813	(1,518,086)	(8.29)	190,145,353	206,816,428	(16,671,075)	(8.06)
18	*BURNED:*								
19	UNITS (TONS)	119,615	156,826	(37,211)	(23.73)	2,134,912	2,251,362	(116,450)	(5.17)
20	UNIT COST ($/TON)	100.86	104.75	(3.89)	(3.71)	101.82	105.90	(4.08)	(3.85)
21	AMOUNT ($)	12,064,143	16,428,286	(4,364,143)	(26.56)	217,371,796	238,408,703	(21,036,907)	(8.82)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	709,929	587,762	122,167	20.79	709,929	587,762	122,167	20.79
24	UNIT COST ($/TON)	100.93	109.40	(8.47)	(7.74)	100.93	109.40	(8.47)	(7.74)
25	AMOUNT ($)	71,652,173	64,302,580	7,349,593	11.43	71,652,173	64,302,580	7,349,593	11.43
26	DAYS SUPPLY	34	28	6	21.43				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	1,703,140	2,347,752	(644,612)	(27.46)	25,749,593	27,847,348	(2,097,755)	(7.53)
29	UNIT COST ($/MMBTU)	5.16	4.99	0.17	3.41	4.71	4.61	0.10	2.17
30	AMOUNT ($)	8,785,450	11,718,585	(2,933,135)	(25.03)	121,284,935	128,456,098	(7,171,163)	(5.58)
31	*BURNED:*								
32	UNITS (MMBTU)	1,667,721	2,510,877	(843,156)	(33.58)	25,697,301	28,075,723	(2,378,422)	(8.47)
33	UNIT COST ($/MMBTU)	4.91	4.90	0.01	0.20	4.68	4.60	0.08	1.74
34	AMOUNT ($)	8,195,352	12,294,905	(4,099,553)	(33.34)	120,362,711	129,260,650	(8,897,939)	(6.88)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	833,598	750,375	83,223	11.09	833,598	0	833,598	100.00
37	UNIT COST ($/MMBTU)	4.85	4.59	0.26	5.66	0.72	0.00	0.72	100.00
38	AMOUNT ($)	4,041,727	3,441,070	600,657	17.46	600,657	0	600,657	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	2,019	700	1,319	188.43
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	128.91	120.62	8.00	6.63
42	AMOUNT ($)	0	0	0	0.00	260,271	84,436	175,835	208.25
43	*BURNED:*								
44	UNITS (BBL)	85	0	85	100.00	1,753	700	1,053	150.43
45	UNIT COST ($/BBL)	112.69	0.00	112.69	100.00	110.16	108.50	1.66	1.53
46	AMOUNT ($)	9,579	0	9,579	100.00	193,103	75,953	117,150	154.24
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,221	5,845	376	6.43	6,221	5,845	376	6.43
49	UNIT COST ($/BBL)	112.92	111.06	1.86	1.67	112.92	111.06	1.86	1.67
50	AMOUNT ($)	702,482	649,138	53,344	8.22	702,482	649,138	53,344	8.22
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

			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		320,944,000	0	320,944,000	2.86	3.19	9,182,000	10,234,000
2	Various	Economy Sales	8,633,000	0	8,633,000	3.12	3.43	269,000	296,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	65,000	65,000
4	TOTAL ESTIMATED SALES		329,577,000	0	329,577,000	2.89	3.21	9,516,000	10,595,000
	ACTUAL								
5	Southern Company Interchange		206,595,404	0	206,595,404	3.04	3.25	6,276,699	6,712,257
6	A.E.C.	External	2,149,448	0	2,149,448	2.80	3.45	60,119	74,204
7	AECI	External	311,040	0	311,040	3.04	3.30	9,455	10,264
8	AEP	External	0	0	0	0.00	0.00	0	0
9	CALPINE	External	0	0	0	0.00	0.00	2	0
10	CARGILE	External	2,079,426	0	2,079,426	2.53	3.06	52,646	63,558
11	CONSTELL	External	0	0	0	0.00	0.00	0	0
12	DUKE PWR	External	27,052	0	27,052	1.33	3.29	360	890
13	EAGLE EN	External	372,099	0	372,099	2.77	3.43	10,300	12,781
14	ENDURE	External	0	0	0	0.00	0.00	0	0
15	ENTERGY	External	114,189	0	114,189	3.67	7.31	4,192	8,347
16	EXELON	External	284,187	0	284,187	2.67	3.48	7,577	9,890
17	FPC	External	175,342	0	175,342	3.26	4.27	5,716	7,488
18	FPL	External	12,583	0	12,583	3.00	4.50	377	566
19	JPMVEC	External	123,305	0	123,305	2.88	4.17	3,553	5,136
20	MERRILL	External	0	0	0	0.00	0.00	0	0
21	MISO	External	19,499	0	19,499	3.05	4.12	595	804
22	MORGAN	External	1,584,454	0	1,584,454	2.76	3.30	43,749	52,364
23	NCEMC	External	13,842	0	13,842	2.86	4.59	397	635
24	NCMPA1	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OGE	External	0	0	0	0.00	0.00	0	0
27	OPC	External	262,526	0	262,526	3.09	3.84	8,100	10,087
28	ORLANDO	External	0	0	0	0.00	0.00	3	0
29	PJM	External	716,200	0	716,200	3.54	4.18	25,359	29,903
30	SCE&G	External	0	0	0	0.00	0.00	22	0
31	SEC	External	64,797	0	64,797	2.77	3.49	1,793	2,260
32	SEPA	External	0	0	0	0.00	0.00	88	0
33	SPP	External	0	0	0	0.00	0.00	0	0
34	TAL	External	70,785	0	70,785	3.52	4.41	2,490	3,122
35	TEA	External	472,548	0	472,548	2.68	3.70	12,644	17,498
36	TECO	External	0	0	0	0.00	0.00	498	0
37	TENASKA	External	0	0	0	0.00	0.00	11	0
38	TVA	External	1,704,945	0	1,704,945	3.05	4.29	52,034	73,102
39	UPP	External	0	0	0	0.00	0.00	0	0
40	WRI	External	1,132,480	0	1,132,480	2.69	3.54	30,479	40,108
41	Less: Flow-Thru Energy		(11,666,526)	0	(11,666,526)	2.81	2.81	(328,332)	(328,332)
42	SEPA		2,511,960	2,511,960	0	0.00	0.00	0	0
43	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	42,676	42,676
44	Other transactions including adj.		106,061,946	111,502,525	(5,440,579)	0.00	0.00	0	0
45	TOTAL ACTUAL SALES		315,193,531	114,014,485	201,179,046	2.01	2.16	6,323,598	6,806,932
46	Difference in Amount		(14,383,469)	114,014,485	(128,397,954)	(0.88)	(1.05)	(3,192,402)	(3,788,068)
47	Difference in Percent		(4.36)	0.00	(38.96)	(30.45)	(32.71)	(33.55)	(35.75)

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 43

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

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		2,816,102,000	0	2,816,102,000	3.23	3.55	90,951,000	100,023,000
2	Various	Economy Sales	76,268,000	0	76,268,000	3.31	3.61	2,522,000	2,750,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	691,000	691,000
4	TOTAL ESTIMATED SALES		2,892,370,000	0	2,892,370,000	3.26	3.58	94,164,000	103,464,000
	ACTUAL								
5	Southern Company Interchange		3,177,787,258	0	3,177,787,258	2.97	3.13	94,381,482	99,544,480
6	A.E.C.	External	8,392,756	0	8,392,756	2.92	3.63	245,461	304,418
7	AECI	External	603,646	0	603,646	2.85	3.67	17,226	22,147
8	AEP	External	0	0	0	0.00	0.00	236	0
9	CALPINE	External	13,086	0	13,086	26.23	4.71	3,433	617
10	CARGILE	External	7,352,865	0	7,352,865	2.65	3.06	194,930	225,167
11	CONSTELL	External	932,943	0	932,943	2.33	2.88	21,744	26,896
12	DUKE PWR	External	545,461	0	545,461	2.57	2.93	14,019	15,969
13	EAGLE EN	External	2,663,761	0	2,663,761	2.63	3.32	70,177	88,444
14	ENDURE	External	119,159	0	119,159	3.73	5.28	4,442	6,287
15	ENTERGY	External	1,580,330	0	1,580,330	3.93	6.28	62,167	99,228
16	EXELON	External	6,513,587	0	6,513,587	2.80	3.18	182,385	207,353
17	FPC	External	1,254,869	0	1,254,869	3.26	4.19	40,967	52,642
18	FPL	External	859,400	0	859,400	2.97	4.11	25,559	35,308
19	JPMVEC	External	1,158,693	0	1,158,693	3.81	3.95	44,129	45,774
20	MERRILL	External	54,612	0	54,612	2.44	3.82	1,331	2,089
21	MISO	External	82,473	0	82,473	3.11	4.50	2,564	3,712
22	MORGAN	External	5,213,129	0	5,213,129	2.69	3.08	140,430	160,361
23	NCEMC	External	714,437	0	714,437	3.15	3.88	22,516	27,753
24	NCMPA1	External	80,223	0	80,223	3.61	4.09	2,894	3,284
25	NRG	External	6,291	0	6,291	296.31	3.50	18,641	220
26	OGE	External	1,260	0	1,260	3.01	3.00	38	38
27	OPC	External	1,944,526	0	1,944,526	2.97	3.84	57,756	74,758
28	ORLANDO	External	97,831	0	97,831	3.27	4.60	3,202	4,504
29	PJM	External	11,188,953	0	11,188,953	3.13	3.85	350,257	430,562
30	SCE&G	External	2,863,424	0	2,863,424	3.42	5.04	97,938	144,275
31	SEC	External	1,660,495	0	1,660,495	3.10	3.71	51,398	61,641
32	SEPA	External	4,444,686	0	4,444,686	2.48	3.12	110,400	138,790
33	SPP	External	6,174	0	6,174	2.30	1.63	142	101
34	TAL	External	1,014,854	0	1,014,854	3.36	4.45	34,122	45,198
35	TEA	External	10,634,438	0	10,634,438	3.06	4.05	325,389	431,088
36	TECO	External	753,772	0	753,772	3.03	4.01	22,875	30,232
37	TENASKA	External	9,437	0	9,437	3.03	4.53	286	428
38	TVA	External	5,424,443	0	5,424,443	3.14	4.36	170,315	236,598
39	UPP	External	0	0	0	0.00	0.00	1,321	0
40	WRI	External	3,245,217	0	3,245,217	2.79	3.31	90,499	107,325
41	Less: Flow-Thru Energy		(80,456,572)	0	(80,456,572)	2.87	2.87	(2,312,214)	(2,312,214)
42	SEPA		20,550,640	20,550,640	0	0.00	0.00	0	0
43	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	194,730	194,730
44	Other transactions including adj.		1,719,303,800	1,600,169,032	119,134,768	0.00	0.00	0	0
45	TOTAL ACTUAL SALES		4,918,616,357	1,620,719,672	3,297,896,685	1.93	2.04	94,695,182	100,265,474
46	Difference in Amount		2,026,246,357	1,620,719,672	405,526,685	(1.33)	(1.54)	531,182	(3,198,526)
47	Difference in Percent		70.05	0.00	14.02	(40.80)	(43.02)	0.56	(3.09)

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 43

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2013

(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 2013

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	4,167,000	0	0	0	7.64	7.64	318,160
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	1,219
5	Ascend Performance Materials	COG 1	21,021,000	0	0	0	3.01	3.01	632,569
6	International Paper	COG 1	0	0	0	0	0.00	0.00	26
7	TOTAL		25,188,000	0	0	0	3.78	3.78	951,974

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	41,392,000	0	0	0	7.63	7.63	3,160,094
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	1,294
5	Ascend Performance Materials	COG 1	223,662,000	0	0	0	3.12	3.12	6,969,010
6	International Paper	COG 1	894,000	0	0	0	3.42	3.42	30,580
7	TOTAL		265,948,000	0	0	0	3.82	3.82	10,160,978

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2013

	(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	25,678,000	3.84	986,000	535,093,000	3.91	20,941,000
2	Economy Energy	3,368,000	3.33	112,000	45,869,000	3.78	1,733,000
3	Other Purchases	537,273,000	3.29	17,655,000	5,716,543,000	3.14	179,487,000
4	TOTAL ESTIMATED PURCHASES	566,319,000	3.31	18,753,000	6,297,505,000	3.21	202,161,000
	ACTUAL						
5	Southern Company Interchange	125,728,192	3.11	3,915,998	883,251,099	3.20	28,228,288
6	Non-Associated Companies	38,871,597	0.33	130,181	619,821,097	1.32	8,198,149
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	464,798,000	3.53	16,421,767	5,316,832,000	3.24	172,443,707
9	Other Wheeled Energy	24,346,000	0.00	N/A	373,650,000	0.00	N/A
10	Other Transactions	51,482,248	(0.02)	(7,801)	916,778,823	0.02	140,450
11	Less: Flow-Thru Energy	(11,666,526)	3.07	(358,400)	(80,456,572)	3.09	(2,485,794)
12	TOTAL ACTUAL PURCHASES	693,559,511	2.90	20,101,745	8,029,876,447	2.57	206,524,800
13	Difference in Amount	127,240,511	(0.41)	1,348,745	1,732,371,447	(0.64)	4,363,800
14	Difference in Percent	22.47	(12.39)	7.19	27.51	(19.94)	2.16

2013 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	$ [1]	MW	$	MW	$	MW	$ [1]	MW	$ [1]	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	177.8	422,287	0	(102,074)	370.1	344,833	18.0	45,196	0	(1,079)	0	8,403	717,566
SUBTOTAL					$ 422,287		$ (102,074)		$ 344,833		$ 45,196		$ (1,079)	0	$ 8,403	$ 717,566
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,961,029	Varies	2,003,882	Varies	2,048,096	Varies	2,003,745	Varies	2,601,116	Varies	6,780,108	17,397,976
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,271)	Varies	(3,146)	Varies	(3,146)	Varies	(3,448)	Varies	(10,619)	(26,776)
SUBTOTAL					$ 1,957,883		$ 2,000,611		$ 2,044,950		$ 2,000,599		$ 2,597,668		$ 6,769,489	$ 17,371,200
TOTAL					**$ 2,380,170**		**$ 1,898,537**		**$ 2,389,783**		**$ 2,045,795**		**$ 2,596,589**		**$ 6,777,892**	**$ 18,088,766**

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only.

Docket No. 140001-EI
2013 Final True-Up Filing
Exhibit RWD-1, Page 211 of 212

2013 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	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$ [1]	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													717,566
SUBTOTAL				0	$ -	0	$ -	120	$ 413,300	58.9	$ 20,971	-83.14	$ (36,525)	0	$ 1,366	$ 1,116,678
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	7,266,443	Varies	7,007,226	Varies	6,797,704	Varies	2,473,170	Varies	2,243,716	Varies	2,087,604	45,273,839
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(3,146)	Varies	(4,052)	Varies	(3,146)	(46,558)
SUBTOTAL					$ 7,263,297		$ 7,004,080		$ 6,794,558		$ 2,470,024		$ 2,239,664		$ 2,084,458	$ 45,227,281
TOTAL					**$ 7,263,297**		**$ 7,004,080**		**$ 7,207,858**		**$ 2,490,995**		**$ 2,203,139**		**$ 2,085,824**	**$ 46,343,959**

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only.

Schedule E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
TO BE INCLUDED IN THE PERIOD JANUARY 2015 - DECEMBER 2015

1.	Estimated over/(under)-recovery for the period January 2014 - December 2014 (Sch. E-1B, Page 2, line C9)	$ (43,001,980)
2.	Final over/(under)-recovery for the period January 2013 - December 2013 (Exhibit RWD-1, Schedule 1, line 3)	(4,954,515)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2015 - December 2015	(47,956,495)
4.	Jurisdictional kWh sales for the period January 2015 - December 2015	11,062,622,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWH)	0.4335

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 39
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: C. S. Boyett CSB-1

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

				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		46,431,505.07	34,868,117.94	33,117,976.77	23,043,097.57	36,584,250.04	40,782,817.28	$214,827,764.67
	1a	Fuel Cost of Hedging Settlement		(1,412,120.00)	(3,266,585.00)	(1,182,675.00)	(715,550.00)	(1,105,865.00)	(776,560.00)	($8,459,355.00)
	2	Fuel Cost of Power Sold		(26,165,795.00)	(9,501,812.57)	(15,455,952.11)	(3,515,147.88)	(11,751,171.10)	(7,693,369.65)	($74,083,248.31)
	3	Fuel Cost of Purchased Power		25,890,323.05	15,443,580.25	20,422,742.75	13,920,285.28	17,680,225.99	15,891,931	$109,249,088.75
	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		1,784,533.44	704,344.70	825,610.72	685,679.02	580,937.44	601,379.33	$5,182,484.65
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		217,392.62	200,672.39	222,732.26	229,680.50	289,280.59	230,995.41	$1,390,753.77
	6	Adjustments to Fuel Cost		266.30	(17,224.74)	2,300.00	5,150.00	940.53	0.00	($8,567.91)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		46,746,105.48	38,431,092.97	37,952,735.39	33,653,194.49	42,278,598.49	49,037,193.80	$248,098,920.62
B	1	Jurisdictional KWH Sales		1,041,533,597	740,745,396	768,919,985	752,971,848	924,994,128	1,078,240,405	5,307,405,359
	2	Non-Jurisdictional KWH Sales		32,651,753	22,559,528	23,396,311	18,952,601	25,562,899	29,040,143	152,163,235
	3	TOTAL SALES (Lines B1 + B2)		1,074,185,350	763,304,924	792,316,296	771,924,449	950,557,027	1,107,280,548	5,459,568,594
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.9603%	97.0445%	97.0471%	97.5448%	97.3107%	97.3773%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	43,044,663.21	30,638,137.47	31,603,211.42	30,827,485.96	37,999,030.30	45,846,336.24	$219,958,864.60
	2	True-Up Provision		(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	($7,999,380.00)
	2a	Incentive Provision		(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	($830,574.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$41,573,004.21	$29,166,478.47	$30,131,552.42	$29,355,826.96	$36,527,371.30	$44,374,677.24	$211,128,910.60
	4	Fuel & Net Power Transactions (Line A7)		46,746,105.48	38,431,092.97	37,952,735.39	33,653,194.49	42,278,598.49	49,037,193.80	$248,098,920.62
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)		45,393,151.86	37,351,204.91	36,887,277.11	32,876,181.67	41,203,312.54	47,822,721.96	$241,533,850.05
	6	Over/(Under) Recovery (Line C3-C5)		(3,820,147.65)	(8,184,726.44)	(6,755,724.69)	(3,520,354.71)	(4,675,941.24)	(3,448,044.72)	($30,404,939.45)
	7	Interest Provision		(1,398.39)	(1,558.31)	(1,914.34)	(2,319.19)	(2,493.53)	(2,284.80)	($11,968.56)
	8	Adjustments		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2014 - JUNE 2014**								($30,416,908.01)

* (Gain)/Loss on sales of natural gas

Note 1: Projected Revenues based on the current approved 2014 Fuel Factor excluding revenue taxes of: 4.1664

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

			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	43,178,200.00	42,753,452.00	32,335,579.00	25,250,108.00	25,087,979.00	30,228,271.00	$413,661,353.67
	1a	Fuel Cost of Hedging Settlement	(592,535.00)	123,525.00	151,320.00	224,812.00	163,905.00	(55,224.00)	($8,443,552.00)
	2	Fuel Cost of Power Sold	(12,199,000.00)	(12,472,200.00)	(7,549,400.00)	(1,671,600.00)	(8,570,200.00)	(7,987,000.00)	($124,532,648.31)
	3	Fuel Cost of Purchased Power	19,768,000.00	19,816,000.00	18,857,000.00	14,360,000.00	17,421,000.00	15,319,000.00	$214,790,088.75
	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	0.00	0.00	0.00	0.00	0.00	0.00	$5,182,484.65
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	312,535.00	312,535.00	302,472.00	208,551.00	201,843.00	208,551.00	$2,937,240.77
	6	Adjustments to Fuel Cost *	0.00	0.00	0.00	0.00	0.00	0.00	($8,567.91)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$50,467,200.00	$50,533,312.00	$44,096,971.00	$38,371,871.00	$34,304,527.00	$37,713,598.00	$503,586,399.62
B	1	Jurisdictional KWH Sales	1,198,218,000	1,178,147,000	1,039,787,000	867,231,000	748,462,000	835,508,000	11,174,758,359
	2	Non-Jurisdictional KWH Sales	34,667,000	35,060,000	30,639,000	26,592,000	24,901,000	29,166,000	333,188,235
	3	TOTAL SALES (Lines B1 + B2)	1,232,885,000	1,213,207,000	1,070,426,000	893,823,000	773,363,000	864,674,000	11,507,946,594
	4	Jurisdictional % Of Total Sales (Line B1/B3)	97.1881%	97.1101%	97.1377%	97.0249%	96.7802%	96.6269%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	49,922,557.05	49,086,318.87	43,321,687.56	36,132,314.05	31,183,922.20	34,810,606.92	$464,416,271.25
	2	True-Up Provision	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,231.00)	($15,998,761.00)
	2a	Incentive Provision	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,427.00)	($1,661,146.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$48,450,898.05	$47,614,659.87	$41,850,028.56	$34,660,655.05	$29,712,263.20	$33,338,948.92	$446,756,364.25
	4	Fuel & Net Power Transactions (Line A7)	50,467,200.00	50,533,312.00	44,096,971.00	38,371,871.00	34,304,527.00	37,713,598.00	$503,586,399.62
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	49,121,684.97	49,146,559.24	42,899,035.57	37,286,114.87	33,249,789.82	36,496,142.85	$489,733,177.37
	6	Over/(Under) Recovery (Line C3-C5)	(670,786.92)	(1,531,899.37)	(1,049,007.01)	(2,625,459.82)	(3,537,526.62)	(3,157,193.93)	($42,976,813.12)
	7	Interest Provision	(2,151.98)	(2,140.49)	(2,138.46)	(2,163.77)	(2,251.29)	(2,352.11)	($25,166.66)
	8	Adjustments	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2014 - DECEMBER 2014**							($43,001,979.78)

* (Gain)/Loss on sales of natural gas
Note 1: Projected Revenues based on the current approved 2014 Fuel Factor excluding revenue taxes of: 4.1664

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 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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	413,661,354	355,672,030	57,989,324	16.30	9,926,448,000	8,851,840,000	1,074,608,000	12.14	4.1673	4.0181	0.1492	3.71
1a	Fuel Cost of Hedging Settlement	(8,443,552)	0	(8,443,552)	(100.00)	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4	Other Generation	2,937,241	3,254,676	(317,435)	(9.75)	80,561,000	81,428,000	(867,000)	(1.06)	3.6460	3.9970	(0.3510)	(8.78)
5	Adjustments to Fuel Cost ***	(8,568)	0	(8,568)	(100.00)	0	0				0.0000		
6	TOTAL COST OF GENERATED POWER	408,146,475	358,926,706	49,219,769	13.71	10,007,009,000	8,933,268,000	1,073,741,000	12.02	4.0786	4.0179	0.0607	1.51
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
9	Energy Cost of Other Economy Purchases (Nonbroker)	214,790,089	173,773,123	41,016,966	23.60	6,359,178,663	5,470,006,000	889,172,663	16.26	3.3776	3.1768	0.2008	6.32
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
12	Energy Payments to Qualifying Facilities	5,182,485	0	5,182,485	100.00	101,915,000	0	101,915,000	100.00	5.0851	0.0000	5.0851	100.00
13	TOTAL COST OF PURCHASED POWER	219,972,573	173,773,123	46,199,450	26.59	6,461,093,663	5,470,006,000	991,087,663	18.12	3.4046	3.1768	0.2278	7.17
14	Total Available kWh (Line 6 + Line 13)	628,119,048	532,699,829	95,419,219	17.91	16,468,102,663	14,403,274,000	2,064,828,663	14.34	3.8142	3.6985	0.1157	3.13
15	Fuel Cost of Economy Sales	(7,021,399)	(2,432,000)	(4,589,399)	188.71	(202,363,932)	(75,070,000)	(127,293,932)	169.57	3.4697	3.2396	0.2301	7.10
16	Gain on Economy Sales	(1,151,614)	(594,995)	(556,619)	93.55	0	0						
17	Fuel Cost of Other Power Sales	(116,359,635)	(69,218,000)	(47,141,635)	68.11	(4,051,494,979)	(2,108,392,000)	(1,943,102,979)	92.16	2.8720	3.2830	(0.4110)	(12.52)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(124,532,648)	(72,244,995)	(52,287,653)	72.38	(4,253,858,911)	(2,183,462,000)	(2,070,396,911)	94.82	2.9275	3.3087	(0.3812)	(11.52)
19	(LINES 15+16+17)												
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
21	**TOTAL FUEL & NET POWER TRANSACTIONS**	503,586,400	460,454,834	43,131,566	9.37	12,214,243,752	12,219,812,000	(5,568,248)	(0.05)	4.1229	3.7681	0.3548	9.42
	(LINES 14+18+20)												
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
23	Company Use *	858,354	808,446	49,908	6.17	20,819,173	21,455,000	(635,827)	(2.96)	4.1229	3.7681	0.3548	9.42
24	T & D Losses *	28,261,485	26,114,139	2,147,326	8.22	685,475,385	693,032,000	(7,556,615)	(1.09)	4.1229	3.7681	0.3548	9.42
25	TERRITORIAL (SYSTEM) SALES	503,586,400	460,454,834	43,131,566	9.37	11,507,949,194	11,505,325,000	2,624,194	0.02	4.3760	4.0021	0.3739	9.34
26	Wholesale Sales	14,580,275	14,049,252	531,023	3.78	333,188,235	351,047,000	(17,858,765)	(5.09)	4.3760	4.0021	0.3739	9.34
27	Jurisdictional Sales	489,006,125	446,405,582	42,600,543	9.54	11,174,760,959	11,154,278,000	20,482,959	0.18	4.3760	4.0021	0.3739	9.34
28	Jurisdictional Loss Multiplier	1.0015	1.0015										
29	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0015)	469,733,177	447,075,190	42,657,987	9.54	11,174,760,959	11,154,278,000	20,482,959	0.18	4.3825	4.0081	0.3744	9.34
30	TRUE-UP **	15,998,761	15,998,761	0	0.00	11,174,760,959	11,154,278,000	20,482,959	0.18	0.1432	0.1434	(0.0002)	(0.14)
31	TOTAL JURISDICTIONAL FUEL COST	505,731,938	463,073,951	42,657,987	9.21	11,174,760,959	11,154,278,000	20,482,959	0.18	4.5257	4.1515	0.3742	9.01
32	Revenue Tax Factor									1.00072	1.00072		
33	Fuel Factor Adjusted for Revenue Taxes									4.5290	4.1545	0.3745	9.01
34	GPIF Reward / (Penalty) **	1,662,342	1,662,342	0	0.00	11,174,760,959	11,154,278,000	20,482,959	0.18	0.0149	0.0149	0.0000	0.00
35	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5439	4.1694	0.3745	8.98
36	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									4.544	4.169	0.3750	8.99

* 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.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

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 ESTIMATED	(m) TOTAL
	$													
1	Fuel Cost of System Generation	46,431,505.07	34,868,117.94	33,117,976.77	23,043,097.57	36,584,250.04	40,782,817.28	43,178,200	42,753,452	32,335,579	25,250,108	25,087,979	30,228,271	413,661,353.67
1a	Other Generation	217,392.62	200,672.39	222,732.26	229,680.50	289,280.59	230,995.41	312,535	312,535	302,472	208,551	201,843	208,551	2,937,240.77
2	Fuel Cost of Power Sold	(26,165,795.00)	(9,501,812.57)	(15,455,952.11)	(3,515,147.88)	(11,751,171.00)	(7,693,369.65)	(12,199,000)	(12,472,200)	(7,549,400)	(1,671,600)	(8,570,200)	(7,987,000)	(124,532,648.21)
3	Fuel Cost of Purchased Power	25,890,323.05	15,443,580.25	20,422,742.75	13,920,285.28	17,680,225.99	15,891,931.43	19,768,000	19,816,000	18,857,000	14,360,000	17,421,000	15,319,000	214,790,088.75
3a	Demand & Non-Fuel Cost of Pur Power	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
3b	Qualifying Facilities	1,784,533.44	704,344.70	825,610.72	685,679.02	580,937.44	601,379.33	0	0	0	0	0	0	5,182,484.65
4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
5	Hedging Settlement	(1,412,120.00)	(3,266,585.00)	(1,182,675.00)	(715,550.00)	(1,105,865.00)	(776,560.00)	(592,535)	123,525	151,320	224,812	163,905	(55,224)	(8,443,552.00)
6	Adjustment to Fuel Cost	266.30	(17,224.74)	2,300.00	5,150.00	940.53		0	0	0	0	0	0	(8,567.91)
7	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 6)	$ 46,746,105.48	$ 38,431,092.97	$ 37,952,735.39	$ 33,653,194.49	$ 42,278,598.59	$ 49,037,193.80	$50,467,200.00	$50,533,312.00	$44,096,971.00	$38,371,871.00	$34,304,527.00	$37,713,598.00	$ 503,586,399.72
8	System kWh Sold	1,074,185,350	763,304,924	792,316,296	771,924,449	950,557,027	1,107,280,548	1,232,885,000	1,213,207,000	1,070,426,000	893,823,000	773,363,000	864,674,000	11,507,946,594
8a	Jurisdictional % of Total Sales	0.9696	0.9704	0.9705	0.9754	0.9731	0.9738	0.9719	0.9711	0.9714	0.9702	0.9678	0.9663	
9	Cost per kWh Sold (¢/kWh)	4.3518	5.0348	4.7901	4.3596	4.4478	4.4286	4.0934	4.1653	4.1196	4.2930	4.4358	4.3616	4.3760
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)	4.3583	5.0424	4.7973	4.3661	4.4545	4.4352	4.0995	4.1715	4.1258	4.2994	4.4425	4.3681	4.3826
10	GPIF (¢/kWh) *	0.0133	0.0187	0.0180	0.0184	0.0150	0.0128	0.0116	0.0117	0.0133	0.0160	0.0185	0.0166	0.0149
11	True-Up (¢/kWh) *	0.1280	0.1800	0.1734	0.1771	0.1441	0.1236	0.1113	0.1132	0.1282	0.1537	0.1781	0.1596	0.1432
12	TOTAL	4.4996	5.2411	4.9887	4.5616	4.6136	4.5716	4.2224	4.2964	4.2673	4.4691	4.6391	4.5443	4.5407
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	4.5028	5.2449	4.9923	4.5649	4.6169	4.5749	4.2254	4.2995	4.2704	4.4723	4.6424	4.5476	4.5440
15	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	4.503	5.245	4.992	4.565	4.617	4.575	4.225	4.300	4.270	4.472	4.642	4.548	4.544

* ¢/kWh calculations based on jurisdictional kWh sales

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	295,888	298,728	114,229	252,748	117,391	101,854	148,846	148,560	147,854	143,983	151,117	135,199	2,056,397
2	COAL	34,506,364	23,361,077	20,665,892	13,578,281	24,642,528	27,883,172	29,990,579	29,867,324	19,940,451	14,251,055	16,295,233	18,907,750	273,889,707
3	GAS - Generation	11,405,320	11,185,298	12,380,486	9,187,315	11,880,743	12,777,213	13,033,661	12,732,628	12,235,110	10,746,713	8,480,490	11,120,635	137,165,613
4	GAS (B.L.)	264,707	158,404	114,698	193,754	133,318	141,149	254,334	254,160	253,401	253,593	301,747	209,923	2,533,187
5	Landfill Gas	62,605	65,282	65,405	60,680	61,287	63,050	63,315	63,315	61,235	63,315	61,235	63,315	754,039
6	OIL - C.T.	114,014	0	0	0	38,264	47,374	0	0	0	0	0	0	199,652
7	TOTAL ($)	46,648,898	35,068,790	33,340,709	23,272,778	36,873,531	41,013,813	43,490,735.00	43,065,987.00	32,638,051.00	25,458,659.00	25,289,822.00	30,436,822.00	416,598,594
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0.00
9	COAL	374,983	490,321	508,119	323,446	588,793	649,815	740,875	739,958	499,949	322,596	363,622	415,028	6,017,505.00
10	GAS	676,710	250,111	311,051	216,541	289,661	305,928	351,919	349,350	333,341	285,947	252,940	340,523	3,964,022.00
11	Landfill Gas	2,157	2,039	2,195	2,029	2,048	2,096	2,100	2,100	2,031	2,100	2,031	2,100	25,026.00
12	OIL - C.T.	360	(6)	(7)	(7)	15	101	0	0	0	0	0	0	456.00
13	TOTAL (MWH)	1,054,210	742,465	821,358	542,009	880,517	957,940	1,094,894	1,091,408	835,321	610,643	618,593	757,651	10,007,009.00
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	2,326	2,322	882	1,975	924	802	1,165	1,165	1,162	1,132	1,189	1,065	16,110
15	COAL (TON)	352,255	238,094	219,492	148,025	284,180	323,941	352,896	351,219	241,699	155,182	172,224	195,432	3,034,639
16	GAS-all (MCF) (1)	2,197,738	1,767,275	2,136,834	1,506,933	1,987,336	2,143,043	2,425,415	2,403,007	2,292,149	1,965,463	1,744,325	2,296,782	24,866,300
17	OIL - C.T. (BBL)	1,003	0	0	0	330	408	0	0	0	0	0	0	1,741
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	7,874,460	5,194,860	5,260,248	3,565,250	6,308,891	7,036,426	7,993,778	7,988,491	5,351,479	3,566,940	4,062,467	4,612,165	88,815,455
19	GAS-Generation (1)	2,200,352	1,788,326	2,170,873	1,522,343	2,030,981	2,189,330	2,468,177	2,445,097	2,330,914	1,994,427	1,756,655	2,345,686	25,243,161
20	OIL - C.T.	5,882	0	0	0	1,927	2,385	0	0	0	0	0	0	10,194
21	TOTAL (MMBTU)	10,080,694	6,983,186	7,431,121	5,087,593	8,341,799	9,228,141	10,461,955	10,433,588	7,682,393	5,561,367	5,819,122	6,957,851	94,068,810

(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.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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
	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	35.58	66.04	61.86	59.68	66.87	67.83	67.67	67.80	59.85	52.83	58.78	54.78	60.14
24	GAS-Generation	64.19	33.69	37.87	39.95	32.90	31.94	32.14	32.01	39.91	46.83	40.89	44.94	39.61
25	Landfill Gas	0.20	0.27	0.27	0.37	0.23	0.22	0.19	0.19	0.24	0.34	0.33	0.28	0.25
26	OIL - C.T.	0.03	0.00	0.00	0.00	0.00	0.01	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 ($/BBL)	127.21	128.65	129.51	127.97	127.05	127.00	127.72	127.47	127.29	127.16	127.08	126.96	127.65
29	COAL ($/TON)	97.96	98.12	94.15	91.73	86.71	86.07	84.98	85.04	82.50	91.83	94.62	96.75	90.25
30	GAS + B.L. ($/MCF) (1)	5.21	6.31	5.74	6.07	5.90	5.92	5.35	5.27	5.32	5.49	4.92	4.84	5.50
31	OIL - C.T.	113.67	0.00	0.01	0.00	115.95	116.11	0.00	0.00	0.00	0.00	0.00	0.00	114.68
	FUEL COST $ / MMBTU													
32	COAL + GAS B.L. + OIL B.L.	4.45	4.58	3.97	3.93	3.95	4.00	3.80	3.79	3.80	4.11	4.12	4.17	4.05
33	GAS-Generation (1)	5.08	6.14	5.60	5.88	5.71	5.73	5.15	5.08	5.12	5.28	4.71	4.65	5.32
34	OIL - C.T.	19.38	0.00	0.00	0.00	19.86	19.86	0.00	0.00	0.00	0.00	0.00	0.00	19.59
35	TOTAL ($/MMBTU)	4.60	4.98	4.45	4.52	4.38	4.41	4.12	4.09	4.20	4.53	4.30	4.34	4.39
	BTU BURNED BTU / KWH													
36	COAL + GAS B.L. + OIL B.L.	21,000	10,595	10,352	11,023	10,715	10,828	10,790	10,796	10,704	11,057	11,172	11,113	11,436
37	GAS-Generation (1)	3,280	7,312	7,124	7,244	7,212	7,299	7,189	7,175	7,171	7,117	7,100	7,006	6,500
38	OIL - C.T.	16,339	0	0	0	128,467	23,614	0	0	0	0	0	0	22,355
39	TOTAL (BTU/KWH)	9,635	9,502	9,142	9,535	9,584	9,715	9,649	9,854	9,312	9,226	9,524	9,279	9,501
	FUEL COST CENTS / KWH													
40	COAL + GAS B.L. + OIL B.L.	9.35	4.86	4.11	4.34	4.23	4.33	4.10	4.09	4.07	4.54	4.61	4.64	4.63
41	GAS-Generation	1.69	4.47	3.98	4.24	4.10	4.18	3.70	3.64	3.67	3.76	3.35	3.27	3.46
42	Landfill Gas	2.90	3.20	2.98	2.99	2.99	3.01	3.02	3.02	3.02	3.02	3.02	3.02	3.01
43	OIL - C.T.	31.67	0.00	0.00	0.00	255.09	46.90	0.00	0.00	0.00	0.00	0.00	0.00	43.78
44	TOTAL (¢/KWH)	4.43	4.72	4.06	4.29	4.19	4.28	3.97	3.95	3.91	4.17	4.09	4.02	4.16

(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 2014

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	17,536	31.4	98.9	65.1	10,980	Coal	8,162	11,795	192,546	798,536	4.55	97.84
2	4			0					Gas - G	-	1,014	-	-	0.00	0.00
									Gas - S	11,904	1,014	12,071	92,229		7.75
									Oil - S	233	137,922	1,349	29,732		127.61
3	Crist 5		75	39,002	69.9	99.8	71.0	10,828	Coal	18,049	11,699	422,305	1,765,772	4.53	97.83
4	5			0					Gas - G	-	1,014	-	-	0.00	0.00
									Gas - S	11,655	1,014	11,818	90,297		7.75
									Oil - S	143	137,922	830	18,289		127.90
5	Crist 6		299	128,310	57.7	99.8	61.9	11,341	Coal	61,543	11,822	1,455,131	6,020,995	4.69	97.83
6	6			0					Gas - G	-	1,014	-	-		0.00
									Gas - S	4,251	1,014	4,311	32,937		7.75
									Oil - S	-	137,922	-	-		0.00
7	Crist 7		475	177,575	50.2	90.9	55.3	10,185	Coal	76,348	11,844	1,808,515	7,469,318	4.21	97.83
	7			0					Gas - G	-	1,014	-	-		0.00
									Gas - S	6,357	1,014	6,445	49,243		7.75
8									Oil - S	57	137,922	331	7,286		127.82
10	Scholz 1		46	6,193	18.1	100.0	48.0	12,626	Coal	3,411	11,461	78,194	296,601	4.79	86.95
									Oil - S	47	137,702	274	6,084		129.45
11	Scholz 2		46	6,555	19.2	98.6	50.8	12,923	Coal	3,678	11,515	84,713	319,819	4.88	86.95
									Oil - S	60	137,702	349	7,745		
12	Smith 1		162	57,912	48.0	98.1	57.0	11,051	Coal	33,264	9,620	639,998	2,814,870	4.86	84.62
									Oil - S	968	139,157	5,658	123,398		127.48
13	Smith 2		195	67,877	46.8	100.0	52.6	11,059	Coal	39,217	9,570	750,619	3,318,656	4.89	84.62
									Oil - S	495	139,157	2,892	63,081		127.44
14	Smith 3		584	308,454	83.9	100.0	78.1	7,133	Gas - G	2,163,571	1,017	2,200,352	11,187,927	3.63	5.17
15	Smith A (CT)	(2)	40	360	1.2	99.3	70.5	16,339	Oil	1,003	1,397,070	5,882	114,013	31.67	113.67
16	Other Generation			5,833					Gas				217,393	3.73	N/A
9	Perdido			2,157					Landfill Gas				62,605	2.90	N/A
17	Daniel 1	(1)	255	117,676	62.0	99.2	62.8	10,224	Coal	54,421	11,054	1,203,085	5,881,677	5.00	108.08
									Oil - S	285	139,603	1,671	35,557		124.76
18	Daniel 2	(1)	255	118,770	62.6	100.0	62.6	10,029	Coal	53,889	11,052	1,191,133	5,824,179	4.90	108.08
									Oil - S	38	139,603	222	4,718		124.16
19	Gas,BL								Gas						
20	Ltr. Oil								Oil						
21			2,507	1,054,210	56.5	98.0	63.6	9635.3				10,080,694	46,652,957	4.43	

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.	(4,059)	
273	Inventory Adjustment - Coal (Daniel)	-	
	Recoverable Fuel	46,648,898	4.43

Docket No. 140001-EI
2014 Estimated/Actual True-Up Filing
Exhibit CSB-1, Page 8 of 32

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2014

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	17,353	34.4	100.0	71.3	10,751	Coal	7,852	11,880	186,559	800,237	4.61	101.92
2	4			0					Gas - G	-	1,016	-	-	0.00	0.00
									Gas - S	347	1,016	352	6,208		17.89
									Oil - S	25	137,543	147	3,246		129.84
3	Crist 5		75	22,526	44.7	100.0	65.5	11,109	Coal	10,537	11,875	250,251	1,073,894	4.77	101.92
4	5			0					Gas - G	-	1,016	-	-	0.00	0.00
									Gas - S	936	1,016	951	16,770		17.92
									Oil - S	79	137,543	457	10,091		127.73
5	Crist 6		299	72,822	36.2	85.7	58.8	11,562	Coal	35,495	11,860	841,952	3,617,610	4.97	101.92
6	6			0					Gas - G	-	1,016	-	-		0.00
									Gas - S	4,142	1,016	4,209	74,218		17.92
									Oil - S	-	137,543	2	30		0.00
7	Crist 7		475	168,979	52.9	93.8	56.5	10,412	Coal	74,460	11,814	1,759,362	7,588,878	4.49	101.92
	7			0					Gas - G	-	1,016	-	-		0.00
									Gas - S	3,417	1,016	3,471	61,207		17.91
8									Oil - S	70	137,543	404	8,922		127.46
10	Scholz 1		46	(268)	0.0	100.0	0.0	0	Coal	-	-	-	-	0.00	0.00
									Oil - S	-	-	-	-		0.00
11	Scholz 2		46	(144)	0.0	100.0	0.0	0	Coal	-	-	-	-	0.00	0.00
									Oil - S	-	-	-	-		0.00
12	Smith 1		162	60,228	55.3	100.0	55.3	10,328	Coal	36,006	8,638	622,033	2,880,445	4.78	80.00
									Oil - S	677	139,461	3,967	87,914		129.86
13	Smith 2		195	37,467	28.6	68.7	51.9	10,605	Coal	23,149	8,582	397,336	1,851,950	4.94	80.00
									Oil - S	732	139,461	4,288	95,023		129.81
14	Smith 3		584	244,566	83.9	100.0	68.5	7,312	Gas - G	1,758,433	1,017	1,788,324	10,984,626	4.49	6.25
15	Smith A (CT)	(2)	40	(6)	0.0	100.0	0.0	0	Oil	-	139,203	-	-	0.00	0.00
16	Other Generation			5,545					Gas				200,672	3.62	0.00
9	Perdido			2,039					Landfill Gas				65,282	3.20	0.00
17	Daniel 1	(1)	255	77,274	45.1	56.9	81.9	10,379	Coal	36,479	10,993	802,009	4,003,066	5.18	109.74
									Oil - S	635	138,651	3,698	80,393		126.60
18	Daniel 2	(1)	255	34,084	19.9	24.3	82.0	9,178	Coal	14,116	1,185	312,811	1,549,057	4.54	109.74
									Oil - S	104	138,651	603	13,109		126.05
19	Gas,BL								Gas						
20	Ltr. Oil								Oil						
21			2,507	742,465	44.1	82.6	62.1	9502.5				6,983,186	35,072,849	4.72	

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.	(4,059)	
	Recoverable Fuel	35,068,791	4.72

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2014

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	(496)	0.0	100.0	0.0	0	Coal	-	-	-	-	0.00	0.00
2	4			0					Gas - G	-	1,014	-	-	0.00	0.00
									Gas - S	-	1,014	-	-		0.00
									Oil - S	-	137,543	-	-		0.00
3	Crist 5		75	41893	75.2	100.0	75.2	10,657	Coal	19,007	11,744	446,440	1,812,976	4.33	95.38
4	5			0					Gas - G	-	1,014	-	-	0.00	0.00
									Gas - S	-	1,014	-	-		0.00
									Oil - S	77	137,543	444	9,814		127.45
5	Crist 6		299	33374	15.0	28.9	61.5	10,824	Coal	15,486	11,664	361,251	1,477,088	4.43	95.38
6	6			0					Gas - G	-	1,014	-	-		0.00
									Gas - S	148	1,014	150	114,698		774.98
									Oil - S	-	137,543	-	-		0.00
7	Crist 7		475	210358	59.6	100.0	59.6	9,942	Coal	92,338	11,324	2,091,276	8,807,574	4.19	95.38
	7			0					Gas - G	-	1,014	-	-		0.00
									Gas - S	-	1,014	-	-		0.00
8									Oil - S	44	137,543	254	5,617		127.66
10	Scholz 1		46	(372)	0.0	100.0	0.0	0	Coal	-	-	-	-	0.00	N/A
									Oil - S	-	-	-	-		N/A
11	Scholz 2		46	(140)	0.0	100.0	0.0	0	Coal	-	-	-	-	0.00	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	45170	37.5	76.9	48.3	11,021	Coal	21,174	11,755	497,809	1,765,318	3.91	83.37
									Oil - S	415	139,291	2,428	53,877		129.82
13	Smith 2		195	53843	37.2	97.7	39.8	11,120	Coal	25,731	11,635	598,750	2,145,171	3.98	83.37
									Oil - S	339	139,291	1,983	44,016		129.84
14	Smith 3		558	304714	83.9	100.0	78.0	7,124	Gas - G	2,136,686	1,016	2,170,873	12,157,754	3.99	5.69
15	Smith A (CT)	(2)	40	(7)	0.0	98.6	0.0	0	Oil	-	139,203	-	-	0.00	N/A
16	Other Generation			6337					Gas				222,732	3.51	N/A
9	Perdido			2195					Landfill Gas				65,403	2.98	N/A
17	Daniel 1	(1)	255	124794	65.9	99.8	65.9	10,092	Coal	62,444	10,084	1,259,421	6,163,828	4.94	98.71
									Oil - S	7	139,052	42	906		129.43
18	Daniel 2	(1)	255	(305)	0.0	0.0	0.0	0	Coal	-	-	-	-	0.00	N/A
									Oil - S	-	139,052	-	-		N/A
19	Gas,BL								Gas					N/A	N/A
20	Ltr. Oil								Oil					N/A	N/A
21			2,481	821,358	44.6	79.4	51.7	9142.3				7,431,121	34,846,772	4.24	

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.	(4,059)	
(7,619)	Inventory Adjustment - Coal (Crist)	(776,513)	
(9,069)	Inventory Adjustment - Coal (Smith)	(725,491)	
	Recoverable Fuel	33,340,709	4.06

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2014

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	(469)	0.0	67.8	0	0	Coal	-	-	-	-	0.00	0.00
2	4			0					Gas - G	-	1,019	-	-	0.00	0.00
									Gas - S	-	1,019	-	-		0.00
									Oil - S	-	137,543	-	-		0.00
3	Crist 5		75	21,830	40.4	67.8	71.9	10,593	Coal	9,835	11,756	231,245	917,386	4.20	93.28
4	5			0					Gas - G	-	1,019	-	-	0.00	0.00
									Gas - S	4,116	1,019	4,194	55,226		13.42
									Oil - S	41	137,543	233	5,159		125.83
5	Crist 6		299	66,364	30.8	96.9	62.5	11,191	Coal	31,196	11,904	742,709	2,909,818	4.38	93.28
6	6			0					Gas - G	0	1,019	-	-		0.00
									Gas - S	10,324	1,019	10,520	138,528		13.42
									Oil - S	0	137,543	1	20		0.00
7	Crist 7		475	182,860	53.5	100	53.5	10,768	Coal	83,087	11,849	1,969,012	7,750,093	4.24	93.28
	7			0					Gas - G	0	1,019	-	-		0.00
									Gas - S	0	1,019	-	-		0.00
8									Oil - S	40	137,543	231	5,107		127.68
10	Scholz 1		46	(218)	0.0	100	0	0	Coal	-	-	-	-	0.00	N/A
									Oil - S	-	-	-	-		N/A
11	Scholz 2		46	(157)	0.0	100	0	0	Coal	-	-	-	-	0.00	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	23,595	20.2	90	49.2	11,093	Coal	11,110	11,779	261,738	973,908	4.13	87.66
									Oil - S	381	138,786	2,222	49,662		130.35
13	Smith 2		195	11,080	7.9	98.3	35.4	11,719	Coal	5,439	11,937	129,849	476,766	4.30	87.66
									Oil - S	240	138,786	1,399	31,264		130.27
14	Smith 3		558	210,138	83.9	71.2	75.8	7,244	Gas - G	1,492,493	1,020	1,522,343	8,957,635	4.26	6.00
15	Smith A (CT)	(2)	36	(7)	0.0	89.4	0	0	Oil	-	139,203	-	-	0.00	N/A
16	Other Generation			6,403					Gas				229,681	3.59	N/A
9	Perdido			2,029					Landfill Gas				60,680	2.99	N/A
17	Daniel 1	(1)	255	15,018	8.2	70.7	44.8	10,454	Coal	8,161	9,619	156,998	688,192	4.58	84.33
									Oil - S	15	139,028	87	1,889		125.93
18	Daniel 2	(1)	255	3,543	1.9	8.9	40.6	13,397	Coal	2,141	11,085	47,464	180,544	5.10	84.33
									Oil - S	1,258	139,028	7,348	159,645		126.90
19	Gas,BL								Gas	-	-	-	-	N/A	N/A
20	Ltr. Oil								Oil	-	-	-	-	N/A	N/A
21			2,477	542,009	30.4	77.9	51.9	9,535				5,087,593	23,591,203	4.35	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses fighter 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)	
(2,945)	Inventory Adjustment - Coal (Daniel)	(314,366)	
	Recoverable Fuel	23,272,778	4.29

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2014

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	(503)	0.0	79.8	0.0	0	Coal	-	-	-	-	-	-
2	4			0					Gas - G	-	1,017	-	-	-	-
									Gas - S	-	1,017	-	-	-	-
									Oil - S	2	137,543	10	218	-	109.00
3	Crist 5		75	(497)	0.0	86.3	0.0	0	Coal	-	-	-	-	-	-
4	5								Gas - G	-	1,017	-	-	-	-
									Gas - S	-	1,017	-	-	-	-
									Oil - S	2	137,543	11	235	-	117.50
5	Crist 6		299	146,217	65.7	100.0	65.7	10,803	Coal	66,558	11,866	1,579,549	6,093,972	4.17	91.56
6	6			0					Gas - G	-	1,017	-	-	-	0.00
									Gas - S	3,557	1,017	3,618	119,887	-	33.70
									Oil - S	-	137,543	-	-	-	0.00
7	Crist 7		475	192,094	54.4	99.7	54.4	10,568	Coal	89,407	11,353	2,030,083	8,186,066	4.26	91.56
	7			0					Gas - G	-	1,017	-	-	-	0.00
									Gas - S	399	1,017	405	13,430	-	33.66
8									Oil - S	20	137,543	114	2,528	-	126.40
10	Scholz 1		46	(199)	0.0	88.0	0.0	0	Coal	-	-	-	-	-	N/A
									Oil - S	-	-	-	-		N/A
11	Scholz 2		46	(186)	0.0	100.0	0.0	0	Coal	-	-	-	-	-	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	56,314	46.7	100.0	46.7	10,957	Coal	25,975	11,877	617,016	2,330,575	4.14	89.72
									Oil - S	137	137,322	796	17,873		130.46
13	Smith 2		195	15,727	10.8	100.0	41.3	11,600	Coal	7,872	11,588	182,438	706,285	4.49	89.72
									Oil - S	112	137,322	649	14,565		130.04
14	Smith 3		558	281,617	83.9	97.8	80.4	7,212	Gas - G	1,983,380	1,024	2,030,981	11,591,462	4.12	5.84
15	Smith A (CT)	(2)	36	15	0.1	49.1	37.5	128,400	Oil	330	139,203	1,926	38,264	255.09	115.95
16	Other Generation			8,044					Gas				289,281	3.60	N/A
9	Perdido			2,048					Landfill Gas				61,287	2.99	N/A
17	Daniel 1	(1)	255	85,875	45.3	96.1	56.2	10,568	Coal	45,706	9,928	907,493	3,550,046	4.13	77.67
									Oil - S	318	137,639	1,836	40,028		125.87
18	Daniel 2	(1)	255	93,951	49.5	99.5	56.4	10,462	Coal	48,662	10,100	982,949	3,779,643	4.02	77.67
									Oil - S	333	137,639	1,924	41,944		125.96
19	Gas,BL								Gas	-	-	-	-	N/A	N/A
20	Ltr. Oil								Oil					N/A	N/A
21			2,477	880,517	47.8	97.0	54.9	9,584				8,341,798	36,877,590	4.19	

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.	(4,059)	
	Recoverable Fuel	36,873,531	4.19

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2014

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	(551)	0.0	88.0	0.0	0	Coal	0	0	-	0	0.00	0.00
2	4			0					Gas - G	0	1,017	-	0	0.00	0.00
									Gas - S	0	1,017	-	0		0.00
									Oil - S	0	137,660	-	0		0.00
3	Crist 5		75	21,962	40.7	99.6	61.7	11,890	Coal	11,144	11,716	261,126	1,017,640	4.63	91.32
4	5			-					Gas - G	0	1,017	-	0	0.00	0.00
									Gas - S	988	1,017	1,005	27,760		28.10
									Oil - S	93	137,660	540	11,947		128.46
5	Crist 6		299	123,105	57.2	86.1	66.4	10,278	Coal	53,940	11,728	1,265,217	4,925,657	4.00	91.32
6	6			0					Gas - G	0	1,017	-	0	0.00	0.00
									Gas - S	4,037	1,017	4,105	113,389		28.09
									Oil - S	0	137,660	-	0		0.00
7	Crist 7		475	192,335	56.2	100.0	56.2	11,089	Coal	99,430	10,725	2,132,796	9,079,773	4.72	91.32
	7			0					Gas - G	0	1,017	-	0	0.00	0.00
									Gas - S	0	1,017	-	0		0.00
8									Oil - S	14	137,660	81	1,788		127.71
10	Scholz 1		46	(231)	0.0	92.4	0.0	0	Coal	0	0	-	0	0.00	N/A
									Oil - S	0	0	-	0		N/A
11	Scholz 2		46	(205)	0.0	80.0	0.0	0	Coal	0	0	-	0	0.00	N/A
									Oil - S	0	0	-	0		
12	Smith 1		162	57,911	49.6	100.0	49.7	11,046	Coal	26,574	12,036	639,688	2,475,883	4.28	93.17
									Oil - S	153	138,471	892	19,701		128.76
13	Smith 2		195	33,916	24.2	100.0	44.3	11,103	Coal	15,843	11,884	376,559	1,476,094	4.35	93.17
									Oil - S	193	138,471	1,121	24,754		128.26
14	Smith 3		556	299,945	74.9	100.0	87.0	7,299	Gas - G	2,138,018	1,024	2,189,330	12,546,218	4.18	5.87
15	Smith A (CT)	(2)	32	101	0.4	92.0	82.0	23,614	Oil	408	139,203	2,385	47,374	46.90	116.11
16	Other Generation			5,983					Gas				230,995	3.86	N/A
9	Perdido			2,096					Landfill Gas				63,050	3.01	N/A
17	Daniel 1	(1)	255	109,598	59.7	96.0	62.2	10,785	Coal	58,843	10,044	1,181,981	4,481,836	4.09	76.17
									Oil - S	234	137,737	1,354	29,359		125.47
18	Daniel 2	(1)	255	111,975	61.0	98.6	61.4	10,443	Coal	58,167	10,051	1,169,301	4,430,348	3.96	76.17
									Oil - S	114	137,737	660	14,306		125.49
19	Gas,BL								Gas					N/A	N/A
20	Ltr. Oil								Oil					N/A	N/A
21			2,471	957,940	53.8	96.8	60.8	9,715				9,228,141	41,017,872	4.28	

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.	(4,059)	
	Recoverable Fuel	41,013,813.04	4.28

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JULY 2014

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	97.1	0.0	N/A	Coal	-	-	-	-		
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	36,399	65.2	97.2	67.1	11,033	Coal	16,884	11,893	401,605	1,454,547	4.00	86.15
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	118,975	53.5	92.9	57.6	11,299	Coal	56,515	11,893	1,344,264	4,868,701	4.09	86.15
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	245,372	69.4	92.3	75.2	10,752	Coal	110,912	11,893	2,638,150	9,554,944	3.89	86.15
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	13,176	38.5	98.4	39.1	13,017	Coal	7,269	11,798	171,510	631,156	4.79	86.83
									Oil - S	-	-	-	-		
11	Scholz 2		46	13,086	38.2	97.7	39.1	13,515	Coal	7,495	11,798	176,855	650,828	4.97	86.83
									Oil - S	-	-	-	-		
12	Smith 1		162	75,909	63.0	98.3	68.0	10,542	Coal	33,017	12,119	800,270	3,513,321	4.63	106.41
									Oil - S	-	-	-	-		
13	Smith 2		195	13,259	9.1	96.6	47.2	11,022	Coal	6,030	12,119	146,145	641,600	4.84	106.40
									Oil - S	-	-	-	-		
14	Smith 3		556	343,347	83.9	98.1	84.6	7,189	Gas - G	2,396,289	1,030	2,468,177	12,721,126	3.71	5.31
15	Smith A (CT)	(2)	32	0	0.0	99.1	0.0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			8,572					Gas	-	-	-	312,535	3.65	N/A
9	Perdido			2,100					Landfill Gas	-	-	-	63,315	3.02	N/A
17	Daniel 1	(1)	255	97,197	51.2	99.0	35.0	10,208	Coal	49,989	9,925	992,231	3,778,531	3.89	75.59
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	127,502	67.2	98.6	34.8	10,086	Coal	64,785	9,925	1,285,925	4,896,951	3.84	75.59
									Oil - S	-	-	-	-		
19	Gas,BL								Gas	29,126	1,030	30,000	254,334	N/A	8.73
20	Ltr. Oil								Oil	1,165	139,400	6,823	148,846	N/A	127.76
21			2,471	1,094,894	59.6	96.4	59.3	10,577				10,461,955	43,490,735	3.97	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: AUGUST 2014

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	97.1	0.0	N/A	Coal	-	-	-	-	N/A	N/A
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	36,399	65.2	97.2	67.1	11,033	Coal	16,810	11,946	401,605	1,459,574	4.01	86.83
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	119,549	53.7	92.9	57.9	11,292	Coal	56,505	11,946	1,349,986	4,906,324	4.10	86.83
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	245,989	69.6	92.3	75.4	10,750	Coal	110,688	11,946	2,644,491	9,611,009	3.91	86.83
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	10,368	30.3	98.3	39.1	13,017	Coal	5,739	11,757	134,959	478,147	4.61	83.32
									Oil - S	-	-	-	-		
11	Scholz 2		46	10,368	30.3	97.7	39.1	13,515	Coal	5,959	11,757	140,122	496,440	4.79	83.31
									Oil - S	-	-	-	-		
12	Smith 1		162	54,951	45.6	98.3	70.1	10,532	Coal	23,794	12,161	578,720	2,689,144	4.89	113.02
									Oil - S	-	-	-	-		
13	Smith 2		195	39,581	27.3	96.6	47.0	11,022	Coal	17,936	12,161	436,245	2,027,103	5.12	113.02
									Oil - S	-	-	-	-		
14	Smith 3		556	340,778	83.9	98.1	84.5	7,175	Gas - G	2,373,881	1,030	2,445,097	12,420,093	3.64	5.23
15	Smith A (CT)	(2)	32	0	0.0	99.1	0.0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			8,572					Gas	-	-	-	312,535	3.65	N/A
9	Perdido			2,100					Landfill Gas	-	-	-	63,315	3.02	N/A
17	Daniel 1	(1)	255	125,978	66.4	98.7	33.7	10,249	Coal	64,846	9,955	1,291,093	4,672,804	3.71	72.06
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	96,774	51.0	99.0	35.0	10,069	Coal	48,942	9,955	974,447	3,526,779	3.64	72.06
									Oil - S	-	-	-	-		
19	Gas,BL								Gas	29,126	1,030	30,000	254,160	N/A	8.73
20	Ltr. Oil								Oil	1,165	139,400	6,823	148,560	N/A	127.52
21			2,471	1,091,407	59.4	96.3	59.4	10,904				10,433,588	43,065,987	3.95	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2014

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	97.04	0	N/A	Coal	-	-	-	-	N/A	N/A
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	35,213	63.1	97.08	67.17	11,032	Coal	16,229	11,969	388,477	1,403,936	3.99	86.51
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	115,448	51.9	92.78	57.8	11,294	Coal	54,468	11,969	1,303,858	4,712,077	4.08	86.51
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	38,481	10.9	15.42	72.98	10,773	Coal	17,319	11,969	414,573	1,498,244	3.89	86.51
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	0	0.0	98.32	0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
11	Scholz 2		46	0	0.0	97.7	0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	25,813	21.4	98.25	59.23	10,618	Coal	11,238	12,194	274,081	1,330,718	5.16	118.41
									Oil - S	-	-	-	-		
13	Smith 2		195	49,279	34.0	96.59	46.97	11,021	Coal	22,269	12,194	543,119	2,636,953	5.35	118.41
									Oil - S	-	-	-	-		
14	Smith 3		556	325,045	83.9	98.19	82.69	7,171	Gas - G	2,263,023	1,030	2,330,914	11,932,638	3.67	5.27
15	Smith A (CT)	(2)	32	0	0.0	99.03	0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			8,296					Gas	-	-	-	302,472	3.65	N/A
9	Perdido			2,031					Landfill Gas	-	-	-	61,235	3.02	N/A
17	Daniel 1	(1)	255	113,836	60.0	98.73	34.34	10,207	Coal	58,413	9,946	1,161,964	4,062,756	3.57	69.55
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	121,879	64.2	98.63	34.14	10,081	Coal	61,763	9,946	1,228,606	4,295,767	3.52	69.55
									Oil - S	-	-	-	-		
19	Gas,BL								Gas	29,126	1,030	30,000	253,401	N/A	8.70
20	Ltr. Oil								Oil	1,162	139,400	6,801	147,854	N/A	127.24
21			2,471	835,321	45.4	81.5	56.3	10,772				7,682,393	32,638,051	3.91	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: OCTOBER 2014

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	7,590	13.6	97.1	55.3	11,503	Coal	3,647	11,968	87,310	325,638	4.29	89.29
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	25,788	46.2	97.1	56.0	11,381	Coal	12,261	11,968	293,492	1,094,638	4.24	89.28
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	86,599	38.9	92.9	41.9	11,798	Coal	42,684	11,968	1,021,728	3,810,740	4.40	89.28
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	0	0.0	0.0	0.0	N/A	Coal	-	-	-	-	N/A	N/A
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	-	0.0	98.3	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
11	Scholz 2		46	-	0.0	97.7	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	48,301	40.1	98.3	70.7	10,493	Coal	20,741	12,219	506,846	2,541,186	5.26	122.52
									Oil - S	-	-	-	-		
13	Smith 2		195	50,327	34.7	96.6	56.2	10,871	Coal	22,389	12,219	547,119	2,743,101	5.45	122.52
									Oil - S	-	-	-	-		
14	Smith 3		556	280,227	83.9	81.6	82.7	7,117	Gas - G	1,936,337	1,030	1,994,427	10,538,162	3.76	5.44
15	Smith A (CT)	(2)	32	0	0.0	99.1	0.0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			5,720					Gas	-	-	-	208,551	3.65	N/A
9	Perdido			2,100					Landfill Gas	-	-	-	63,315	3.02	N/A
17	Daniel 1	(1)	255	51,345	27.1	99.3	28.0	10,449	Coal	26,711	10,043	536,523	1,866,538	3.64	69.88
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	52,646	27.7	99.4	30.6	10,206	Coal	26,749	10,043	537,292	1,869,214	3.55	69.88
									Oil - S	-	-	-			
19	Gas,BL								Gas	29,126	1,030	30,000	253,593	N/A	8.71
20	Ltr. Oil								Oil	1,132	139,400	6,630	143,983	N/A	127.19
21			2,471	610,643	33.2	75.0	42.2	10,046				5,561,367	25,458,659	4.17	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: NOVEMBER 2014

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	9,318	16.7	35.6	55.7	11,480	Coal	4,479	11,942	106,970	401,425	4.31	89.62
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	1,676	3.0	35.6	54.5	11,467	Coal	805	11,942	19,216	72,110	4.30	89.58
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	83,712	37.6	92.8	41.9	11,799	Coal	41,352	11,942	987,683	3,706,459	4.43	89.63
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	106,531	30.1	64.6	53.7	11,206	Coal	49,983	11,942	1,193,818	4,480,017	4.21	89.63
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	-	0.0	98.3	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S						
11	Scholz 2		46	-	0.0	97.7	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S						
12	Smith 1		162	45,080	37.4	98.3	71.0	10,489	Coal	19,321	12,237	472,850	2,438,471	5.41	126.21
									Oil - S	-	-	-	-		
13	Smith 2		195	48,127	33.2	96.6	56.2	10,871	Coal	21,379	12,237	523,210	2,698,173	5.61	126.21
									Oil - S	-	-	-	-		
14	Smith 3		558	247,404	83.9	84.3	73.0	7,100	Gas - G	1,705,490	1,030	1,756,656	8,278,647	3.35	4.85
15	Smith A (CT)	(2)	36	0	0.0	99.0	0.0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			5,536					Gas	-	-	-	201,843	3.65	N/A
9	Perdido			2,031					Landfill Gas	-	-	-	61,235	3.02	N/A
17	Daniel 1	(1)	255	45,047	23.7	99.4	29.8	10,295	Coal	22,744	10,196	463,770	1,628,034	3.61	71.58
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	24,130	12.7	99.7	27.0	10,277	Coal	12,161	10,196	247,988	870,544	3.61	71.58
									Oil - S	-	-	-	-		
19	Gas,BL								Gas	38,835	1,030	40,000	301,747	N/A	7.77
20	Ltr. Oil								Oil	1,189	139,400	6,962	151,117	N/A	127.10
21			2,477	618,593	33.6	84.3	50.1	10,245				5,819,123	25,289,822	4.09	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: DECEMBER

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	62.6	0.0	N/A	Coal	-	-	-	-	N/A	N/A
2	4								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
3	Crist 5		75	-	0.0	62.6	0.0	N/A	Coal	-	-	-	-	N/A	N/A
4	5								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
5	Crist 6		299	86,599	38.9	92.9	41.9	11,798	Coal	42,780	11,942	1,021,728	3,884,444	4.49	90.80
6	6								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
									Oil - S	-	-	-	-		
7	Crist 7		475	175,671	49.7	92.3	53.8	11,199	Coal	82,371	11,942	1,967,278	7,479,270	4.26	90.80
	7								Gas - G	-	-	-	-		
									Gas - S	-	-	-	-		
8									Oil - S	-	-	-	-		
10	Scholz 1		46	-	0.0	25.4	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
11	Scholz 2		46	-	0.0	97.7	0.0	N/A	Coal	-	-	-	-	N/A	N/A
									Oil - S	-	-	-	-		
12	Smith 1		162	13,571	11.3	98.3	69.8	10,505	Coal	5,825	12,237	142,559	784,896	5.78	134.75
									Oil - S	-	-	-	-		
13	Smith 2		195	75,737	52.2	96.6	56.3	10,870	Coal	33,640	12,237	823,275	4,532,764	5.98	134.74
									Oil - S	-	-	-	-		
14	Smith 3		584	334,803	83.9	97.2	84.6	7,006	Gas - G	2,277,365	1,030	2,345,686	10,912,084	3.26	4.79
15	Smith A (CT)	(2)	40	0	0.0	99.1	0.0	N/A	Oil	-	-	-	-	N/A	N/A
16	Other Generation			5,720					Gas	-	-	-	208,551	3.65	N/A
9	Perdido			2,100					Landfill Gas	-	-	-	63,315	3.02	N/A
17	Daniel 1	(1)	255	38,826	20.5	99.6	35.7	10,008	Coal	18,973	10,240	388,552	1,370,745	3.53	72.25
									Oil - S	-	-	-	-		
18	Daniel 2	(1)	255	24,624	13.0	99.8	38.0	9,850	Coal	11,843	10,240	242,538	855,631	3.47	72.25
									Oil - S	-	-	-	-		
19	Gas,BL								Gas	19,417	1,030	20,000	209,923	N/A	10.81
20	Ltr. Oil								Oil	1,065	139,400	6,235	135,199	N/A	126.95
21			2,507	757,651	40.6	92.9	51.3	9,757				6,957,851	30,436,822	4.02	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

Line	(a) Plant/Unit	(b)	(c) Net Cap. (MW)	(d) Net Gen. (MWh)	(e) Cap. Factor (%)	(f) Equiv. Avail. Factor (%)	(g) Net Output Factor (%)	(h) Avg. Net Heat Rate (Btu/kWh)	(i) Fuel Type	(j) Fuel Burned (Units) (Tons/MCF/Bbl)	(k) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(l) Fuel Burned (MMBtu)	(m) Fuel Burned Cost ($)	(n) Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	49,778	3.7	85.1	20.8	11,519	Coal	24,140	11,876	573,385	2,325,836	4.67	96.35
2	4								Gas - G	-	-	-	-		
									Gas - S	12,251	1,014	12,423	98,437		
									Oil - S	260	137,912	1,506	33,196		
3	Crist 5		75	282,191	21.1	86.7	54.8	11,041	Coal	131,561	11,842	3,115,762	12,072,473	4.28	91.76
4	5								Gas - G	-	-	-	-		
									Gas - S	17,695	1,015	17,968	190,053		
									Oil - S	435	137,657	2,515	55,535		
5	Crist 6		299	1,181,074	22.1	87.9	56.3	11,240	Coal	558,522	11,884	13,275,056	50,933,885	4.31	91.19
6	6								Gas - G	-	-	-	-		
									Gas - S	26,459	1,017	26,913	593,658		
									Oil - S	-	-	3	50		
7	Crist 7		475	1,936,245	22.8	78.5	55.5	10,665	Coal	886,343	11,649	20,649,354	81,505,185	4.21	91.96
	7								Gas - G	-	-	-	-		
									Gas - S	10,173	1,015	10,321	123,881		
8									Oil - S	245	137,512	1,415	31,248		
10	Scholz 1		46	28,449	3.5	91.5	10.5	13,521	Coal	16,419	11,714	384,663	1,405,904	4.94	85.63
									Oil - S	47	138,804	274	6,084		
11	Scholz 2		46	29,177	3.6	97.1	10.8	13,767	Coal	17,132	11,723	401,690	1,467,087	5.03	85.63
									Oil - S	60	138,492	349	7,745		
12	Smith 1		162	564,755	19.5	96.2	59.6	10,719	Coal	268,039	11,292	6,053,608	26,538,735	4.70	99.01
									Oil - S	2,731	139,169	15,963	352,425		
13	Smith 2		195	496,221	14.3	95.4	47.9	10,992	Coal	240,894	11,322	5,454,664	25,254,616	5.09	104.84
									Oil - S	2,111	139,090	12,332	272,703		
14	Smith 3		564	3,521,038	35.0	93.9	80.0	7,169	Gas - G	24,624,966	513	25,243,160	134,228,372	3.81	5.45
15	Smith A (CT)	(2)	36	456	0.1	93.6	15.8	22,353	Oil - G	1,741	139,397	10,193	199,652	43.78	114.66
16	Other Generation			80,561					Gas	-		-	2,937,241	3.65	N/A
9	Perdido			25,026					Landfill Gas	-		-	754,037	3.01	N/A
17	Daniel 1	(1)	255	1,002,464	22.0	92.8	47.5	10,320	Coal	507,730	10,188	10,345,120	42,148,053	4.20	83.01
									Oil - S	1,494	138,459	8,688	188,132		
18	Daniel 2	(1)	255	809,574	17.8	77.2	41.9	10,154	Coal	403,218	10,194	8,220,454	32,078,657	3.96	79.56
									Oil - S	1,847	138,668	10,757	233,722		
19	Gas,BL								Gas	174,756	1,030	180,000	1,527,158	N/A	8.74
20	Ltr. Oil								Oil	6,878	139,416	40,274	875,559	N/A	127.30
21			2,483	10,007,009	22.6	88.2	55.3	10,541				94,088,810	418,439,318	4.18	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Inventory Adjustments	$	units
COAL Crist	(776,513)	(7,619)
Scholz	0	0
Smith	(725,491)	(9,069)
Daniel	(314,366)	(2,672)
Crist Coal Additive	0	0
Daniel Railcar Track Deprec.	(24,354)	
Total Adjustments	$ (1,840,723)	$ (19,360)
Total Fuel Burned Cost	**$ 416,598,594**	

Docket No. 140001-EI
2014 Estimated/Actual True-Up Filing
Exhibit CSB-1, Page 20 of 32

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	2,601	2,410	904	2,238	2,998	982	1,063	1,063	1,063	1,034	1,091	966	18,413
3	UNIT COST ($/BBL)	127.87	130.14	129.90	128.35	126.57	126.31	125.78	125.78	125.78	125.75	125.76	125.79	127.31
4	AMOUNT ($)	332,577	313,640	117,433	287,246	379,448	124,036	133,709	133,709	133,709	130,022	137,199	121,514	2,344,242
5	*BURNED :*													
6	UNITS (BBL)	2,417	2,363	927	2,016	972	835	1,165	1,165	1,162	1,132	1,189	1,065	16,408
7	UNIT COST ($/BBL)	127.22	128.66	129.49	128.00	127.18	127.16	127.76	127.52	127.24	127.19	127.10	126.95	127.68
8	AMOUNT ($)	307,481	304,021	120,040	258,045	123,618	106,180	148,846	148,560	147,854	143,983	151,117	135,199	2,094,944
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	5,236	5,283	5,260	5,482	7,507	7,654	8,663	8,561	8,462	8,364	8,266	8,167	
11	UNIT COST ($/BBL)	126.68	127.37	127.43	127.60	127.26	127.15	128.60	128.39	128.23	128.06	127.89	127.77	
12	AMOUNT ($)	663,283	672,901	670,294	699,495	955,325	973,181	1,114,036	1,099,185	1,085,040	1,071,079	1,057,161	1,043,476	
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													
14	*PURCHASES :*													
15	UNITS (TONS)	218,025	159,815	202,808	214,967	281,057	282,420	345,750	345,052	252,100	170,820	154,536	153,900	2,781,250
16	UNIT COST ($/TON)	84.65	99.14	83.70	82.31	81.00	87.16	84.28	85.43	83.23	93.72	95.59	93.53	86.70
17	AMOUNT ($)	18,455,399	15,844,053	16,975,981	17,693,969	22,766,607	24,615,377	29,141,535	29,476,122	20,983,477	16,008,627	14,771,615	14,394,057	241,126,819
18	*BURNED :*													
19	UNITS (TONS)	352,255	238,094	219,492	148,025	284,180	323,941	352,896	351,219	241,699	155,182	172,224	195,432	3,034,639
20	UNIT COST ($/TON)	97.97	98.13	94.17	91.76	86.73	86.09	84.98	85.04	82.50	91.83	94.62	96.75	90.26
21	AMOUNT ($)	34,510,423	23,365,136	20,669,951	13,582,340	24,646,587	27,887,231	29,990,579	29,867,324	19,940,451	14,251,055	16,295,233	18,907,750	273,914,060
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	575,700	497,421	480,737	547,678	544,515	502,993	510,450	504,283	514,684	530,322	512,634	471,102	
24	UNIT COST ($/TON)	96.57	96.65	92.32	88.54	85.61	86.17	87.29	87.58	87.84	88.56	88.65	86.88	
25	AMOUNT ($)	55,597,149	48,076,066	44,382,096	48,493,725	46,613,745	43,341,892	44,558,223	44,167,021	45,210,047	46,967,619	45,444,001	40,930,308	
26	DAYS SUPPLY:	28	24	23	43	26	24	25	24	25	26	25	23	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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
	GAS (Reported on a MMBTU and $ basis)													
31	*BURNED :*													
32	UNITS (MMBTU)	2,234,998	1,797,309	2,171,023	1,537,057	2,035,031	2,194,440	2,425,415	2,403,007	2,292,149	1,965,463	1,744,325	2,296,782	25,096,999
33	UNIT COST ($/MMBTU)	5.12	6.20	5.65	5.95	5.76	5.78	5.35	5.27	5.32	5.49	4.92	4.84	5.45
34	AMOUNT ($)	11,452,634	11,143,030	12,270,993	9,150,903	11,724,294	12,686,881	$ 12,975,460	$ 12,674,253	$ 12,186,039	$ 10,791,755	$ 8,580,394	$ 11,122,007	136,758,643
	OTHER - C.T. OIL													
39	*PURCHASES :*													
40	UNITS (BBL)	296	895	0	0	0	0	0	0	0	0	0	0	1,191
41	UNIT COST ($/BBL)	130.91	130.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.94
42	AMOUNT ($)	38,748	117,199	0	0	0	0	0	0	0	0	0	0	155,947
43	*BURNED :*													
44	UNITS (BBL)	1,003	0	0	0	330	408	0	0	0	0	0	0	1,741
45	UNIT COST ($/BBL)	113.67	0.00	0.00	0.00	115.95	116.11	0.00	0.00	0.00	0.00	0.00	0.00	114.68
46	AMOUNT ($)	114,014	0	0	0	38,264	47,374	0	0	0	0	0	0	199,652
47	*ENDING INVENTORY :*													
48	UNITS (BBL)	5,515	6,410	6,410	6,410	6,081	5,673	5,673	5,673	5,673	5,673	5,673	5,673	
49	UNIT COST ($/BBL)	113.73	116.13	116.13	116.13	116.12	116.13	116.13	116.13	116.13	116.13	116.13	116.13	
50	AMOUNT ($)	627,217	744,416	744,416	744,416	706,152	658,779	658,779	658,779	658,779	658,779	658,779	658,779	
51	DAYS SUPPLY:	3	3	3	3	3	3	3	3	3	3	3	3	

(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
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)		
		TOTAL	KWH WHEELED	KWH	¢ / KWH		TOTAL $	
LINE	MONTH TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JANUARY							
1	Other Power Sales	657,486,944	147,923,422	509,563,522	3.77	4.11	24,770,319	27,008,449
2	Economy Sales	20,418,949	0	20,418,949	5.59	6.32	1,141,471	1,291,093
3	Gain on Economy Sales	0	0	0	0.00	0.00	254,005	254,005
4	TOTAL ACTUAL SALES	677,905,893	147,923,422	529,982,471	3.86	4.21	26,165,795	28,553,547
	FEBRUARY							
5	Other Power Sales	348,763,887	98,174,451	250,589,436	2.31	2.39	8,069,410	8,341,473
6	Economy Sales	34,803,334	0	34,803,334	3.18	3.86	1,108,056	1,343,683
7	Gain on Economy Sales	0	0	0	0.00	0.00	324,347	370,782
8	TOTAL ACTUAL SALES	383,567,221	98,174,451	285,392,770	2.48	2.62	9,501,813	10,055,938
	MARCH							
9	Other Power Sales	602,021,231	132,205,382	469,815,849	2.34	2.39	14,070,991	14,414,818
10	Economy Sales	36,409,675	0	36,409,675	3.11	3.69	1,132,135	1,345,077
11	Gain on Economy Sales	0	0	0	0.00	0.00	252,826	316,033
12	TOTAL ACTUAL SALES	638,430,906	132,205,382	506,225,524	2.42	2.52	15,455,952	16,075,928
	APRIL							
13	Other Power Sales	184,828,825	103,154,103	81,674,722	1.45	1.46	2,677,091	2,700,507
14	Economy Sales	23,459,546	0	23,459,546	3.30	3.56	774,447	834,332
15	Gain on Economy Sales	0	0	0	0.00	0.00	63,609	79,512
16	TOTAL ACTUAL SALES	208,288,371	103,154,103	105,134,268	1.69	1.74	3,515,147	3,614,351
	MAY							
17	Other Power Sales	475,285,281	139,379,762	335,905,519	2.32	2.40	11,031,848	11,386,995
18	Economy Sales	20,157,708	0	20,157,708	3.25	3.81	655,674	767,773
19	Gain on Economy Sales	0	0	0	0.00	0.00	63,649	79,551
20	TOTAL ACTUAL SALES	495,442,989	139,379,762	356,063,227	2.37	2.47	11,751,171	12,234,319
	JUNE							
21	Other Power Sales	357,540,811	172,104,971	185,435,840	2.04	2.21	7,275,976	7,887,224
22	Economy Sales	10,571,720	0	10,571,720	3.77	4.40	398,616	465,006
23	Gain on Economy Sales	0	0	0	0.00	0.00	18,778	23,472
24	TOTAL ACTUAL SALES	368,112,531	172,104,971	196,007,560	2.09	2.28	7,693,370	8,375,702

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

(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	298,665,000	0	298,665,000	3.99	4.28	11,914,000	12,778,000
2	Economy Sales	6,511,000	0	6,511,000	3.76	4.12	245,000	268,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	40,000	50,000
4	TOTAL ESTIMATED SALES	305,176,000	0	305,176,000	4.00	4.29	12,199,000	13,096,000
AUGUST								
5	Other Power Sales	324,665,000	0	324,665,000	3.74	4.05	12,131,000	13,146,000
6	Economy Sales	8,637,000	0	8,637,000	3.50	3.87	302,000	334,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	39,200	49,000
8	TOTAL ESTIMATED SALES	333,302,000	0	333,302,000	3.74	4.06	12,472,200	13,529,000
SEPTEMBER								
9	Other Power Sales	210,024,000	0	210,024,000	3.47	3.87	7,296,000	8,126,000
10	Economy Sales	6,412,000	0	6,412,000	3.54	3.85	227,000	247,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	26,400	33,000
12	TOTAL ESTIMATED SALES	216,436,000	0	216,436,000	3.49	3.88	7,549,400	8,406,000
OCTOBER								
13	Other Power Sales	47,284,000	0	47,284,000	2.85	3.34	1,349,000	1,580,000
14	Economy Sales	10,126,000	0	10,126,000	2.97	3.32	301,000	336,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	21,600	27,000
16	TOTAL ESTIMATED SALES	57,410,000	0	57,410,000	2.91	3.38	1,671,600	1,943,000
NOVEMBER								
17	Other Power Sales	289,123,000	0	289,123,000	2.84	3.25	8,208,000	9,393,000
18	Economy Sales	11,901,000	0	11,901,000	2.88	3.31	343,000	394,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	19,200	24,000
20	TOTAL ESTIMATED SALES	301,024,000	0	301,024,000	2.85	3.26	8,570,200	9,811,000
DECEMBER								
21	Other Power Sales	255,807,000	0	255,807,000	2.96	3.33	7,566,000	8,526,000
22	Economy Sales	12,956,000	0	12,956,000	3.03	3.37	393,000	437,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	28,000	35,000
24	TOTAL ESTIMATED SALES	268,763,000	0	268,763,000	2.97	3.35	7,987,000	8,998,000
TOTAL								
25	Other Power Sales	4,051,494,979	792,942,091	3,258,552,888	2.87	3.09	116,359,635	125,288,466
26	Economy Sales	202,363,932	0	202,363,932	3.47	3.98	7,021,399	8,062,964
27	Gain on Economy Sales	0	0	0	0.00	0.00	1,151,614	1,341,355
28	TOTAL ESTIMATED SALES	4,253,858,911	792,942,091	3,460,916,820	2.93	3.17	124,532,648	134,692,785

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

(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 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

(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		28,003,000	0	0	0	6.37	6.37	1,784,533
FEBRUARY	Total		16,951,000	0	0	0	4.16	4.16	704,345
MARCH	Total		18,444,000	0	0	0	4.48	4.48	825,611
APRIL	Total		15,048,000	0	0	0	4.56	4.56	685,679
MAY	Total		11,664,000	0	0	0	4.98	4.98	580,937
JUNE	Total		11,805,000	0	0	0	5.09	5.09	601,379
JULY	Total		-	0	0	0	0.00	0.00	0
AUGUST	Total		-	0	0	0	0.00	0.00	0
SEPTEMBEF	Total		-	0	0	0	0.00	0.00	0
OCTOBER	Total		-	0	0	0	0.00	0.00	0
NOVEMBER	Total		-	0	0	0	0.00	0.00	0
DECEMBER	Total		-	0	0	0	0.00	0.00	0
TOTAL			101,915,000	0	0	0	5.09	5.09	5,182,485

SCHEDULE E-9
Page 1 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
LINE	MONTH / TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	94,183,865	3.63	3,421,002
2	Other Purchases	654,569,898	3.43	22,469,321
3	ACTUAL TOTAL PURCHASES	748,753,763	3.46	25,890,323
	FEBRUARY			
4	Southern Co. Interchange	86,041,180	3.35	2,879,773
5	Other Purchases	341,986,349	3.67	12,563,807
6	ACTUAL TOTAL PURCHASES	428,027,529	3.61	15,443,580
	MARCH			
7	Southern Co. Interchange	40,793,891	3.34	1,361,111
8	Other Purchases	588,853,539	3.24	19,061,632
9	ACTUAL TOTAL PURCHASES	629,647,430	3.24	20,422,743
	APRIL			
10	Southern Co. Interchange	155,822,035	3.42	5,326,243
11	Other Purchases	310,764,670	2.77	8,594,042
12	ACTUAL TOTAL PURCHASES	466,586,705	2.98	13,920,285
	MAY			
13	Southern Co. Interchange	34,606,984	3.43	1,186,066
14	Other Purchases	567,572,283	2.91	16,494,160
15	ACTUAL TOTAL PURCHASES	602,179,267	2.94	17,680,226
	JUNE			
16	Southern Co. Interchange	57,691,049	3.35	1,934,843
17	Other Purchases	508,420,320	2.75	13,957,089
18	ACTUAL TOTAL PURCHASES	566,111,369	2.81	15,891,932

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY				
1		Southern Co. Interchange	18,504,100	3.66	677,000
2		Other Purchases	519,874,000	3.67	19,091,000
3		TOTAL ESTIMATED PURCHASES	538,378,100	3.67	19,768,000
	AUGUST				
4		Southern Co. Interchange	19,008,900	4.32	821,000
5		Other Purchases	528,642,000	3.59	18,995,000
6		TOTAL ESTIMATED PURCHASES	547,650,900	3.62	19,816,000
	SEPTEMBER				
7		Southern Co. Interchange	20,253,400	4.02	815,000
8		Other Purchases	503,397,000	3.58	18,042,000
9		TOTAL ESTIMATED PURCHASES	523,650,400	3.60	18,857,000
	OCTOBER				
10		Southern Co. Interchange	243,461,900	3.41	8,302,000
11		Other Purchases	147,603,000	4.10	6,058,000
12		TOTAL ESTIMATED PURCHASES	391,064,900	3.67	14,360,000
	NOVEMBER				
13		Southern Co. Interchange	88,703,000	3.25	2,884,000
14		Other Purchases	405,097,000	3.59	14,537,000
15		TOTAL ESTIMATED PURCHASES	493,800,000	3.53	17,421,000
	DECEMBER				
16		Southern Co. Interchange	108,430,300	3.39	3,674,000
17		Other Purchases	314,898,000	3.70	11,645,000
18		TOTAL ESTIMATED PURCHASES	423,328,300	3.62	15,319,000
	TOTAL FOR PERIOD				
19		Southern Co. Interchange	967,500,604	3.44	33,282,038
20		Other Purchases	5,391,678,059	3.37	181,508,051
21		TOTAL ACT/EST PURCHASES	6,359,178,663	3.38	214,790,089

Schedule CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2015 - DECEMBER 2015

1.	Estimated over/(under)-recovery, January 2014 - December 2014 (Schedule CCE-1b, line 15 + 18)	$ 1,263,407
2.	Final over/(under)-recovery, January 2013 - December 2013 (Exhibit RWD-1, Schedule CCA-1, filed March 3, 2014)	(662,017)
3.	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2015 - December 2015)	$ 601,390
4.	Jurisdictional kWh sales, January 2015 - December 2015	11,062,622,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	(0.0054)

SCHEDULE CCE-1B

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2014 - December 2014

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projection July	Projection August	Projection September	Projection October	Projection November	Projection December	Total
1	IIC Payments/(Receipts) ($)	(33,722)	(32,988)	(39,220)	(45,333)	(37,166)	(37,845)	0	0	0	0	0	0	(226,274)
2	Other Capacity Payments / (Receipts)	2,296,591	2,346,149	2,253,681	2,203,248	2,818,646	7,426,005	7,250,781	7,250,781	7,250,781	7,250,781	7,243,781	7,249,781	62,841,005
3	Transmission Revenue	(28,042)	(25,831)	(25,328)	(5,964)	(7,298)	(3,735)	(5,000)	(6,000)	(5,000)	(7,000)	(8,000)	(9,000)	(136,198)
4	Total Capacity Payments/(Receipts)	2,234,827	2,287,330	2,189,133	2,151,950	2,774,182	7,384,425	7,245,781	7,244,781	7,245,781	7,243,781	7,235,781	7,240,781	62,478,533
5	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	2,169,379	2,220,345	2,125,023	2,088,930	2,692,939	7,168,169	7,033,585	7,032,615	7,033,585	7,031,644	7,023,878	7,028,732	60,648,824
7	Retail KWH Sales							1,198,218,000	1,178,147,000	1,039,787,000	867,231,000	748,462,000	835,508,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.574	0.574	0.574	0.574	0.574	0.574	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	5,940,341	4,436,418	4,461,136	4,222,622	5,189,606	6,186,944	6,877,771	6,762,564	5,968,377	4,977,906	4,296,172	4,795,816	64,115,673
10	Revenue Taxes (Line 9 x .00072) ($)	4,277	3,194	3,212	3,040	3,737	4,455	4,952	4,869	4,297	3,584	3,093	3,453	46,163
11	True-Up Provision ($)	(180,083)	(180,083)	(180,083)	(180,083)	(180,083)	(180,083)	(180,085)	(180,085)	(180,085)	(180,085)	(180,085)	(180,087)	(2,161,010)
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	5,755,981	4,253,141	4,277,841	4,039,499	5,005,786	6,002,406	6,692,734	6,577,610	5,783,995	4,794,237	4,112,994	4,612,276	61,908,500
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	3,586,602	2,032,796	2,152,818	1,950,569	2,312,847	(1,165,763)	(340,851)	(455,005)	(1,249,590)	(2,237,407)	(2,910,884)	(2,416,456)	1,259,676
14	Interest Provision ($)	(59)	119	251	413	559	520	452	442	408	330	210	86	3,731
15	Total Estimated True-Up for the Period January 2014 - December 2014 (Line 13 + Line 14) ($)													1,263,407
16	Beginning Balance True-Up & Interest Provision ($)	(2,823,027)	943,599	3,158,597	5,469,749	7,620,814	10,114,303	9,129,143	8,968,829	8,694,351	7,625,254	5,568,262	2,837,673	(2,823,027)
17	True-Up Collected/(Refunded) ($)	180,083	180,083	180,083	180,083	180,083	180,083	180,085	180,085	180,085	180,085	180,085	180,087	2,161,010
18	Adjustment	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 +	943,599	3,156,597	5,489,749	7,620,814	10,114,303	9,129,143	8,968,829	8,694,351	7,625,254	5,568,262	2,837,873	601,390	

Gulf Power Company
2014 Capacity Contracts

Schedule CCE-4
Page 1 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Firm
Other			
Alabama Electric Cooperative	1/4/2014	6/30/2014	Other
Cargill Power, LLC	1/1/2014	1/23/2014	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2014	6/30/2014	Other
The Energy Authority	4/17/2014	4/17/2014	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts became firm on June 1, 2014.

Capacity Costs

2014	January		February [1]		March		April		May [1]		June	
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$
Southern Intercompany Interchange	(82.5)	(2,318)	(193.7)	3,659	(34.9)	(1,453)	(217.5)	(7,492)	(119.2)	549	0.0	0
PPAs												
Coral Power,LLC												
Southern Power Company												
Shell Energy N.A. (U.S.), LP												
Other												
Alabama Electric Cooperative												
Cargill Power, LLC			0.0	0	0.0	0	0.0	0	0.0	0	0.0	0
South Carolina PSA												
South Carolina Electric & Gas												
The Energy Authority	0.0	0	0.0	0	0.0	0			0.0	0	0.0	0
Total		2,262,869		2,313,161		2,214,461		2,157,914		2,781,480		7,388,160

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true up only

Docket No. 140001-EI
2014 Estimated/Actual True-Up Filing
Exhibit CSB-1, Page 31 of 32

Gulf Power Company
2014 Capacity Contracts

Schedule CCE-4
Page 2 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Firm
Other			
Alabama Electric Cooperative	1/4/2014	6/30/2014	Other
Cargill Power, LLC	1/1/2014	1/23/2014	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2014	6/30/2014	Other
The Energy Authority	4/17/2014	4/17/2014	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts became firm on June 1, 2014.

Capacity Costs

2014	July		August		September		October		November		December		
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	0.0	0	0.0	0	(203.0)	(7,000)	(29.0)	(1,000)	(15,055)
PPAs													
Coral Power,LLC	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]
Southern Power Company	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]
Shell Energy N.A. (U.S.), LP	[redacted]												
Total PPAs													63,062,282
Other													
Alabama Electric Cooperative	[redacted]												(114,813)
Cargill Power, LLC	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]
South Carolina PSA	[redacted]												(39,108)
South Carolina Electric & Gas													(279,715)
The Energy Authority	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]
Total		7,250,781		7,250,781		7,250,781		7,250,781		7,243,781		7,249,781	62,614,731

Docket No. 140001-EI
2014 Estimated/Actual True-Up Filing
Exhibit CSB-1, Page 32 of 32

SCHEDULE E-1
Revised August 29, 2014

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

Line				(a) $	(b) kWh	(c) ¢ / kWh
1	Fuel Cost of System Net Generation		E-3	277,100,854	7,445,892,000	3.7215
2	Coal Car Investment					
3	Other Generation		E-3	2,968,865	81,428,000	3.6460
4	Hedging Settlement		E-2			
5	**Total Cost of Generated Power**	(Line 1 - 4)		280,069,719	7,527,320,000	3.7207
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	209,724,000	6,100,957,000	3.4376
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			
12	**Total Cost of Purchased Power**	(Line 6 - 11)		209,724,000	6,100,957,000	3.4376
13	**Total Available kWh**	(Line 5 + 12)			13,628,277,000	
14	Fuel Cost of Economy Sales		E-6	(3,596,000)	(112,658,000)	3.1920
15	Gain on Economy Sales		E-6	(394,000)	0	N/A
16	Fuel Cost of Other Power Sales		E-6	(43,976,000)	(1,391,053,000)	3.1613
17	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -16)		(47,966,000)	(1,503,711,000)	3.1898
18	Net Inadvertant Interchange					
19	**Total Fuel & Net Power Trans.**	(Line 5+12+17+18)		441,827,719	12,124,566,000	3.6441
20	Net Unbilled Sales *					
21	Company Use *			767,411	21,059,000	3.6441
22	T & D Losses *			25,025,930	686,752,000	3.6441
23	**System kWh Sales**			441,827,719	11,416,755,000	3.8700
24	Wholesale kWh Sales			13,704,947	354,133,000	3.8700
25	Jurisdictional kWh Sales			428,122,772	11,062,622,000	3.8700
25a	Jurisdictional Line Loss Multiplier			1.0015		1.0015
26	Jurisdictional kWh Sales Adjusted for Line Losses			428,764,957	11,062,622,000	3.8758
27	**True-Up ****			47,956,495	11,062,622,000	0.4335
28	**Total Jurisdictional Fuel Cost**			476,721,452	11,062,622,000	4.3093
29	Revenue Tax Factor					1.00072
30	Fuel Factor Adjusted For Revenue Taxes			477,064,691	11,062,622,000	4.3124
31	GPIF Reward/(Penalty) **			2,523,938	11,062,622,000	0.0228
32	Fuel Factor Adjusted for GPIF			479,588,629	11,062,622,000	4.3352
33	**Fuel Factor Rounded to Nearest .001(¢ / kWh)**					**4.335**

*For informational purposes only
** Calculation Based on Jurisdictional kWh Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 40
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: C. S. Boyett CSB-2

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

1.	Estimated over/(under)-recovery, January 2014 - December 2014 (Sch. E-1B, page 2, line C9)	($43,001,980)
2.	Final over/(under)-recovery, January 2013 - December 2013 (Exhibit RWD-1, Schedule 1, Line 3)	($4,954,515)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2015 - December 2015 (Schedule E1, Line 27)	(47,956,495)
4.	Jurisdictional kWh sales For the period: January 2015 - December 2015	11,062,622,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / kWh)	0.4335

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

			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	46,431,505.07	34,868,117.94	33,117,976.77	23,043,097.57	36,584,250.04	40,782,817.28	$214,827,764.67
	1a	Fuel Cost of Hedging Settlement	(1,412,120.00)	(3,266,585.00)	(1,182,675.00)	(715,550.00)	(1,105,865.00)	(776,560.00)	($8,459,355.00)
	2	Fuel Cost of Power Sold	(26,165,795.00)	(9,501,812.57)	(15,455,952.11)	(3,515,147.88)	(11,751,171.10)	(7,693,369.65)	($74,083,248.31)
	3	Fuel Cost of Purchased Power	25,890,323.05	15,443,580.25	20,422,742.75	13,920,285.28	17,680,225.99	15,891,931.43	$109,249,088.75
	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	1,784,533.44	704,344.70	825,610.72	685,679.02	580,937.44	601,379.33	$5,182,484.65
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	217,392.62	200,672.39	222,732.26	229,680.50	289,280.59	230,995.41	$1,390,753.77
	6	Adjustments to Fuel Cost *	266.30	(17,224.74)	2,300.00	5,150.00	940.53	0.00	($8,567.91)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	46,746,105.48	38,431,092.97	37,952,735.39	33,653,194.49	$42,278,598.49	$49,037,193.80	$248,098,920.62
B	1	Jurisdictional KWH Sales	1,041,533,597	740,745,396	768,919,985	752,971,848	924,994,128	1,078,240,405	5,307,405,359
	2	Non-Jurisdictional KWH Sales	32,651,753	22,559,528	23,396,311	18,952,601	25,562,899	29,040,143	152,163,235
	3	TOTAL SALES (Lines B1 + B2)	1,074,185,350	763,304,924	792,316,296	771,924,449	950,557,027	1,107,280,548	5,459,568,594
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.9603%	97.0445%	97.0471%	97.5448%	97.3107%	97.3773%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	43,044,663.21	30,638,137.47	31,603,211.42	30,827,485.96	37,999,030.30	45,846,336.24	$219,958,864.60
	2	True-Up Provision	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	(1,333,230.00)	($7,999,380.00)
	2a	Incentive Provision	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	(138,429.00)	($830,574.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$41,573,004.21	$29,166,478.47	$30,131,552.42	$29,355,826.96	$36,527,371.30	$44,374,677.24	$211,128,910.60
	4	Fuel & Net Power Transactions (Line A7)	46,746,105.48	38,431,092.97	37,952,735.39	33,653,194.49	42,278,598.49	49,037,193.80	$248,098,920.62
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	45,393,151.86	37,351,204.91	36,887,277.11	32,876,181.67	41,203,312.54	47,822,721.96	$241,533,850.05
	6	Over/(Under) Recovery (Line C3-C5)	(3,820,147.65)	(8,184,726.44)	(6,755,724.69)	(3,520,354.71)	(4,675,941.24)	(3,448,044.72)	($30,404,939.45)
	7	Interest Provision	(1,398.39)	(1,558.31)	(1,914.34)	(2,319.19)	(2,493.53)	(2,284.80)	($11,968.56)
	8	Adjustments	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2014 - JUNE 2014**							($30,416,908.01)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Projected revenues for based on the current approved 2014 Fuel Factor excluding revenue taxes of: 4.1664 ¢/KWH

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

			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	43,178,200.00	42,753,452.00	32,335,579.00	25,250,108.00	25,087,979.00	30,228,271.00	$413,661,353.67
	1a	Fuel Cost of Hedging Settlement	(592,535.00)	123,525.00	151,320.00	224,812.00	163,905.00	(55,224.00)	($8,443,552.00)
	2	Fuel Cost of Power Sold	(12,199,000.00)	(12,472,200.00)	(7,549,400.00)	(1,671,600.00)	(8,570,200.00)	(7,987,000.00)	($124,532,648.31)
	3	Fuel Cost of Purchased Power	19,768,000.00	19,816,000.00	18,857,000.00	14,360,000.00	17,421,000.00	15,319,000.00	$214,790,088.75
	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	0.00	0.00	0.00	0.00	0.00	0.00	$5,182,484.65
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	312,535.00	312,535.00	302,472.00	208,551.00	201,843.00	208,551.00	$2,937,240.77
	6	Adjustments to Fuel Cost *	0.00	0.00	0.00	0.00	0.00	0.00	($8,567.91)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$50,467,200.00	$50,533,312.00	$44,096,971.00	$38,371,871.00	$34,304,527.00	$37,713,598.00	$503,586,399.62
B	1	Jurisdictional KWH Sales	1,198,218,000	1,178,147,000	1,039,787,000	867,231,000	748,462,000	835,508,000	11,174,758,359
	2	Non-Jurisdictional KWH Sales	34,667,000	35,060,000	30,639,000	26,592,000	24,901,000	29,166,000	333,188,235
	3	TOTAL SALES (Lines B1 + B2)	1,232,885,000	1,213,207,000	1,070,426,000	893,823,000	773,363,000	864,674,000	11,507,946,594
	4	Jurisdictional % Of Total Sales (Line B1/B3)	97.1881%	97.1101%	97.1377%	97.0249%	96.7802%	96.6269%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	49,922,557.05	49,086,318.87	43,321,687.56	36,132,314.05	31,183,922.20	34,810,606.92	$464,416,271.25
	2	True-Up Provision	(1,333,230)	(1,333,230)	(1,333,230)	(1,333,230)	(1,333,230)	(1,333,231)	($15,998,761.00)
	2a	Incentive Provision	(138,429)	(138,429)	(138,429)	(138,429)	(138,429)	(138,427)	($1,661,146.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$48,450,898.05	$47,614,659.87	$41,850,028.56	$34,660,655.05	$29,712,263.20	$33,338,948.92	$446,756,364.25
	4	Fuel & Net Power Transactions (Line A7)	50,467,200.00	50,533,312.00	44,096,971.00	38,371,871.00	34,304,527.00	37,713,598.00	$503,586,399.62
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	49,121,684.97	49,146,559.24	42,899,035.57	37,286,114.87	33,249,789.82	36,496,142.85	$489,733,177.37
	6	Over/(Under) Recovery (Line C3-C5)	(670,786.92)	(1,531,899.37)	(1,049,007.01)	(2,625,459.82)	(3,537,526.62)	(3,157,193.93)	($42,976,813.12)
	7	Interest Provision	(2,151.98)	(2,140.49)	(2,138.46)	(2,163.77)	(2,251.29)	(2,352.11)	($25,166.66)
	8	Adjustments	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2014 - DECEMBER 2014**							($43,001,979.78)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Projected revenues for based on the current approved 2014 Fuel Factor excluding revenue taxes of: 4.1664

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 2014 - JUNE 2014 / ESTIMATED FOR JULY 2014 - DECEMBER 2014

		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	413,661,354	355,672,030	57,989,324	16.30	9,926,448,000	8,851,840,000	1,074,608,000	12.14	4.1673	4.0181	0.1492	3.71
1a	Fuel Cost of Hedging Settlement	(8,443,552)	0	(8,443,552)	(100.00)	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4	Other Generation	2,937,241	3,254,676	(317,435)	(9.75)	80,561,000	81,428,000	(867,000)	(1.06)	3.6460	3.9970	(0.3510)	(8.78)
5	Adjustments to Fuel Cost ***	(8,568)	0	(8,568)	(100.00)	0	0				0.0000		
6	TOTAL COST OF GENERATED POWER	408,146,475	358,926,706	49,219,769	13.71	10,007,009,000	8,933,268,000	1,073,741,000	12.02	4.0786	4.0179	0.0607	1.51
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
9	Energy Cost of Other Economy Purchases (Nonbroker)	214,790,089	173,773,123	41,016,966	23.60	6,359,178,663	5,470,006,000	889,172,663	16.26	3.3776	3.1768	0.2008	6.32
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
12	Energy Payments to Qualifying Facilities	5,182,485	0	5,182,485	100.00	101,915,000	0	101,915,000	100.00	5.0851	0.0000	5.0851	100.00
13	TOTAL COST OF PURCHASED POWER	219,972,573	173,773,123	46,199,450	26.59	6,461,093,663	5,470,006,000	991,087,663	18.12	3.4046	3.1768	0.2278	7.17
14	Total Available kWh (Line 6 + Line 13)	628,119,048	532,699,829	95,419,219	17.91	16,468,102,663	14,403,274,000	2,064,828,663	14.34	3.8142	3.6985	0.1157	3.13
15	Fuel Cost of Economy Sales	(7,021,399)	(2,432,000)	(4,589,399)	188.71	(202,363,932)	(75,070,000)	(127,293,932)	169.57	3.4697	3.2396	0.2301	7.10
16	Gain on Economy Sales	(1,151,614)	(594,995)	(556,619)	93.55	0	0						
17	Fuel Cost of Other Power Sales	(116,359,635)	(69,218,000)	(47,141,635)	68.11	(4,051,494,979)	(2,108,392,000)	(1,943,102,979)	92.16	2.8720	3.2830	(0.4110)	(12.52)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(124,532,648)	(72,244,995)	(52,287,653)	72.38	(4,253,858,911)	(2,183,462,000)	(2,070,396,911)	94.82	2.9275	3.3087	(0.3812)	(11.52)
19	(LINES 15+16+17)												
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
21	**TOTAL FUEL & NET POWER TRANSACTIONS**	503,586,400	460,454,834	43,131,566	9.37	12,214,243,752	12,219,812,000	(5,568,248)	(0.05)	4.1229	3.7681	0.3548	9.42
	(LINES 14+18+20)												
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
23	Company Use *	858,354	808,446	49,908	6.17	20,819,173	21,455,000	(635,827)	(2.96)	4.1229	3.7681	0.3548	9.42
24	T & D Losses *	28,261,465	26,114,139	2,147,326	8.22	685,475,385	693,032,000	(7,556,615)	(1.09)	4.1229	3.7681	0.3548	9.42
25	TERRITORIAL (SYSTEM) SALES	503,586,400	460,454,834	43,131,566	9.37	12,214,243,752	12,219,812,000	(5,568,248)	(0.05)	4.1229	3.7681	0.3548	9.42
26	Wholesale Sales	13,737,164	14,049,252	(312,088)	(2.22)	333,188,235	333,188,235	0	0.00	4.1229	4.2166	(0.0937)	(2.23)
27	Jurisdictional Sales	489,849,236	446,405,582	43,443,654	9.73	11,881,055,517	11,137,571,643	743,483,874	6.68	4.1229	4.0081	0.1148	2.86
28	Jurisdictional Loss Multiplier	1.0015	1.0015										
29	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0015)	489,733,177	447,075,190	42,657,987	9.54	11,174,760,959	11,154,278,000	20,482,959	0.18	4.3825	4.0081	0.3744	9.34
30	TRUE-UP **	15,998,761	15,998,761	0	0.00	11,174,760,959	11,154,278,000	20,482,959	0.18	0.1432	0.1434	(0.0002)	(0.14)
31	TOTAL JURISDICTIONAL FUEL COST	505,731,938	463,073,951	42,657,987	9.21	11,174,760,959	11,154,278,000	20,482,959	0.18	4.5257	4.1515	0.3742	9.01
32	Revenue Tax Factor									1.00072	1.00072		
33	Fuel Factor Adjusted for Revenue Taxes									4.5290	4.1545	0.3745	9.01
34	GPIF Reward / (Penalty) **	1,662,342	1,662,342	0	0.00	11,174,760,959	11,154,278,000	20,482,959	0.18	0.0149	0.0149	0.0000	0.00
35	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5439	4.1694	0.3745	8.98
36	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									4.544	4.169	0.3750	8.99

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

SCHEDULE E-1C
Revised August 29, 2014

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

1.	TOTAL AMOUNT OF ADJUSTMENTS:			
	A.	Generating Performance Incentive Reward/(Penalty)	$	2,523,938
	B.	True-Up (Over)/Under Recovered	$	47,956,495
2.	Jurisdictional kWh sales For the period: January 2015 - December 2015			11,062,622,000
3.	ADJUSTMENT FACTORS:			
	A.	Generating Performance Incentive Factor		0.0228
	B.	True-Up Factor		0.4335

SCHEDULE E-1D
Revised August 29, 2014

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

		NET ENERGY FOR LOAD %
	On-Peak	29.57
	Off-Peak	70.43
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per kWh Sold	3.8700	4.6670	3.5356
Jurisdictional Loss Factor	1.0015	1.0015	1.0015
Jurisdictional Fuel Factor	3.8758	4.6740	3.5409
GPIF	0.0228	0.0228	0.0228
True-Up	0.4335	0.4335	0.4335
TOTAL	4.3321	5.1303	3.9972
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	4.3352	5.1340	4.0001
Recovery Factor Rounded to the Nearest .001 ¢/kWh	4.335	5.134	4.000

HOURS:	ON-PEAK	25.10%
	OFF-PEAK	74.90%
		100.00%

SCHEDULE E-1E
Revised August 29, 2014

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, RSVP, GS, GSD, GSDT, GSTOU, OSIII, SBS (1)	4.335	1.00773	4.369
B	LP, LPT, SBS (2)	4.335	0.98353	4.264
C	PX, PXT, RTP, SBS (3)	4.335	0.96591	4.187
D	OS-I/II	4.335	1.00777	4.318 *

		TOU
A	On-Peak	5.174
	Off-Peak	4.031
B	On-Peak	5.049
	Off-Peak	3.934
C	On-Peak	4.959
	Off-Peak	3.864
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	5.134	¢ / kWh	x	0.2510	=	1.289	¢ / kWh
	Off-Peak	4.000	¢ / kWh	x	0.7490	=	2.996	¢ / kWh
							4.285	¢ / kWh
			Line Loss Multiplier			x	1.00777	
							4.318	¢ / kWh

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

SCHEDULE E-2
Revised August 29, 2014

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	26,324,352	26,549,512	26,062,657	28,060,175	19,535,197	24,157,597	30,392,655	28,842,815	22,086,320	17,532,198	11,811,459	15,745,917	277,100,854
1a	Other Generation	208,551	188,425	208,551	201,843	312,535	302,472	312,535	312,535	302,472	208,551	201,843	208,551	2,968,865
2	Fuel Cost of Power Sold	(6,443,000)	(10,235,000)	(722,000)	(1,223,000)	(2,327,000)	(2,555,000)	(5,267,000)	(4,958,000)	(2,240,000)	(1,191,000)	(5,882,000)	(4,923,000)	(47,966,000)
3	Fuel Cost of Purchased Power	18,968,000	15,687,000	6,622,000	5,796,000	18,720,000	20,368,000	21,232,000	21,390,000	19,708,000	17,357,000	22,398,000	21,478,000	209,724,000
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	39,057,903	32,189,937	32,171,208	32,835,017	36,240,732	42,273,069	46,670,191	45,587,350	39,856,792	33,906,750	28,529,302	32,509,468	441,827,719
7	System kWh Sold	902,308,000	766,957,000	785,829,000	787,285,000	979,704,000	1,128,419,000	1,228,842,000	1,211,999,000	1,071,895,000	898,952,000	780,357,000	874,208,000	11,416,755,000
7a	Jurisdictional % of Total Sales	96.6685	96.7003	96.8253	96.8884	96.9664	97.0871	97.1047	97.0310	97.0560	96.9332	96.6850	96.5485	96.8981
8	Cost per kWh Sold (¢/kWh)	4.3287	4.1971	4.0939	4.1707	3.6992	3.7462	3.7979	3.7613	3.7183	3.7718	3.6559	3.7187	3.8700
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)	4.3352	4.2034	4.1000	4.1770	3.7047	3.7518	3.8036	3.7669	3.7239	3.7775	3.6614	3.7243	3.8758
9	GPIF (¢/kWh) *	0.0241	0.0284	0.0276	0.0276	0.0221	0.0192	0.0176	0.0179	0.0202	0.0241	0.0279	0.0249	0.0228
10	True-Up (¢/kWh) *	0.4582	0.5388	0.5252	0.5239	0.4207	0.3648	0.3349	0.3398	0.3841	0.4586	0.5297	0.4735	0.4335
11	TOTAL	4.8175	4.7706	4.6528	4.7285	4.1475	4.1358	4.1561	4.1246	4.1282	4.2602	4.2190	4.2227	4.3321
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	4.8210	4.7740	4.6562	4.7319	4.1505	4.1388	4.1591	4.1276	4.1312	4.2633	4.2220	4.2257	4.3352
14	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	4.821	4.774	4.656	4.732	4.151	4.139	4.159	4.128	4.131	4.263	4.222	4.226	4.335

* CALCULATIONS BASED ON JURISDICTIONAL kWh SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	136,749	106,902	106,635	105,024	63,271	70,337	85,947	85,824	70,029	62,776	62,722	85,554	1,041,770
2	COAL	14,959,242	14,633,280	13,282,829	17,754,612	8,155,943	12,215,780	17,572,939	16,190,515	10,235,732	5,294,016	3,477,059	3,793,219	137,565,166
3	GAS - Generation	11,146,060.7	11,713,054.9	12,590,893.3	10,133,610.7	11,417,667.3	11,914,609.3	12,723,886.6	12,576,592.9	11,823,658.5	12,141,539.5	8,234,148.0	11,753,276.9	138,168,999
4	GAS (B.L.)	227,536	227,536	227,536	207,536	147,536	167,536	227,536	207,536	167,536	147,536	147,536	227,536	2,330,432
5	LANDFILL GAS	63,315	57,164	63,315	61,235	63,315	91,807	94,882	94,882	91,837	94,882	91,837	94,882	963,353
6	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TOTAL ($)	26,532,903	26,737,937	26,271,208	28,262,017	19,847,732	24,460,069	30,705,191	29,155,350	22,388,792	17,740,750	12,013,302	15,954,468	280,069,719
	SYSTEM NET GEN. (MWh)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	339,668	375,344	335,796	458,004	224,173	328,397	461,756	432,676	278,983	140,797	96,511	86,396	3,558,501
10	GAS	287,013	315,640	346,339	276,369	321,892	338,633	369,125	367,116	340,020	353,032	250,012	371,676	3,936,867
11	LANDFILL GAS	2,100	1,896	2,100	2,031	2,100	3,045	3,147	3,147	3,046	3,147	3,046	3,147	31,952
12	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL (MWH)	628,781	692,880	684,235	736,404	548,165	670,075	834,028	802,939	622,049	496,976	349,569	461,219	7,527,320
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	1,091	856	856	842	511	567	692	692	567	511	511	692	8,388
15	COAL (TON)	159,057	175,374	160,849	226,671	117,150	163,403	225,828	210,291	140,337	78,260	52,637	42,792	1,752,649
16	GAS-all (MCF) (1)	1,936,986	2,132,631	2,341,416	1,857,370	2,150,633	2,270,734	2,465,460	2,452,799	2,279,273	2,358,250	1,671,729	2,498,747	26,416,028
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.	3,770,293	4,002,674	3,689,087	4,971,249	2,340,455	3,420,333	4,890,959	4,526,186	2,892,580	1,540,004	1,021,332	986,803	38,051,955
19	GAS-Generation (1)	1,936,986	2,132,631	2,341,416	1,857,370	2,150,633	2,270,734	2,465,460	2,452,799	2,279,273	2,358,250	1,671,729	2,498,747	26,416,028
20	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL (MMBtu) (1)	5,707,279	6,135,305	6,030,503	6,828,619	4,491,088	5,691,067	7,356,419	6,978,985	5,171,853	3,898,254	2,693,061	3,485,550	64,467,983

(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.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

		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	54.02	54.18	49.07	62.19	40.90	49.01	55.36	53.89	44.85	28.33	27.61	18.73	47.28
24	GAS-Generation	45.65	45.55	50.62	37.53	58.72	50.54	44.26	45.72	54.66	71.04	71.52	80.59	52.30
25	LANDFILL GAS	0.33	0.27	0.31	0.28	0.38	0.45	0.38	0.39	0.49	0.63	0.87	0.68	0.42
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 ($/BBL)	125.34	124.89	124.57	124.73	123.82	124.05	124.20	124.02	123.51	122.85	122.74	123.63	124.20
29	COAL ($/TON)	94.05	83.44	82.58	78.33	69.62	74.76	77.82	76.99	72.94	67.65	66.06	88.64	78.49
30	GAS + B.L. ($/MCF) (1)	5.76	5.51	5.39	5.46	5.23	5.19	5.13	5.08	5.13	5.12	4.89	4.71	5.21
31	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST ($ / MMBtu)													
32	COAL + GAS B.L. + OIL B.L.	4.06	3.74	3.69	3.63	3.57	3.64	3.66	3.64	3.62	3.57	3.61	4.16	3.70
33	GAS-Generation (1)	5.65	5.40	5.29	5.35	5.16	5.11	5.03	5.00	5.05	5.06	4.80	4.62	5.12
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)	4.60	4.32	4.31	4.10	4.34	4.23	4.12	4.12	4.25	4.47	4.35	4.49	4.28
	BTU BURNED (Btu / kWh)													
36	COAL + GAS B.L. + OIL B.L.	11,100	10,664	10,986	10,854	10,440	10,415	10,592	10,461	10,368	10,938	10,583	11,422	10,693
37	GAS-Generation (1)	6,886	6,869	6,874	6,858	6,864	6,874	6,838	6,841	6,871	6,790	6,838	6,828	6,852
38	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
39	TOTAL (Btu/kWh) (1)	9,191	8,946	8,915	9,369	8,356	8,639	8,946	8,821	8,469	7,986	7,898	7,705	8,696
	FUEL COST (CENTS / kWh)													
40	COAL + GAS B.L. + OIL B.L.	4.51	3.99	4.06	3.94	3.73	3.79	3.87	3.81	3.75	3.91	3.82	4.75	3.96
41	GAS-Generation	3.88	3.71	3.64	3.67	3.55	3.52	3.45	3.43	3.48	3.44	3.29	3.16	3.51
42	LANDFILL GAS	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02
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)	4.22	3.86	3.84	3.84	3.62	3.65	3.68	3.63	3.60	3.57	3.44	3.46	3.72

(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
PROJECTED FOR THE MONTH OF: JANUARY 2015

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	8,055	14.4	86.6	55.4	12,091	Coal	4,092	11,901	97,393	362,161	4.50	88.50
2	4							Gas - G						
3	Crist 5	75	23,054	41.3	93.3	55.8	11,576	Coal	11,212	11,901	266,871	992,373	4.30	88.51
4	5							Gas - G						
5	Crist 6	299	22,845	10.3	95.6	41.8	12,828	Coal	12,312	11,901	293,053	1,089,732	4.77	88.51
6	6							Gas - G						
7	Crist 7	475	145,730	41.2	97.8	54.7	10,947	Coal	67,023	11,901	1,595,305	5,932,223	4.07	88.51
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				63,315	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	59,572	49.4	99.5	70.4	10,931	Coal	26,608	12,237	651,182	3,108,266	5.22	116.82
13	Smith 2	195	37,515	25.9	99.8	55.9	10,944	Coal	16,776	12,237	410,562	1,959,722	5.22	116.82
14	Smith 3	584	281,293	64.7	83.1	77.9	6,886	Gas	1,880,569	1,030	1,936,986	10,937,510	3.89	5.82
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				208,551	3.65	N/A
17	Daniel 1 (1)	255	21,171	11.2	51.2	38.1	10,150	Coal	10,523	10,211	214,889	757,798	3.58	72.01
18	Daniel 2 (1)	255	21,726	11.5	70.5	35.0	9,880	Coal	10,511	10,211	214,653	756,967	3.48	72.02
19	Gas,BL							Gas	19,417	1,030	20,000	227,536	N/A	11.72
20	Ltr. Oil							Oil	1,091	139,400	6,385	136,749	N/A	125.34
21		2,507	628,781	33.7	86.5	53.1	9,191				5,707,279	26,532,903	4.22	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: FEBRUARY 2015

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	22,884	45.4	98.6	55.9	12,056	Coal	11,603	11,889	275,890	1,012,742	4.43	87.28
2	4							Gas - G						
3	Crist 5	75	5,284	10.5	99.8	54.3	11,654	Coal	2,590	11,889	61,580	226,049	4.28	87.28
4	5							Gas - G						
5	Crist 6	299	1,510	0.8	92.8	38.8	13,574	Coal	862	11,889	20,496	75,237	4.98	87.28
6	6							Gas - G						
7	Crist 7	475	169,991	53.3	97.2	54.5	10,951	Coal	78,293	11,889	1,861,573	6,833,498	4.02	87.28
8	7							Gas - G						
9	Perdido		1,896					Landfill Gas				57,164	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	59,227	54.4	95.9	70.4	10,931	Coal	27,987	11,566	647,410	2,533,097	4.28	90.51
13	Smith 2	195	11,942	9.1	78.5	54.2	10,748	Coal	5,549	11,566	128,355	502,210	4.21	90.50
14	Smith 3	584	310,472	79.1	98.9	79.9	6,869	Gas	2,070,516	1,030	2,132,631	11,524,630	3.71	5.57
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,168					Gas				188,425	3.65	N/A
17	Daniel 1 (1)	255	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18	Daniel 2 (1)	255	104,506	61.0	97.6	33.0	9,400	Coal	48,490	10,129	982,361	3,450,447	3.30	71.16
19	Gas,BL							Gas	19,417	1,030	20,000	227,536	N/A	11.72
20	Ltr. Oil							Oil	856	139,400	5,009	106,902	N/A	124.89
21		2,507	692,880	41.1	86.0	49.0	8,946				6,135,305	26,737,938	3.86	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: MARCH 2015

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	4,446	8.0	99.7	55.9	12,056	Coal	2,259	11,863	53,601	194,263	4.37	86.00
2	4							Gas - G						
3	Crist 5	75	26,033	46.7	99.3	55.9	11,576	Coal	12,702	11,863	301,366	1,092,221	4.20	85.99
4	5							Gas - G						
5	Crist 6	299	28,245	12.7	85.6	41.8	13,201	Coal	15,715	11,863	372,864	1,351,346	4.78	85.99
6	6							Gas - G						
7	Crist 7	475	127,178	36.0	78.7	53.5	10,680	Coal	57,247	11,863	1,358,259	4,922,648	3.87	85.99
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				63,315	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	17,022	14.1	83.6	69.6	10,831	Coal	8,016	11,500	184,365	687,093	4.04	85.72
13	Smith 2	195	63,695	43.9	99.6	56.2	10,728	Coal	29,709	11,500	683,318	2,546,596	4.00	85.72
14	Smith 3	557	340,619	82.1	99.0	83.1	6,874	Gas	2,273,219	1,030	2,341,416	12,382,342	3.64	5.45
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				208,551	3.65	N/A
17	Daniel 1 (1)	255	0	0.0	6.3	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18	Daniel 2 (1)	255	69,177	36.5	69.5	0.0	10,268	Coal	35,201	10,089	710,305	2,488,662	3.60	70.70
19	Gas,BL							Gas	19,417	1,030	20,000	227,536	N/A	11.72
20	Ltr. Oil							Oil	856	139,400	5,009	106,635	N/A	124.57
21		2,476	684,235	37.1	80.0	46.4	8,915				6,030,503	26,271,208	3.84	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: APRIL 2015

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	26,196	48.5	98.5	55.8	12,065	Coal	13,331	11,854	316,055	1,137,820	4.34	85.35
2	4							Gas - G						
3	Crist 5	75	6,002	11.1	99.9	54.9	11,892	Coal	3,011	11,854	71,373	256,948	4.28	85.34
4	5							Gas - G						
5	Crist 6	299	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	173,361	50.7	94.1	53.7	11,274	Coal	82,440	11,854	1,954,474	7,036,240	4.06	85.35
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				61,235	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	39,327	28.0	49.8	56.3	10,727	Coal	18,342	11,500	421,864	1,718,914	4.37	93.71
14	Smith 3	557	270,833	67.5	79.3	85.1	6,858	Gas	1,803,272	1,030	1,857,370	9,931,768	3.67	5.51
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,536					Gas				201,843	3.65	N/A
17	Daniel 1 (1)	255	96,332	52.5	97.7	32.0	10,316	Coal	49,765	9,984	993,762	3,454,665	3.59	69.42
18	Daniel 2 (1)	255	116,786	63.6	97.3	32.9	10,222	Coal	59,782	9,984	1,193,788	4,150,025	3.55	69.42
19	Gas,BL							Gas	14,563	1,030	15,000	207,536	N/A	14.25
20	Ltr. Oil							Oil	842	139,400	4,933	105,024	N/A	124.73
21		2,476	736,404	41.3	71.1	43.9	9,369				6,828,619	28,262,017	3.84	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: MAY 2015

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	77.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	0	0.0	77.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
4	5							Gas - G						
5	Crist 6	299	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	0	0.0	77.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				63,315	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	581	313,320	72.4	89.5	80.9	6,864	Gas	2,087,993	1,030	2,150,633	11,105,132	3.54	5.32
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,572					Gas				312,535	3.65	N/A
17	Daniel 1 (1)	255	107,255	56.5	97.6	31.1	10,595	Coal	56,953	9,976	1,136,370	3,965,050	3.70	69.62
18	Daniel 2 (1)	255	116,918	61.6	97.4	31.6	10,273	Coal	60,197	9,976	1,201,096	4,190,893	3.58	69.62
19	Gas,BL							Gas	0	0	0	147,536	N/A	N/A
20	Ltr. Oil							Oil	511	139,400	2,989	63,271	N/A	123.82
21		2,500	548,165	29.5	65.2	25.2	8,356				4,491,088	19,847,732	3.62	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: JUNE 2015

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	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
4	5							Gas - G						
5	Crist 6	299	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	89,476	26.2	98.9	61.6	10,821	Coal	40,856	11,849	968,225	3,666,502	4.10	89.74
8	7							Gas - G						
9	Perdido		3,045					Landfill Gas				91,807	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	556	330,337	82.5	99.0	83.4	6,874	Gas	2,204,596	1,030	2,270,734	11,612,137	3.52	5.27
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,296					Gas				302,472	3.65	N/A
17	Daniel 1 (1)	255	117,088	63.8	97.4	33.0	10,282	Coal	60,371	9,971	1,203,897	4,211,681	3.60	69.76
18	Daniel 2 (1)	255	121,833	66.4	97.4	34.1	10,177	Coal	62,176	9,971	1,239,889	4,337,597	3.56	69.76
19	Gas,BL							Gas	4,854	1,030	5,000	167,536	N/A	34.52
20	Ltr. Oil							Oil	567	139,400	3,322	70,337	N/A	124.05
21		2,471	670,075	37.7	84.6	37.5	8,639				5,691,067	24,460,069	3.65	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: JULY 2015

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	3,041	5.4	99.8	54.8	12,127	Coal	1,558	11,838	36,878	137,181	4.51	88.05
2	4							Gas - G						
3	Crist 5	75	4,302	7.7	100.0	53.6	11,691	Coal	2,124	11,838	50,294	187,087	4.35	88.08
4	5							Gas - G						
5	Crist 6	299	36,026	16.2	98.2	41.7	12,029	Coal	18,304	11,838	433,358	1,612,034	4.47	88.07
6	6							Gas - G						
7	Crist 7	475	159,298	45.1	98.3	68.4	10,723	Coal	72,149	11,838	1,708,150	6,354,089	3.99	88.07
8	7							Gas - G						
9	Perdido		3,147					Landfill Gas				94,882	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	556	360,553	87.2	99.0	88.0	6,838	Gas	2,393,650	1,030	2,465,460	12,411,351	3.44	5.19
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,572					Gas				312,535	3.65	N/A
17	Daniel 1 (1)	255	128,751	67.9	97.4	34.8	10,231	Coal	65,753	10,017	1,317,247	4,634,704	3.60	70.49
18	Daniel 2 (1)	255	130,338	68.7	97.4	35.3	10,135	Coal	65,940	10,017	1,320,982	4,647,844	3.57	70.49
19	Gas,BL							Gas	19,417	1,030	20,000	227,536	N/A	11.72
20	Ltr. Oil							Oil	692	139,400	4,050	85,947	N/A	124.20
21		2,471	834,028	45.4	84.2	48.5	8,946				7,356,419	30,705,190	3.68	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: AUGUST 2015

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	2,892	5.2	99.8	55.1	12,109	Coal	1,480	11,832	35,019	129,334	4.47	87.39
2	4							Gas - G						
3	Crist 5	75	2,894	5.2	100.0	53.5	11,696	Coal	1,430	11,832	33,849	125,013	4.32	87.42
4	5							Gas - G						
5	Crist 6	299	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	167,341	47.4	98.2	67.2	10,739	Coal	75,944	11,832	1,797,076	6,637,054	3.97	87.39
8	7							Gas - G						
9	Perdido		3,147					Landfill Gas				94,882	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	556	358,544	86.7	99.0	87.5	6,841	Gas	2,381,358	1,030	2,452,799	12,264,058	3.42	5.15
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,572					Gas				312,535	3.65	N/A
17	Daniel 1 (1)	255	128,583	67.8	97.4	35.1	10,224	Coal	65,422	10,047	1,314,634	4,628,564	3.60	70.75
18	Daniel 2 (1)	255	130,966	69.0	97.4	35.4	10,129	Coal	66,015	10,047	1,326,559	4,670,550	3.57	70.75
19	Gas,BL							Gas	14,563	1,030	15,000	207,536	N/A	14.25
20	Ltr. Oil							Oil	692	139,400	4,049	85,824	N/A	124.02
21		2,471	802,939	43.7	84.4	43.2	8,821				6,978,985	29,155,350	3.63	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: SEPTEMBER 2015

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	99.7	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
4	5							Gas - G						
5	Crist 6	299	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	43,730	12.8	99.3	59.0	10,864	Coal	20,079	11,830	475,085	1,798,267	4.11	89.56
8	7							Gas - G						
9	Perdido		3,046					Landfill Gas				91,837	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	556	331,724	82.9	99.0	83.7	6,871	Gas	2,212,886	1,030	2,279,273	11,521,187	3.47	5.21
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,296					Gas				302,472	3.65	N/A
17	Daniel 1 (1)	255	116,000	63.2	97.4	32.7	10,293	Coal	59,600	10,017	1,193,986	4,181,607	3.60	70.16
18	Daniel 2 (1)	255	119,253	65.0	97.3	33.7	10,190	Coal	60,658	10,017	1,215,187	4,255,858	3.57	70.16
19	Gas,BL							Gas	4,854	1,030	5,000	167,536	N/A	34.52
20	Ltr. Oil							Oil	567	139,400	3,322	70,029	N/A	123.51
21		2,471	622,049	35.0	84.6	37.0	8,469				5,171,853	22,388,793	3.60	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: OCTOBER 2015

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	99.7	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
4	5							Gas - G						
5	Crist 6	299	0	0.0	99.7	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
8	7							Gas - G						
9	Perdido		3,147					Landfill Gas				94,882	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	557	347,312	83.7	99.0	84.6	6,790	Gas	2,289,563	1,030	2,358,250	11,932,988	3.44	5.21
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				208,551	3.65	N/A
17	Daniel 1 (1)	255	33,766	17.8	63.7	28.6	10,912	Coal	18,761	9,820	368,457	1,269,094	3.76	67.65
18	Daniel 2 (1)	255	107,031	56.4	97.4	29.0	10,918	Coal	59,499	9,820	1,168,558	4,024,922	3.76	67.65
19	Gas,BL							Gas	0	0	0	147,536	N/A	N/A
20	Ltr. Oil							Oil	511	139,400	2,989	62,776	N/A	122.85
21		2,476	496,976	27.0	81.3	25.0	7,986				3,898,254	17,740,749	3.57	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: NOVEMBER 2015

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	99.9	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	0	0.0	99.9	0.0	N/A	Coal	0	0	0	0	N/A	N/A
4	5							Gas - G						
5	Crist 6	299	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	6							Gas - G						
7	Crist 7	475	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
8	7							Gas - G						
9	Perdido		3,046					Landfill Gas				91,837	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	557	244,476	60.9	69.2	87.7	6,838	Gas	1,623,038	1,030	1,671,729	8,032,305	3.29	4.95
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,536					Gas				201,843	3.65	N/A
17	Daniel 1 (1)	255	42,111	22.9	68.8	28.5	10,750	Coal	23,399	9,673	452,691	1,545,681	3.67	66.06
18	Daniel 2 (1)	255	54,400	29.6	68.7	28.9	10,398	Coal	29,238	9,673	565,652	1,931,378	3.55	66.06
19	Gas,BL							Gas	0	0	0	147,536	N/A	N/A
20	Ltr. Oil							Oil	511	139,400	2,989	62,722	N/A	122.74
21		2,476	349,569	19.6	72.2	25.7	7,898				2,693,061	12,013,301	3.44	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE MONTH OF: DECEMBER 2015

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	1,968	3.5	99.9	54.7	12,136	Coal	1,009	11,840	23,884	97,867	4.97	96.99
2	4							Gas - G						
3	Crist 5	75	1,970	3.5	100.0	52.3	11,760	Coal	978	11,840	23,167	94,929	4.82	97.06
4	5							Gas - G						
5	Crist 6	299	17,950	8.1	99.0	41.7	12,029	Coal	9,119	11,840	215,924	884,768	4.93	97.02
6	6							Gas - G						
7	Crist 7	475	44,630	12.6	99.5	57.3	10,896	Coal	20,536	11,840	486,284	1,992,593	4.46	97.03
8	7							Gas - G						
9	Perdido		3,147					Landfill Gas				94,882	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
13	Smith 2	195	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	Smith 3	584	365,956	84.2	98.9	85.1	6,828	Gas	2,425,968	1,030	2,498,747	11,544,726	3.15	4.76
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				208,551	3.65	N/A
17	Daniel 1 (1)	255	12,859	6.8	99.6	23.6	10,684	Coal	7,175	9,574	137,387	465,302	3.62	64.85
18	Daniel 2 (1)	255	7,019	3.7	77.2	0.0	10,843	Coal	3,975	9,574	76,107	257,760	3.67	64.85
19	Gas,BL							Gas	19,417	1,030	20,000	227,536	N/A	11.72
20	Ltr. Oil							Oil	692	139,400	4,050	85,554	N/A	123.63
21		2,507	461,219	24.7	82.9	41.2	7,705				3,485,550	15,954,468	3.46	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROJECTED FOR THE PERIOD OF: JANUARY 2015 - DECEMBER 2015

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	69,482	10.5	99.9	32.3	12,071	Coal	35,332	11,869	838,720	3,071,368	4.42	86.93
2	4							Gas - G	0	0	0	0		
3	Crist 5	75	69,539	10.6	100.0	31.7	11,627	Coal	34,047	11,873	808,500	2,974,620	4.28	87.37
4	5							Gas - G	0	0	0	0		
5	Crist 6	299	106,576	4.1	99.0	17.1	12,533	Coal	56,312	11,860	1,335,695	5,013,117	4.70	89.02
6	6							Gas - G	0	0	0	0		
7	Crist 7	475	1,120,735	26.9	99.5	44.2	10,890	Coal	514,567	11,859	12,204,431	45,173,114	4.03	87.79
8	7							Gas - G	0	0	0	0		
9	Perdido		31,952					Landfill Gas				963,353	3.02	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	135,821	9.5	0.0	17.5	10,918	Coal	62,611	11,843	1,482,957	6,328,456	4.66	101.08
13	Smith 2	195	152,479	8.9	0.0	18.6	10,782	Coal	70,376	11,681	1,644,099	6,727,442	4.41	95.59
14	Smith 3	566	3,855,439	77.6	98.9	83.9	6,852	Gas - G	25,646,628	1,030	26,416,028	135,200,134	3.51	5.27
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil - G	0	0	0	0	N/A	N/A
16	Other Generation		81,428					Gas				2,968,865	3.65	N/A
17	Daniel 1 (1)	255	803,916	35.9	99.6	26.4	10,366	Coal	417,722	9,975	8,333,320	29,114,146	3.62	69.70
18	Daniel 2 (1)	255	1,099,953	49.1	77.2	27.4	10,196	Coal	561,682	9,984	11,215,137	39,162,903	3.56	69.72
19	Gas,BL							Gas	135,919	1,030	140,000	2,330,432	N/A	17.15
20	Ltr. Oil							Oil	8,388	139,360	49,096	1,041,770	N/A	124.20
21		2,484	7,527,320	34.5	82.8	39.7	8,696				64,467,983	280,069,720	3.72	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,091	856	856	842	511	567	692	692	567	511	511	692	8,388
3	UNIT COST ($/BBL)	122.72	122.82	122.82	122.75	122.25	122.54	122.53	122.53	122.54	122.25	122.25	122.53	122.59
4	AMOUNT ($)	133,890	105,132	105,132	103,354	62,470	69,478	84,794	84,791	69,478	62,470	62,470	84,794	1,028,253
5	*BURNED :*													
6	UNITS (BBL)	1,091	856	856	842	511	567	692	692	567	511	511	692	8,388
7	UNIT COST ($/BBL)	125.34	124.89	124.57	124.73	123.82	124.05	124.20	124.02	123.51	122.85	122.74	123.63	124.20
8	AMOUNT ($)	136,749	106,902	106,635	105,024	63,271	70,337	85,947	85,824	70,029	62,776	62,722	85,554	1,041,770
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	7,166	7,166	7,166	7,166	7,166	7,166	7,166	7,166	7,166	7,166	7,166	7,166	
11	UNIT COST ($/BBL)	126.40	126.16	125.95	125.72	125.60	125.48	125.32	125.18	125.10	125.06	125.02	124.92	
12	AMOUNT ($)	905,818	904,048	902,545	900,875	900,074	899,215	898,062	897,029	896,478	896,172	895,920	895,160	
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													
14	*PURCHASES :*													
15	UNITS (TONS)	125,631	175,911	189,288	177,180	109,550	150,404	215,885	200,619	129,637	107,950	107,950	139,606	1,829,611
16	UNIT COST ($/TON)	79.10	79.82	80.15	76.23	77.41	77.50	77.90	77.49	76.48	69.22	70.23	71.92	76.61
17	AMOUNT ($)	9,937,547	14,041,663	15,172,142	13,505,854	8,480,566	11,656,748	16,817,892	15,545,469	9,914,147	7,471,986	7,581,577	10,040,141	140,165,732
18	*BURNED :*													
19	UNITS (TONS)	159,057	175,374	160,849	226,671	117,150	163,403	225,828	210,291	140,337	78,260	52,637	42,792	1,752,649
20	UNIT COST ($/TON)	94.05	83.44	82.58	78.33	69.62	74.76	77.82	76.99	72.94	67.65	66.06	88.64	78.49
21	AMOUNT ($)	14,959,242	14,633,280	13,282,829	17,754,612	8,155,943	12,215,780	17,572,939	16,190,515	10,235,732	5,294,016	3,477,059	3,793,219	137,565,166
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	470,725	471,262	499,701	450,210	442,610	429,611	419,668	409,996	399,296	428,986	484,299	581,113	
24	UNIT COST ($/TON)	78.52	77.18	76.57	75.54	77.58	78.62	78.68	78.97	80.28	79.80	79.16	76.72	
25	AMOUNT ($)	36,962,021	36,370,404	38,259,717	34,010,959	34,335,582	33,776,550	33,021,503	32,376,457	32,054,872	34,232,842	38,337,360	44,584,282	
26	DAYS SUPPLY:	23	23	24	22	21	21	20	20	19	21	23	28	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GAS (1)													
27	*BURNED :*													
28	UNITS (MMBtu)	1,956,986	2,152,631	2,361,416	1,872,370	2,150,633	2,275,734	2,485,460	2,467,799	2,284,273	2,358,250	1,671,729	2,518,747	26,556,028
29	UNIT COST ($/MMBtu	5.71	5.46	5.34	5.42	5.23	5.18	5.09	5.05	5.12	5.12	4.89	4.67	5.18
30	AMOUNT ($)	$11,165,046	$11,752,166	$12,609,878	$10,139,304	$11,252,668	$11,779,673	$12,638,887	$12,471,594	$11,688,722	$12,080,524	$8,179,841	$11,772,262	137,530,566
	OTHER - C.T. OIL													
31	*PURCHASES :*													
32	UNITS (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
33	UNIT COST ($/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
34	AMOUNT ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
35	*BURNED :*													
36	UNITS (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
37	UNIT COST ($/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
38	AMOUNT ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
39	*ENDING INVENTORY :*													
40	UNITS (BBL)	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	
41	UNIT COST ($/BBL)	117.59	117.59	117.59	117.59	117.59	117.59	117.59	117.59	117.59	117.59	117.59	117.59	
42	AMOUNT ($)	839,922	839,922	839,922	839,922	839,922	839,922	839,922	839,922	839,922	839,922	839,922	839,922	
43	DAYS SUPPLY:	3	3	3	3	3	3	3	3	3	3	3	3	

(1) Data excludes 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
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(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	$
	JANUARY							
1	Southern Co. Interchange	204,578,000	0	204,578,000	2.97	3.36	6,086,000	6,865,000
2	Economy Sales	10,255,000	0	10,255,000	3.14	3.45	322,000	354,000
3	Gain on Economy 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
	FEBRUARY							
5	Southern Co. Interchange	327,974,000	0	327,974,000	3.00	3.38	9,845,000	11,077,000
6	Economy Sales	11,596,000	0	11,596,000	3.08	3.33	357,000	386,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	33,000	33,000
8	TOTAL ESTIMATED SALES	339,570,000	0	339,570,000	3.01	3.39	10,235,000	11,496,000
	MARCH							
9	Southern Co. Interchange	14,838,000	0	14,838,000	2.92	3.28	433,000	486,000
10	Economy Sales	8,955,000	0	8,955,000	2.99	3.33	268,000	298,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	21,000	21,000
12	TOTAL ESTIMATED SALES	23,793,000	0	23,793,000	3.03	3.38	722,000	805,000
	APRIL							
13	Southern Co. Interchange	35,669,000	0	35,669,000	2.60	2.93	928,000	1,045,000
14	Economy Sales	8,789,000	0	8,789,000	3.12	3.31	274,000	291,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	21,000	21,000
16	TOTAL ESTIMATED SALES	44,458,000	0	44,458,000	2.75	3.05	1,223,000	1,357,000
	MAY							
17	Southern Co. Interchange	67,209,000	0	67,209,000	2.98	3.39	2,001,000	2,280,000
18	Economy Sales	9,617,000	0	9,617,000	3.15	3.40	303,000	327,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	23,000	23,000
20	TOTAL ESTIMATED SALES	76,826,000	0	76,826,000	3.03	3.42	2,327,000	2,630,000
	JUNE							
21	Southern Co. Interchange	57,476,000	0	57,476,000	3.93	4.21	2,261,000	2,422,000
22	Economy Sales	6,905,000	0	6,905,000	3.64	3.82	251,000	264,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	43,000	43,000
24	TOTAL ESTIMATED SALES	64,381,000	0	64,381,000	3.97	4.24	2,555,000	2,729,000

POWER SOLD
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(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	Southern Co. Interchange	126,239,000	0	126,239,000	3.94	4.23	4,972,000	5,342,000
2	Economy Sales	6,511,000	0	6,511,000	3.76	4.09	245,000	266,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	50,000	50,000
4	TOTAL ESTIMATED SALES	132,750,000	0	132,750,000	3.97	4.26	5,267,000	5,658,000
AUGUST								
5	Southern Co. Interchange	116,497,000	0	116,497,000	3.94	4.23	4,590,000	4,930,000
6	Economy Sales	8,637,000	0	8,637,000	3.69	3.92	319,000	339,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	49,000	49,000
8	TOTAL ESTIMATED SALES	125,134,000	0	125,134,000	3.96	4.25	4,958,000	5,318,000
SEPTEMBER								
9	Southern Co. Interchange	57,588,000	0	57,588,000	3.44	3.78	1,980,000	2,174,000
10	Economy Sales	6,411,000	0	6,411,000	3.54	3.71	227,000	238,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	33,000	33,000
12	TOTAL ESTIMATED SALES	63,999,000	0	63,999,000	3.50	3.82	2,240,000	2,445,000
OCTOBER								
13	Southern Co. Interchange	31,750,000	0	31,750,000	2.69	3.07	853,000	975,000
14	Economy Sales	10,126,000	0	10,126,000	3.07	3.29	311,000	333,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	27,000	27,000
16	TOTAL ESTIMATED SALES	41,876,000	0	41,876,000	2.84	3.19	1,191,000	1,335,000
NOVEMBER								
17	Southern Co. Interchange	195,819,000	0	195,819,000	2.81	3.23	5,511,000	6,333,000
18	Economy Sales	11,900,000	0	11,900,000	2.92	3.19	347,000	380,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	24,000	24,000
20	TOTAL ESTIMATED SALES	207,719,000	0	207,719,000	2.83	3.24	5,882,000	6,737,000
DECEMBER								
21	Southern Co. Interchange	155,416,000	0	155,416,000	2.91	3.27	4,516,000	5,084,000
22	Economy Sales	12,956,000	0	12,956,000	2.87	3.27	372,000	424,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	35,000	35,000
24	TOTAL ESTIMATED SALES	168,372,000	0	168,372,000	2.92	3.29	4,923,000	5,543,000
TOTAL								
25	Southern Co. Interchange	1,391,053,000	0	1,391,053,000	3.16	3.52	43,976,000	49,013,000
26	Economy Sales	112,658,000	0	112,658,000	3.19	3.46	3,596,000	3,900,000
27	Gain on Economy Sales	0	0	0	0.00	0.00	394,000	394,000
28	TOTAL ESTIMATED SALES	1,503,711,000	0	1,503,711,000	3.19	3.55	47,966,000	53,307,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	# ¢ / 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
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(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		COG-1				None			
FEBRUARY		COG-1				None			
MARCH		COG-1				None			
APRIL		COG-1				None			
MAY		COG-1				None			
JUNE		COG-1				None			
JULY		COG-1				None			
AUGUST		COG-1				None			
SEPTEMBER		COG-1				None			
OCTOBER		COG-1				None			
NOVEMBER		COG-1				None			
DECEMBER		COG-1				None			
TOTAL			0			0			0

SCHEDULE E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL kWh PURCHASED	TRANSACTION COST ¢ / kWh	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	108,405,000	3.58	3,880,000
2	Economy Energy	4,613,000	3.69	170,000
3	Other Purchases	427,156,000	3.49	14,918,000
4	TOTAL ESTIMATED PURCHASES	540,174,000	3.51	18,968,000
	FEBRUARY			
5	Southern Co. Interchange	83,945,000	3.22	2,703,000
6	Economy Energy	2,298,000	3.70	85,000
7	Other Purchases	365,241,000	3.53	12,899,000
8	TOTAL ESTIMATED PURCHASES	451,484,000	3.47	15,687,000
	MARCH			
9	Southern Co. Interchange	157,067,000	3.28	5,148,000
10	Economy Energy	5,115,000	3.38	173,000
11	Other Purchases	2,696,000	48.26	1,301,000
12	TOTAL ESTIMATED PURCHASES	164,878,000	4.02	6,622,000
	APRIL			
13	Southern Co. Interchange	109,927,000	3.40	3,741,000
14	Economy Energy	2,796,000	3.15	88,000
15	Other Purchases	22,072,000	8.91	1,967,000
16	TOTAL ESTIMATED PURCHASES	134,795,000	4.30	5,796,000
	MAY			
17	Southern Co. Interchange	92,181,000	3.16	2,912,000
18	Economy Energy	3,472,000	3.43	119,000
19	Other Purchases	473,222,000	3.32	15,689,000
20	TOTAL ESTIMATED PURCHASES	568,875,000	3.29	18,720,000
	JUNE			
21	Southern Co. Interchange	134,826,000	3.33	4,490,000
22	Economy Energy	3,044,000	4.11	125,000
23	Other Purchases	465,069,000	3.39	15,753,000
24	TOTAL ESTIMATED PURCHASES	602,939,000	3.38	20,368,000

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL kWh PURCHASED	TRANSACTION COST ¢ / kWh	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	55,185,000	3.94	2,176,000
2	Economy Energy	3,034,000	4.61	140,000
3	Other Purchases	564,344,000	3.35	18,916,000
4	TOTAL ESTIMATED PURCHASES	622,563,000	3.41	21,232,000
	AUGUST			
5	Southern Co. Interchange	70,391,000	3.73	2,624,000
6	Economy Energy	3,949,000	4.46	176,000
7	Other Purchases	552,597,000	3.36	18,590,000
8	TOTAL ESTIMATED PURCHASES	626,937,000	3.41	21,390,000
	SEPTEMBER			
9	Southern Co. Interchange	72,719,000	3.31	2,407,000
10	Economy Energy	2,233,000	3.90	87,000
11	Other Purchases	511,372,000	3.37	17,214,000
12	TOTAL ESTIMATED PURCHASES	586,324,000	3.36	19,708,000
	OCTOBER			
13	Southern Co. Interchange	317,812,000	3.34	10,607,000
14	Economy Energy	3,014,000	3.48	105,000
15	Other Purchases	174,075,000	3.82	6,645,000
16	TOTAL ESTIMATED PURCHASES	494,901,000	3.51	17,357,000
	NOVEMBER			
17	Southern Co. Interchange	204,534,000	3.12	6,385,000
18	Economy Energy	4,796,000	3.38	162,000
19	Other Purchases	467,819,000	3.39	15,851,000
20	TOTAL ESTIMATED PURCHASES	677,149,000	3.31	22,398,000
	DECEMBER			
21	Southern Co. Interchange	124,976,000	3.20	3,998,000
22	Economy Energy	7,501,000	3.45	259,000
23	Other Purchases	497,461,000	3.46	17,221,000
24	TOTAL ESTIMATED PURCHASES	629,938,000	3.41	21,478,000
	TOTAL FOR PERIOD			
25	Southern Co. Interchange	1,531,968,000	3.33	51,071,000
26	Economy Energy	45,865,000	3.68	1,689,000
27	Other Purchases	4,523,124,000	3.47	156,964,000
28	TOTAL ESTIMATED PURCHASES	6,100,957,000	3.44	209,724,000

SCHEDULE E-10
Revised August 29, 2014

GULF POWER COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 kWh

	Current Approved Jan. 14 - Dec. 14 ($/1,000 kWh)	Proposed Jan. 15 - Dec. 15 ($/1,000 kWh)	Difference from Current ($)	Difference from Current (%)
Base Rate	$ 62.09	$ 64.45	$ 2.36	3.8%
Fuel Cost Recovery	42.01	43.69	1.68	4.0%
Capacity Cost Recovery	6.80	9.16	2.36	34.7%
Energy Conservation Cost Recovery	2.26	2.50	0.24	10.6%
Environmental Cost Recovery	15.54	15.92	0.38	2.4%
Subtotal	$ 128.70	$ 135.72	$ 7.02	5.5%
Gross Receipts Tax	3.30	3.48	0.18	5.5%
Total	$ 132.00	$ 139.20	$ 7.20	5.5%

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / kWh
2015	JANUARY	3.286
	FEBRUARY	3.286
	MARCH	3.286
	APRIL	3.604
	MAY	3.604
	JUNE	3.604
	JULY	3.604
	AUGUST	3.604
	SEPTEMBER	3.604
	OCTOBER	3.604
	NOVEMBER	3.286
	DECEMBER	3.286
2016	JANUARY	3.221
	FEBRUARY	3.221
	MARCH	3.221
	APRIL	3.602
	MAY	3.602
	JUNE	3.602
	JULY	3.602
	AUGUST	3.602
	SEPTEMBER	3.602
	OCTOBER	3.602
	NOVEMBER	3.221
	DECEMBER	3.221

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY

LINE	LINE DESCRIPTION	2012	2013	2014	2015	% Change 2012 to 2013	% Change 2013 to 2014	% Change 2014 to 2015
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	LIGHTER OIL (B.L.)	663,864	806,844	1,745,999	1,041,770	21.54	116.40	(40.33)
2	COAL	411,231,936	230,848,996	227,098,836	137,565,166	(43.86)	(1.62)	(39.42)
3	GAS	131,747,551	125,616,386	124,330,289	135,200,134	(4.65)	(1.02)	8.74
4	GAS (B.L.)	0	0	1,807,910	2,330,432	0.00	100.00	28.90
5	LANDFILL GAS	685,856	704,503	680,294	963,353	2.72	(3.44)	41.61
6	OTHER - C.T.	0	123,790	8,702	0	100.00	(92.97)	(100.00)
7	OTHER GENERATION	2,453,961	1,814,318	3,254,676	2,968,865	(26.07)	79.39	(8.78)
8	TOTAL ($)	546,783,168	359,914,837	358,926,706	280,069,720	(34.18)	(0.27)	(21.97)
	SYSTEM NET GENERATION (MWh)							
9	COAL	8,417,818	4,624,257	4,980,200	3,558,501	(45.07)	7.70	(28.55)
10	GAS	3,428,937	4,059,172	3,846,888	3,855,439	18.38	(5.23)	0.22
11	LANDFILL GAS	26,440	26,366	24,720	31,952	(0.28)	(6.24)	29.26
12	OTHER - C.T.	0	512	32	0	100.00	(93.75)	(100.00)
13	OTHER GENERATION	50,618	50,524	81,428	81,428	(0.19)	61.17	0.00
14	TOTAL (MWH)	11,923,813	8,760,831	8,933,268	7,527,320	(26.53)	1.97	(15.74)
	UNITS OF FUEL BURNED							
15	LIGHTER OIL (BBL)	4,895	6,864	13,792	8,388	40.22	100.93	(39.18)
16	COAL (TON)	3,958,270	2,201,050	2,389,900	1,752,649	(44.39)	8.58	(26.66)
17	GAS (MCF)	23,659,285	28,342,618	25,903,786	26,416,028	19.79	(8.60)	1.98
18	OTHER - C.T. (BBL)	0	1,161	77	0	100.00	(93.37)	(100.00)
	BTUS BURNED (MMBtu)							
19	COAL + GAS B.L. + OIL B.L.	91,370,112	51,387,546	55,686,060	38,051,955	(43.76)	8.36	(31.67)
20	GAS - Generation	24,369,058	27,773,568	26,250,901	26,416,028	13.97	(5.48)	0.63
21	OTHER - C.T.	0	6,802	450	0	100.00	(93.38)	(100.00)
22	TOTAL (MMBtu)	115,739,170	79,167,916	81,937,411	64,467,983	(31.60)	3.50	(21.32)
	GENERATION MIX (% MWh)							
23	COAL + GAS B.L. + OIL B.L.	70.60	52.78	55.75	47.27	(25.24)	5.63	(15.21)
24	GAS - Generation	28.76	46.33	43.06	51.22	61.09	(7.06)	18.95
25	LANDFILL GAS	0.22	0.30	0.28	0.42	36.36	(6.67)	50.00
26	OTHER - C.T.	0.00	0.01	0.00	0.00	100.00	(100.00)	0.00
27	OTHER GENERATION	0.42	0.58	0.91	1.08	38.10	56.90	18.68
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. ($/BBL)	135.62	117.55	126.60	124.20	(13.32)	7.70	(1.90)
30	COAL ($/TON)	103.89	104.88	95.02	78.49	0.95	(9.40)	(17.40)
31	GAS +B.L. ($/MCF)	5.57	4.43	4.87	5.21	(20.47)	9.93	6.98
32	OTHER - C.T.	#N/A	106.62	113.01	#N/A	#N/A	5.99	#N/A
	FUEL COST ($ / MMBtu)							
33	COAL + GAS B.L. + OIL B.L.	4.51	4.51	4.14	3.70	0.00	(8.20)	(10.63)
34	GAS - Generation	5.41	4.52	4.74	5.12	(16.45)	4.87	8.02
35	OTHER - C.T.	#N/A	18.20	19.34	#N/A	#N/A	6.26	#N/A
36	TOTAL ($/MMBtu)	4.70	4.51	4.33	4.28	(4.04)	(3.99)	(1.15)
	BTU BURNED (Btu / kWh)							
37	COAL + GAS B.L. + OIL B.L.	10,854	11,113	11,181	10,693	2.39	0.61	(4.36)
38	GAS - Generation	7,107	6,842	6,824	6,852	(3.73)	(0.26)	0.41
39	OTHER - C.T.	#N/A	13,285	14,063	#N/A	#N/A	5.86	#N/A
40	TOTAL (Btu/kWh)	9,748	9,089	9,257	8,696	(6.76)	1.85	(6.06)
	FUEL COST (¢ / kWh)							
41	COAL + GAS B.L. + OIL B.L.	4.89	5.01	4.63	3.96	2.45	(7.58)	(14.47)
42	GAS - Generation	3.84	3.09	3.23	3.51	(19.53)	4.53	8.67
43	LANDFILL GAS	2.59	2.67	2.75	3.02	3.09	3.00	9.82
44	OTHER - C.T.	#N/A	24.18	27.19	#N/A	#N/A	12.45	#N/A
45	OTHER GENERATION	4.85	3.59	4.00	3.65	(25.98)	11.42	(8.75)
46	TOTAL (¢ / kWh)	4.59	4.11	4.02	3.72	(10.46)	(2.19)	(7.46)

Projected Purchased Power Capacity Payments / (Receipts)
Gulf Power Company
For January 2015 - December 2015

		January	February	March	April	May	June	July	August	September	October	November	December	**Total**
1	Projected IIC Payments / (Receipts) ($)	0	0	0	0	0	0	0	0	0	0	(1,000)	0	(1,000)
2	Other Capacity Payments / (Receipts) ($)	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	7,396,477	88,757,724
3	Projected Transmission Revenue	(15,000)	(16,000)	(13,000)	(13,000)	(14,000)	(10,000)	(9,000)	(12,000)	(9,000)	(14,000)	(17,000)	(18,000)	(160,000)
4	Total Projected Capacity Payments / (Receipts) (Line 1 + 2 + 3) ($)	7,381,477	7,380,477	7,383,477	7,383,477	7,382,477	7,386,477	7,387,477	7,384,477	7,387,477	7,382,477	7,378,477	7,378,477	88,596,724
5	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6	Projected Jurisdictional Capacity Payments / (Receipts) (Line 4 x Line 5) ($)	7,165,307	7,164,337	7,167,249	7,167,249	7,166,278	7,170,161	7,171,132	7,168,220	7,171,132	7,166,278	7,162,395	7,162,395	86,002,133
7	True-Up ($)													(601,390)
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													85,400,743
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments / (Receipts) (Line 8 x Line 9) ($)													85,462,232

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,788,856.26	97.07146%
FERC	53,967.91	2.92854%
Total	1,842,824.17	100.00000%

* Based on 2012 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 2015 - DECEMBER 2015

1.	Estimated over/(under)-recovery, January 2014 - December 2014 (Schedule CCE-1B, Line 15 + Line 18)	1,263,407
2.	Final over/(under)-recovery, January 2013 - December 2013 (Exhibit RWD-1, Schedule CCA-1, filed March 3, 2014)	(662,017)
3.	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2015 - December 2015)	$601,390
4.	Jurisdictional kWh sales, January 2015 - December 2015	11,062,622,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	(0.0054)

SCHEDULE CCE-1B

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2014 - DECEMBER 2014

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	!IC Payments/(Receipts) ($)	(33,722)	(32,988)	(39,220)	(45,333)	(37,166)	(37,845)	0	0	0	0	0	0	(226,274)
2	Other Capacity Payments / (Receipts) ($)	2,296,591	2,346,149	2,253,681	2,203,248	2,818,646	7,426,005	7,250,781	7,250,781	7,250,781	7,250,781	7,243,781	7,249,781	62,841,005
3	Transmission Revenue ($)	(28,042)	(25,831)	(25,328)	(5,964)	(7,298)	(3,735)	(5,000)	(6,000)	(5,000)	(7,000)	(8,000)	(9,000)	(136,198)
4	Total Capacity Payments/(Receipts) ($)	2,234,827	2,287,330	2,189,133	2,151,950	2,774,182	7,384,425	7,245,781	7,244,781	7,245,781	7,243,781	7,235,781	7,240,781	62,478,533
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) ($)	2,169,379	2,220,345	2,125,023	2,088,930	2,692,939	7,168,169	7,033,585	7,032,615	7,033,585	7,031,644	7,023,878	7,028,732	60,648,824
7	Retail kWh Sales							1,198,218,000	1,178,147,000	1,039,787,000	867,231,000	748,462,000	835,508,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/kWh)							0.574	0.574	0.574	0.574	0.574	0.574	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	5,940,341	4,436,418	4,461,136	4,222,622	5,189,606	6,186,944	6,877,771	6,762,564	5,968,377	4,977,906	4,296,172	4,795,816	64,115,673
10	Revenue Taxes (Line 9 x .00072) ($)	4,277	3,194	3,212	3,040	3,737	4,455	4,952	4,869	4,297	3,584	3,093	3,453	46,163
11	True-Up Provision ($)	(180,083)	(180,083)	(180,083)	(180,083)	(180,083)	(180,083)	(180,085)	(180,085)	(180,085)	(180,085)	(180,085)	(180,087)	(2,161,010)
12	Capacity Cost Recovery Revenues Net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	5,755,981	4,253,141	4,277,841	4,039,499	5,005,786	6,002,406	6,692,734	6,577,610	5,783,995	4,794,237	4,112,994	4,612,276	61,908,500
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	3,586,602	2,032,796	2,152,818	1,950,569	2,312,847	(1,165,763)	(340,851)	(455,005)	(1,249,590)	(2,237,407)	(2,910,884)	(2,416,458)	1,259,676
14	Interest Provision ($)	(59)	119	251	413	559	520	452	442	408	330	210	86	3,731
15	Total Estimated True-Up for the Period January 2014 - December 2014 (Line 13 + Line 14) ($)													1,263,407
16	Beginning Balance True-Up & Interest Provision ($)	(2,823,027)	943,599	3,156,597	5,489,749	7,620,814	10,114,303	9,129,143	8,968,829	8,694,351	7,625,254	5,568,282	2,837,673	(2,823,027)
17	True-Up Collected/(Refunded) ($)	180,083	180,083	180,083	180,083	180,083	180,083	180,085	180,085	180,085	180,085	180,085	180,087	2,161,010
18	Adjustment ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
19	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	943,599	3,156,597	5,489,749	7,620,814	10,114,303	9,129,143	8,968,829	8,694,351	7,625,254	5,568,262	2,837,673	601,390	601,390

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2015 - December 2015

Rate Class	A Average 12 CP Load Factor at Meter	B 2015 Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F 2015 Projected KWH Sales at Generation Col B x Col E	G Projected Avg 12 CP KW at Generation Col C x Col D	H Percentage of KWH Sales at Generation Col F / Total Col F	I Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	57.025261%	5,188,672,000	1,038,687	1.00820508	1.00777864	5,229,032,812	1,047,210	47.29633%	56.32886%
GS	65.082883%	293,459,000	51,473	1.00820395	1.00777656	295,741,102	51,895	2.67496%	2.79140%
GSD, GSDT, GSTOU	75.900487%	2,703,797,000	406,654	1.00800263	1.00762887	2,724,423,916	409,909	24.64227%	22.04877%
LP, LPT	85.148219%	1,168,926,000	156,714	0.97344897	0.98364378	1,149,806,789	152,553	10.39994%	8.20574%
PX, PXT, RTP, SBS	88.430490%	1,552,162,000	200,369	0.95247952	0.96644352	1,500,076,907	190,848	13.56811%	10.26559%
OS - I / II	782.722832%	111,207,000	1,622	1.00802086	1.00777465	112,071,596	1,635	1.01368%	0.08794%
OS-III	101.182319%	44,399,000	5,009	1.00838359	1.00778595	44,744,688	5,051	0.40471%	0.27170%
TOTAL		11,062,622,000	1,860,528			11,055,897,810	1,859,100	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2012 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 2015 - December 2015

Rate Class	A 2015 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 ($) Col C + Col D	F 2015 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100	H 2015 Projected KW at Meter Page 1, Col C	I Capacity Costs Recovery Factors ($/KW) Col E / Col F x 100
RS, RSVP	47.29633%	56.32886%	3,109,269	44,436,831	47,546,100	5,188,672,000	0.916		
GS	2.67496%	2.79140%	175,852	2,202,086	2,377,938	293,459,000	0.810		
GSD, GSDT, GSTOU	24.64227%	22.04877%	1,619,987	17,393,881	19,013,868	2,703,797,000	0.703		
LP, LPT	10.39994%	8.20574%	683,694	6,473,362	7,157,056	1,168,926,000	0.000	2,539,000	2.82
PX, PXT, RTP, SBS	13.56811%	10.26559%	891,970	8,098,341	8,990,311	1,552,162,000	0.579		
OS - I / II	1.01368%	0.08794%	66,640	69,374	136,014	111,207,000	0.122		
OS-III	0.40471%	0.27170%	26,606	214,339	240,945	44,399,000	0.543		
TOTAL	100.00000%	100.00000%	$6,574,018	$78,888,214	$85,462,232	11,062,622,000	0.773	2,539,000	2.819

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

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Gulf Power Company
2015 Capacity Contracts

Schedule CCE-4
Page 1 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract 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			
South Carolina PSA	9/1/2003	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts became firm on June 1, 2014.

Capacity Costs
2015

Contract	January MW	January $	February MW	February $	March MW	March $	April MW	April $	May MW	May $	June MW	June $
Southern Intercompany Interchange	0.0		0.0	0	0.0	0	0.0	0	0.0	0	0.0	0
PPAs												
Shell Energy N.A. (U.S.), LP	[redacted]											
Other												
South Carolina PSA	[redacted]											
Total		7,396,477		7,396,477		7,396,477		7,396,477		7,396,477		7,396,477

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Gulf Power Company
2015 Capacity Contracts

Schedule CCE-4
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Contract/Counterparty	Term Start	Term End [1]	Contract 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			
South Carolina PSA	9/1/2003	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts became firm onn June 1, 2014.

Capacity Costs
2015

Contract	July MW	July $	August MW	August $	September MW	September $	October MW	October $	November MW	November $	December MW	December $	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	0.0	0	0.0	0	(2.3)	(1,000)	0.0	0	(1,000)
PPAs													
Shell Energy N.A. (U.S.), LP	[redacted]												
Other													
South Carolina PSA	[redacted]												
Total		7,396,477		7,396,477		7,396,477		7,396,477		7,395,477		7,396,477	88,756,724

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EXHIBIT TO THE TESTIMONY OF

M. A. YOUNG, III

IN FPSC DOCKET 140001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 41
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: M. A. Young MAY-1

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2013 - DECEMBER 2013 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2013 - December 2013 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
3/24/13	Crist 7	Add outage	PFO	3.0	288.0	ID fan tripped on vibration

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2013 - December 2013

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	1	10/26/13 -12/22/13	1393.0	Canceled	0.0
Smith 3	2	3/22/13 - 4/07/13	408.0	3/21/13 - 4/10/13	475.0
Smith 3	3	12/14/13 - 12/20/13	168.0	12/01/13 - 12/09/13	193.3
Daniel 2	4	none	0.0	01/22/13 - 03/18/13	1325.8

* Planned outage hours in the January 2013 - December 2013 period only.

Notes: 1. The outage was canceled subsequent to the target filing.

2. The outage was extended to complete hot gas path work.

3. The outage date was changed subsequent to the target filing.

4. The outage date was added subsequent to the target filing.

Calculation of Actual Equivalent Availability
for January 2013 - December 2013
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	0.0	0.0	0.0	0.0	0.0	162.4	
	0.0	0.0	0.0	0.0	0.0	0.0	162.4
EFOH	0.0	0.0	0.0	0.0	0.0	10.7	
	0.0	0.0	0.0	0.0	0.0	0.0	10.7
MOH	0.0	0.0	0.0	8.4	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	90.0	98.4
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	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	744.0	672.0	743.0	231.1	744.0	243.0	
	0.0	661.0	111.1	657.9	721.0	654.0	6182.1

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(162.4 + 10.7 + 98.4 + 0.0)}{(8760.0 - 0.0 - 6182.1)}$$

$$EUOR = 0.1053$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1393.0

Target RSH* = 4162.6

$$EA = \left[1 - \frac{(1393.0 + 0.1053\ (8760.0 - 1393.0 - 4162.6))}{8760.0} \right] \times 100 = 80.2\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2013 - December 2013
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	5.2	0.0	10.2	0.0	0.0	0.0	
	12.6	0.0	38.0	0.0	0.0	6.8	72.7
EFOH	0.0	0.0	0.6	0.0	0.0	0.0	
	1.2	0.0	0.0	0.0	0.0	0.0	1.8
MOH	0.0	0.0	0.0	31.8	0.0	0.0	
	20.7	0.0	292.2	0.0	0.0	329.9	674.6
EMOH	0.0	0.0	0.0	0.0	1.7	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1.7
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	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	423.2	0.0	0.0	
	100.6	26.4	0.0	0.0	0.0	63.4	613.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(72.7 + 1.8 + 674.6 + 1.7)}{(8760.0 - 0.0 - 613.5)}$$

EUOR = 0.0922

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 1539.1

$$EA = \left[1 - \frac{(0.0 + 0.0922\ (8760.0 - 0.0 - 1539.1))}{8760.0} \right] \times 100 = 92.4\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2013 - December 2013
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	2.9	8.8	
	0.0	0.0	12.3	4.2	0.0	0.0	28.1
EFOH	3.8	3.7	0.0	0.7	8.6	11.6	
	4.1	0.0	1.9	0.0	15.7	7.5	57.6
MOH	0.0	7.7	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	26.4	0.0	34.1
EMOH	9.1	1.0	16.0	11.6	1.7	61.6	
	0.0	3.1	6.7	0.0	20.7	3.9	135.4
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	241.6	233.4	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	193.3	668.3
RSH	0.8	0.0	0.0	0.0	30.3	0.0	
	0.0	0.0	0.0	0.0	37.4	9.0	77.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(28.1 + 57.6 + 34.1 + 135.4)}{(8760.0 - 668.3 - 77.5)}$$

$$EUOR = 0.0318$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 576.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(576.0 + 0.0318\ (8760.0 - 576.0 - 0.0))}{8760.0} \right] \times 100 = 90.5\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2013 - December 2013
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	10.1	3.0	0.0	5.1	
	0.0	3.3	0.0	0.0	0.0	4.4	25.9
EFOH	0.0	0.0	1.8	4.2	0.1	4.2	
	0.0	0.5	0.0	0.0	1.7	0.0	12.5
MOH	0.0	30.0	0.0	0.0	95.0	0.0	
	0.0	36.7	0.0	0.0	0.0	264.0	425.7
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	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	744.0	633.7	427.8	193.0	554.6	0.0	
	0.0	376.0	720.0	577.4	284.6	310.4	4821.4

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(25.9 + 12.5 + 425.7 + 0.0)}{(8760.0 - 0.0 - 4821.4)}$$

EUOR = 0.1178

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 4733.2

$$EA = \left[1 - \frac{(0.0 + 0.1178\ (8760.0 - 0.0 - 4733.2))}{8760.0} \right] \times 100 = 94.6\ \%$$

#VALUE!

Calculation of Actual Equivalent Availability
for January 2013 - December 2013
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	4.2	
	0.0	0.0	0.0	46.9	0.0	0.0	51.1
EFOH	0.0	0.0	2.3	17.3	0.6	6.9	
	0.4	0.0	0.0	0.0	0.0	44.3	71.8
MOH	0.0	0.0	0.0	58.9	132.0	0.0	
	0.0	0.0	0.0	33.2	0.0	155.4	379.6
EMOH	0.0	0.0	0.0	0.0	1.2	3.9	
	0.0	0.0	0.0	0.0	0.0	0.0	5.1
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	234.0	672.0	419.8	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1325.8
RSH	510.0	0.0	287.2	294.0	280.0	0.0	
	0.0	0.0	625.0	589.9	645.3	107.4	3338.8

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(51.1 + 71.8 + 379.6 + 5.1)}{(8760.0 - 1325.8 - 3338.8)}$$

$$EUOR = 0.1239$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 5901.1

$$EA = \left[1 - \frac{(0.0 + 0.1239\ (8760.0 - 0.0 - 5901.1))}{8760.0} \right] \times 100 = 96.0\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2013 - December 2013

(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	81.2	80.2	80.0	-8.33
Crist 7	94.0	92.4	91.7	-6.96
Smith 3	91.1	90.5	90.0	-5.45
Daniel 1	94.7	94.6	92.6	-0.48
Daniel 2	97.1	96.0	96.8	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-EI.

** Refer to pages 3 through 7 of this Schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2013 - December 2013

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0	0.0	0.0	89689.2	0.0	55473.8	
	128585.5	13682.3	105915.2	11818.0	0.0	0.0	405164.0
BTU/Lb*	0.0	0.0	0.0	11781.4	0.0	11436.8	
	11531.9	11535.6	11728.1	11649.7	0.0	0.0	11629.0
Coal, MMBTU	0.0	0.0	0.0	1056664.3	0.0	634442.8	
	1482835.1	157833.5	1242184.1	137676.7	0.0	0.0	4711636.5
Oil, MMBTU	0.0	0.0	0.0	28.2	0.0	200.4	
	39.2	5.9	0.0	0.0	0.0	0.0	273.7
Gas, MMBTU	0.0	0.0	0.0	8144.0	0.0	16963.0	
	7942.0	4462.0	6449.0	38532.1	0.0	0.0	82492.1
Startup, MMBTU **	0.0	0.0	0.0	-4040.0	0.0	-8080.0	
	0.0	-4040.0	0.0	-4040.0	0.0	0.0	-20200.0
Total Fuel Consumption, MMBTU	0.0	0.0	0.0	1060796.5	0.0	643526.2	
	1490816.3	158261.4	1248633.1	172168.8	0.0	0.0	4774202.3
Net MWH Generation***	0	0	0	94237	0	56317	
	141920	14381	117459	15674	0	0	439988
Average Net Operating Heat Rate	---	---	---	11257	---	11427	
	10505	11005	10630	10984	---	---	10851

* 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 2013 - December 2013

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	184990.6	125653.9	162019.4	62922.2	175730.4	183361.9	
	149734.9	187864.4	103128.5	174894.4	161927.4	74117.5	1746345.5
BTU/Lb*	11731.1	11631.0	11752.3	11768.7	11765.2	11674.4	
	11464.9	11785.3	11255.5	11874.6	11854.2	11788.6	11707.8
Coal, MMBTU	2170143.2	1461480.5	1904100.6	740512.5	2067503.3	2140640.2	
	1716695.7	2214038.3	1160762.8	2076802.5	1919512.2	873740.5	20445932.3
Oil, MMBTU	115.5	115.2	264.0	156.8	59.5	173.6	
	286.3	141.0	80.1	84.8	321.3	357.6	2155.7
Gas, MMBTU	2053.0	431927.0	64153.0	9991.0	0.0	961.0	
	6097.0	5199.0	6538.0	0.0	3.1	4311.6	531233.7
Startup, MMBTU **	0.0	0.0	0.0	-2256.0	0.0	0.0	
	0.0	-2256.0	-4512.0	0.0	0.0	-2256.0	-11280.0
Total Fuel Consumption, MMBTU	2172311.7	1893522.7	1968517.6	748404.3	2067562.8	2141774.8	
	1723079.0	2217122.3	1162868.9	2076887.3	1919836.6	876153.7	20968041.7
Net MWH Generation***	199581	168159	184237	68305	192625	198793	
	158035	198810	114993	196453	181469	85503	1946963
Average Net Operating Heat Rate	10884	11260	10685	10957	10734	10774	
	10903	11152	10113	10572	10579	10247	10770

* 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 2013 - December 2013

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	2250346.0	2142450.0	1541990.0	1386123.0	1942142.0	1829799.0	
	2135046.0	2253546.0	2188777.0	2447377.9	2086787.9	1586720.9	23791105.7
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	2250346.0	2142450.0	1541990.0	1386123.0	1942142.0	1829799.0	
	2135046.0	2253546.0	2188777.0	2447377.9	2086787.9	1586720.9	23791105.7
Net MWH Generation***	328166	312983	223706	199732	282938	264578	
	310540	330024	320469	358267	304075	230444	3465922
Average Net Operating Heat Rate	6857	6845	6893	6940	6864	6916	
	6875	6828	6830	6831	6863	6885	6864

* 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 2013 - December 2013

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0	2204.0	67468.0	125710.0	23754.0	181408.0	
	172546.0	71442.0	0.0	36136.0	151056.5	41640.0	873364.5
BTU/Lb*	0.0	10861.0	11175.7	10968.8	11176.7	11109.9	
	10954.6	11005.9	0.0	11145.7	9815.3	10937.1	10826.0
Coal, MMBTU	0.0	23937.6	754002.1	1378887.8	265491.3	2015424.7	
	1890172.4	786283.5	0.0	402761.0	1482659.7	455421.6	9455041.7
Oil, MMBTU	0.0	3656.5	8349.6	5971.3	3923.6	1724.2	
	25.1	712.2	0.0	3191.3	342.5	3849.1	31745.4
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-2388.7	-2388.7	-2388.7	-2388.7	0.0	
	0.0	0.0	0.0	-2388.7	0.0	-2388.7	-14332.2
Total Fuel Consumption, MMBTU	0.0	25205.4	759963.0	1382470.4	267026.2	2017148.9	
	1890197.5	786995.7	0.0	403563.6	1483002.2	456882.0	9472454.9
Net MWH Generation***	0	1995	71241	133468	22380	193523	
	177259	76388	0	34324	134276	44801	889655
Average Net Operating Heat Rate	---	12634	10667	10358	11931	10423	
	10663	10303	---	11757	11044	10198	10647

* 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 2013 - December 2013

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0	0.0	8372.0	91748.0	78498.0	190526.0	
	163790.0	161506.0	22192.0	17230.0	15670.6	127876.0	877408.6
BTU/Lb*	0.0	0.0	11288.0	10986.4	11134.3	11107.4	
	10950.5	11013.4	11113.3	11045.0	11106.7	10896.8	11020.5
Coal, MMBTU	0.0	0.0	94503.1	1007980.2	874020.3	2116248.5	
	1793582.4	1778730.2	246626.4	190305.4	174048.4	1393438.4	9669483.3
Oil, MMBTU	0.0	0.0	7969.0	6478.6	4096.7	3237.0	
	254.0	15.3	1780.4	4939.8	3082.7	4107.4	35960.9
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-2388.7	-2388.7	-2388.7	0.0	
	0.0	0.0	0.0	-2388.7	-2388.7	-2388.7	-14332.2
Total Fuel Consumption, MMBTU	0.0	0.0	100083.4	1012070.1	875728.3	2119485.5	
	1793836.4	1778745.5	248406.8	192856.5	174742.4	1395157.1	9691112.0
Net MWH Generation***	0	0	8607	93180	81623	201489	
	168006	166886	23308	16356	15889	130743	906087
Average Net Operating Heat Rate	---	---	11628	10861	10729	10519	
	10677	10658	10658	11791	10998	10671	10696

* 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 2013 - December 2013
Adjusted to Target Basis Using Heat Rate
Equations Filed August 31, 2012

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	12183	12117	12137	12166	11888	12098	
		12633	12240	12160	12683	0	12372	
2.	Target Heat Rate	12183	12117	12137	10761	11888	11013	
	at Actual Conditions**	11066	11280	10673	11323	0	12372	
3.	Adjustment to Actual	0	0	0	1405	0	1085	
	Heat Rate (1-2)	1567	960	1487	1360	0	0	
4.	Actual Heat Rate	0	0	0	11257	0	11427	
	(Page 2 of Sched. 3)	10505	11005	10630	10984	0	0	
5.	Adjusted Actual	0	0	0	12662	0	12512	
	Heat Rate (4+3)	12072	11965	12117	12344	0	0	
6.	Net MWH Generation	0	0	0	94237	0	56317	
		141920	14381	117459	15674	0	0	
7.	Adjusted Actual Heat Rate for January 2013 - December 2013 $=(\Sigma(5*6)/\Sigma 6)$							12273

* From pages 17 & 18, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013
Adjusted to Target Basis Using Heat Rate
Equations Filed August 31, 2012

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11404	11417	11394	11654	11280	10791	
		10820	10769	11034	11220	11421	11405	
2.	Target Heat Rate	11261	11443	11434	11628	11344	10982	
	at Actual Conditions**	11352	11203	11079	11293	11429	11452	
3.	Adjustment to Actual	143	-26	-40	26	-64	-191	
	Heat Rate (1-2)	-532	-434	-45	-73	-8	-47	
4.	Actual Heat Rate	10884	11260	10685	10957	10734	10774	
	(Page 3 of Sched. 3)	10903	11152	10113	10572	10579	10247	
5.	Adjusted Actual	11027	11234	10645	10983	10670	10583	
	Heat Rate (4+3)	10371	10718	10068	10499	10571	10200	
6.	Net MWH Generation	199581	168159	184237	68305	192625	198793	
		158035	198810	114993	196453	181469	85503	
7.	Adjusted Actual Heat Rate for January 2013 - December 2013 $=(\Sigma(5*6)/\Sigma 6)$							10653

* From pages 19 & 20, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013
Adjusted to Target Basis Using Heat Rate
Equations Filed August 31, 2012

Smith 3

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	6820	6826	6831	6842	6849	6865	
		6863	6862	6868	6765	6866	6861	
2.	Target Heat Rate	7244	7221	7240	7272	7284	7313	
	at Actual Conditions**	7265	7242	7235	7122	7227	7258	
3.	Adjustment to Actual	-424	-395	-409	-430	-435	-448	
	Heat Rate (1-2)	-402	-380	-367	-357	-361	-397	
4.	Actual Heat Rate	6857	6845	6893	6940	6864	6916	
	(Page 4 of Sched. 3)	6875	6828	6830	6831	6863	6885	
5.	Adjusted Actual	6433	6450	6484	6510	6429	6468	
	Heat Rate (4+3)	6473	6448	6463	6474	6502	6488	
6.	Net MWH Generation	328166	312983	223706	199732	282938	264578	
		310540	330024	320469	358267	304075	230444	
7.	Adjusted Actual Heat Rate for January 2013 - December 2013 =(Σ (5*6) / Σ 6)							6466

* From pages 21 & 22, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013
Adjusted to Target Basis Using Heat Rate
Equations Filed August 31, 2012

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11129	11283	10470	10402	10321	10718	
		10771	10475	10238	10658	10362	10722	
2.	Target Heat Rate	11129	10927	10977	10793	10944	10674	
	at Actual Conditions**	11207	10983	10238	11271	10741	10671	
3.	Adjustment to Actual	0	356	-507	-391	-623	44	
	Heat Rate (1-2)	-436	-508	0	-613	-379	51	
4.	Actual Heat Rate***	0	12634	10667	10358	11931	10423	
	(Page 5 of Sched. 3)	10663	10303	0	11757	11044	10198	
5.	Adjusted Actual	0	12990	10160	9967	11308	10467	
	Heat Rate (4+3)	10227	9795	0	11144	10665	10249	
6.	Net MWH Generation	0	1995	71241	133468	22380	193523	
		177259	76388	0	34324	134276	44801	
7.	Adjusted Actual Heat Rate for January 2013 - December 2013 =(Σ (5*6) / Σ 6)							10334

* From pages 23 & 24, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013
Adjusted to Target Basis Using Heat Rate
Equations Filed August 31, 2012

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10544	10479	12030	10269	0	10631	
		10621	10566	10593	10702	10379	10932	
2.	Target Heat Rate	10544	10479	10708	10777	10926	10447	
	at Actual Conditions**	10830	10879	10709	10928	10954	10709	
3.	Adjustment to Actual	0	0	1322	-508	-315	184	
	Heat Rate (1-2)	-209	-313	-116	-226	-575	223	
4.	Actual Heat Rate***	0	0	11628	10861	10729	10519	
	(Page 6 of Sched. 3)	10677	10658	10658	11791	10998	10671	
5.	Adjusted Actual	0	0	12950	10353	10414	10703	
	Heat Rate (4+3)	10468	10345	10542	11565	10423	10894	
6.	Net MWH Generation	0	0	8607	93180	81623	201489	
		168006	166886	23308	16356	15889	130743	
7.	Adjusted Actual Heat Rate for January 2013 - December 2013 =(Σ (5*6) / Σ 6)							10587

* From pages 25 & 26, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 6						
+3						
AKW * 10	0.0	0.0	0.0	196.1	0.0	179.0
	190.8	173.3	192.9	182.1	0.0	0.0
+6						
LSRF * 10	0.0	0.0	0.0	39356.6	0.0	33887.3
	36636.7	32129.7	37298.8	34955.5	0.0	0.0
Crist 7						
+3						
AKW * 10	270.1	250.2	251.4	257.7	258.9	276.1
	259.0	277.0	295.0	264.0	251.7	248.7
+6						
LSRF * 10	76436.5	62833.1	63820.6	67396.5	67836.7	80154.6
	68431.5	81094.5	94166.1	71060.9	63880.9	61456.3
Smith 3						
+3						
AKW * 10	441.5	471.1	446.2	410.4	398.1	372.0
	417.4	443.6	452.8	484.3	462.7	425.4
+6						
LSRF * 10	207279.5	228409.2	210817.0	189070.4	179834.0	159664.3
	190747.5	206352.3	215811.7	241735.2	221516.9	195320.5
Daniel 1						
+3						
AKW * 10	0.0	238.9	233.5	254.7	237.0	270.7
	238.3	232.8	0.0	206.0	307.7	271.1
+6						
LSRF * 10	0.0	73030.6	60843.3	72834.3	64389.7	84679.1
	66665.1	61293.1	0.0	44654.3	111305.9	84549.5
Daniel 2						
+3						
AKW * 10	0.0	0.0	239.4	253.8	245.9	281.5
	225.8	224.3	245.3	221.0	209.9	271.7
+6						
LSRF * 10	0.0	0.0	69988.4	71783.5	71720.4	93078.8
	59129.4	56309.4	72168.4	52924.6	48102.3	82145.3

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [1092.37 - 31.97 * MAY + 69.51 * JUL + 28.15 * AUG + 63.58 * OCT]
+ 247 + 0.02463 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [1109.67 + 68.77 * APR - 61.47 * JUN]
+ 5,868 + 0.00454 * LSRF / AKW

Smith 3 ANOHR = 10^6 / AKW * [160.82 - 42.90 * OCT]
+ 6,894 - 0.00003 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [515.05 + 63.65 * JAN + 65.39 * JUL - 84.66 * SEP + 91.23 * NOV]
+ 8,771

Daniel 2 ANOHR = 10^6 / AKW * [-99.14 - 68.37 * JAN + 50.20 * MAY - 38.91 * JUN]
+ 12,531 - 0.00482 * LSRF / AKW

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 2013 - December 2013

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 6	12243	12273	11876	0.00
Crist 7	11178	10653	10843	10.00
Smith 3	6842	6466	6637	10.00
Daniel 1	10591	10334	10273	7.49
Daniel 2	10611	10587	10293	0.00

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-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 2013 - December 2013

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 6	-8.33	0.032	0.00	0.071
Crist 7	-6.96	0.061	10.00	0.307
Smith 3	-5.45	0.006	10.00	0.359
Daniel 1	-0.48	0.025	7.49	0.078
Daniel 2	-10.00	0.010	0.00	0.051

Company GPIF Points =

- 8.33 * 0.032 + 0.00 * 0.071
- 6.96 * 0.061 + 10.00 * 0.307
- 5.45 * 0.006 + 10.00 * 0.359
- 0.48 * 0.025 + 7.49 * 0.078
- 10.00 * 0.010 + 0.00 * 0.051

= 6.41

Company reward/penalty = 6.41 points * $479864 per point

= $3,075,930

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's August 31, 2012 GPIF Testimony in Docket 120001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2013 - DECEMBER 2013 PERIOD

CONTENTS	SCHEDULE 5 PAGE
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Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2013 - December 2013

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	7875	4799
+ 9	7088	4319
+ 8	6300	3839
+ 7	5513	3359
+ 6	4725	2879
+ 5	3938	2399
+ 4	3150	1919
+ 3	2363	1440
+ 2	1575	960
+ 1	788	480
0	0	0
- 1	-812	-480
- 2	-1624	-960
- 3	-2436	-1440
- 4	-3248	-1919
- 5	-4061	-2399
- 6	-4873	-2879
- 7	-5685	-3359
- 8	-6497	-3839
- 9	-7309	-4319
- 10	-8121	-4799
	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

Actual

Gulf Power Company

Period of: January 2013 - December 2013

Line 1	Beginning of Period Balance of Common Equity	$1,180,741,781
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '13	$1,158,261,211
Line 3	Month of Feb '13	$1,206,612,037
Line 4	Month of Mar '13	$1,214,961,494
Line 5	Month of Apr '13	$1,190,919,135
Line 6	Month of May '13	$1,203,427,412
Line 7	Month of Jun '13	$1,220,350,594
Line 8	Month of Jul '13	$1,205,757,716
Line 9	Month of Aug '13	$1,221,645,779
Line 10	Month of Sep '13	$1,237,032,568
Line 11	Month of Oct '13	$1,215,474,231
Line 12	Month of Nov '13	$1,224,611,149
Line 13	Month of Dec '13	$1,235,125,575
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,208,840,052
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)	$4,938,653
Line 18	Jurisdictional Sales (KWH)	10,619,888,662
Line 19	Total Territorial Sales (KWH)	10,929,744,702
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.1650%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$4,798,643

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Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2013 - December 2013

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 6	EAF1	3.2%	-8.33	-0.267
Crist 6	ANOHR1	7.1%	0.00	0.000
Crist 7	EAF2	6.1%	-6.96	-0.425
Crist 7	ANOHR2	30.7%	10.00	3.070
Smith 3	EAF3	0.6%	-5.45	-0.033
Smith 3	ANOHR3	35.9%	10.00	3.590
Daniel 1	EAF4	2.5%	-0.48	-0.012
Daniel 1	ANOHR4	7.8%	7.49	0.584
Daniel 2	EAF5	1.0%	-10.00	-0.100
Daniel 2	ANOHR5	5.1%	0.00	0.000
Gulf Power GPIF Total		100.0%		6.41

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2013 - December 2013

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	250	82.10	+ 10	558	11,876
+ 9	225	82.01	+ 9	502	11,905
+ 8	200	81.92	+ 8	446	11,934
+ 7	175	81.83	+ 7	391	11,964
+ 6	150	81.74	+ 6	335	11,993
+ 5	125	81.65	+ 5	279	12,022
+ 4	100	81.56	+ 4	223	12,051
+ 3	75	81.47	+ 3	167	12,080
+ 2	50	81.38	+ 2	112	12,110
+ 1	25	81.29	+ 1	56	12,139
				0	12,168
0	0	81.20	0	0	12,243
				0	12,318
- 1	(22)	81.08	- 1	(56)	12,347
- 2	(44)	80.96	- 2	(112)	12,376
- 3	(65)	80.84	- 3	(167)	12,406
- 4	(87)	80.72	- 4	(223)	12,435
- 5	(109)	80.60	- 5	(279)	12,464
- 6	(131)	80.48	- 6	(335)	12,493
- 7	(153)	80.36	- 7	(391)	12,522
- 8	(174)	80.24	- 8	(446)	12,552
- 9	(196)	80.12	- 9	(502)	12,581
- 10	(218)	80.00	- 10	(558)	12,610
Weighting Factor:		0.032	Weighting Factor:		0.071

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2013 - December 2013

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	482	96.00	+ 10	2,414	10,843
+ 9	434	95.80	+ 9	2,173	10,869
+ 8	386	95.60	+ 8	1,931	10,895
+ 7	337	95.40	+ 7	1,690	10,921
+ 6	289	95.20	+ 6	1,448	10,947
+ 5	241	95.00	+ 5	1,207	10,973
+ 4	193	94.80	+ 4	966	10,999
+ 3	145	94.60	+ 3	724	11,025
+ 2	96	94.40	+ 2	483	11,051
+ 1	48	94.20	+ 1	241	11,077
				0	11,103
0	0	94.00	0	0	11,178
				0	11,253
- 1	(68)	93.77	- 1	(241)	11,279
- 2	(136)	93.54	- 2	(483)	11,305
- 3	(204)	93.31	- 3	(724)	11,331
- 4	(272)	93.08	- 4	(966)	11,357
- 5	(340)	92.85	- 5	(1,207)	11,383
- 6	(408)	92.62	- 6	(1,448)	11,409
- 7	(476)	92.39	- 7	(1,690)	11,435
- 8	(544)	92.16	- 8	(1,931)	11,461
- 9	(612)	91.93	- 9	(2,173)	11,487
- 10	(680)	91.70	- 10	(2,414)	11,513
Weighting Factor:		0.061	Weighting Factor:		0.307

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2013 - December 2013

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	51	91.80	+ 10	2,827	6,637
+ 9	46	91.73	+ 9	2,544	6,650
+ 8	41	91.66	+ 8	2,262	6,663
+ 7	36	91.59	+ 7	1,979	6,676
+ 6	31	91.52	+ 6	1,696	6,689
+ 5	26	91.45	+ 5	1,414	6,702
+ 4	20	91.38	+ 4	1,131	6,715
+ 3	15	91.31	+ 3	848	6,728
+ 2	10	91.24	+ 2	565	6,741
+ 1	5	91.17	+ 1	283	6,754
				0	6,767
0	0	91.10	0	0	6,842
				0	6,917
- 1	(8)	90.99	- 1	(283)	6,930
- 2	(16)	90.88	- 2	(565)	6,943
- 3	(23)	90.77	- 3	(848)	6,956
- 4	(31)	90.66	- 4	(1,131)	6,969
- 5	(39)	90.55	- 5	(1,414)	6,982
- 6	(47)	90.44	- 6	(1,696)	6,995
- 7	(55)	90.33	- 7	(1,979)	7,008
- 8	(62)	90.22	- 8	(2,262)	7,021
- 9	(70)	90.11	- 9	(2,544)	7,034
- 10	(78)	90.00	- 10	(2,827)	7,047
Weighting Factor:		0.006	Weighting Factor:		0.359

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2013 - December 2013

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	194	96.50	+ 10	613	10,273
+ 9	175	96.32	+ 9	552	10,297
+ 8	155	96.14	+ 8	490	10,322
+ 7	136	95.96	+ 7	429	10,346
+ 6	116	95.78	+ 6	368	10,370
+ 5	97	95.60	+ 5	307	10,395
+ 4	78	95.42	+ 4	245	10,419
+ 3	58	95.24	+ 3	184	10,443
+ 2	39	95.06	+ 2	123	10,467
+ 1	19	94.88	+ 1	61	10,492
				0	10,516
0	0	94.70	0	0	10,591
				0	10,666
- 1	(27)	94.49	- 1	(61)	10,690
- 2	(54)	94.28	- 2	(123)	10,715
- 3	(82)	94.07	- 3	(184)	10,739
- 4	(109)	93.86	- 4	(245)	10,763
- 5	(136)	93.65	- 5	(307)	10,788
- 6	(163)	93.44	- 6	(368)	10,812
- 7	(190)	93.23	- 7	(429)	10,836
- 8	(218)	93.02	- 8	(490)	10,860
- 9	(245)	92.81	- 9	(552)	10,885
- 10	(272)	92.60	- 10	(613)	10,909
Weighting Factor:		0.025	Weighting Factor:		0.078

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2013 - December 2013

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	81	98.40	+ 10	405	10,293
+ 9	73	98.27	+ 9	365	10,317
+ 8	65	98.14	+ 8	324	10,342
+ 7	57	98.01	+ 7	284	10,366
+ 6	49	97.88	+ 6	243	10,390
+ 5	41	97.75	+ 5	203	10,415
+ 4	32	97.62	+ 4	162	10,439
+ 3	24	97.49	+ 3	122	10,463
+ 2	16	97.36	+ 2	81	10,487
+ 1	8	97.23	+ 1	41	10,512
				0	10,536
0	0	97.10	0	0	10,611
				0	10,686
- 1	(6)	97.07	- 1	(41)	10,710
- 2	(11)	97.04	- 2	(81)	10,735
- 3	(17)	97.01	- 3	(122)	10,759
- 4	(22)	96.98	- 4	(162)	10,783
- 5	(28)	96.95	- 5	(203)	10,808
- 6	(34)	96.92	- 6	(243)	10,832
- 7	(39)	96.89	- 7	(284)	10,856
- 8	(45)	96.86	- 8	(324)	10,880
- 9	(50)	96.83	- 9	(365)	10,905
- 10	(56)	96.80	- 10	(405)	10,929
Weighting Factor:		0.010	Weighting Factor:		0.051

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2013 - December 2013

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	3.2	81.2	82.1	80.0	$250	($218)	80.2	($182)
Crist 7	6.1	94.0	96.0	91.7	$482	($680)	92.4	($473)
Smith 3	0.6	91.1	91.8	90.0	$51	($78)	90.5	($43)
Daniel 1	2.5	94.7	96.5	92.6	$194	($272)	94.6	($13)
Daniel 2	1.0	97.1	98.4	96.8	$81	($56)	96.0	($56)
Total:	13.4							

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	7.1	12,243	42.1	12,610	11,876	$558	($558)	12,273	$0
Crist 7	30.7	11,178	59.2	11,513	10,843	$2,414	($2,414)	10,653	$2,414
Smith 3	35.9	6,842	90.5	7,047	6,637	$2,827	($2,827)	6,466	$2,827
Daniel 1	7.8	10,591	56.3	10,909	10,273	$613	($613)	10,334	$459
Daniel 2	5.1	10,611	51.6	10,929	10,293	$405	($405)	10,587	$0
Total:	86.6								

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2013 - December 2013

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 6	96.9	-16.7	80.2
Crist 7	91.4	1.0	92.4
Smith 3	89.5	1.0	90.5
Daniel 1	94.7	-0.1	94.6
Daniel 2	79.1	16.9	96.0

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 6	10,851	1422	12,273
Crist 7	10,770	-117	10,653
Smith 3	6,864	-398	6,466
Daniel 1	10,647	-313	10,334
Daniel 2	10,696	-109	10,587

* Refer to pages 3 through 7, Schedule 2.

** Refer to pages 7 through 11, Schedule 3.

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	CRIST 6	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Jun '13	
1.	EAF (%)	100.0	100.0	100.0	98.8	100.0	76.0	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	0.0	0.0	0.0	480.5	0.0	314.6	
4.	RSH	744.0	672.0	743.0	231.1	744.0	243.0	
5.	UH	0.0	0.0	0.0	8.4	0.0	162.4	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	162.4	
8.	MOH	0.0	0.0	0.0	8.4	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	20.6	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	155.0	
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)	299.0	299.0	299.0	299.0	299.0	299.0	
14.	Oper MBtu	0	0	0	1060797	0	643526	
15.	Net Gen (MWH	0	0	0	94237	0	56317	
16.	ANOHR (Btu/K	0	0	0	11257	0	11427	
17.	NOF %	0.0	0.0	0.0	65.6	0.0	59.9	
18.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	
19.	ANOHR Equati	10^6 / AKW * [1092.37 - 31.97 * MAY + 69.51 * JUL + 28.15 * AUG + 63.58 * OCT] + 247 + 0.02463 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	CRIST 6	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Total
1.	EAF (%)	100.0	100.0	100.0	100.0	100.0	87.9	96.9
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	83.0	608.9	86.1	0.0	0.0	2317.1
4.	RSH	0.0	661.0	111.1	657.9	721.0	654.0	6182.1
5.	UH	0.0	0.0	0.0	0.0	0.0	90.0	260.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	162.4
8.	MOH	0.0	0.0	0.0	0.0	0.0	90.0	98.4
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	20.6
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	155.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	299.0
14.	Oper MBtu	1490816	158261	1248633	172169	0	0	4774202
15.	Net Gen (MWH	141920	14381	117459	15674	0	0	439988
16.	ANOHR (Btu/K	10505	11005	10630	10984	0	0	10851
17.	NOF %	63.8	58.0	64.5	60.9	0.0	0.0	63.5
18.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	299.0
19.	ANOHR Equati	10^6 / AKW * [1092.37 - 31.97 * MAY + 69.51 * JUL + 28.15 * AUG + 63.58 * OCT] + 247 + 0.02463 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	CRIST 7	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Jun '13	
1.	EAF (%)	99.3	100.0	98.6	95.6	99.8	100.0	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	738.8	672.0	732.8	265.1	744.0	720.0	
4.	RSH	0.0	0.0	0.0	423.2	0.0	0.0	
5.	UH	5.2	0.0	10.2	31.8	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	5.2	0.0	10.2	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	31.8	0.0	0.0	
9.	PFOH	0.0	0.0	3.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	88.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	9.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	88.0	0.0	
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
14.	Oper MBtu	2172312	1893523	1968518	748404	2067563	2141775	
15.	Net Gen (MWH	199581	168159	184237	68305	192625	198793	
16.	ANOHR (Btu/K	10884	11260	10685	10957	10734	10774	
17.	NOF %	56.9	52.7	52.9	54.3	54.5	58.1	
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	

19.	ANOHR Equati	10^6 / AKW * [1109.67 + 68.77 * APR - 61.47 * JUN] + 5,868 + 0.00454 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	CRIST 7	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Total
1.	EAF (%)	95.4	100.0	54.1	100.0	100.0	54.7	91.4
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	610.2	717.7	389.8	744.0	721.0	343.9	7399.2
4.	RSH	100.6	26.4	0.0	0.0	0.0	63.4	613.5
5.	UH	33.2	0.0	330.2	0.0	0.0	336.7	747.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	12.6	0.0	38.0	0.0	0.0	6.8	72.7
8.	MOH	20.7	0.0	292.2	0.0	0.0	329.9	674.6
9.	PFOH	2.7	0.0	0.0	0.0	0.0	0.0	5.7
10.	LR pf (MW)	209.0	0.0	0.0	0.0	0.0	0.0	145.7
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	9.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	88.0
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
14.	Oper MBtu	1723079	2217122	1162869	2076887	1919836	876147	20968035
15.	Net Gen (MWH	158035	198810	114993	196453	181469	85503	1946963
16.	ANOHR (Btu/K	10903	11152	10113	10572	10579	10247	10770
17.	NOF %	54.5	58.3	62.1	55.6	53.0	52.3	55.4
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0

19.	ANOHR Equati	10^6 / AKW * [1109.67 + 68.77 * APR - 61.47 * JUN] + 5,868 + 0.00454 * LSRF / AKW

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	SMITH 3	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Jun '13	
1.	EAF (%)	98.3	98.2	65.3	65.9	98.2	88.6	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	743.2	664.3	501.4	486.7	710.8	711.3	
4.	RSH	0.8	0.0	0.0	0.0	30.3	0.0	
5.	UH	0.0	7.7	241.6	233.4	2.9	8.8	
6.	POH	0.0	0.0	241.6	233.4	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	2.9	8.8	
8.	MOH	0.0	7.7	0.0	0.0	0.0	0.0	
9.	PFOH	8.4	9.2	0.0	1.6	30.3	28.0	
10.	LR pf (MW)	265.3	237.3	0.0	239.0	159.0	229.5	
11.	PMOH	20.1	5.0	33.6	27.2	4.0	143.3	
12.	LR pm (MW)	265.0	121.0	265.0	239.0	239.0	239.0	
13.	NSC (MW)	584.0	584.0	558.0	558.0	558.0	556.0	
14.	Oper MBtu	2250346	2142450	1541990	1386123	1942142	1829799	
15.	Net Gen (MWH	328166	312983	223706	199732	282938	264578	
16.	ANOHR (Btu/K	6857	6845	6893	6940	6864	6916	
17.	NOF %	75.6	80.7	80.0	73.6	71.3	66.9	
18.	NPC (MW)	584.0	584.0	558.0	558.0	558.0	556.0	

19.	ANOHR Equati	10^6 / AKW * [160.82 - 42.90 * OCT] + 6,894 - 0.00003 * LSRF / AKW

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	SMITH 3	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Total
1.	EAF (%)	99.4	99.6	97.1	99.4	91.3	72.5	89.5
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	707.7	739.8	657.2	541.7	7952.0
4.	RSH	0.0	0.0	0.0	0.0	37.4	9.0	77.5
5.	UH	0.0	0.0	12.3	4.2	26.4	193.3	730.5
6.	POH	0.0	0.0	0.0	0.0	0.0	193.3	668.3
7.	FOH	0.0	0.0	12.3	4.2	0.0	0.0	28.1
8.	MOH	0.0	0.0	0.0	0.0	26.4	0.0	34.1
9.	PFOH	9.6	0.0	4.3	0.0	49.4	81.9	222.7
10.	LR pf (MW)	239.0	0.0	239.0	0.0	177.6	53.3	145.9
11.	PMOH	0.0	7.3	15.7	0.0	43.6	8.6	308.3
12.	LR pm (MW)	0.0	239.0	239.0	0.0	265.0	265.0	246.0
13.	NSC (MW)	556.0	556.0	556.0	558.0	558.0	584.0	563.8
14.	Oper MBtu	2135046	2253546	2188777	2447378	2086788	1586721	23791106
15.	Net Gen (MWH	310540	330024	320469	358267	304075	230444	3465922
16.	ANOHR (Btu/K	6875	6828	6830	6831	6863	6885	6864
17.	NOF %	75.1	79.8	81.4	86.8	82.9	72.8	77.3
18.	NPC (MW)	556.0	556.0	556.0	558.0	558.0	584.0	563.8
19.	ANOHR Equati	10^6 / AKW * [160.82 - 42.90 * OCT] + 6,894 - 0.00003 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	DANIEL 1	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Jun '13	
1.	EAF (%)	100.0	95.5	98.4	99.0	87.2	98.7	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	0.0	8.4	305.1	523.9	94.4	714.9	
4.	RSH	744.0	633.7	427.8	193.0	554.6	0.0	
5.	UH	0.0	30.0	10.1	3.0	95.0	5.1	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	10.1	3.0	0.0	5.1	
8.	MOH	0.0	30.0	0.0	0.0	95.0	0.0	
9.	PFOH	0.0	0.0	7.3	14.1	0.5	9.5	
10.	LR pf (MW)	0.0	0.0	126.0	150.6	85.0	226.0	
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	0	25205	759963	1382470	267026	2017149	
15.	Net Gen (MWH	0	1995	71241	133468	22380	193523	
16.	ANOHR (Btu/K	0	12634	10667	10358	11931	10423	
17.	NOF %	0.0	46.8	45.8	49.9	46.5	53.1	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
19.	ANOHR Equati	10^6 / AKW * [515.05 + 63.65 * JAN + 65.39 * JUL - 84.66 * SEP + 91.23 * NOV] + 8,771						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	DANIEL 1	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Total
1.	EAF (%)	100.0	94.6	100.0	100.0	99.8	63.9	94.7
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	328.1	0.0	166.6	436.4	165.3	3487.1
4.	RSH	0.0	376.0	720.0	577.4	284.6	310.4	4821.4
5.	UH	0.0	39.9	0.0	0.0	0.0	268.4	451.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	3.3	0.0	0.0	0.0	4.4	25.9
8.	MOH	0.0	36.7	0.0	0.0	0.0	264.0	425.7
9.	PFOH	0.0	1.9	0.0	0.0	9.9	0.0	43.2
10.	LR pf (MW)	0.0	136.0	0.0	0.0	85.0	0.0	146.6
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	1890198	786996	0	403564	1482997	456862	9472431
15.	Net Gen (MWH	177259	76388	0	34324	134276	44801	889655
16.	ANOHR (Btu/K	10663	10303	0	11757	11044	10198	10647
17.	NOF %	46.7	45.7	0.0	40.4	60.3	53.2	50.0
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
19.	ANOHR Equati	10^6 / AKW * [515.05 + 63.65 * JAN + 65.39 * JUL - 84.66 * SEP + 91.23 * NOV] + 8,771						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	DANIEL 2	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Jun '13	
1.	EAF (%)	68.5	0.0	43.2	89.4	82.0	97.9	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	0.0	0.0	36.0	367.1	332.0	715.8	
4.	RSH	510.0	0.0	287.2	294.0	280.0	0.0	
5.	UH	234.0	672.0	419.8	58.9	132.0	4.2	
6.	POH	234.0	672.0	419.8	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	4.2	
8.	MOH	0.0	0.0	0.0	58.9	132.0	0.0	
9.	PFOH	0.0	0.0	4.8	36.7	1.2	20.0	
10.	LR pf (MW)	0.0	0.0	246.9	239.7	235.0	176.8	
11.	PMOH	0.0	0.0	0.0	0.0	2.7	8.1	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	236.0	245.0	
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
14.	Oper MBtu	0	0	100083	1012070	875728	2119485	
15.	Net Gen (MWH	0	0	8607	93180	81623	201489	
16.	ANOHR (Btu/K	0	0	11628	10861	10729	10519	
17.	NOF %	0.0	0.0	46.9	49.8	48.2	55.2	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equati	10^6 / AKW * [-99.14 - 68.37 * JAN + 50.20 * MAY - 38.91 * JUN] + 12,531 - 0.00482 * LSRF / AKW

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2013 - December 2013

	DANIEL 2	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Total
1.	EAF (%)	99.9	100.0	100.0	89.2	100.0	73.2	79.1
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	95.0	74.0	75.7	481.2	3664.7
4.	RSH	0.0	0.0	625.0	589.9	645.3	107.4	3338.8
5.	UH	0.0	0.0	0.0	80.1	0.0	155.4	1756.5
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1325.8
7.	FOH	0.0	0.0	0.0	46.9	0.0	0.0	51.1
8.	MOH	0.0	0.0	0.0	33.2	0.0	155.4	379.6
9.	PFOH	0.6	0.0	0.0	0.0	0.0	97.1	160.3
10.	LR pf (MW)	365.0	0.0	0.0	0.0	0.0	232.8	228.3
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	10.8
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	242.8
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
14.	Oper MBtu	1793836	1778745	248407	192857	174742	1395136	9691089
15.	Net Gen (MWH	168006	166886	23308	16356	15889	130743	906087
16.	ANOHR (Btu/K	10677	10658	10658	11791	10998	10671	10696
17.	NOF %	44.3	44.0	48.1	43.3	41.2	53.3	48.5
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
19.	ANOHR Equati	10^6 / AKW * [-99.14 - 68.37 * JAN + 50.20 * MAY - 38.91 * JUN] + 12,531 - 0.00482 * LSRF / AKW						

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Planned Outage Schedules (Actual)

Period of: January 2013 - December 2013

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

M. A. YOUNG, III

IN FPSC DOCKET 140001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 42
PARTY: GULF POWER (GULF)(DIRECT)
DESCRIPTION: M. A. Young MAY-2

I. DETERMINATION OF HEAT RATE TARGETS

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
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 CRIST 6 Target Heat Rate Equation

HtRt	HR	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
11992	108	166.00	31680.	0	0	0	0	0	0	1	0	0	0	0	1	2011	
12017	168	162.20	29049.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
12302	168	137.30	19866.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
11797	93	152.00	23793.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
11856	161	150.70	25323.	0	0	0	0	0	0	0	1	0	0	0	1	2011	
11632	54	173.00	34919.	0	0	0	0	0	0	0	1	0	0	0	1	2011	
11171	168	178.20	35342.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11212	168	172.80	32908.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11098	168	183.30	37552.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11855	163	135.80	19869.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
11625	168	153.70	26369.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
11604	168	155.70	27090.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
11198	136	166.30	32011.	0	0	0	0	0	0	0	0	1	0	0	1	2011	
11975	168	127.20	16651.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
12182	168	134.50	18587.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
12317	168	124.30	15560.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
12343	164	122.20	15044.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
12250	76	119.60	14538.	0	0	0	0	0	0	0	0	0	0	1	1	2011	
11456	140	136.70	20466.	0	0	0	0	0	0	0	0	0	0	1	1	2011	
11800	72	128.60	16878.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
11952	140	137.10	19829.	0	0	0	0	0	0	0	0	0	0	0	1	2011	
12056	168	132.10	18221.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
12084	168	126.00	16071.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
12017	24	124.90	15682.	0	0	0	0	0	0	0	0	0	0	0	0	2011	Dec
11889	120	144.10	22044.	1	0	0	0	0	0	0	0	0	0	0	0	2012	
12270	106	145.20	26039.	0	0	0	1	0	0	0	0	0	0	0	1	2012	
11057	168	173.20	34715.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10426	168	193.00	40563.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10227	168	216.00	48109.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10091	168	241.80	59959.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
* 8718	168	213.10	45408.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10882	168	229.90	53953.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
10915	168	218.40	48094.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
10660	153	223.60	51774.	0	0	0	0	0	1	0	0	0	0	0	0	2012	Jun
11033	33	180.50	36522.	0	0	0	0	0	0	1	0	0	0	0	1	2012	
10437	168	217.10	47588.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
11197	168	201.30	40633.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11388	160	226.60	53652.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11726	153	189.30	36646.	0	0	0	0	0	0	0	1	0	0	0	1	2012	
10989	168	192.40	37036.	0	0	0	0	0	0	0	0	1	0	0	0	2012	
10773	168	196.90	39175.	0	0	0	0	0	0	0	0	1	0	0	0	2012	
10638	165	197.60	39630.	0	0	0	0	0	0	0	0	1	0	0	0	2012	
10787	137	195.70	39790.	0	0	0	0	0	0	0	0	1	0	0	1	2012	
10961	97	197.00	40584.	0	0	0	0	0	0	0	0	0	1	0	1	2012	
10768	168	205.70	42661.	0	0	0	0	0	0	0	0	0	1	0	0	2012	
10790	168	193.70	37770.	0	0	0	0	0	0	0	0	0	1	0	0	2012	
10857	168	192.70	37305.	0	0	0	0	0	0	0	0	0	1	0	0	2012	
10775	151	192.80	37303.	0	0	0	0	0	0	0	0	0	1	0	0	2012	
11141	104	173.10	30700.	0	0	0	0	0	0	0	0	0	0	1	1	2012	
*11212	85	120.30	14877.	0	0	0	0	0	0	0	0	0	0	1	1	2012	
11053	168	176.60	32009.	0	0	0	0	0	0	0	0	0	0	1	0	2012	
10531	168	208.60	44859.	0	0	0	0	0	0	0	0	0	0	1	0	2012	
10537	168	211.20	46048.	0	0	0	0	0	0	0	0	0	0	0	0	2012	

Data Base for CRIST 6 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10467	168	204.00	42392.	0	0	0	0	0	0	0	0	0	0	0	0	2012	
10412	142	193.30	37486.	0	0	0	0	0	0	0	0	0	0	0	0	2012	Dec
11409	125	191.20	37711.	0	0	0	1	0	0	0	0	0	0	0	1	2013	
11326	168	200.80	40954.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
11300	168	197.90	39674.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
10248	19	176.40	33251.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
11434	165	185.20	35872.	0	0	0	0	0	1	0	0	0	0	0	1	2013	
11319	117	174.20	31816.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
*13293	32	168.20	31224.	0	0	0	0	0	1	0	0	0	0	0	1	2013	Jun
10647	168	193.47	37441	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
10498	168	193.99	37648	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10511	168	198.91	39977	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10385	168	190.33	36369	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10661	126	166.06	22340	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	1	0	0	0	0	2013	
10865	53	179.38	11226	0	0	0	0	0	0	0	1	0	0	0	1	2013	
10749	168	192.99	37289	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10730	168	192.04	36912	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10611	168	195.32	38228	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10228	81	189.42	20445	0	0	0	0	0	0	0	0	1	0	0	0	2013	
11357	66	181.00	14562	0	0	0	0	0	0	0	0	0	1	0	1	2013	
* 9790	20	186.40	5075	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	
* 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	
* 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	1	0	2013	
* 0	0	0.00	0	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	
* 0	0	0.00	0	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	
11329	93	183.80	20529	1	0	0	0	0	0	0	0	0	0	0	1	2014	JAN
11336	168	192.32	36996	1	0	0	0	0	0	0	0	0	0	0	0	2014	
11090	168	193.83	37617	1	0	0	0	0	0	0	0	0	0	0	0	2014	
11413	168	193.65	37510	1	0	0	0	0	0	0	0	0	0	0	0	2014	
11354	168	194.94	38126	0	1	0	0	0	0	0	0	0	0	0	0	2014	
11293	168	194.85	38108	0	1	0	0	0	0	0	0	0	0	0	0	2014	
11202	58	190.16	15411	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	
11439	163	188.02	35938	0	0	1	0	0	0	0	0	0	0	0	1	2014	
11400	86	191.02	20886	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	
*11423	17	153.65	3981	0	0	0	1	0	0	0	0	0	0	0	1	2014	
12055	145	185.41	34130	0	0	0	1	0	0	0	0	0	0	0	0	2014	
*12072	168	199.15	40012	0	0	0	1	0	0	0	0	0	0	0	0	2014	
10811	168	196.76	38877	0	0	0	0	1	0	0	0	0	0	0	0	2014	

Data Base for CRIST 6 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10936	168	198.95	39961	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10941	168	195.01	38099	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10938	168	194.50	37872	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10185	168	204.47	42570	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10241	133	206.55	37184	0	0	0	0	0	1	0	0	0	0	0	0	2014	JUN
10438	103	188.93	23755	0	0	0	0	0	1	0	0	0	0	0	1	2014	
10124	168	198.93	39777	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10205	144	196.13	38586	0	0	0	0	0	1	0	0	0	0	0	0	2014	

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	
10391	168	365.20	143627.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10459	168	383.70	156888.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10596	168	340.90	124823.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10622	168	352.80	133652.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10619	168	377.30	150389.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10960	168	364.30	141904.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11118	166	308.70	109252.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10895	168	368.60	145447.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11046	115	342.80	129452.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11031	163	297.70	95801.	0	0	0	0	0	0	0	0	1	0	0	1	2011	
10697	168	336.90	122645.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
10564	168	349.30	131195.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
10325	168	385.60	154815.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
10380	168	345.80	121915.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
10762	168	337.80	118429.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
10628	168	335.20	117078.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
10766	168	310.60	99012.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
10886	168	309.00	96689.	0	0	0	0	0	0	0	0	0	1	0	0	2011	
10913	169	299.80	90940.	0	0	0	0	0	0	0	0	0	0	1	0	2011	
10904	168	312.80	99933.	0	0	0	0	0	0	0	0	0	0	1	0	2011	
11124	168	296.30	88421.	0	0	0	0	0	0	0	0	0	0	1	0	2011	
10828	168	318.30	104866.	0	0	0	0	0	0	0	0	0	0	1	0	2011	
10973	168	324.00	108398.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
10825	49	343.20	123127.	0	0	0	0	0	0	0	0	0	0	0	0	2011	Dec
11562	109	252.50	66806.	1	0	0	0	0	0	0	0	0	0	0	1	2012	
11363	168	257.70	66959.	1	0	0	0	0	0	0	0	0	0	0	0	2012	
11325	168	263.00	70273.	1	0	0	0	0	0	0	0	0	0	0	0	2012	
11742	119	251.10	65202.	1	0	0	0	0	0	0	0	0	0	0	1	2012	
11276	168	253.10	64136.	0	1	0	0	0	0	0	0	0	0	0	0	2012	
11438	168	260.10	68885.	0	1	0	0	0	0	0	0	0	0	0	0	2012	
11410	168	264.90	72304.	0	1	0	0	0	0	0	0	0	0	0	0	2012	
11488	168	251.70	63397.	0	1	0	0	0	0	0	0	0	0	0	0	2012	
11957	168	248.90	61984.	0	1	0	0	0	0	0	0	0	0	0	0	2012	
*12412	168	259.80	69450.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
11830	167	252.20	63729.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
10377	168	271.10	76417.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
10308	168	253.30	64299.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
11664	161	251.80	65330.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
11435	168	250.00	62674.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
11574	168	264.00	72473.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
11942	167	266.30	74523.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
12131	133	257.40	68409.	0	0	0	0	1	0	0	0	0	0	0	1	2012	
*12302	96	271.30	78575.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
11943	147	290.30	91734.	0	0	0	0	1	0	0	0	0	0	0	1	2012	
11814	139	280.90	83423.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10999	143	289.20	90503.	0	0	0	0	0	1	0	0	0	0	0	1	2012	
11259	168	257.30	66737.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
11159	168	285.70	87054.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
10837	168	291.20	88708.	0	0	0	0	0	1	0	0	0	0	0	0	2012	Jun
11257	168	285.50	85623.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
11380	168	267.30	74218.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
11382	146	267.90	74080.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
11531	145	269.60	80788.	0	0	0	0	0	0	1	0	0	0	0	1	2012	

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	
10852	168	275.90	79324.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
10173	165	294.10	93489.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11021	168	263.30	71173.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
12054	168	250.90	63309.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
10464	100	268.20	75448.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
*13729	70	223.10	60117.	0	0	0	0	0	0	0	0	0	0	0	3	2012	
10981	168	265.90	73931.	0	0	0	0	0	0	0	0	0	0	0	0	2012	
*12871	24	264.20	71849.	0	0	0	0	0	0	0	0	0	0	0	0	2012	Dec
11066	168	261.00	70443.	1	0	0	0	0	0	0	0	0	0	0	0	2013	
10829	163	280.80	83537.	1	0	0	0	0	0	0	0	0	0	0	0	2013	
10860	168	280.80	84120.	1	0	0	0	0	0	0	0	0	0	0	0	2013	
10729	168	266.70	73652.	1	0	0	0	0	0	0	0	0	0	0	0	2013	
11046	168	248.10	61794.	0	1	0	0	0	0	0	0	0	0	0	0	2013	
11434	168	247.20	61146.	0	1	0	0	0	0	0	0	0	0	0	0	2013	
11335	168	254.60	65469.	0	1	0	0	0	0	0	0	0	0	0	0	2013	
11239	168	250.10	62578.	0	1	0	0	0	0	0	0	0	0	0	0	2013	
10821	168	249.00	62111.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10640	167	247.10	61080.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10783	168	254.20	65281.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10683	158	249.70	63426.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10602	168	258.40	67874.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10847	168	259.70	68351.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
10946	61	255.80	67270.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
11356	157	249.10	62769.	0	0	0	0	1	0	0	0	0	0	0	1	2013	
10664	168	255.40	65980.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10610	168	258.10	67310.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10640	168	266.80	72485.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10647	168	272.90	76573.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10812	168	254.30	65164.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10508	168	295.90	93213.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
11057	168	259.70	70677.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10858	144	292.40	90936.	0	0	0	0	0	1	0	0	0	0	0	0	2013	Jun
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	

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	
	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	

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	
10536	168	279.50	89916.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10471	168	296.50	98027.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10788	168	260.00	75155.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10975	168	251.60	69027.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10543	168	284.90	92113.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10181	162	317.20	117344.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10163	168	307.20	108656.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10155	168	317.50	115100.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10552	90	275.80	92847.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11811	88	235.60	63632.	0	0	0	0	0	0	0	0	0	0	1	1	2011	
10285	98	278.50	78931.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
13154	9	191.80	64686.	0	0	0	0	0	0	0	0	0	0	0	1	2011	Dec
10089	77	370.80	144774.	1	0	0	0	0	0	0	0	0	0	0	1	2012	
10808	39	319.30	122981.	1	0	0	0	0	0	0	0	0	0	0	1	2012	
9909	99	323.10	126738.	0	0	1	0	0	0	0	0	0	0	0	1	2012	
*19948	7	151.00	27381.	0	0	0	0	1	0	0	0	0	0	0	1	2012	
10473	102	346.00	147336.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
11272	39	286.80	105300.	0	0	0	0	1	0	0	0	0	0	0	1	2012	
11301	168	240.30	69262.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
11298	72	178.00	31764.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
9983	94	359.60	150831.	0	0	0	0	0	1	0	0	0	0	0	1	2012	
9742	168	371.50	158440.	0	0	0	0	0	1	0	0	0	0	0	0	2012	Jun
10013	168	361.10	149830.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
9971	168	374.00	158967.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
10510	168	312.40	115455.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
10625	168	343.70	131178.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
10611	168	286.70	97691.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11228	168	204.30	45512.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11099	168	204.60	45347.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11585	96	178.20	32209.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11321	100	200.30	44484.	0	0	0	0	0	0	0	1	0	0	0	1	2012	
10783	146	343.30	133308.	0	0	0	0	0	0	0	0	0	1	0	1	2012	
10175	169	361.90	143659.	0	0	0	0	0	0	0	0	0	0	1	0	2012	
10169	168	398.80	168098.	0	0	0	0	0	0	0	0	0	0	1	0	2012	
10189	42	338.00	121188.	0	0	0	0	0	0	0	0	0	0	1	0	2012	Dec
11137	104	215.60	49851.	0	0	1	0	0	0	0	0	0	0	0	1	2013	
10651	96	220.20	52089.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
12226	14	282.70	91968.	0	0	1	0	0	0	0	0	0	0	0	1	2013	
10370	100	257.20	77297.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
10552	164	232.60	61519.	0	0	0	1	0	0	0	0	0	0	0	1	2013	
10273	168	270.40	82594.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
10284	168	267.70	78340.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
11445	45	197.50	40266.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
11261	145	264.60	80249.	0	0	0	0	1	0	0	0	0	0	0	1	2013	
10626	163	236.50	62606.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10295	168	302.80	106712.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10310	168	262.30	79346.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10434	144	278.20	88380.	0	0	0	0	0	1	0	0	0	0	0	0	2013	Jun
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	

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	
	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	
	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

Data Base for DANIEL 1 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 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10359	168	263.80	81452.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10386	168	287.40	91199.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10746	163	245.20	66586.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10509	168	253.90	69948.	0	0	0	0	0	0	1	0	0	0	0	0	2011	
10497	168	287.00	92871.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10392	168	308.20	109479.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10480	168	292.00	100090.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10438	168	305.70	107287.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
10335	168	298.80	102724.	0	0	0	0	0	0	0	1	0	0	0	0	2011	
11300	141	209.50	48123.	0	0	0	0	0	0	0	0	1	0	0	0	2011	
10581	128	332.80	126935.	0	0	0	0	0	0	0	0	0	0	0	1	2011	
10466	168	276.90	90276.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
10291	168	288.50	97975.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
10209	168	373.50	153695.	0	0	0	0	0	0	0	0	0	0	0	0	2011	
9954	24	329.70	122738.	0	0	0	0	0	0	0	0	0	0	0	0	2011	Dec
9753	168	374.70	159244.	1	0	0	0	0	0	0	0	0	0	0	0	2012	
10043	155	299.10	107323.	1	0	0	0	0	0	0	0	0	0	0	0	2012	
10269	43	374.20	163246.	0	0	1	0	0	0	0	0	0	0	0	1	2012	
10278	167	389.80	169344.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
10362	165	359.60	151162.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
10302	168	376.90	161951.	0	0	1	0	0	0	0	0	0	0	0	0	2012	
10043	168	371.40	158313.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
10082	167	379.40	164137.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
9927	168	387.20	169036.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
9925	168	393.10	172596.	0	0	0	1	0	0	0	0	0	0	0	0	2012	
10524	168	277.00	93180.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
11546	97	198.20	41410.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10654	93	262.70	84175.	0	0	0	0	1	0	0	0	0	0	0	1	2012	
10670	168	237.60	65490.	0	0	0	0	1	0	0	0	0	0	0	0	2012	
10562	145	180.20	32662.	0	0	0	0	0	1	0	0	0	0	0	0	2012	
10347	45	262.80	79088.	0	0	0	0	0	1	0	0	0	0	0	1	2012	Jun
10689	168	233.00	60434.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
10693	47	249.60	71761.	0	0	0	0	0	0	1	0	0	0	0	0	2012	
11437	117	230.30	60609.	0	0	0	0	0	0	1	0	0	0	0	1	2012	
11165	168	219.80	52979.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11343	165	194.90	39325.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11103	168	205.10	44972.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11436	74	182.20	33715.	0	0	0	0	0	0	0	1	0	0	0	0	2012	
11371	92	194.30	40683.	0	0	0	0	0	0	0	1	0	0	0	1	2012	Dec
10756	25	275.40	89609.	0	0	1	0	0	0	0	0	0	0	0	0	2013	
11099	168	242.90	64699.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
10571	168	276.50	84927.	0	0	0	1	0	0	0	0	0	0	0	0	2013	
11184	45	192.90	38123.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
11136	47	223.60	59418.	0	0	0	0	1	0	0	0	0	0	0	1	2013	
10639	168	256.60	79529.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10537	164	268.40	83134.	0	0	0	0	1	0	0	0	0	0	0	0	2013	
10469	168	269.50	85660.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10392	168	300.90	106250.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10582	168	272.10	87508.	0	0	0	0	0	1	0	0	0	0	0	0	2013	
10759	144	279.00	90632.	0	0	0	0	0	1	0	0	0	0	0	0	2013	Jun
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	

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	
	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	0	1	0	0	2013	
*	0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	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

Data Base for DANIEL 2 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 SMITH 3 Target Heat Rate Equation

	HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR
	6945	168	444.44	5048187	0	0	0	0	0	0	1	0	0	0	0	0	2011
	6837	168	498.95	6026769	0	0	0	0	0	0	1	0	0	0	0	0	2011
	6857	168	459.35	5259554	0	0	0	0	0	0	1	0	0	0	0	0	2011
	6811	168	485.48	5750907	0	0	0	0	0	0	1	0	0	0	0	0	2011
	6865	168	492.42	5894218	0	0	0	0	0	0	0	1	0	0	0	0	2011
	7008	168	464.97	5320635	0	0	0	0	0	0	0	1	0	0	0	0	2011
	6918	168	469.74	5427225	0	0	0	0	0	0	0	1	0	0	0	0	2011
	6871	168	490.74	5870318	0	0	0	0	0	0	0	1	0	0	0	0	2011
	6895	168	466.44	5441192	0	0	0	0	0	0	0	1	0	0	0	0	2011
	6926	168	430.11	4742897	0	0	0	0	0	0	0	0	1	0	0	0	2011
	6915	168	437.70	4962962	0	0	0	0	0	0	0	0	1	0	0	0	2011
	6814	168	451.81	5225634	0	0	0	0	0	0	0	0	1	0	0	0	2011
	6769	168	500.43	6067034	0	0	0	0	0	0	0	0	1	0	0	0	2011
	6766	168	475.45	5527666	0	0	0	0	0	0	0	0	0	1	0	0	2011
	6933	168	445.82	5222503	0	0	0	0	0	0	0	0	0	1	0	0	2011
	6758	168	496.99	6070664	0	0	0	0	0	0	0	0	0	1	0	0	2011
	6532	168	506.11	6205182	0	0	0	0	0	0	0	0	0	1	0	0	2011
	6631	168	548.43	7244548	0	0	0	0	0	0	0	0	0	1	0	0	2011
	6850	154	522.89	6159788	0	0	0	0	0	0	0	0	0	0	1	0	2011
	6845	168	499.96	6267007	0	0	0	0	0	0	0	0	0	0	1	0	2011
	6656	168	489.82	5868475	0	0	0	0	0	0	0	0	0	0	1	0	2011
	6713	168	531.07	6829199	0	0	0	0	0	0	0	0	0	0	1	0	2011
	6781	168	544.40	7158707	0	0	0	0	0	0	0	0	0	0	0	0	2011
	6700	71	550.01	3088808	0	0	0	0	0	0	0	0	0	0	0	0	2011
	7516	104	472.93	3543799	0	0	0	0	0	0	0	0	0	0	0	1	2011
	6714	168	505.54	6266301	0	0	0	0	0	0	0	0	0	0	0	0	2011
*	7604	168	465.82	5602499	1	0	0	0	0	0	0	0	0	0	0	0	2012
	6685	168	497.82	6101146	1	0	0	0	0	0	0	0	0	0	0	0	2012
*	6048	168	519.22	6522906	1	0	0	0	0	0	0	0	0	0	0	0	2012
	6793	168	465.99	5305272	1	0	0	0	0	0	0	0	0	0	0	0	2012
	6783	168	499.14	6081033	0	1	0	0	0	0	0	0	0	0	0	0	2012
	6733	168	520.54	6575713	0	1	0	0	0	0	0	0	0	0	0	0	2012
	6671	168	528.52	6771934	0	1	0	0	0	0	0	0	0	0	0	0	2012
	6626	168	519.85	6532882	0	1	0	0	0	0	0	0	0	0	0	0	2012
	7078	168	482.89	5758709	0	0	1	0	0	0	0	0	0	0	0	0	2012
	6784	168	482.71	5758691	0	0	1	0	0	0	0	0	0	0	0	0	2012
	6918	167	491.46	5910600	0	0	1	0	0	0	0	0	0	0	0	0	2012
	6938	164	425.55	4616062	0	0	1	0	0	0	0	0	0	0	0	0	2012
	6715	168	482.56	5726942	0	0	1	0	0	0	0	0	0	0	0	0	2012
	6948	168	449.54	5121395	0	0	0	1	0	0	0	0	0	0	0	0	2012
	6951	168	462.16	5461289	0	0	0	1	0	0	0	0	0	0	0	0	2012
	6986	144	427.06	4062434	0	0	0	1	0	0	0	0	0	0	0	0	2012
	8143	11	241.82	152386	0	0	0	1	0	0	0	0	0	0	0	1	2012
	6939	168	468.46	5543674	0	0	0	0	1	0	0	0	0	0	0	0	2012
	7090	147	390.35	3731842	0	0	0	0	1	0	0	0	0	0	0	0	2012
	6985	168	442.75	5033686	0	0	0	0	1	0	0	0	0	0	0	0	2012
	6956	168	406.09	4467339	0	0	0	0	1	0	0	0	0	0	0	0	2012
	6860	168	418.54	4637114	0	0	0	0	1	0	0	0	0	0	0	0	2012
	7026	168	398.32	4287367	0	0	0	0	0	1	0	0	0	0	0	0	2012
	7029	168	437.01	4982789	0	0	0	0	0	1	0	0	0	0	0	0	2012
	6979	168	453.07	5281488	0	0	0	0	0	1	0	0	0	0	0	0	2012
	6792	168	453.75	5315887	0	0	0	0	0	1	0	0	0	0	0	0	2012
	6999	168	461.48	5388468	0	0	0	0	0	0	1	0	0	0	0	0	2012

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	454.48	5257919	0	0	0	0	0	0	1	0	0	0	0	0	2012	
	7015	166	400.96	4274036	0	0	0	0	0	0	1	0	0	0	0	0	2012	
	7550	160	414.48	4483062	0	0	0	0	0	0	1	0	0	0	0	0	2012	
	6925	168	438.30	4884696	0	0	0	0	0	0	0	1	0	0	0	0	2012	
	7073	162	436.93	4860974	0	0	0	0	0	0	0	1	0	0	0	0	2012	
	6951	168	450.84	5222579	0	0	0	0	0	0	0	1	0	0	0	0	2012	
	6894	168	399.58	4342649	0	0	0	0	0	0	0	1	0	0	0	0	2012	
	6721	168	474.36	5691842	0	0	0	0	0	0	0	1	0	0	0	0	2012	
	6956	168	490.93	5888894	0	0	0	0	0	0	0	0	1	0	0	0	2012	
	6974	168	397.38	4266039	0	0	0	0	0	0	0	0	1	0	0	0	2012	
	6868	168	415.70	4594784	0	0	0	0	0	0	0	0	1	0	0	0	2012	
	6675	168	398.61	4331498	0	0	0	0	0	0	0	0	1	0	0	0	2012	
	6929	168	430.39	4872628	0	0	0	0	0	0	0	0	0	1	0	0	2012	
	6975	166	368.20	3686142	0	0	0	0	0	0	0	0	0	1	0	0	2012	
	6972	168	380.85	3933243	0	0	0	0	0	0	0	0	0	1	0	0	2012	
	6876	168	373.11	3833994	0	0	0	0	0	0	0	0	0	1	0	0	2012	
	6867	168	438.88	4911687	0	0	0	0	0	0	0	0	0	1	0	0	2012	
	6865	169	524.55	6806213	0	0	0	0	0	0	0	0	0	0	1	0	2012	
*	3927	95	478.92	3287708	0	0	0	0	0	0	0	0	0	0	1	0	2012	
*	6012	143	444.57	4318381	0	0	0	0	0	0	0	0	0	0	1	1	2012	
	6920	168	525.60	6781653	0	0	0	0	0	0	0	0	0	0	1	0	2012	
	6908	168	452.67	5172495	0	0	0	0	0	0	0	0	0	0	0	0	2012	
*	4808	88	484.20	3207702	0	0	0	0	0	0	0	0	0	0	0	1	2012	
	6828	166	482.33	5786938	0	0	0	0	0	0	0	0	0	0	0	0	2012	
	7037	168	463.96	5471478	0	0	0	0	0	0	0	0	0	0	0	0	2012	
	6835	168	475.91	5667167	1	0	0	0	0	0	0	0	0	0	0	0	2013	
	6909	168	409.08	4362094	1	0	0	0	0	0	0	0	0	0	0	0	2013	
	6884	168	482.70	5752735	1	0	0	0	0	0	0	0	0	0	0	0	2013	
	6794	168	432.89	4727002	1	0	0	0	0	0	0	0	0	0	0	0	2013	
	6881	168	430.72	4841022	0	1	0	0	0	0	0	0	0	0	0	0	2013	
	6917	168	451.61	5002365	0	1	0	0	0	0	0	0	0	0	0	0	2013	
	6887	168	509.44	6368007	0	1	0	0	0	0	0	0	0	0	0	0	2013	
	6802	160	444.98	4689971	0	1	0	0	0	0	0	0	0	0	0	0	2013	
	6816	168	483.80	5729668	0	0	1	0	0	0	0	0	0	0	0	0	2013	
	6920	167	446.29	4988275	0	0	1	0	0	0	0	0	0	0	0	0	2013	
	6980	168	407.58	4376709	0	0	1	0	0	0	0	0	0	0	0	0	2013	
*	2950	71	465.66	2310669	0	0	1	0	0	0	0	0	0	0	0	0	2013	
*	12591	125	306.89	1995382	0	0	0	1	0	0	0	0	0	0	0	1	2013	
	6840	168	452.42	5184928	0	0	0	1	0	0	0	0	0	0	0	0	2013	
	6996	168	452.34	5327757	0	0	0	1	0	0	0	0	0	0	0	0	2013	
	7039	135	372.16	3086094	0	0	0	0	1	0	0	0	0	0	0	1	2013	
	6785	168	398.89	4302152	0	0	0	0	1	0	0	0	0	0	0	0	2013	
	7763	168	393.76	4244322	0	0	0	0	1	0	0	0	0	0	0	0	2013	
	6864	168	404.90	4475529	0	0	0	0	1	0	0	0	0	0	0	0	2013	
	7669	160	366.57	3813752	0	0	0	0	1	0	0	0	0	0	0	0	2013	
	6909	168	413.53	4434528	0	0	0	0	0	1	0	0	0	0	0	0	2013	
*	6883	168	266.39	1871261	0	0	0	0	0	1	0	0	0	0	0	0	2013	
	6860	168	414.05	4575812	0	0	0	0	0	1	0	0	0	0	0	0	2013	
	6817	144	437.62	5010249	0	0	0	0	0	1	0	0	0	0	0	0	2013	
	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	

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	
	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	

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 2015 - December 2015

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
CRIST 6	Jan '15	124.8	17,296	12,828	22,845	
	Feb '15	116.1	16,103	13,575	1,510	
	Mar '15	125.0	17,326	13,201	28,245	
	Apr '15	0.0	0	-	0	
	May '15	0.0	0	-	0	
	Jun '15	0.0	0	-	0	
	Jul '15	124.7	17,280	12,029	36,026	
	Aug '15	0.0	0	-	0	
	Sep '15	0.0	0	-	0	
	Oct '15	0.0	0	-	0	
	Nov '15	0.0	0	-	0	
	Dec '15	124.7	17,280	12,029	17,950	12,533
CRIST 7	Jan '15	259.8	67,446	10,947	145,730	
	Feb '15	259.0	66,897	10,951	169,991	
	Mar '15	254.4	63,746	10,680	127,178	
	Apr '15	255.0	64,156	11,274	173,361	
	May '15	0.0	0	-	0	
	Jun '15	292.4	89,977	10,821	89,477	
	Jul '15	325.1	112,906	10,723	159,298	
	Aug '15	319.4	108,886	10,739	167,341	
	Sep '15	280.3	81,576	10,864	43,730	
	Oct '15	0.0	0	-	0	
	Nov '15	0.0	0	-	0	
	Dec '15	272.1	75,909	10,896	44,630	10,890

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 2015 - December 2015

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 '15	388.2	154,604	10,150	42,343	
	Feb '15	0.0	0	-	0	
	Mar '15	0.0	0	-	0	
	Apr '15	325.9	116,968	10,316	192,664	
	May '15	317.0	111,452	10,595	214,511	
	Jun '15	337.0	123,798	10,282	234,176	
	Jul '15	355.4	135,001	10,230	257,501	
	Aug '15	357.7	136,391	10,224	257,166	
	Sep '15	333.4	121,589	10,293	232,000	
	Oct '15	291.3	95,331	10,911	67,532	
	Nov '15	290.7	94,951	10,749	84,222	
	Dec '15	240.6	62,679	10,684	25,718	10,366
DANIEL 2	Jan '15	356.5	136,375	9,880	43,452	
	Feb '15	337.1	124,930	9,400	209,013	
	Mar '15	374.7	146,876	10,268	138,353	
	Apr '15	335.2	123,795	10,222	233,572	
	May '15	322.6	116,207	10,273	233,835	
	Jun '15	347.4	131,039	10,177	243,665	
	Jul '15	359.7	138,238	10,135	260,677	
	Aug '15	361.4	139,225	10,129	261,933	
	Sep '15	343.8	128,912	10,190	238,506	
	Oct '15	296.1	99,890	10,917	214,061	
	Nov '15	295.0	99,202	10,398	108,800	
	Dec '15	226.0	54,392	10,843	14,038	10,196
SMITH 3	Jan '15	455.2	3,670,978	6,886	281,293	
	Feb '15	466.7	3,997,158	6,869	310,472	
	Mar '15	463.1	3,893,754	6,874	340,619	
	Apr '15	474.3	4,219,335	6,858	270,833	
	May '15	470.5	4,107,589	6,864	313,321	
	Jun '15	463.4	3,902,326	6,874	330,337	
	Jul '15	489.5	4,679,480	6,838	360,553	
	Aug '15	486.7	4,593,134	6,841	358,544	
	Sep '15	465.4	3,959,682	6,871	331,724	
	Oct '15	471.5	4,136,868	6,790	347,312	
	Nov '15	489.0	4,664,009	6,838	244,476	
	Dec '15	496.9	4,911,118	6,828	365,956	6,852

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 2015 - December 2015

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 6	12,533	12,157	12,909
CRIST 7	10,890	10,563	11,217
DANIEL 1	10,366	10,055	10,677
DANIEL 2	10,196	9,890	10,502
SMITH 3	6,852	6,646	7,058

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2015 - December 2015

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '15 - Dec '15	Reserve Shutdown Hours for Jan '15 - Dec '15	Target Equivalent Availability **
Crist 6	0.0828	1,560	6,248	81.1
Crist 7	0.0594	168	4,290	94.9
Daniel 1	0.1263	1,704	1,582	73.3
Daniel 2	0.0916	432	1,238	88.7
Smith 3	0.0250	432	0	92.7

* For Period July 2009 through June 2014.

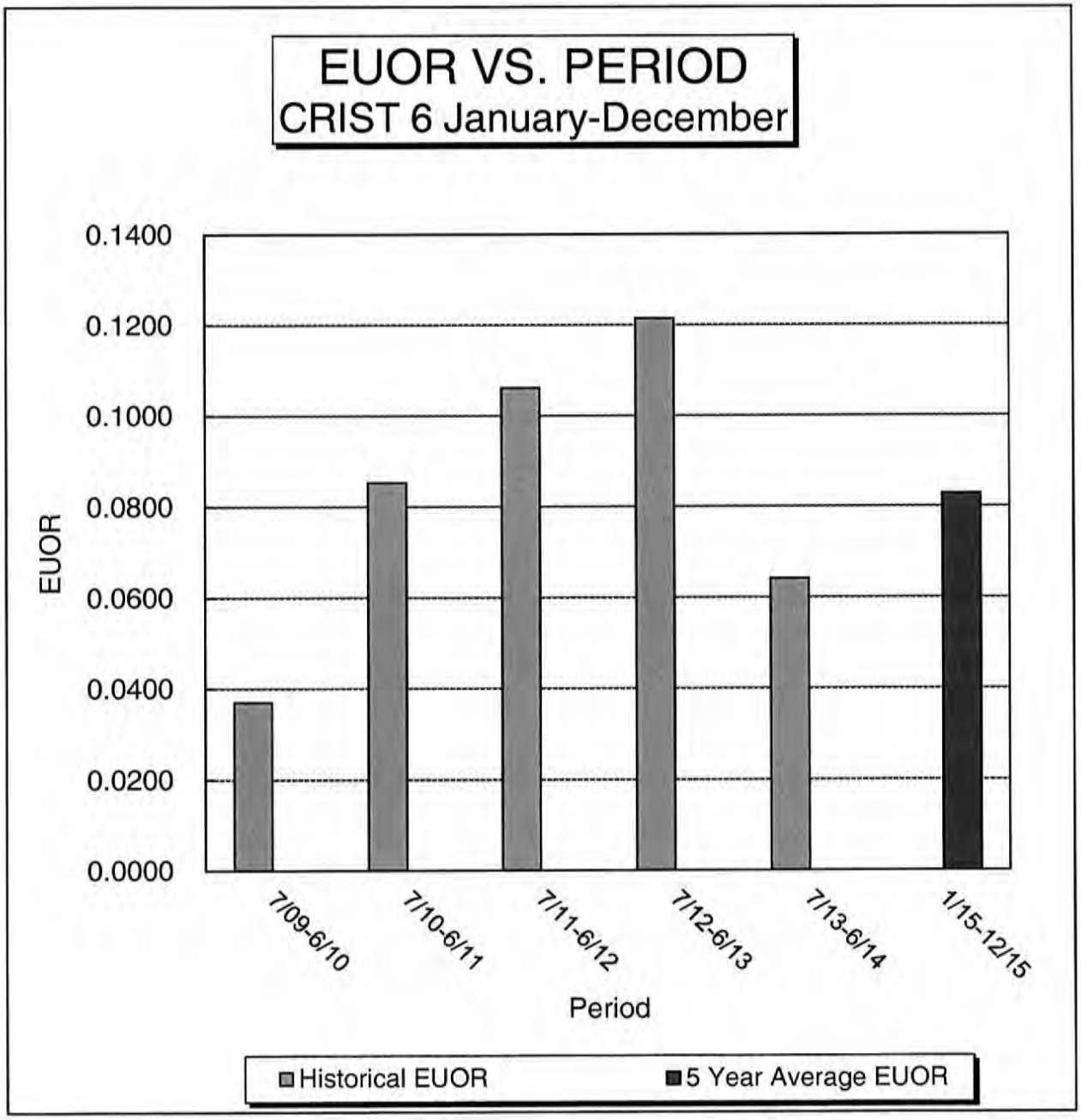
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

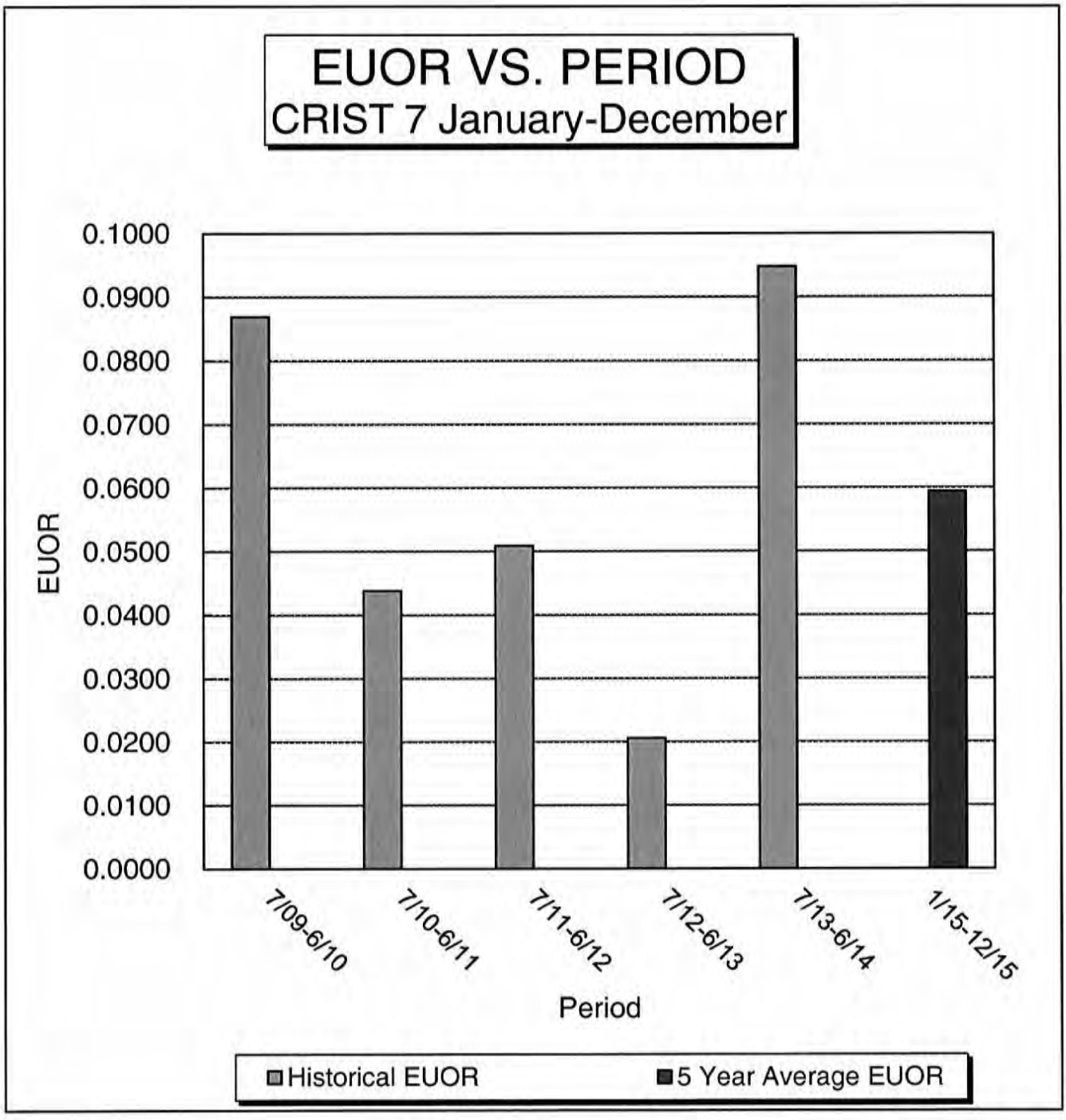
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2015 - December 2015

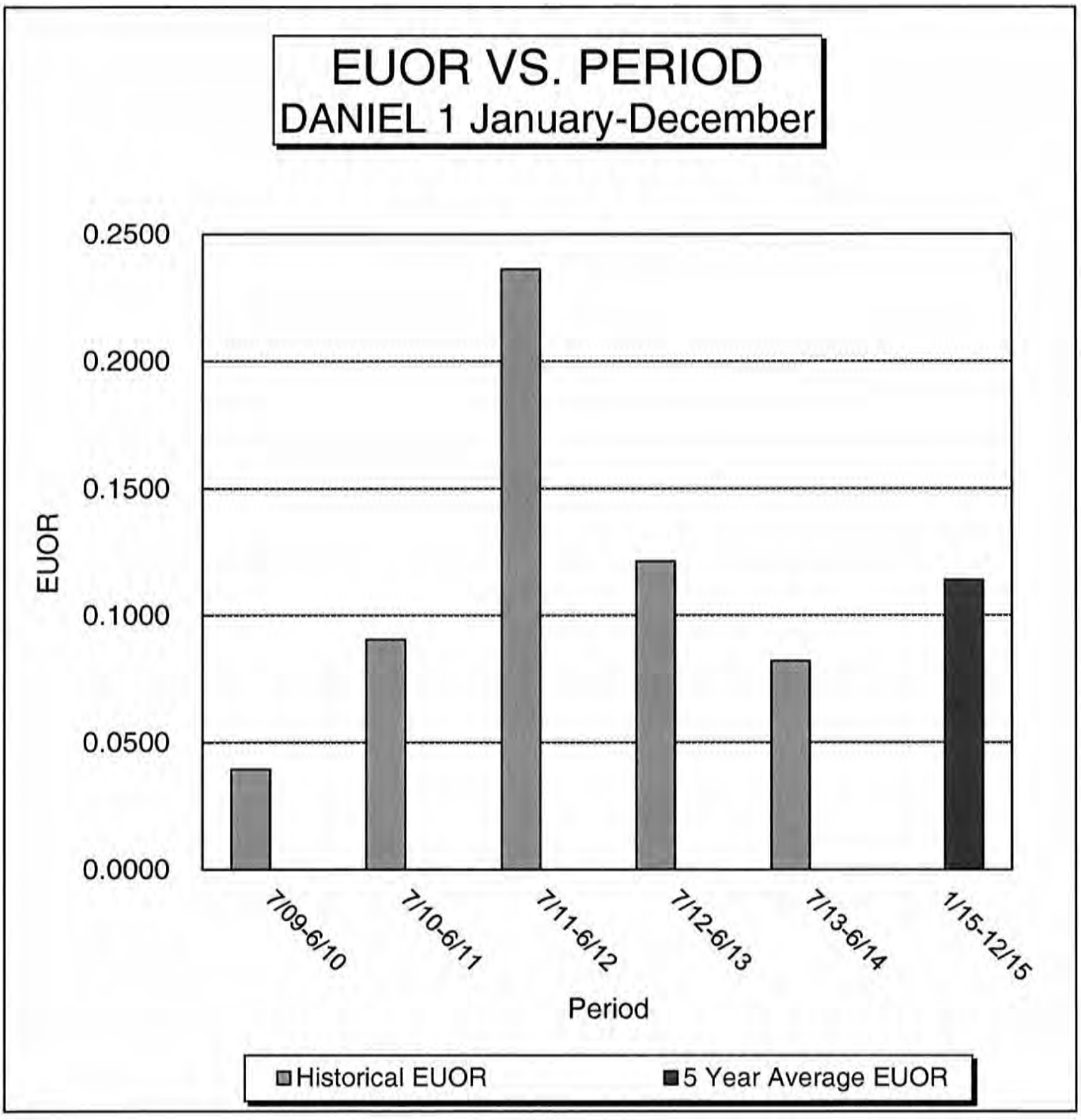
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 6	0.0828	0.0580	81.6	0.1201	80.9
Crist 7	0.0594	0.0416	96.0	0.0861	93.9
Daniel 1	0.1263	0.0884	75.0	0.1831	69.1
Daniel 2	0.0916	0.0641	89.9	0.1328	84.3
Smith 3	0.0250	0.0175	93.4	0.0363	91.6

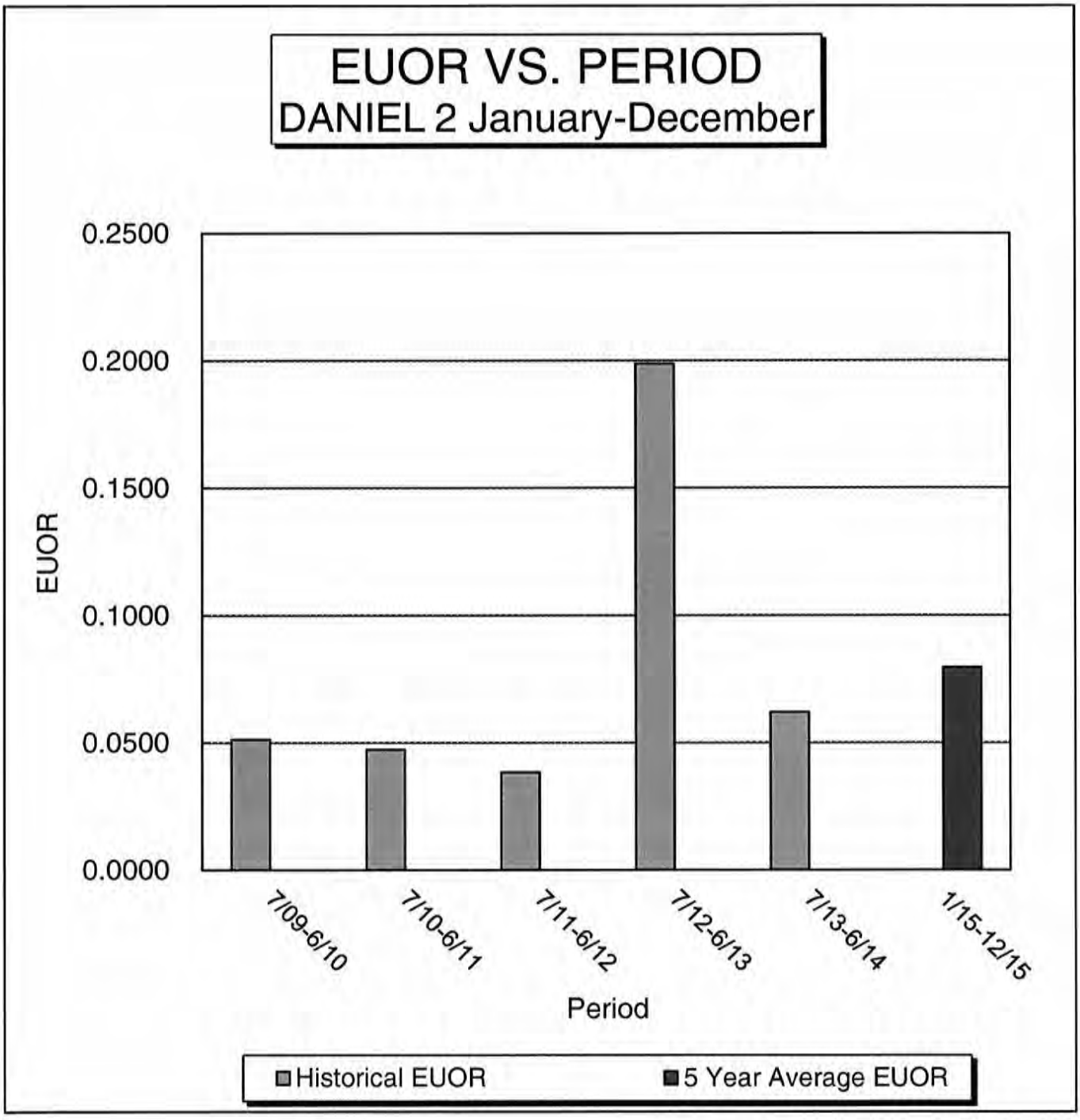
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2015 - December 2015

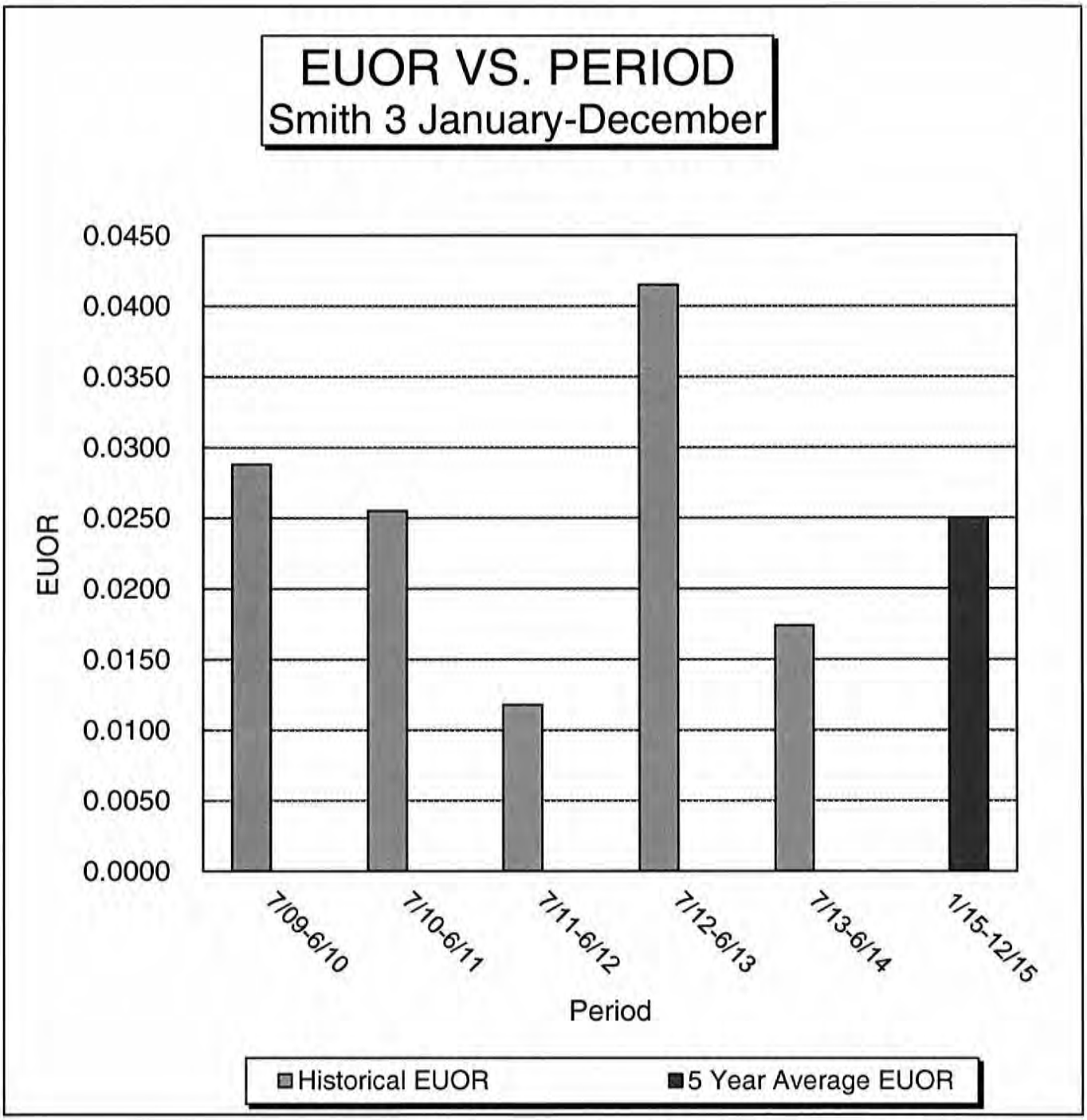
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 6	81.1	81.6	80.9
Crist 7	94.9	96.0	93.9
Daniel 1	73.3	75.0	69.1
Daniel 2	88.7	89.9	84.3
Smith 3	92.7	93.4	91.6


EUOR VS. PERIOD
CRIST 6 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
7/13-6/14
1/15-12/15
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
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
7/13-6/14
1/15-12/15
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
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
7/13-6/14
1/15-12/15
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
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
7/13-6/14
1/15-12/15
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
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
7/13-6/14
1/15-12/15
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2015 - DECEMBER 2015

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Generating Performance Incentive Factor

Estimated 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	5314
+ 9	6329	4783
+ 8	5626	4251
+ 7	4922	3720
+ 6	4219	3188
+ 5	3516	2657
+ 4	2813	2126
+ 3	2110	1594
+ 2	1406	1063
+ 1	703	531
0	0	0
- 1	-706	-531
- 2	-1412	-1063
- 3	-2119	-1594
- 4	-2825	-2126
- 5	-3531	-2657
- 6	-4237	-3188
- 7	-4943	-3720
- 8	-5650	-4251
- 9	-6356	-4783
- 10	-7062	-5314
	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 2015 - December 2015

Line 1	Beginning of Period Balance of Common Equity	$1,334,147,631
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '15	$1,325,602,296
Line 3	Month of Feb '15	$1,334,625,838
Line 4	Month of Mar '15	$1,345,194,525
Line 5	Month of Apr '15	$1,319,259,960
Line 6	Month of May '15	$1,331,530,889
Line 7	Month of Jun '15	$1,348,927,593
Line 8	Month of Jul '15	$1,334,993,412
Line 9	Month of Aug '15	$1,353,392,009
Line 10	Month of Sep '15	$1,368,452,020
Line 11	Month of Oct '15	$1,343,705,430
Line 12	Month of Nov '15	$1,350,066,522
Line 13	Month of Dec '15	$1,362,843,508
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,342,518,587
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.2006%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$5,484,091
Line 18	Jurisdictional Sales (KWH)	11,062,622,534
Line 19	Total Territorial Sales (KWH)	11,416,754,984
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.8981%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$5,313,982

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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)
Crist 6	0.0%	81.1	81.6	80.9	$0	$0
Crist 7	0.0%	94.9	96.0	93.9	$0	$0
Daniel 1	0.6%	73.3	75.0	69.1	$45	($96)
Daniel 2	0.5%	88.7	89.9	84.3	$38	($68)
Smith 3	1.9%	92.7	93.4	91.6	$137	($86)

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)
Crist 6	2.1%	12,533	41.7	12,157	12,909	$150	($150)
Crist 7	18.2%	10,890	58.4	10,563	11,217	$1,280	($1,280)
Daniel 1	10.1%	10,366	65.1	10,055	10,677	$708	($708)
Daniel 2	13.5%	10,196	66.0	9,890	10,502	$946	($946)
Smith 3	53.0%	6,852	83.9	6,646	7,058	$3,728	($3,728)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2015 - December 2015

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '013 - Jun '014			Actual Performance 2nd Prior Period Jul '012 - Jun '013		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 6	0.0%	0.0%	0.1781	0.0111	0.0828	0.0603	0.0354	0.0641	0.0000	0.0605	0.1214
Crist 7	0.0%	0.0%	0.0192	0.0317	0.0594	0.0000	0.0927	0.0948	0.2632	0.0133	0.0206
Daniel 1	0.6%	20.5%	0.1945	0.0727	0.1263	0.0482	0.0519	0.0820	0.0000	0.0553	0.1213
Daniel 2	0.5%	17.3%	0.0493	0.0640	0.0916	0.2175	0.0338	0.0620	0.1514	0.0681	0.1988
Smith 3	1.9%	62.3%	0.0493	0.0232	0.0250	0.0447	0.0165	0.0174	0.0654	0.0386	0.0415
Weighted GPIF System Average:			0.0790	0.0404	0.0572	0.0753	0.0267	0.0383	0.0669	0.0471	0.0850

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2015 - December 2015

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '011 - Jun '012			Actual Performance 4th Prior Period Jul '010 - Jun '011			Actual Performance 5th Prior Period Jul '09 - Jun '010		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 6	0.0%	0.0%	0.2197	0.0661	0.1061	0.2576	0.0495	0.0853	0.0626	0.0254	0.0370
Crist 7	0.0%	0.0%	0.0000	0.0470	0.0509	0.0867	0.0398	0.0438	0.1773	0.0715	0.0869
Daniel 1	0.6%	20.5%	0.1378	0.0872	0.2362	0.0000	0.0895	0.0905	0.1500	0.0312	0.0395
Daniel 2	0.5%	17.3%	0.2123	0.0201	0.0384	0.1655	0.0340	0.0473	0.0449	0.0485	0.0513
Smith 3	1.9%	62.3%	0.0390	0.0113	0.0118	0.0460	0.0240	0.0255	0.1999	0.0212	0.0288
Weighted GPIF System Average:			0.0891	0.0283	0.0623	0.0572	0.0391	0.0426	0.1629	0.0280	0.0349

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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 2015 - December 2015

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '013 - Jun '014	2nd Prior Period Heat Rate Jul '012 - Jun '013	3rd Prior Period Heat Rate Jul '011 - Jun '012
Crist 6	2.1%	2.2%	12,533	12,427	12,474	12,723
Crist 7	18.2%	18.8%	10,890	10,649	10,937	11,181
Daniel 1	10.1%	10.4%	10,366	10,455	10,506	10,402
Daniel 2	13.5%	13.9%	10,196	10,374	10,306	10,155
Smith 3	53.0%	54.7%	6,852	6,807	6,833	6,834
Weighted GPIF System Average:			8,565	8,527	8,592	8,613

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '012 - Jun '013

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	12029.0 12828.0	- 13575.0	- 13201.0	- -	- -	12029.0 -
2. Target Heat Rate at Actual Conditions**	10559.0 0.0	10921.0 0.0	10672.0 0.0	10869.0 11360.0	10926.0 0.0	10626.0 10910.0
3. Adjustments to Actual Heat Rate (1-2)	1470.0 12828.0	0.0 13575.0	0.0 13201.0	0.0 0.0	0.0 0.0	1403.0 0.0
4. Actual Heat Rate for Prior Period	10460.0 0.0	11577.0 0.0	10755.0 0.0	10798.0 11257.0	10822.0 0.0	10476.0 11427.0
5. Adjusted actual Heat Rate (4+3)	11930.0 12828.0	11577.0 13575.0	10755.0 13201.0	10798.0 11257.0	10822.0 0.0	11879.0 11427.0
6. Forecast Net MWH Generation*	36026.1 22844.8	0.0 1509.8	0.0 28245.1	0.0 0.0	0.0 0.0	17950.3 0.0

7. Adjusted Actual Heat Rate for Jul '012 - Jun '013 = (Σ ((5)*(6)))/(Σ (6)) 12,474

* For the January 2015 - December 2015 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 2015 - December 2015

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 6	EA-3	$450,749	$450,749	$0	0.0%
Crist 6	ANOHR-3	$450,749	$450,599	$150	2.1%
Crist 7	EA-4	$450,749	$450,749	$0	0.0%
Crist 7	ANOHR-4	$450,749	$449,469	$1,280	18.2%
Daniel 1	EA-5	$450,749	$450,704	$45	0.6%
Daniel 1	ANOHR-5	$450,749	$450,041	$708	10.1%
Daniel 2	EA-6	$450,749	$450,711	$38	0.5%
Daniel 2	ANOHR-6	$450,749	$449,803	$946	13.5%
Smith 3	EA-7	$450,749	$450,612	$137	1.9%
Smith 3	ANOHR-7	$450,749	$447,021	$3,728	53.0%

(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 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	81.57	+ 9	135	12,187
+ 8	0	81.54	+ 8	120	12,217
+ 7	0	81.51	+ 7	105	12,247
+ 6	0	81.48	+ 6	90	12,277
+ 5	0	81.45	+ 5	75	12,308
+ 4	0	81.42	+ 4	60	12,338
+ 3	0	81.39	+ 3	45	12,368
+ 2	0	81.36	+ 2	30	12,398
+ 1	0	81.33	+ 1	15	12,428
				0	12,458
0	0	81.30	0	0	12,533
				0	12,608
- 1	0	81.26	- 1	(15)	12,638
- 2	0	81.22	- 2	(30)	12,668
- 3	0	81.18	- 3	(45)	12,698
- 4	0	81.14	- 4	(60)	12,728
- 5	0	81.10	- 5	(75)	12,759
- 6	0	81.06	- 6	(90)	12,789
- 7	0	81.02	- 7	(105)	12,819
- 8	0	80.98	- 8	(120)	12,849
- 9	0	80.94	- 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	95.92	+ 9	1,152	10,588
+ 8	0	95.84	+ 8	1,024	10,613
+ 7	0	95.76	+ 7	896	10,639
+ 6	0	95.68	+ 6	768	10,664
+ 5	0	95.60	+ 5	640	10,689
+ 4	0	95.52	+ 4	512	10,714
+ 3	0	95.44	+ 3	384	10,739
+ 2	0	95.36	+ 2	256	10,765
+ 1	0	95.28	+ 1	128	10,790
				0	10,815
0	0	95.20	0	0	10,890
				0	10,965
- 1	0	95.07	- 1	(128)	10,990
- 2	0	94.94	- 2	(256)	11,015
- 3	0	94.81	- 3	(384)	11,041
- 4	0	94.68	- 4	(512)	11,066
- 5	0	94.55	- 5	(640)	11,091
- 6	0	94.42	- 6	(768)	11,116
- 7	0	94.29	- 7	(896)	11,141
- 8	0	94.16	- 8	(1,024)	11,167
- 9	0	94.03	- 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	74.77	+ 9	637	10,079
+ 8	36	74.54	+ 8	566	10,102
+ 7	32	74.31	+ 7	496	10,126
+ 6	27	74.08	+ 6	425	10,149
+ 5	23	73.85	+ 5	354	10,173
+ 4	18	73.62	+ 4	283	10,197
+ 3	14	73.39	+ 3	212	10,220
+ 2	9	73.16	+ 2	142	10,244
+ 1	5	72.93	+ 1	71	10,267
				0	10,291
0	0	72.70	0	0	10,366
				0	10,441
- 1	(10)	72.34	- 1	(71)	10,465
- 2	(19)	71.98	- 2	(142)	10,488
- 3	(29)	71.62	- 3	(212)	10,512
- 4	(38)	71.26	- 4	(283)	10,535
- 5	(48)	70.90	- 5	(354)	10,559
- 6	(58)	70.54	- 6	(425)	10,583
- 7	(67)	70.18	- 7	(496)	10,606
- 8	(77)	69.82	- 8	(566)	10,630
- 9	(86)	69.46	- 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	89.68	+ 9	851	9,913
+ 8	30	89.46	+ 8	757	9,936
+ 7	27	89.24	+ 7	662	9,959
+ 6	23	89.02	+ 6	568	9,982
+ 5	19	88.80	+ 5	473	10,006
+ 4	15	88.58	+ 4	378	10,029
+ 3	11	88.36	+ 3	284	10,052
+ 2	8	88.14	+ 2	189	10,075
+ 1	4	87.92	+ 1	95	10,098
				0	10,121
0	0	87.70	0	0	10,196
				0	10,271
- 1	(7)	87.36	- 1	(95)	10,294
- 2	(14)	87.02	- 2	(189)	10,317
- 3	(20)	86.68	- 3	(284)	10,340
- 4	(27)	86.34	- 4	(378)	10,363
- 5	(34)	86.00	- 5	(473)	10,387
- 6	(41)	85.66	- 6	(568)	10,410
- 7	(48)	85.32	- 7	(662)	10,433
- 8	(54)	84.98	- 8	(757)	10,456
- 9	(61)	84.64	- 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

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED 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 (%)	96.0	92.8	86.2	0.0	0.0	100.0	
2.	POF (%)	0.0	0.0	12.9	100.0	100.0	0.0	
3.	EUOF (%)	4.0	7.2	0.9	0.0	0.0	0.0	
4.	EUOR (%)	13.9	78.8	2.9	0.0	0.0	0.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	183.0	13.0	226.0	0.0	0.0	0.0	
7.	RSH	531.6	610.6	414.2	0.0	0.0	720.0	
8.	UH	29.4	48.4	102.8	720.0	744.0	0.0	
9.	POH	0.0	0.0	96.0	720.0	744.0	0.0	
10.	FOH & EFOH	5.4	0.4	6.8	0.0	0.0	0.0	
11.	MOH & EMOH	24.0	48.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	293053	20496	372864	0	0	0	
13.	Net Gen (MWH)	22844.8	1509.8	28245.1	0.0	0.0	0.0	
14.	ANOHR (Btu/KWH)	12828.0	13575.0	13201.0	-	-	-	
15.	NOF %	41.8	38.8	41.8	0.0	0.0	0.0	
16.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	

19.	ANOHR Equation	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

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ESTIMATED 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 (%)	98.8	100.0	100.0	100.0	100.0	99.4	81.1
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	17.8
3.	EUOF (%)	1.2	0.0	0.0	0.0	0.0	0.6	1.1
4.	EUOR (%)	2.9	0.0	0.0	0.0	0.0	2.9	10.2
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	289.0	0.0	0.0	0.0	0.0	144.0	855.0
7.	RSH	446.4	744.0	720.0	744.0	721.0	595.7	6247.5
8.	UH	8.6	0.0	0.0	0.0	0.0	4.3	1657.5
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1560.0
10.	FOH & EFOH	8.6	0.0	0.0	0.0	0.0	4.3	25.5
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	72.0
12.	Oper MBtu	433358	0	0	0	0	215924	1335695
13.	Net Gen (MWH)	36026.1	0.0	0.0	0.0	0.0	17950.3	106576.1
14.	ANOHR (Btu/KWH)	12029.0	-	-	-	-	12029.0	12533.0
15.	NOF %	41.7	0.0	0.0	0.0	0.0	41.7	41.7
16.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	299.0

19.	ANOHR Equation	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.

ESTIMATED 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 (%)	97.8	97.2	78.7	94.1	77.4	98.9	
2.	POF (%)	0.0	0.0	0.0	0.0	22.6	0.0	
3.	EUOF (%)	2.2	2.8	21.3	5.9	0.0	1.1	
4.	EUOR (%)	2.8	2.8	24.1	5.9	0.0	2.6	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	561.0	656.4	500.0	679.8	0.0	306.0	
7.	RSH	169.7	0.0	87.1	0.0	576.0	406.7	
8.	UH	13.3	15.6	155.9	40.2	168.0	7.3	
9.	POH	0.0	0.0	0.0	0.0	168.0	0.0	
10.	FOH & EFOH	16.3	18.6	13.9	18.2	0.0	8.3	
11.	MOH & EMOH	0.0	0.0	144.0	24.0	0.0	0.0	
12.	Oper MBtu	1595305	1861573	1358259	1954474	0	968225	
13.	Net Gen (MWH)	145729.9	169991.1	127177.8	173361.2	0.0	89476.5	
14.	ANOHR (Btu/KWH)	10947.0	10951.0	10680.0	11274.0	-	10821.0	
15.	NOF %	54.7	54.5	53.5	53.7	0.0	61.6	
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	

19.	ANOHR Equation	10^6 / AKW * [735.33 - 74.26 * MAR + 77.66 * APR] + 7,097 + 0.00393 * LSRF / AKW

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ESTIMATED 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 (%)	98.3	98.2	99.3	100.0	100.0	99.5	94.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3.	EUOF (%)	1.7	1.8	0.7	0.0	0.0	0.5	3.2
4.	EUOR (%)	2.5	2.5	2.9	0.0	0.0	2.3	6.5
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	490.0	524.0	156.0	0.0	1.0	164.0	4038.2
7.	RSH	242.4	207.6	560.3	744.0	720.0	576.1	4289.8
8.	UH	11.6	12.4	3.7	0.0	0.0	3.9	431.9
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	168.0
10.	FOH & EFOH	12.6	13.4	4.7	0.0	0.0	3.9	109.9
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	168.0
12.	Oper MBtu	1708150	1797076	475085	0	0	486284	12204431
13.	Net Gen (MWH)	159297.8	167341.1	43730.2	0.0	0.0	44629.6	1120735.2
14.	ANOHR (Btu/KWH)	10723.0	10739.0	10864.0	-	-	10896.0	10890.0
15.	NOF %	68.4	67.2	59.0	0.0	0.0	57.3	58.4
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0

19.	ANOHR Equation	10^6 / AKW * [735.33 - 74.26 * MAR + 77.66 * APR] + 7,097 + 0.00393 * LSRF / AKW

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ESTIMATED 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 (%)	51.2	0.0	6.3	97.7	97.6	97.4	
2.	POF (%)	45.2	100.0	93.7	0.0	0.0	0.0	
3.	EUOF (%)	3.6	0.0	0.0	2.3	2.4	2.6	
4.	EUOR (%)	19.9	0.0	0.0	2.8	2.6	2.6	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	109.1	0.0	0.0	591.1	676.8	694.8	
7.	RSH	271.8	0.0	47.0	113.0	49.1	6.5	
8.	UH	363.1	672.0	696.0	15.9	18.2	18.6	
9.	POH	336.0	672.0	696.0	0.0	0.0	0.0	
10.	FOH & EFOH	3.1	0.0	0.0	16.9	18.2	18.6	
11.	MOH & EMOH	24.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	429777	0	0	1987524	2272740	2407794	
13.	Net Gen (MWH)	42342.6	0.0	0.0	192664.2	214510.6	234175.6	
14.	ANOHR (Btu/KWH)	10150.0	-	-	10316.0	10595.0	10282.0	
15.	NOF %	76.1	0.0	0.0	63.9	62.2	66.1	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [338.36 + 79.10 * MAY + 137.43 * OCT + 89.35 * NOV] + 9,278

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ESTIMATED 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 (%)	97.4	97.4	97.4	63.7	68.8	99.6	73.3
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	19.5
3.	EUOF (%)	2.6	2.6	2.6	36.3	31.2	0.4	7.2
4.	EUOR (%)	2.6	2.6	2.6	53.8	43.8	3.0	11.6
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	724.6	718.9	695.9	231.9	289.7	106.9	4839.5
7.	RSH	0.0	5.9	5.5	241.8	207.4	633.8	1581.7
8.	UH	19.4	19.3	18.7	270.4	223.9	3.3	2338.7
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1704.0
10.	FOH & EFOH	19.4	19.3	18.7	6.4	8.9	3.3	132.7
11.	MOH & EMOH	0.0	0.0	0.0	264.0	216.0	0.0	504.0
12.	Oper MBtu	2634237	2629267	2387972	736846	905298	274773	16666228
13.	Net Gen (MWH)	257501.2	257166.2	231999.6	67532.4	84221.6	25718.2	1607832.2
14.	ANOHR (Btu/KWH)	10230.0	10224.0	10293.0	10911.0	10749.0	10684.0	10366.0
15.	NOF %	69.7	70.1	65.4	57.1	57.0	47.2	65.1
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [338.36 + 79.10 * MAY + 137.43 * OCT + 89.35 * NOV] + 9,278

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ESTIMATED 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 (%)	70.5	97.6	69.5	97.3	97.4	97.4	
2.	POF (%)	29.0	0.0	29.1	0.0	0.0	0.0	
3.	EUOF (%)	0.5	2.4	1.4	2.7	2.6	2.6	
4.	EUOR (%)	2.8	2.6	2.9	2.7	2.6	2.6	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	121.9	620.1	369.3	696.9	724.8	701.4	
7.	RSH	402.6	35.4	147.8	4.7	0.0	0.0	
8.	UH	219.5	16.4	225.9	18.5	19.2	18.6	
9.	POH	216.0	0.0	216.0	0.0	0.0	0.0	
10.	FOH & EFOH	3.5	16.4	10.9	19.5	19.2	18.6	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	429306	1964722	1420611	2387575	2402191	2479779	
13.	Net Gen (MWH)	43452.0	209013.0	138353.2	233572.2	233835.4	243665.0	
14.	ANOHR (Btu/KWH)	10822.0	9400.0	10268.0	10222.0	10273.0	10177.0	
15.	NOF %	35.0	66.1	73.5	65.7	63.3	68.1	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [430.73 - 94.68 * JAN - 274.79 * FEB + 67.80 * MAR + 155.49 * OCT] + 8,937

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ESTIMATED 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 (%)	97.4	97.4	97.3	97.4	68.7	77.2	88.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	4.9
3.	EUOF (%)	2.6	2.6	2.7	2.6	31.3	22.8	6.4
4.	EUOR (%)	2.6	2.6	2.7	2.6	38.0	73.2	7.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	724.8	724.8	693.8	723.0	368.8	62.1	6531.7
7.	RSH	0.0	0.0	7.8	1.9	126.4	511.9	1238.5
8.	UH	19.2	19.2	18.4	19.1	225.8	170.0	989.8
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	432.0
10.	FOH & EFOH	19.2	19.2	19.4	19.1	9.8	2.0	176.8
11.	MOH & EMOH	0.0	0.0	0.0	0.0	216.0	168.0	384.0
12.	Oper MBtu	2641963	2653117	2430374	2336902	1131304	152214	22430058
13.	Net Gen (MWH)	260677.2	261932.8	238505.8	214060.8	108800.2	14038.0	2199905.6
14.	ANOHR (Btu/KWH)	10135.0	10129.0	10190.0	10917.0	10398.0	10843.0	10196.0
15.	NOF %	70.5	70.9	67.4	58.1	57.8	44.3	66.0
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	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.

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	SMITH 3	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	83.1	98.9	99.0	79.3	89.5	99.0	
2.	POF (%)	0.0	0.0	0.0	20.0	9.7	0.0	
3.	EUOF (%)	16.9	1.1	1.0	0.7	0.8	1.0	
4.	EUOR (%)	16.9	1.1	1.0	0.9	0.9	1.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	618.0	665.3	735.6	571.0	666.0	712.8	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	126.0	6.7	7.4	149.0	78.0	7.2	
9.	POH	0.0	0.0	0.0	144.0	72.0	0.0	
10.	FOH & EFOH	6.0	7.7	7.4	5.0	6.0	7.2	
11.	MOH & EMOH	120.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1936986	2132631	2341416	1857370	2150633	2270734	
13.	Net Gen (MWH)	281293.4	310471.9	340619.1	270832.6	313320.6	330336.7	
14.	ANOHR (Btu/KWH)	6886.0	6869.0	6874.0	6858.0	6864.0	6874.0	
15.	NOF %	77.9	79.9	83.1	85.1	80.9	83.4	
16.	NPC (MW)	584.0	584.0	557.4	557.4	581.4	556.0	

19.	ANOHR Equation	10^6 / AKW * [314.69 - 33.91 * OCT] + 6,195

Issued by: S. W. Connally, Jr.

ESTIMATED 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 (%)	99.0	99.0	99.0	99.0	69.2	98.9	92.7
2.	POF (%)	0.0	0.0	0.0	0.0	30.0	0.0	4.9
3.	EUOF (%)	1.0	1.0	1.0	1.0	0.8	1.1	2.3
4.	EUOR (%)	1.0	1.0	1.0	1.0	1.2	1.1	2.4
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	736.6	736.6	712.8	736.6	500.0	736.5	8127.8
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	7.4	7.4	7.2	7.4	221.0	7.5	632.2
9.	POH	0.0	0.0	0.0	0.0	216.0	0.0	432.0
10.	FOH & EFOH	7.4	7.4	7.2	7.4	6.0	8.5	83.2
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	120.0
12.	Oper MBtu	2465460	2452799	2279273	2358250	1671729	2498747	26416028
13.	Net Gen (MWH)	360552.8	358543.9	331723.6	347312.2	244476.3	365955.9	3855439.0
14.	ANOHR (Btu/KWH)	6838.0	6841.0	6871.0	6790.0	6838.0	6828.0	6852.0
15.	NOF %	88.0	87.5	83.7	84.6	87.7	85.1	83.9
16.	NPC (MW)	556.0	556.0	556.0	557.4	557.4	584.0	565.6

19.	ANOHR Equation	10^6 / AKW * [314.69 - 33.91 * OCT] + 6,195

Issued by: S. W. Connally, Jr.

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2015 - December 2015

Plant & Unit	Planned Outage Dates			Reason for Outage
Daniel 1	01/17/15	-	03/29/15	Major boiler outage and inspection
Daniel 2	01/19/15	-	01/27/15	Common Stack outage
Daniel 2	03/16/15	-	03/24/15	Common Stack outage
Crist 6	03/28/15	-	05/31/15	Controls upgrqade and boiler inspection.
Crist 7	05/09/15	-	05/15/15	Common outage for scrubber maintenance
Smith 3	04/25/15	-	05/03/15	Borescope Inspection
Smith 3	11/21/15	-	11/29/15	Borescope Inspection

Issued by: S. W. Connally, Jr.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2015 - December 2015

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 2015 - December 2015, 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: 140001-EI EXHIBIT: 43
PARTY: TAMPA ELECTRIC COMPANY
(TECO)(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 2013 – DECEMBER 2013

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

1.	Actual End-of-Period True-up: Over/(Under) Recovery	($599,839)
2.	Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-13-0665-FOF-EI For the January 2013 Through December 2013 Period	(591,765)
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2015 Through December 2015 Period	**($8,074)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	Total
1 UNIT POWER CAPACITY CHARGES	0	0	0	0	0	(24,417)	0	0	0	0	0	0	(24,417)
2 CAPACITY PAYMENTS TO COGENERATORS	1,115,270	1,115,269	1,115,270	1,115,270	1,115,270	1,115,269	1,115,270	1,115,270	1,115,269	1,115,271	1,115,270	1,115,270	13,383,238
3 SCHEDULE J,D, & EMERG CAPACITY CHARGES	1,411,229	1,408,204	1,408,398	1,434,065	2,053,921	1,603,485	1,566,276	1,563,592	1,595,382	1,568,266	1,426,583	1,342,940	18,382,341
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(13,105)	(34,867)	(141,219)	(241,263)	(206,895)	(121,887)	(91,690)	(73,328)	(132,514)	(257,668)	(64,455)	(83,647)	(1,462,538)
6 TOTAL CAPACITY DOLLARS	2,513,394	2,488,606	2,382,449	2,308,072	2,962,296	2,572,450	2,589,856	2,605,534	2,578,137	2,425,869	2,477,398	2,374,563	30,278,624
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	2,513,394	2,488,606	2,382,449	2,308,072	2,962,296	2,572,450	2,589,856	2,605,534	2,578,137	2,425,869	2,477,398	2,374,563	30,278,624
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,777,423	2,561,761	2,632,627	2,766,435	2,917,104	3,336,068	3,432,775	3,541,356	3,667,491	3,313,013	2,859,588	2,705,500	36,511,141
10 PRIOR PERIOD TRUE-UP PROVISION	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,543)	(6,702,505)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	2,218,881	2,003,219	2,074,085	2,207,893	2,358,562	2,777,526	2,874,233	2,982,814	3,108,949	2,754,471	2,301,046	2,146,957	29,808,636
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(294,513)	(485,387)	(308,364)	(100,179)	(603,734)	205,076	284,377	377,280	530,812	328,602	(176,352)	(227,606)	(469,988)
13 INTEREST PROVISION FOR PERIOD	(402)	(522)	(509)	(421)	(348)	(272)	(232)	(188)	(137)	(70)	(56)	(46)	(3,203)
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	(6,829,153)	(6,565,526)	(6,492,893)	(6,243,224)	(5,785,282)	(5,830,822)	(5,067,476)	(4,224,789)	(3,289,155)	(2,199,938)	(1,312,864)	(930,730)	(6,829,153)
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,543	6,702,505
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(6,565,526)	(6,492,893)	(6,243,224)	(5,785,282)	(5,830,822)	(5,067,476)	(4,224,789)	(3,289,155)	(2,199,938)	(1,312,864)	(930,730)	(599,839)	**(599,839)**

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DOCKET NO. 140001-EI
CCR 2013 FINAL TRUE-UP
EXHIBIT NO._____ (PAR-1)
DOCUMENT NO. 1
PAGE 2 OF 4

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	Total
1 BEGINNING TRUE-UP AMOUNT	(6,829,153)	(6,565,526)	(6,492,893)	(6,243,224)	(5,785,282)	(5,830,822)	(5,067,476)	(4,224,789)	(3,289,155)	(2,199,938)	(1,312,864)	(930,730)	(6,829,153)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(6,565,124)	(6,492,371)	(6,242,715)	(5,784,861)	(5,830,474)	(5,067,204)	(4,224,557)	(3,288,967)	(2,199,801)	(1,312,794)	(930,674)	(599,793)	(596,636)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(13,394,277)	(13,057,897)	(12,735,608)	(12,028,085)	(11,615,756)	(10,898,026)	(9,292,033)	(7,513,756)	(5,488,956)	(3,512,732)	(2,243,538)	(1,530,523)	(7,425,789)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(6,697,139)	(6,528,949)	(6,367,804)	(6,014,043)	(5,807,878)	(5,449,013)	(4,646,017)	(3,756,878)	(2,744,478)	(1,756,366)	(1,121,769)	(765,262)	(3,712,895)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.050	0.090	0.100	0.080	0.080	0.070	0.060	0.050	0.060	0.050	0.050	0.060	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.090	0.100	0.080	0.080	0.070	0.060	0.050	0.060	0.050	0.050	0.060	0.080	NA
7 TOTAL (LINE 5 + LINE 6)	0.140	0.190	0.180	0.160	0.150	0.130	0.110	0.110	0.110	0.100	0.110	0.140	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.070	0.095	0.090	0.080	0.075	0.065	0.055	0.055	0.055	0.050	0.055	0.070	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.006	0.008	0.008	0.007	0.006	0.005	0.005	0.005	0.005	0.004	0.005	0.006	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(402)	(522)	(509)	(421)	(348)	(272)	(232)	(188)	(137)	(70)	(56)	(46)	(3,203)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	($24,417)	$0	($24,417)	0.00%
2 CAPACITY PAYMENTS TO COGENERATORS	13,383,238	13,383,240	(2)	0.00%
3 SCHEDULE J & D CAPACITY CHARGES	18,382,341	$18,282,225	100,116	1.00%
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5 (CAPACITY REVENUES)	(1,462,538)	(1,518,476)	55,938	-3.68%
6 TOTAL CAPACITY DOLLARS	$30,278,624	$30,146,989	$131,635	0.44%
7 JURISDICTIONAL PERCENTAGE	100.00000%	100.00000%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$30,278,624	$30,146,989	$131,635	0.44%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	36,511,141	36,388,659	122,482	0.34%
10 PRIOR PERIOD TRUE-UP PROVISION	(6,702,505)	(6,702,505)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$29,808,636	$29,686,154	$122,482	0.41%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($469,988)	($460,835)	($9,153)	1.99%
13 INTEREST PROVISION FOR PERIOD	(3,203)	(4,282)	1,079	-25.20%
14 OTHER ADJUSTMENT	0	0	0	0.00%
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(6,829,153)	(6,829,153)	0	0.00%
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	6,702,505	6,702,505	0	0.00%
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	($599,839)	($591,765)	($8,074)	1.36%

EXHIBIT TO THE TESTIMONY OF
PENELOPE A. RUSK

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY
FOR
JANUARY 2013 – DECEMBER 2013

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2013 THROUGH DECEMBER 2013

1 TOTAL FUEL COSTS FOR THE PERIOD	$710,706,692
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	710,706,692
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	748,947,237
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	38,240,545
5 ADJUSTMENTS	0
6 INTEREST	39,139
7 TRUE-UP COLLECTED	(69,319,858)
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/12)	70,222,929
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	39,182,755
10 PROJECTED OVER-RECOVERY PER PROJECTION FILED 8/30/13 (SCHEDULE E1-A LINE 3)	15,630,547
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	**$23,552,208**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2013 – DECEMBER 2013

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2013 THROUGH DECEMBER 2013

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$682,755,620	$719,428,456	($36,672,836)	(5.1)
	2. FUEL COST OF POWER SOLD	6,507,703	4,849,517	1,658,186	34.2
	2a. GAINS FROM SALES	894,047	485,483	408,564	84.2
	3. FUEL COST OF PURCHASED POWER	7,885,466	4,606,910	3,278,556	71.2
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	7,855,181	8,298,210	(443,029)	(5.3)
	4. ENERGY COST OF ECONOMY PURCHASES	17,167,772	15,763,980	1,403,792	8.9
	6a. ADJ. TO FUEL COST (Polk 1 conversion depreciation & ROI)	2,444,403	2,571,400	(126,997)	(4.9)
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. (SUM OF LINES A1 THRU 6a)	$710,706,692	$745,333,956	($34,627,264)	(4.6)
C	1. JURISDICTIONAL FUEL REVENUE	$679,089,360	$675,823,197	$3,266,163	0.5
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	2a. TRUE-UP PROVISION	69,319,858	69,319,858	0	0.0
	2b. INCENTIVE PROVISION	538,019	538,019	0	0.0
	2c. ADJUSTMENT	0	0	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	748,947,237	745,681,074	3,266,163	0.4
	6d.JURISD. TOTAL FUEL & NET PWR. TRANS.	710,706,692	745,333,956	(34,627,264)	(4.6)
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	38,240,545	347,118	37,893,427	10,916.6
	8. INTEREST PROVISION - THIS PERIOD	39,139	116,849	(77,710)	(66.5)
	8a. TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8)	$38,279,684	$463,967	$37,815,717	8,150.5
	9.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2013)	70,222,929	69,319,858	903,071	1.3
	10.TRUE-UP COLLECTED (REFUNDED)	(69,319,858)	(69,319,858)	0	0.0
	11.END OF PERIOD TOTAL NET TRUE-UP (LINE C8a through C10)	$39,182,755	$463,967	$38,718,788	8,345.2

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 2013

SCHEDULES A1 AND A2
AND
SCHEDULES A6 THROUGH A9
AND
SCHEDULE A12

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 AND A2

DECEMBER 2013

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2013

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	50,230,411	53,412,629	(3,182,218)	-6.0%	1,386,535	1,374,330	12,205	0.9%	3.62273	3.88645	(0.26372)	-6.8%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments to Fuel Cost (Polk 1 conversion depreciation & ROI)	393,420	360,838	32,582	9.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4b)	**50,623,831**	**53,773,467**	**(3,149,636)**	**-5.9%**	**1,386,535**	**1,374,330**	**12,205**	**0.9%**	**3.65110**	**3.91270**	**(0.26160)**	**-6.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	763,884	38,710	725,174	1873.4%	14,545	690	13,855	2008.0%	5.25187	5.61014	(0.35828)	-6.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	614,473	1,445,770	(831,297)	-57.5%	14,835	43,550	(28,715)	-65.9%	4.14205	3.31979	0.82226	24.8%
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)	521,556	647,960	(126,404)	-19.5%	17,051	15,930	1,121	7.0%	3.05880	4.06755	(1.00875)	-24.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**1,899,913**	**2,132,440**	**(232,527)**	**-10.9%**	**46,431**	**60,170**	**(13,739)**	**-22.8%**	**4.09191**	**3.54403**	**0.54788**	**15.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,432,966**	**1,434,500**	**(1,534)**	**-0.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	81,245	0	81,245	0.0%	2,802	0	2,802	0.0%	2.89954	0.00000	2.89954	0.0%
15. Fuel Cost of Sch. C/CB Sales (A6)	111,632	0	111,632	0.0%	4,250	0	4,250	0.0%	2.62664	0.00000	2.62664	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)	65,564	441,947	(376,383)	-85.2%	2,652	14,520	(11,868)	-81.7%	2.47225	3.04371	(0.57146)	-18.8%
18. Gains on Sales	28,588	44,243	(15,655)	-35.4%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**287,029**	**486,190**	**(199,161)**	**-41.0%**	**9,704**	**14,520**	**(4,816)**	**-33.2%**	**2.95784**	**3.34842**	**(0.39057)**	**-11.7%**
20. Net Inadvertant Interchange					(337)	0	(337)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					327	0	327	0.0%				
22. Interchange and Wheeling Losses					656	233	423	181.4%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**52,236,715**	**55,419,717**	**(3,183,002)**	**-5.7%**	**1,422,596**	**1,419,747**	**2,849**	**0.2%**	**3.67193**	**3.90349**	**(0.23156)**	**-5.9%**
24. Net Unbilled	(845,829) (a)	(422,982) (a)	(422,847)	100.0%	(23,035)	(10,836)	(12,199)	112.6%	3.67193	3.90349	(0.23156)	-5.9%
25. Company Use	86,804 (a)	107,346 (a)	(20,542)	-19.1%	2,364	2,750	(386)	-14.0%	3.67191	3.90349	(0.23158)	-5.9%
26. T & D Losses	2,467,573 (a)	2,861,647 (a)	(394,074)	-13.8%	67,201	73,310	(6,109)	-8.3%	3.67193	3.90349	(0.23156)	-5.9%
27. System KWH Sales	52,236,715	55,419,717	(3,183,002)	-5.7%	1,376,066	1,354,523	21,543	1.6%	3.79609	4.09146	(0.29537)	-7.2%
28. Wholesale KWH Sales	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	52,236,715	55,419,717	(3,183,002)	-5.7%	1,376,066	1,354,523	21,543	1.6%	3.79609	4.09146	(0.29537)	-7.2%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	52,236,715	55,419,717	(3,183,002)	-5.7%	1,376,066	1,354,523	21,543	1.6%	3.79609	4.09146	(0.29537)	-7.2%
32. Other	0	0	0	0.0%	1,376,066	1,354,523	21,543	1.6%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(5,776,653)	(5,776,653)	0	0.0%	1,376,066	1,354,523	21,543	1.6%	(0.41979)	(0.42647)	0.00668	-1.6%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	46,460,062	49,643,064	(3,183,002)	-6.4%	1,376,066	1,354,523	21,543	1.6%	3.37630	3.66498	(0.28869)	-7.9%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	46,493,513	49,678,807	(3,185,294)	-6.4%	1,376,066	1,354,523	21,543	1.6%	3.37873	3.66762	(0.28889)	-7.9%
37. GPIF * (Already Adjusted for Taxes)	(44,834)	(44,834)	0	0.0%	1,376,066	1,354,523	21,543	1.6%	(0.00326)	(0.00331)	0.00005	-1.6%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**46,448,679**	**49,633,973**	**(3,185,294)**	**-6.4%**	**1,376,066**	**1,354,523**	**21,543**	**1.6%**	**3.37547**	**3.66431**	**(0.28884)**	**-7.9%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.375**	**3.664**	**(0.289)**	**-7.9%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: December 2013

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	682,755,620	719,428,456	(36,672,836)	-5.1%	18,430,621	18,584,460	(153,839)	-0.8%	3.70446	3.87113	(0.16667)	-4.3%
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 to Fuel Cost (Polk 1 conversion depreciation & ROI)	2,444,403	2,571,400	(126,997)	-4.9%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4b)	**685,200,023**	**721,999,856**	**(36,799,833)**	**-5.1%**	**18,430,621**	**18,584,460**	**(153,839)**	**-0.8%**	**3.71773**	**3.88497**	**(0.16724)**	**-4.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	7,885,466	4,606,910	3,278,556	71.2%	211,876	81,890	129,986	158.7%	3.72174	5.62573	(1.90399)	-33.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	17,167,772	15,763,980	1,403,792	8.9%	489,385	450,000	39,385	8.8%	3.50803	3.50311	0.00492	0.1%
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)	7,855,181	8,298,210	(443,029)	-5.3%	276,172	193,540	82,632	42.7%	2.84431	4.28759	(1.44329)	-33.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**32,908,419**	**28,669,100**	**4,239,319**	**14.8%**	**977,433**	**725,430**	**252,003**	**34.7%**	**3.36682**	**3.95201**	**(0.58519)**	**-14.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**19,408,054**	**19,309,890**	**98,164**	**0.5%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	416,217	0	416,217	0.0%	15,090	0	15,090	0.0%	2.75823	0.00000	2.75823	0.0%
15. Fuel Cost of Sch. C/CB Sales (A6)	4,602,321	0	4,602,321	0.0%	153,293	0	153,293	0.0%	3.00230	0.00000	3.00230	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)	1,489,165	4,849,517	(3,360,352)	-69.3%	53,882	150,000	(96,118)	-64.1%	2.76375	3.23301	(0.46926)	-14.5%
18. Gains on Sales	894,047	485,483	408,564	84.2%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**7,401,750**	**5,335,000**	**2,066,750**	**38.7%**	**222,265**	**150,000**	**72,265**	**48.2%**	**3.33015**	**3.55667**	**(0.22652)**	**-6.4%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					(471)	0	(471)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					35,668	0	35,668	0.0%				
22. Interchange and Wheeling Losses					39,255	2,408	36,847	1530.2%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**710,706,692**	**745,333,956**	**(34,627,264)**	**-4.6%**	**19,181,731**	**19,157,482**	**24,249**	**0.1%**	**3.70512**	**3.89056**	**(0.18544)**	**-4.8%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	(2,846,683) (a)	(2,864,996) (a)	18,313	-0.6%	(77,994)	(72,617)	(5,377)	7.4%	3.64987	3.94535	(0.29548)	-7.5%
25. Company Use	1,223,953 (a)	1,282,703 (a)	(58,750)	-4.6%	33,112	33,000	112	0.3%	3.69635	3.88698	(0.19063)	-4.9%
26. T & D Losses	29,951,131 (a)	38,748,774 (a)	(8,797,643)	-22.7%	808,950	995,083	(186,133)	-18.7%	3.70247	3.89402	(0.19156)	-4.9%
27. System KWH Sales	710,706,692	745,333,956	(34,627,264)	-4.6%	18,417,662	18,202,016	215,646	1.2%	3.85883	4.09479	(0.23596)	-5.8%
28. Wholesale KWH Sales	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	710,706,692	745,333,956	(34,627,264)	-4.6%	18,417,662	18,202,016	215,646	1.2%	3.85883	4.09479	(0.23596)	-5.8%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	710,706,692	745,333,956	(34,627,264)	-4.6%	18,417,662	18,202,016	215,646	1.2%	3.85883	4.09479	(0.23596)	-5.8%
32. Other	0	0	0	0.0%	18,417,662	18,202,016	215,646	1.2%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(69,319,858)	(69,319,858)	0	0.0%	18,417,662	18,202,016	215,646	1.2%	(0.37638)	(0.38084)	0.00446	-1.2%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	641,386,834	676,014,098	(34,627,264)	-5.1%	18,417,662	18,202,016	215,646	1.2%	3.48246	3.71395	(0.23150)	-6.2%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	641,848,632	676,500,829	(34,652,197)	-5.1%	18,417,662	18,202,016	215,646	1.2%	3.48496	3.71663	(0.23167)	-6.2%
37. GPIF * (Already Adjusted for Taxes)	(538,019)	(538,019)	0	0.0%	18,417,662	18,202,016	215,646	1.2%	(0.00292)	(0.00296)	0.00003	-1.2%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**641,310,613**	**675,962,810**	**(34,652,197)**	**-5.1%**	**18,417,662**	**18,202,016**	**215,646**	**1.2%**	**3.48204**	**3.71367**	**(0.23164)**	**-6.2%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.482**	**3.714**	**(0.232)**	**-6.2%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2013

	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	50,230,411	53,412,629	(3,182,218)	-6.0%	682,755,620	719,428,456	(36,672,836)	-5.1%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	258,441	441,947	(183,506)	-41.5%	6,507,703	4,849,517	1,658,186	34.2%
2a. GAINS FROM SALES	28,588	44,243	(15,655)	-35.4%	894,047	485,483	408,564	84.2%
3. FUEL COST OF PURCHASED POWER	763,884	38,710	725,174	1873.4%	7,885,466	4,606,910	3,278,556	71.2%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	521,556	647,960	(126,404)	-19.5%	7,855,181	8,298,210	(443,029)	-5.3%
4. ENERGY COST OF ECONOMY PURCHASES	614,473	1,445,770	(831,297)	-57.5%	17,167,772	15,763,980	1,403,792	8.9%
5. TOTAL FUEL & NET POWER TRANSACTION	51,843,295	55,058,879	(3,215,584)	-5.8%	708,262,289	742,762,556	(34,500,267)	-4.6%
6a. ADJUSTMENTS TO FUEL COST (Polk 1 conversion depreciation & ROI)	393,420	360,838	32,582	9.0%	2,444,403	2,571,400	(126,997)	-4.9%
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	52,236,715	55,419,717	(3,183,002)	-5.7%	710,706,692	745,333,956	(34,627,264)	-4.6%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,376,066	1,354,523	21,543	1.6%	18,417,662	18,202,016	215,646	1.2%
2. NONJURISDICTIONAL SALES	0	0	0	0.0%	0	0	0	0.0%
3. TOTAL SALES	1,376,066	1,354,523	21,543	1.6%	18,417,662	18,202,016	215,646	1.2%
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 2013

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	50,275,793	49,784,004	491,789	1.0%	679,089,360	675,823,197	3,266,163	0.5%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	5,776,653	5,776,653	0	0.0%	69,319,858	69,319,858	0	0.0%
2b. INCENTIVE PROVISION	44,834	44,834	0	0.0%	538,019	538,019	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	56,097,280	55,605,491	491,789	0.9%	748,947,237	745,681,074	3,266,163	0.4%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	52,236,715	55,419,717	(3,183,002)	-5.7%	710,706,692	745,333,956	(34,627,264)	-4.6%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1.0000000	1.0000000	0.0000000	0.0%	-	-	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	52,236,715	55,419,717	(3,183,002)	-5.7%	710,706,692	745,333,956	(34,627,264)	-4.6%
6a. JURISDIC. LOSS MULTIPLIER	1.00000	1.00000	0.00000	0.0%	-	-	-	0.0%
6b. (LINE C6 x LINE C6a)	52,236,715	55,419,717	(3,183,002)	-5.7%	710,706,692	745,333,956	(34,627,264)	-4.6%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	52,236,715	55,419,717	(3,183,002)	-5.7%	710,706,692	745,333,956	(34,627,264)	-4.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	3,860,565	185,774	3,674,791	1978.1%	38,240,545	347,118	37,893,427	10916.6%
8. INTEREST PROVISION FOR THE MONTH	2,408	912	1,496	164.0%	39,139	116,849	(77,710)	-66.5%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	41,096,435	6,053,934	35,042,501	578.8%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(5,776,653)	(5,776,653)	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	39,182,755	463,967	38,718,788	8345.2%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2013

	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)	41,096,435	6,053,934	35,042,501	578.8%	-----	NOT APPLICABLE	-----	
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	39,180,347	463,055	38,717,292	8361.3%	-----	NOT APPLICABLE	-----	
3. TOTAL BEG. & END. TRUE-UP AMOUNT	80,276,782	6,516,989	73,759,793	1131.8%	-----	NOT APPLICABLE	-----	
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	40,138,391	3,258,495	36,879,896	1131.8%	-----	NOT APPLICABLE	-----	
5. INT. RATE-FIRST DAY REP. BUS. MONTH	0.060	0.330	(0.270)	-81.8%	-----	NOT APPLICABLE	-----	
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	0.080	0.330	(0.250)	-75.8%	-----	NOT APPLICABLE	-----	
7. TOTAL (LINE D5 + LINE D6)	0.140	0.660	(0.520)	-78.8%	-----	NOT APPLICABLE	-----	
8. AVERAGE INT. RATE (50% OF LINE D7)	0.070	0.330	(0.260)	-78.8%	-----	NOT APPLICABLE	-----	
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.006	0.028	(0.022)	-78.6%	-----	NOT APPLICABLE	-----	
10. INT. PROVISION (LINE D4 x LINE D9)	2,408	912	1,496	164.0%	-----	NOT APPLICABLE	-----	

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2013 - DECEMBER 2013

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	MKT.BASE	150,000.0	0.0	150,000.0	3.233	3.965	4,849,517.00	5,947,000.00	485,483.00
TOTAL			**150,000.0**	**0.0**	**150,000.0**	**3.233**	**3.965**	**4,849,517.00**	**5,947,000.00**	**485,483.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	15,089.3	0.0	15,089.3	2.758	3.034	416,216.49	457,838.14	22,782.24
FLORIDA POWER & LIGHT		SCH. - C	597.0	0.0	597.0	2.664	3.301	15,904.04	19,704.66	3,561.18
REEDY CREEK		SCH. - C	185.0	0.0	185.0	2.406	2.999	4,450.75	5,548.74	868.09
FLORIDA MUNICIPAL POWER		SCH. - C	50.0	0.0	50.0	2.141	2.589	1,070.50	1,294.50	195.50
PROGRESS ENERGY FLORIDA		SCH. - C	255.0	0.0	255.0	2.526	3.561	6,441.16	9,080.31	2,572.85
ORLANDO UTILITIES COMMISSION		SCH. - C	3,415.0	0.0	3,415.0	2.316	2.776	79,080.61	94,787.81	12,712.98
THE ENERGY AUTHORITY		SCH. - C	118.0	0.0	118.0	2.444	2.920	2,884.19	3,445.63	359.60
CITY OF HOMESTEAD		SCH. - C	15.0	0.0	15.0	2.562	3.493	384.25	523.95	102.26
PROGRESS ENERGY FLORIDA		SCH. - CB	32,436.0	0.0	32,436.0	3.220	3.749	1,044,488.65	1,215,988.65	110,334.90
FLORIDA POWER & LIGHT		SCH. - CB	15,300.0	0.0	15,300.0	3.607	4.155	551,825.13	635,644.77	56,484.49
REEDY CREEK		SCH. - CB	58,865.0	0.0	58,865.0	2.788	3.225	1,641,192.32	1,898,228.80	154,820.51
ORLANDO UTILITIES COMMISSION		SCH. - CB	14,300.0	0.0	14,300.0	3.129	3.648	447,457.00	521,631.14	47,324.24
SEMINOLE ELECTRIC		SCH. - CB	20,736.0	0.0	20,736.0	2.862	3.334	593,490.73	691,271.06	61,079.67
THE ENERGY AUTHORITY		SCH. - CB	7,021.0	0.0	7,021.0	3.043	3.469	213,651.97	243,584.15	21,533.86
CARGILL ALLIANT		SCH. - MA	99.0	0.0	99.0	2.572	4.510	2,546.11	4,465.38	1,884.62
EXGEN (CONSTELLATION)		SCH. - MA	5,341.0	0.0	5,341.0	2.615	3.374	139,654.48	180,202.80	31,249.49
THE ENERGY AUTHORITY		SCH. - MA	10,760.0	0.0	10,760.0	2.637	3.300	283,708.95	355,029.70	52,432.69
CITY OF LAKELAND		SCH. - MA	8,900.0	0.0	8,900.0	3.364	4.914	299,396.00	437,389.00	121,706.00
NEW SMYRNA BEACH		SCH. - MA	5,175.0	0.0	5,175.0	2.918	3.724	151,014.20	192,737.47	35,419.54
REEDY CREEK		SCH. - MA	915.0	0.0	915.0	2.659	2.946	24,328.00	26,958.50	2,630.50
SOUTHERN COMPANY		SCH. - MA	7,407.0	0.0	7,407.0	2.627	3.561	194,599.99	263,784.04	61,708.43
EDF TRADING		SCH. - MA	4,624.0	0.0	4,624.0	2.552	3.313	118,023.21	153,200.66	28,893.67
JP MORGAN VENTURES		SCH. - MA	3,229.0	0.0	3,229.0	2.563	3.279	82,743.55	105,863.65	20,421.58
MORGAN STANLEY		SCH. - MA	7,219.0	0.0	7,219.0	2.582	3.328	186,408.61	240,226.30	41,869.75
CITY OF HOMESTEAD		SCH. - MA	213.0	0.0	213.0	3.166	3.762	6,743.56	8,013.44	1,096.02
SUB-TOTAL			**222,264.3**	**0.0**	**222,264.3**	**2.928**	**3.494**	**6,507,704.45**	**7,766,443.25**	**894,044.66**
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			15,089.3	0.0	15,089.3	2.758	3.034	416,216.49	457,838.14	22,782.24
SUB-TOTAL SCHEDULE C POWER SALES			4,635.0	0.0	4,635.0	2.378	2.899	110,215.50	134,385.60	20,372.46
SUB-TOTAL SCHEDULE CB POWER SALES			148,658.0	0.0	148,658.0	3.022	3.502	4,492,105.80	5,206,348.57	451,577.67
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			53,882.0	0.0	53,882.0	2.764	3.652	1,489,166.66	1,967,870.94	399,312.29
TOTAL			**222,264.3**	**0.0**	**222,264.3**	**2.928**	**3.494**	**6,507,704.45**	**7,766,443.25**	**894,044.66**
DIFFERENCE			72,264.3	0.0	72,264.3	(0.305)	(0.471)	1,658,187.45	1,819,443.25	408,561.66
DIFFERENCE %			48.2%	0.0%	48.2%	-9.4%	-11.9%	34.2%	30.6%	84.2%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2013 - DECEMBER 2013

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
OLEANDER	SCH. - D	21,060.0	0.0	0.0	21,060.0	6.344	6.344	1,336,110.00
CALPINE	SCH. - D	3,650.0	0.0	0.0	3,650.0	6.956	6.956	253,900.00
PASCO COGEN	SCH. - D	57,180.0	0.0	0.0	57,180.0	5.276	5.276	3,016,900.00
TOTAL		**81,890.0**	**0.0**	**0.0**	**81,890.0**	**5.626**	**5.626**	**4,606,910.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	0.0	0.0	0.0	0.0	0.000	0.000	(97,726.42)
FLORIDA POWER & LIGHT	EMERG A	150.0	0.0	0.0	150.0	16.637	16.637	24,955.50
OLEANDER	SCH. - D	16,474.0	0.0	0.0	16,474.0	6.223	6.223	1,025,148.71
CALPINE	SCH. - D	7,722.0	0.0	0.0	7,722.0	6.290	6.290	485,693.25
PASCO COGEN	SCH. - D	176,285.0	0.0	0.0	176,285.0	3.484	3.484	6,141,948.17
CALPINE	OATT	11,245.0	0.0	0.0	11,245.0	2.716	2.716	305,446.60
SUB-TOTAL		**211,876.0**	**0.0**	**0.0**	**211,876.0**	**3.722**	**3.722**	**7,885,465.81**
SUB-TOTAL SCHEDULE EMERGENCY A		150.0	0.0	0.0	150.0	16.637	16.637	24,955.50
SUB-TOTAL SCHEDULE IPP PURCHASED POWER		0.0	0.0	0.0	0.0	0.000	0.000	(97,726.42)
SUB-TOTAL SCHEDULE D PURCHASED POWER		200,481.0	0.0	0.0	200,481.0	3.817	3.817	7,652,790.13
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		11,245.0	0.0	0.0	11,245.0	2.716	2.716	305,446.60
TOTAL		**211,876.0**	**0.0**	**0.0**	**211,876.0**	**3.722**	**3.722**	**7,885,465.81**
DIFFERENCE		129,986.0	0.0	0.0	129,986.0	(1.904)	(1.904)	3,278,555.81
DIFFERENCE %		158.7%	0.0%	0.0%	158.7%	-33.8%	-33.8%	71.2%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2013 - DECEMBER 2013

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	**COGEN.**							
	FIRM	72,770.0	0.0	0.0	72,770.0	3.527	3.527	2,566,870.00
	AS AVAIL.	120,770.0	0.0	0.0	120,770.0	4.746	4.746	5,731,340.00
TOTAL		**193,540.0**	**0.0**	**0.0**	**193,540.0**	**4.288**	**4.288**	**8,298,210.00**
ACTUAL:								
	FIRM							
ORANGE COGENERATION L.P.	COGEN.	71,353.0	0.0	0.0	71,353.0	2.752	2.752	1,963,598.86
	AS AVAILABLE							
McKAY BAY REFUSE	COGEN.	62.0	0.0	0.0	62.0	2.832	2.832	1,755.95
CARGILL RIDGEWOOD	COGEN.	18,623.0	0.0	0.0	18,623.0	2.867	2.867	533,878.98
CARGILL MILLPOINT	COGEN.	47,866.0	0.0	0.0	47,866.0	2.866	2.866	1,372,025.01
CF INDUSTRIES INC.	COGEN.	3,041.0	0.0	0.0	3,041.0	2.930	2.930	89,102.61
IMC-AGRICO-NEW WALES	COGEN.	21,977.0	0.0	0.0	21,977.0	2.900	2.900	637,397.74
IMC-AGRICO-S. PIERCE	COGEN.	112,822.0	0.0	0.0	112,822.0	2.877	2.877	3,246,161.25
AUBURNDALE POWER PARTNERS	COGEN.	236.0	0.0	0.0	236.0	2.923	2.923	6,897.85
HILLSBOROUGH COUNTY	COGEN.	192.0	0.0	0.0	192.0	2.272	2.272	4,361.53
SUB-TOTAL		**276,172.0**	**0.0**	**0.0**	**276,172.0**	**2.844**	**2.844**	**7,855,179.78**
SUB-TOTAL FOR FIRM		71,353.0	0.0	0.0	71,353.0	2.752	2.752	1,963,598.86
SUB-TOTAL FOR AS AVAIL.		204,819.0	0.0	0.0	204,819.0	2.876	2.876	5,891,580.92
TOTAL		**276,172.0**	**0.0**	**0.0**	**276,172.0**	**2.844**	**2.844**	**7,855,179.78**
DIFFERENCE		82,632.0	0.0	0.0	82,632.0	(1.443)	(1.443)	(443,030.22)
DIFFERENCE %		42.7%	0.0%	0.0%	42.7%	-33.7%	-33.7%	-5.3%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2013 - DECEMBER 2013

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

(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 CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT (5) X (6)	(A) CENTS PER KWH	(B) TOTAL COST	FUEL SAVINGS (8B)-6
ESTIMATED:									
VARIOUS	Economy	450,000.0	0.0	450,000.0	3.503	15,763,980.00	3.503	15,763,980.00	0.00
TOTAL		**450,000.0**	**0.0**	**450,000.0**	**3.503**	**15,763,980.00**	**3.503**	**15,763,980.00**	**0.00**
ACTUAL:									
OKEELANTA	SCH. - REB	11,468.0	0.0	11,468.0	2.713	311,121.00	3.000	344,035.36	32,914.36
FLA. POWER & LIGHT	SCH. - C	932.0	0.0	932.0	3.301	30,761.38	4.483	41,780.67	11,019.29
ORLANDO UTIL. COMM.	SCH. - C	100.0	0.0	100.0	4.329	4,328.65	4.942	4,942.00	613.35
PROGRESS ENERGY FLORIDA	SCH. - C	49.0	0.0	49.0	3.950	1,935.50	5.086	2,492.14	556.64
CALPINE	SCH. - J	265,317.0	0.0	265,317.0	3.454	9,163,469.50	3.758	9,969,999.58	806,530.08
CARGILL ALLIANT	SCH. - J	800.0	0.0	800.0	2.800	22,400.00	2.994	23,952.00	1,552.00
CITY OF TALLAHASSEE	SCH. - J	50.0	0.0	50.0	2.500	1,250.00	2.898	1,449.00	199.00
CONSTELLATION COMMODITIES	SCH. - J	2,808.0	0.0	2,808.0	3.072	86,254.00	3.852	108,176.20	21,922.20
EAGLE ENERGY	SCH. - J	441.0	0.0	441.0	2.838	12,515.00	3.866	17,049.35	4,534.35
EDF TRADING	SCH. - J	2,005.0	0.0	2,005.0	3.369	67,544.00	4.361	87,433.23	19,889.23
EXGEN (CONSTELLATION)	SCH. - J	10,100.0	0.0	10,100.0	3.588	362,361.00	4.352	439,601.02	77,240.02
FLA. POWER & LIGHT	SCH. - J	149,924.0	0.0	149,924.0	3.440	5,157,080.00	3.969	5,950,671.07	793,591.07
J P MORGAN VENTURES	SCH. - J	1,114.0	0.0	1,114.0	3.537	39,402.00	4.263	47,487.40	8,085.40
MORGAN STANLEY	SCH. - J	5,142.0	0.0	5,142.0	3.692	189,832.00	4.240	218,038.06	28,206.06
ORLANDO UTIL. COMM.	SCH. - J	9,295.0	0.0	9,295.0	4.661	433,195.00	5.295	492,164.60	58,969.60
PROGRESS ENERGY FLORIDA	SCH. - J	2,076.0	0.0	2,076.0	4.052	84,128.00	4.819	100,049.33	15,921.33
SEMINOLE ELEC. CO-OP	SCH. - J	7,162.0	0.0	7,162.0	4.287	307,069.00	4.954	354,814.91	47,745.91
SOUTHERN COMPANY	SCH. - J	11,981.0	0.0	11,981.0	4.011	480,541.00	4.743	568,231.12	87,690.12
THE ENERGY AUTHORITY	SCH. - J	8,621.0	0.0	8,621.0	4.786	412,584.00	5.350	461,226.80	48,642.80
SUB-TOTAL		**489,385.0**	**0.0**	**489,385.0**	**3.508**	**17,167,771.03**	**3.930**	**19,233,593.84**	**2,065,822.81**
SUB-TOTAL SCHEDULE REB ECONOMY PURCHASES		11,468.0	0.0	11,468.0	2.713	311,121.00	3.000	344,035.36	32,914.36
SUB-TOTAL SCHEDULE C ECONOMY PURCHASES		1,081.0	0.0	1,081.0	3.425	37,025.53	4.553	49,214.81	12,189.28
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES		476,836.0	0.0	476,836.0	3.527	16,819,624.50	3.951	18,840,343.67	2,020,719.17
TOTAL		**489,385.0**	**0.0**	**489,385.0**	**3.508**	**17,167,771.03**	**3.930**	**19,233,593.84**	**2,065,822.81**
DIFFERENCE		39,385.0	0.0	39,385.0	0.005	1,403,791.03	0.427	3,469,613.84	2,065,822.81
DIFFERENCE %		8.8%	0.0%	8.8%	0.1%	8.9%	12.2%	22.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2013 - DECEMBER 2013

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

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	12/31/2016		

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	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
SEMINOLE ELECTRIC	1.1	1.1	4.8	5.3	1.0	1.2	6.2	7.2	6.5	4.3	3.9	6.8

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
													-
ORANGE COGEN LP	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
TOTAL COGENERATION	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 1,115,270**	**$ 13,383,240**

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
HARDEE POWER PARTNERS	[redacted]												
CALPINE - D													
OLEANDER - D													
PASCO COGEN LTD - D													
FLORIDA POWER & LIGHT-EMERG A													
ORLANDO UTILITIES													
FLORIDA POWER & LIGHT													
PROGRESS ENERGY FLORIDA													
THE ENERGY AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
PROGRESS ENERGY FLORIDA - CB													
FLORIDA POWER & LIGHT - CB													
ORLANDO UTILITIES - CB													
REEDY CREEK - CB													
SEMINOLE ELECTRIC - CB													
THE ENERGY AUTHORITY - CB													
CARGILL ALLIANT - MA													
CITY OF LAKELAND - MA													
EXGEN (CONSTELLATION) - MA													
THE ENERGY AUTHORITY - MA													
J P MORGAN VENTURES - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
CITY OF HOMESTEAD - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$ 1,398,124**	**$ 1,373,336**	**$ 1,267,179**	**$ 1,192,802**	**$ 1,847,026**	**$ 1,457,180**	**$ 1,474,586**	**$ 1,490,264**	**$ 1,462,867**	**$ 1,310,599**	**$ 1,362,128**	**$ 1,259,293**	**$ 16,895,384**
TOTAL CAPACITY	**$ 2,513,394**	**$ 2,488,606**	**$ 2,382,449**	**$ 2,308,072**	**$ 2,962,296**	**$ 2,572,450**	**$ 2,589,856**	**$ 2,605,534**	**$ 2,578,137**	**$ 2,425,869**	**$ 2,477,398**	**$ 2,374,563**	**$ 30,278,624**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 5

CALCULATION OF REVENUE REQUIREMENT RATE OF RETURN

JANUARY 2013 – DECEMBER 2013

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP

CALCULATION OF REVENUE REQUIREMENT RATE OF RETURN
FOR THE PERIOD
JANUARY 2013 THROUGH JUNE 2013

	(1) Jurisdictional Rate Base Actual May 2012 ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,488,583	39.08%	6.59%	2.5754%
Short Term Debt	9,122	0.24%	0.64%	0.0015%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	105,073	2.76%	6.21%	0.1714%
Common Equity	1,633,530	42.87%	11.25%	4.8229%
Deferred ITC - Weighted Cost	8,810	0.23%	9.00%	0.0207%
Accumulated Deferred Income Taxes & Zero Cost ITCs	564,424	14.82%	0.00%	0.0000%
Total	$ 3,809,542	100.00%		7.5919%

ITC split between Debt and Equity:

Long Term Debt	$ 1,488,583	Long Term Debt	47.54%	
Short Term Debt	9,122	Short Term Debt	0.29%	47.83%
Equity - Preferred	0	Equity - Preferred	0.00%	
Equity - Common	1,633,530	Equity - Common	52.17%	52.17%
Total	$ 3,131,235	Total	100.00%	

Deferred ITC - Weighted Cost:

Debt = .0207% * 47.83%	0.0099%
Equity = .0207% * 52.17%	0.0108%
Weighted Cost	0.0207%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.8229%
Deferred ITC - Weighted Cost	0.0108%
	4.8337%
Times Tax Multiplier	1.628002
Total Equity Component	7.8693%

Total Debt Cost Rate:

Long Term Debt	2.5754%
Short Term Debt	0.0015%
Customer Deposits	0.1714%
Deferred ITC - Weighted Cost	0.0099%
Total Debt Component	2.7582%

Notes:

Column (1) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
Column (2) - Column (1) / Total Column (1)
Column (3) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
Column (4) - Column (2) x Column (3)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP

CALCULATION OF REVENUE REQUIREMENT RATE OF RETURN
FOR THE PERIOD
JULY 2013 THROUGH DECEMBER 2013

	(1) Jurisdictional Rate Base Actual May 2013 ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,425,239	37.00%	5.78%	2.1386%
Short Term Debt	0	0.00%	0.66%	0.0000%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	106,560	2.77%	2.91%	0.0806%
Common Equity	1,647,409	42.77%	11.25%	4.8116%
Deferred ITC - Weighted Cost	8,381	0.22%	8.71%	0.0192%
Accumulated Deferred Income Taxes & Zero Cost ITCs	664,214	17.24%	0.00%	0.0000%
Total	$ 3,851,803	100.00%		7.0500%

ITC split between Debt and Equity:

Long Term Debt	$ 1,425,239	Long Term Debt	46.38%		
Short Term Debt	0	Short Term Debt	0.00%	46.38%	
Equity - Preferred	0	Equity - Preferred	0.00%		
Equity - Common	1,647,409	Equity - Common	53.62%	53.62%	
Total	$ 3,072,648	Total	100.00%		

Deferred ITC - Weighted Cost:

Debt = .0192% * 46.38%	0.0089%
Equity = .0192% * 53.62%	0.0103%
Weighted Cost	0.0192%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.8116%
Deferred ITC - Weighted Cost	0.0103%
	4.8219%
Times Tax Multiplier	1.628002
Total Equity Component	7.8501%

Total Debt Cost Rate:

Long Term Debt	2.1386%
Short Term Debt	0.0000%
Customer Deposits	0.0806%
Deferred ITC - Weighted Cost	0.0089%
Total Debt Component	2.2281%

Notes:

Column (1) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
Column (2) - Column (1) / Total Column (1)
Column (3) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
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 2014 THROUGH DECEMBER 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 44
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-2

TAMPA ELECTRIC COMPANY

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6-17	Schedule E4 System Net Generation and Fuel Cost	(")
18-19	Schedule E5 Inventory Analysis	(")
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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 2014 THROUGH DECEMBER 2014

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
A. 1.	Fuel Cost of System Net Generation	57,764,938	47,875,542	49,332,428	55,197,751	63,124,670	67,735,546	70,905,654	69,482,991	66,712,164	61,674,178	51,814,693	53,944,340	715,564,895
2.	Fuel Cost of Power Sold [1]	3,444,211	2,290,662	456,799	421,996	120,329	408,254	530,975	368,361	645,782	395,981	1,235,877	400,618	10,719,845
3.	Fuel Cost of Purchased Power	955,641	495,222	996,131	638,073	1,314,753	1,337,249	918,360	800,030	1,245,980	308,160	324,570	237,640	9,571,809
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	631,105	604,739	844,315	895,023	902,598	737,672	793,830	681,060	529,370	613,960	636,020	412,840	8,282,532
4.	Energy Cost of Economy Purchases	631,870	1,080,139	3,828,623	1,635,113	2,300,098	2,055,484	2,119,750	1,916,600	1,870,170	1,282,210	1,209,630	1,023,610	20,953,297
5.	Polk 1 Conversion Depreciation & ROI	382,437	380,180	378,068	375,953	373,838	371,722	366,401	364,356	362,309	360,265	358,219	356,172	4,429,920
5a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**56,921,780**	**48,145,160**	**54,922,766**	**58,319,917**	**67,895,628**	**71,829,419**	**74,573,020**	**72,876,676**	**70,074,211**	**63,842,792**	**53,107,255**	**55,573,984**	**748,082,608**
[1]	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,423,894	1,371,917	1,275,956	1,290,230	1,515,132	1,773,051	1,819,390	1,784,609	1,848,447	1,657,171	1,400,577	1,348,999	18,509,373
2.	Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**TOTAL SALES (LINE B1+B2)**	**1,423,894**	**1,371,917**	**1,275,956**	**1,290,230**	**1,515,132**	**1,773,051**	**1,819,390**	**1,784,609**	**1,848,447**	**1,657,171**	**1,400,577**	**1,348,999**	**18,509,373**
4.	**Jurisdictional % of Total Sales**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**-**
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	55,070,048	53,060,829	48,999,802	49,597,852	58,937,972	69,755,512	71,795,984	70,653,928	72,937,142	64,523,855	53,770,782	51,984,126	721,087,832
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,546	1,302,541	15,630,547
2a.	Incentive Provision	98,088	98,088	98,088	98,088	98,088	98,088	98,088	98,088	98,088	98,088	98,088	98,091	1,177,059
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**56,470,682**	**54,461,463**	**50,400,436**	**50,998,486**	**60,338,606**	**71,156,146**	**73,196,618**	**72,054,562**	**74,337,776**	**65,924,489**	**55,171,416**	**53,384,758**	**737,895,438**
4.	Total Fuel and Net Power Transactions (Line A6)	56,921,780	48,145,160	54,922,766	58,319,917	67,895,628	71,829,419	74,573,020	72,876,676	70,074,211	63,842,792	53,107,255	55,573,984	748,082,608
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	56,921,780	48,145,160	54,922,766	58,319,917	67,895,628	71,829,419	74,573,020	72,876,676	70,074,211	63,842,792	53,107,255	55,573,984	748,082,608
5a.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
5b.	Jurisdictional Sales Adjusted for Line Losses	56,921,780	48,145,160	54,922,766	58,319,917	67,895,628	71,829,419	74,573,020	72,876,676	70,074,211	63,842,792	53,107,255	55,573,984	748,082,608
5c.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**56,921,780**	**48,145,160**	**54,922,766**	**58,319,917**	**67,895,628**	**71,829,419**	**74,573,020**	**72,876,676**	**70,074,211**	**63,842,792**	**53,107,255**	**55,573,984**	**748,082,608**
7.	Over/(Under) Recovery	(451,098)	6,316,303	(4,522,330)	(7,321,431)	(7,557,022)	(673,273)	(1,376,402)	(822,114)	4,263,565	2,081,697	2,064,161	(2,189,226)	(10,187,170)
7a.	Revenue Refund True-Up Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Interest Provision	2,298	1,997	1,977	1,939	1,179	726	1,266	1,477	1,523	2,044	2,474	2,269	21,169
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(10,166,001)**

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Actual						Estimated						TOTAL
		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	PERIOD
1.	Fuel Cost of System Net Generation	57,764,938	47,875,542	49,332,428	55,197,751	63,124,670	67,735,546	70,905,654	69,482,991	66,712,164	61,674,178	51,814,693	53,944,340	715,564,895
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold {1}	3,444,211	2,290,662	456,799	421,996	120,329	408,254	530,975	368,361	645,782	395,981	1,235,877	400,618	10,719,845
4.	Fuel Cost of Purchased Power	955,641	495,222	996,131	638,073	1,314,753	1,337,249	918,360	800,030	1,245,980	308,160	324,570	237,640	9,571,809
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	631,105	604,739	844,315	895,023	902,598	737,672	793,830	681,060	529,370	613,960	636,020	412,840	8,282,532
7.	Energy Cost of Economy Purchases	631,870	1,080,139	3,828,623	1,635,113	2,300,098	2,055,484	2,119,750	1,916,600	1,870,170	1,282,210	1,209,630	1,023,610	20,953,297
8.	Polk 1 Conversion Depreciation & ROI	382,437	380,180	378,068	375,953	373,838	371,722	366,401	364,356	362,309	360,265	358,219	356,172	4,429,920
8a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**56,921,780**	**48,145,160**	**54,922,766**	**58,319,917**	**67,895,628**	**71,829,419**	**74,573,020**	**72,876,676**	**70,074,211**	**63,842,792**	**53,107,255**	**55,573,984**	**748,082,608**
10.	Jurisdictional MWH Sold	1,423,894	1,371,917	1,275,956	1,290,230	1,515,132	1,773,051	1,819,390	1,784,609	1,848,447	1,657,171	1,400,577	1,348,999	18,509,373
11.	Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	56,921,780	48,145,160	54,922,766	58,319,917	67,895,628	71,829,419	74,573,020	72,876,676	70,074,211	63,842,792	53,107,255	55,573,984	748,082,608
13.	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	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	56,921,780	48,145,160	54,922,766	58,319,917	67,895,628	71,829,419	74,573,020	72,876,676	70,074,211	63,842,792	53,107,255	55,573,984	748,082,608
15.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16.	**JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 14+15)**	**56,921,780**	**48,145,160**	**54,922,766**	**58,319,917**	**67,895,628**	**71,829,419**	**74,573,020**	**72,876,676**	**70,074,211**	**63,842,792**	**53,107,255**	**55,573,984**	**748,082,608**
17.	Cost Per kWh Sold (Cents/kWh)	3.9976	3.5093	4.3044	4.5201	4.4812	4.0512	4.0988	4.0836	3.7910	3.8525	3.7918	4.1196	4.0416
18.	True-up (Cents/kWh) {2}	(0.0915)	(0.0949)	(0.1021)	(0.1010)	(0.0860)	(0.0735)	(0.0716)	(0.0730)	(0.0705)	(0.0786)	(0.0930)	(0.0966)	(0.0860)
19.	Total (Cents/kWh) (Line 17+18)	3.9061	3.4144	4.2023	4.4191	4.3952	3.9777	4.0272	4.0106	3.7205	3.7739	3.6988	4.0230	3.9556
20.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
21.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.9089	3.4169	4.2053	4.4223	4.3984	3.9806	4.0301	4.0135	3.7232	3.7766	3.7015	4.0259	3.9584
22.	GPIF Adjusted for Taxes (Cents/kWh) {2}	(0.0069)	(0.0071)	(0.0077)	(0.0076)	(0.0065)	(0.0055)	(0.0054)	(0.0055)	(0.0053)	(0.0059)	(0.0070)	(0.0073)	(0.0065)
23.	**TOTAL RECOVERY FACTOR (LINE 21+22)**	**3.9020**	**3.4098**	**4.1976**	**4.4147**	**4.3919**	**3.9751**	**4.0247**	**4.0080**	**3.7179**	**3.7707**	**3.6945**	**4.0186**	**3.9519**
24.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.902**	**3.410**	**4.198**	**4.415**	**4.392**	**3.975**	**4.025**	**4.008**	**3.718**	**3.771**	**3.695**	**4.019**	**3.952**

{1} Includes Gains
{2} Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E3

	ACTUAL					
	Jan-14	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	0	0	0	0	0	0
3. COAL	37,375,651	30,641,723	23,236,564	26,724,063	31,354,133	36,914,265
4. NATURAL GAS	20,389,287	17,233,819	26,095,864	28,473,688	31,770,537	30,821,281
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**57,764,938**	**47,875,542**	**49,332,428**	**55,197,751**	**63,124,670**	**67,735,546**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	0	0	0	0	0	0
10. COAL	1,101,227	869,340	625,520	746,682	904,397	1,049,864
11. NATURAL GAS	442,206	418,016	614,095	666,818	738,957	728,963
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,543,433**	**1,287,356**	**1,239,615**	**1,413,500**	**1,643,354**	**1,778,827**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	0	0	0	0	0	0
17. COAL (TON)	479,132	376,564	273,928	315,633	393,355	444,631
18. NATURAL GAS (MCF)	3,334,922	3,102,784	4,532,946	4,874,369	5,416,370	5,373,413
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	0	0	0	0	0	0
23. COAL	11,474,527	9,053,846	6,614,741	7,709,932	9,511,043	10,813,587
24. NATURAL GAS	3,388,832	3,157,828	4,603,963	4,973,592	5,530,263	5,480,316
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**14,863,358**	**12,211,673**	**11,218,704**	**12,683,524**	**15,041,306**	**16,293,903**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00
30. COAL	71.35	67.53	50.46	52.83	55.03	59.02
31. NATURAL GAS	28.65	32.47	49.54	47.17	44.97	40.98
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
37. COAL ($/TON)	78.01	81.37	84.83	84.67	79.71	83.02
38. NATURAL GAS ($/MCF)	6.11	5.55	5.76	5.84	5.87	5.74
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	0.00	0.00	0.00	0.00	0.00	0.00
43. COAL	3.26	3.38	3.51	3.47	3.30	3.41
44. NATURAL GAS	6.02	5.46	5.67	5.72	5.74	5.62
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)	**3.89**	**3.92**	**4.40**	**4.35**	**4.20**	**4.16**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	0	0	0	0	0	0
50. COAL	10,420	10,415	10,575	10,326	10,516	10,300
51. NATURAL GAS	7,663	7,554	7,497	7,459	7,484	7,518
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,630**	**9,486**	**9,050**	**8,973**	**9,153**	**9,160**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00
57. COAL	3.39	3.52	3.71	3.58	3.47	3.52
58. NATURAL GAS	4.61	4.12	4.25	4.27	4.30	4.23
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)	**3.74**	**3.72**	**3.98**	**3.91**	**3.84**	**3.81**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE **SCHEDULE E3**
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

	Estimated						
	Jul-14	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**TOTAL**
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	12,951	10,401	11,528	9,928	12,312	13,912	71,032
3. COAL	38,766,700	39,219,612	38,163,618	33,542,986	34,788,348	36,121,834	406,849,497
4. NATURAL GAS	32,126,003	30,252,978	28,537,018	28,121,264	17,014,033	17,808,594	308,644,366
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**70,905,654**	**69,482,991**	**66,712,164**	**61,674,178**	**51,814,693**	**53,944,340**	**715,564,895**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	50	50	50	50	50	50	300
10. COAL	1,134,440	1,136,640	1,089,820	945,130	966,090	1,016,840	11,585,990
11. NATURAL GAS	738,010	730,590	654,690	660,290	363,540	374,040	7,130,215
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,872,500**	**1,867,280**	**1,744,560**	**1,605,470**	**1,329,680**	**1,390,930**	**18,716,505**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	1,870	1,850	3,630	3,710	4,020	3,650	18,730
17. COAL (TON)	499,200	500,090	479,840	415,050	428,920	445,540	5,051,883
18. NATURAL GAS (MCF)	5,531,290	5,417,220	4,831,920	4,846,850	2,733,360	2,836,920	52,832,364
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	600	480	500	480	630	520	3,210
23. COAL	11,571,090	11,591,450	11,124,110	9,638,800	9,923,280	10,377,540	119,403,945
24. NATURAL GAS	5,683,750	5,566,510	4,964,810	4,980,160	2,803,900	2,913,980	54,047,903
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**17,255,440**	**17,158,440**	**16,089,420**	**14,619,440**	**12,727,810**	**13,292,040**	**173,455,058**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30. COAL	60.59	60.87	62.47	58.87	72.66	73.11	61.90
31. NATURAL GAS	39.41	39.13	37.53	41.13	27.34	26.89	38.10
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	6.93	5.62	3.18	2.68	3.06	3.81	3.79
37. COAL ($/TON)	77.66	78.43	79.53	80.82	81.11	81.07	80.53
38. NATURAL GAS ($/MCF)	5.81	5.58	5.91	5.80	6.22	6.28	5.84
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	21.59	21.67	23.06	20.68	19.54	26.75	22.13
43. COAL	3.35	3.38	3.43	3.48	3.51	3.48	3.41
44. NATURAL GAS	5.65	5.43	5.75	5.65	6.07	6.11	5.71
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)	**4.11**	**4.05**	**4.15**	**4.22**	**4.07**	**4.06**	**4.13**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	12,000	9,600	10,000	9,600	12,600	10,400	10,700
50. COAL	10,200	10,198	10,207	10,198	10,272	10,206	10,306
51. NATURAL GAS	7,701	7,619	7,583	7,542	7,713	7,791	7,580
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,215**	**9,189**	**9,223**	**9,106**	**9,572**	**9,556**	**9,267**
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	25.90	20.80	23.06	19.86	24.62	27.82	23.68
57. COAL	3.42	3.45	3.50	3.55	3.60	3.55	3.51
58. NATURAL GAS	4.35	4.14	4.36	4.26	4.68	4.76	4.33
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)	**3.79**	**3.72**	**3.82**	**3.84**	**3.90**	**3.88**	**3.82**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2014

SCHEDULE A4
PAGE 1 OF 1
REVISED 6/20/14

(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)
B.B.#1	395	215,512	73.3	82.1	83.6	10,467	COAL	92,879	24,286,000	2,255,664.5	7,051,220	3.27	75.92
B.B.#2	395	277,430	94.4	98.5	94.4	10,166	COAL	120,500	23,406,000	2,820,425.3	9,148,160	3.30	75.92
B.B.#3	365	274,889	101.2	98.2	102.9	10,410	COAL	123,129	23,240,000	2,861,519.6	9,347,750	3.40	75.92
B.B.#4	417	197,571	63.7	68.6	91.8	10,661	COAL	91,065	23,130,000	2,106,333.0	6,913,504	3.50	75.92
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	5,306	5,744,185	30,478.2	701,562	-	132.22
B.B. COAL	**1,572**	**965,402**	**82.5**	**86.4**	**93.4**	**10,404**	**-**	**-**	**-**	**-**	**33,162,196**	**3.44**	**-**
B.B.C.T.#4 (GAS)	61	904	2.0	82.4	88.0	12,252	GAS	10,890	1,017,000	11,075.6	70,062	7.75	6.43
B.B.C.T. #4 TOTAL	**61**	**904**	**2.0**	**82.4**	**88.0**	**12,252**	**GAS**	**10,890**	**1,017,000**	**11,075.6**	**70,062**	**7.75**	**6.43**
BIG BEND STATION TOTAL	**1,633**	**966,306**	**79.5**	**86.3**	**93.3**	**10,406**	**-**	**-**	**-**	**10,055,018.0**	**33,232,258**	**3.44**	**-**
POLK #1 GASIFIER	220	135,825	83.1	85.8	97.2	10,520	COAL	51,559	27,746,686	1,430,584.1	4,213,455	3.10	81.72
POLK #1 CT (GAS)	235	18,701	10.7	99.1	50.4	8,520	GAS	159,402	1,017,000	159,328.0	969,474	5.18	6.08
POLK #1 TOTAL	**220**	**154,526**	**94.5**	**99.1**	**95.0**	**10,278**	**-**	**-**	**-**	**1,589,912.1**	**5,182,929**	**3.35**	**-**
POLK #2 CT (GAS)	183	1,279	0.9	95.4	49.8	14,505	GAS	18,242	1,017,000	18,552.0	146,669	11.47	8.04
POLK #2 CT (OIL)	187	0	0.0	95.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**1,279**	**0.9**	**95.4**	**49.8**	**14,505**	**-**	**-**	**-**	**18,552.0**	**146,669**	**11.47**	**-**
POLK #3 CT (GAS)	183	372	0.3	100.0	49.2	17,196	GAS	6,290	1,017,000	6,397.0	47,407	12.74	7.54
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**	**372**	**0.3**	**100.0**	**49.2**	**17,196**	**-**	**-**	**-**	**6,397.0**	**47,407**	**12.74**	**-**
POLK #4 (GAS)	**183**	**4,764**	**3.5**	**100.0**	**66.5**	**12,353**	GAS	**57,868**	**1,017,000**	**58,852.0**	**334,611**	**7.02**	**5.78**
POLK #5 (GAS)	**183**	**2,784**	**2.0**	**100.0**	**65.4**	**11,870**	GAS	**32,495**	**1,017,000**	**33,047.0**	**190,334**	**6.84**	**5.86**
POLK STATION TOTAL	**952**	**163,725**	**23.1**	**98.9**	**92.3**	**10,414**	**-**	**-**	**-**	**1,706,760.1**	**5,901,950**	**3.60**	**-**
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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	10,850	6.0	87.2	49.4	-		-	-	-	-	-	-
BAYSIDE CT1A	183	3,179	2.3	78.9	74.9	11,523	GAS	36,020	1,017,000	36,632.0	269,370	8.47	7.48
BAYSIDE CT1B	183	8,458	6.2	88.1	70.0	11,521	GAS	95,812	1,017,000	97,441.0	716,514	8.47	7.48
BAYSIDE CT1C	183	9,397	6.9	92.4	63.9	11,521	GAS	106,456	1,017,000	108,266.0	796,113	8.47	7.48
BAYSIDE UNIT 1 TOTAL	**792**	**31,884**	**5.4**	**73.7**	**44.5**	**7,601**	**GAS**	**238,288**	**1,017,000**	**242,339.0**	**1,781,997**	**5.59**	**7.48**
BAYSIDE ST 2	315	128,740	54.9	100.0	54.9	-		-	-	-	-	-	-
BAYSIDE CT2A	183	61,393	45.1	100.0	72.6	11,314	GAS	682,977	1,017,000	694,588.0	4,089,463	6.66	5.99
BAYSIDE CT2B	183	57,004	41.9	99.9	75.3	11,314	GAS	634,144	1,017,000	644,924.0	3,797,066	6.66	5.99
BAYSIDE CT2C	183	68,554	50.4	97.1	73.6	11,314	GAS	762,639	1,017,000	775,604.0	4,566,456	6.66	5.99
BAYSIDE CT2D	183	61,147	44.9	100.0	73.9	11,314	GAS	680,240	1,017,000	691,804.0	4,073,075	6.66	5.99
BAYSIDE UNIT 2 TOTAL	**1,047**	**376,838**	**48.4**	**99.2**	**48.4**	**7,449**	**GAS**	**2,760,000**	**1,017,000**	**2,806,920.0**	**16,526,060**	**4.39**	**5.99**
BAYSIDE UNIT 3 TOTAL [4]	**61**	**(27)**	**0.0**	**46.9**	**0.0**	**0**	**GAS**	**54**	**1,017,000**	**55.0**	**2,114**	**(7.83)**	**39.15**
BAYSIDE UNIT 4 TOTAL	**61**	**602**	**1.3**	**100.0**	**91.0**	**11,262**	**GAS**	**6,667**	**1,017,000**	**6,780.0**	**47,016**	**7.81**	**7.05**
BAYSIDE UNIT 5 TOTAL	**61**	**2,697**	**5.9**	**100.0**	**90.2**	**11,082**	**GAS**	**29,389**	**1,017,000**	**29,888.0**	**176,733**	**6.55**	**6.01**
BAYSIDE UNIT 6 TOTAL	**61**	**1,408**	**3.1**	**100.0**	**94.1**	**11,078**	**GAS**	**15,337**	**1,017,000**	**15,598.0**	**96,810**	**6.88**	**6.31**
BAYSIDE STATION TOTAL	**2,083**	**413,402**	**26.7**	**88.1**	**48.3**	**7,503**	**GAS**	**3,049,735**	**1,017,000**	**3,101,580.0**	**18,630,730**	**4.51**	**6.11**
SYSTEM	**4,668**	**1,543,433**	**44.4**	**89.6**	**74.6**	**9,630**	**-**	**-**	**-**	**14,863,358.1**	**57,764,938**	**3.74**	**-**

Footnotes:
[1] **As burned fuel cost system total includes ignition oil.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil.**
[3] **City of Tampa on Long Term Reserve Stand-by.**
[4] **Station Service**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 6 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2014

SCHEDULE A4
PAGE 1 OF 1
REVISED 6/20/14

(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)
B.B.#1		395	118,258	44.6	46.8	88.3	10,366	COAL	49,937	24,548,000	1,225,863.3	4,178,762	3.53	83.68
B.B.#2		395	113,981	42.9	46.6	91.0	9,689	COAL	46,760	23,616,000	1,104,307.5	3,912,909	3.43	83.68
B.B.#3		365	246,362	100.4	98.4	101.5	10,570	COAL	111,619	23,330,000	2,604,060.1	9,340,355	3.79	83.68
B.B.#4		417	254,435	90.8	94.5	91.0	10,354	COAL	113,916	23,126,000	2,634,411.2	9,532,569	3.75	83.68
B.B. IGNITION		-	-	-	-	-	-	LGT.OIL	1,522	5,744,185	8,745.4	201,305	-	132.26
B.B. COAL		**1,572**	**733,036**	**69.4**	**71.4**	**93.8**	**10,325**	**-**	**-**	**-**	**-**	**27,165,900**	**3.71**	**-**
B.B.C.T.#4 (GAS)		61	15	0.0	90.0	12.2	89,040	GAS	1,312	1,018,000	1,335.6	7,456	49.71	5.68
B.B.C.T. #4 TOTAL		**61**	**15**	**0.0**	**90.0**	**12.2**	**89,040**	**GAS**	**1,312**	**1,018,000**	**1,335.6**	**7,456**	**49.71**	**5.68**
BIG BEND STATION TOTAL		**1,633**	**733,051**	**66.8**	**72.1**	**93.8**	**10,327**	**-**	**-**	**-**	**7,569,977.7**	**27,173,356**	**3.71**	**-**
POLK #1 GASIFIER		220	136,304	92.8	94.2	95.7	10,822	COAL	54,332	27,335,840	1,485,203.7	3,475,823	2.55	63.97
POLK #1 CT (GAS)		235	5,517	3.5	99.3	26.0	6,802	GAS	37,653	1,018,000	37,524.0	299,566	5.43	7.96
POLK #1 TOTAL		**220**	**141,821**	**96.6**	**99.3**	**97.3**	**10,666**	**-**	**-**	**-**	**1,522,727.7**	**3,775,389**	**2.66**	**-**
POLK #2 CT (GAS)		183	2,429	2.0	99.4	65.2	12,071	GAS	28,803	1,018,000	29,321.0	229,152	9.43	7.96
POLK #2 CT (OIL)		187	0	0.0	99.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**183**	**2,429**	**2.0**	**99.4**	**65.2**	**12,071**	**-**	**-**	**-**	**29,321.0**	**229,152**	**9.43**	**-**
POLK #3 CT (GAS)		183	145	0.1	100.0	28.8	26,110	GAS	3,719	1,018,000	3,786.0	29,583	20.40	7.95
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**	**145**	**0.1**	**100.0**	**28.8**	**26,110**	**-**	**-**	**-**	**3,786.0**	**29,583**	**20.40**	**-**
POLK #4 (GAS)	[4]	**183**	**(165)**	**0.0**	**100.0**	**0.0**	**0**	GAS	**0**	**0**	**0.0**	**77**	**(0.05)**	**0.00**
POLK #5 (GAS)		**183**	**8**	**0.0**	**100.0**	**2.7**	**279,625**	GAS	**2,197**	**1,018,000**	**2,237.0**	**17,496**	**218.70**	**7.96**
POLK STATION TOTAL		**952**	**144,238**	**22.7**	**99.7**	**96.0**	**10,732**	**-**	**-**	**-**	**1,558,071.7**	**4,051,697**	**2.81**	**-**
COT 1		0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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	25,791	15.8	72.8	54.5	-		-	-	-	-	-	-
BAYSIDE CT1A		183	12,521	10.2	69.6	74.5	11,334	GAS	139,405	1,018,000	141,914.0	766,142	6.12	5.50
BAYSIDE CT1B		183	19,504	15.9	83.0	71.7	11,438	GAS	219,147	1,018,000	223,092.0	1,204,388	6.18	5.50
BAYSIDE CT1C		183	16,859	13.7	90.5	67.0	11,118	GAS	184,120	1,018,000	187,434.0	1,011,887	6.00	5.50
BAYSIDE UNIT 1 TOTAL		**792**	**74,675**	**14.0**	**53.9**	**48.5**	**7,398**	**GAS**	**542,672**	**1,018,000**	**552,440.0**	**2,982,417**	**3.99**	**5.50**
BAYSIDE ST 2		315	114,321	54.0	100.0	54.0	-		-	-	-	-	-	-
BAYSIDE CT2A		183	42,445	34.5	71.6	70.1	11,460	GAS	477,806	1,018,000	486,407.0	2,626,529	6.19	5.50
BAYSIDE CT2B		183	65,948	53.6	100.0	73.4	11,566	GAS	749,253	1,018,000	762,740.0	4,118,690	6.25	5.50
BAYSIDE CT2C		183	53,832	43.8	98.2	73.6	11,507	GAS	608,513	1,018,000	619,466.0	3,345,033	6.21	5.50
BAYSIDE CT2D		183	53,894	43.8	100.0	72.7	11,499	GAS	608,796	1,018,000	619,754.0	3,346,589	6.21	5.50
BAYSIDE UNIT 2 TOTAL		**1,047**	**330,440**	**47.0**	**92.5**	**47.0**	**7,530**	**GAS**	**2,444,368**	**1,018,000**	**2,488,367.0**	**13,436,841**	**4.07**	**5.50**
BAYSIDE UNIT 3 TOTAL	[4]	**61**	**(14)**	**0.0**	**48.4**	**0.0**	**0**	**GAS**	**175**	**1,018,000**	**178.0**	**967**	**(6.91)**	**5.53**
BAYSIDE UNIT 4 TOTAL		**61**	**2,302**	**5.6**	**100.0**	**93.1**	**7,989**	**GAS**	**18,065**	**1,018,000**	**18,390.0**	**99,316**	**4.31**	**5.50**
BAYSIDE UNIT 5 TOTAL		**61**	**1,452**	**3.5**	**100.0**	**89.1**	**11,441**	**GAS**	**16,318**	**1,018,000**	**16,612.0**	**89,708**	**6.18**	**5.50**
BAYSIDE UNIT 6 TOTAL		**61**	**1,212**	**3.0**	**100.0**	**88.2**	**6,301**	**GAS**	**7,502**	**1,018,000**	**7,637.0**	**41,240**	**3.40**	**5.50**
BAYSIDE STATION TOTAL		**2,083**	**410,067**	**29.3**	**77.2**	**47.5**	**7,520**	**GAS**	**3,029,100**	**1,018,000**	**3,083,624.0**	**16,650,489**	**4.06**	**5.50**
SYSTEM		**4,668**	**1,287,356**	**41.0**	**80.0**	**71.7**	**9,486**	**-**	**-**	**-**	**12,211,673.4**	**47,875,542**	**3.72**	**-**

Footnotes:
[1] **As burned fuel cost system total includes ignition oil.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil.**
[3] **City of Tampa on Long Term Reserve Stand-by.**
[4] **Station Service**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

Docket No. 140001-EI
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2014

SCHEDULE A4
PAGE 1 OF 1
REVISED 6/20/14

(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)
B.B.#1	395	228,305	77.8	80.9	83.9	10,589	COAL	98,978	24,424,000	2,417,444.3	8,253,516	3.62	83.39
B.B.#2	395	89,768	30.6	33.2	87.8	11,156	COAL	41,295	24,250,000	1,001,407.6	3,443,482	3.84	83.39
B.B.#3	365	81,387	30.0	30.1	92.4	10,529	COAL	36,504	23,476,000	856,959.2	3,043,973	3.74	83.39
B.B.#4	417	183,838	59.3	60.9	87.6	10,238	COAL	79,140	23,448,000	1,855,674.7	6,599,277	3.59	83.39
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	2,904	5,745,371	16,686.6	384,674	-	132.46
B.B. COAL	**1,572**	**583,298**	**49.9**	**51.8**	**86.8**	**10,557**	**-**	**-**	**-**	**-**	**21,724,922**	**3.72**	**-**
B.B.C.T.#4 (GAS)	61	1,082	2.4	98.4	82.1	12,144	GAS	12,920	1,017,000	13,139.8	72,624	6.71	5.62
B.B.C.T. #4 TOTAL	**61**	**1,082**	**2.4**	**98.4**	**82.1**	**12,144**	**GAS**	**12,920**	**1,017,000**	**13,139.8**	**72,624**	**6.71**	**5.62**
BIG BEND STATION TOTAL	**1,633**	**584,380**	**48.2**	**53.5**	**86.8**	**10,560**	**-**	**-**	**-**	**6,144,625.6**	**21,797,546**	**3.73**	**-**
POLK #1 GASIFIER	220	42,222	26.1	45.2	85.5	11,335	COAL	18,011	26,830,981	483,254.9	1,511,642	3.58	83.93
POLK #1 CT (GAS)	235	16,767	9.6	49.6	51.9	8,619	GAS	148,033	1,017,000	144,507.0	793,184	4.73	5.36
POLK #1 TOTAL	**220**	**58,989**	**36.3**	**49.6**	**76.7**	**10,568**	**-**	**-**	**-**	**627,761.9**	**2,304,826**	**3.91**	**-**
POLK #2 CT (GAS)	183	470	0.3	98.0	33.8	17,770	GAS	8,212	1,017,000	8,352.0	44,011	9.36	5.36
POLK #2 CT (OIL)	187	0	0.0	98.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**470**	**0.3**	**98.0**	**33.8**	**17,770**	**-**	**-**	**-**	**8,352.0**	**44,011**	**9.36**	**-**
POLK #3 CT (GAS)	183	2,222	1.6	98.0	60.8	12,151	GAS	26,548	1,017,000	26,999.0	142,228	6.40	5.36
POLK #3 CT (OIL)	187	0	0.0	98.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**183**	**2,222**	**1.6**	**98.0**	**60.8**	**12,151**	**-**	**-**	**-**	**26,999.0**	**142,228**	**6.40**	**-**
POLK #4 (GAS) [4]	**183**	**(181)**	**0.0**	**100.0**	**0.0**	**0**	GAS	**0**	**0**	**0.0**	**47**	**(0.03)**	**0.00**
POLK #5 (GAS)	**183**	**4,346**	**3.2**	**100.0**	**68.3**	**11,137**	GAS	**47,594**	**1,017,000**	**48,403.0**	**254,999**	**5.87**	**5.36**
POLK STATION TOTAL	**952**	**65,846**	**9.4**	**87.6**	**74.5**	**10,739**	**-**	**-**	**-**	**711,515.9**	**2,746,111**	**4.17**	**-**
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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	101,656	56.3	82.2	68.5	-		-	-	-	-	-	-
BAYSIDE CT1A	183	64,201	47.2	84.9	74.7	11,360	GAS	717,132	1,017,000	729,323.0	4,143,783	6.45	5.78
BAYSIDE CT1B	183	56,620	41.6	65.4	74.7	11,382	GAS	633,701	1,017,000	644,474.0	3,661,696	6.47	5.78
BAYSIDE CT1C	183	71,411	52.5	82.7	73.2	10,859	GAS	762,518	1,017,000	775,481.0	4,406,036	6.17	5.78
BAYSIDE UNIT 1 TOTAL	**792**	**293,888**	**49.9**	**75.4**	**60.7**	**7,313**	**GAS**	**2,113,351**	**1,017,000**	**2,149,278.0**	**12,211,515**	**4.16**	**5.78**
BAYSIDE ST 2	315	99,110	42.3	72.1	58.7	-		-	-	-	-	-	-
BAYSIDE CT2A	183	41,844	30.8	56.7	70.9	11,096	GAS	456,543	1,017,000	464,304.0	2,638,464	6.31	5.78
BAYSIDE CT2B	183	52,866	38.9	62.9	73.6	11,565	GAS	601,160	1,017,000	611,380.0	3,474,239	6.57	5.78
BAYSIDE CT2C	183	45,792	33.7	67.8	75.0	11,366	GAS	511,765	1,017,000	520,465.0	2,957,605	6.46	5.78
BAYSIDE CT2D	183	49,858	36.7	58.9	74.0	11,481	GAS	562,848	1,017,000	572,415.0	3,252,825	6.52	5.78
BAYSIDE UNIT 2 TOTAL	**1,047**	**289,470**	**37.2**	**60.9**	**51.6**	**7,491**	**GAS**	**2,132,316**	**1,017,000**	**2,168,564.0**	**12,323,133**	**4.26**	**5.78**
BAYSIDE UNIT 3 TOTAL	**61**	**16**	**0.0**	**100.0**	**26.7**	**35,563**	**GAS**	**559**	**1,017,000**	**569.0**	**3,233**	**20.21**	**5.78**
BAYSIDE UNIT 4 TOTAL	**61**	**3,617**	**8.0**	**100.0**	**91.7**	**7,720**	**GAS**	**27,458**	**1,017,000**	**27,925.0**	**158,664**	**4.39**	**5.78**
BAYSIDE UNIT 5 TOTAL	**61**	**149**	**0.3**	**86.2**	**74.4**	**14,483**	**GAS**	**2,122**	**1,017,000**	**2,158.0**	**12,285**	**8.24**	**5.79**
BAYSIDE UNIT 6 TOTAL	**61**	**2,249**	**5.0**	**99.4**	**90.6**	**6,255**	**GAS**	**13,833**	**1,017,000**	**14,068.0**	**79,941**	**3.55**	**5.78**
BAYSIDE STATION TOTAL	**2,083**	**589,389**	**38.1**	**70.6**	**56.1**	**7,402**	**GAS**	**4,289,639**	**1,017,000**	**4,362,562.0**	**24,788,771**	**4.21**	**5.78**
SYSTEM	**4,668**	**1,239,615**	**35.7**	**68.1**	**68.3**	**9,072**	**-**	**-**	**-**	**11,218,703.5**	**49,332,428**	**3.98**	**-**

Footnotes:
[1] **As burned fuel cost system total includes ignition oil.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil.**
[3] **City of Tampa on Long Term Reserve Stand-by.**
[4] **Station Service**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2014

SCHEDULE A4
PAGE 1 OF 1
REVISED 6/20/14

(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)
B.B.#1	385	241,047	87.0	91.1	87.0	10,788	COAL	107,291	24,238,000	2,600,519.3	9,046,540	3.75	84.32
B.B.#2	385	265,772	95.9	98.5	96.5	10,227	COAL	115,014	23,632,000	2,718,011.3	9,697,726	3.65	84.32
B.B.#3	365	85,654	32.6	32.5	100.0	10,372	COAL	37,757	23,530,000	888,422.4	3,183,586	3.72	84.32
B.B.#4	407	0	0.0	0.0	0.0	0	COAL	232	0	5,440.0	19,562	0.00	84.32
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	2,420	5,746,744	13,906.6	320,557	-	132.46
B.B. COAL	**1,542**	**592,473**	**53.4**	**55.0**	**92.8**	**10,476**	**-**	**-**	**-**	**-**	**22,267,971**	**3.76**	**-**
B.B.C.T.#4 (GAS)	56	1,626	4.0	80.4	92.2	11,681	GAS	18,602	1,021,000	18,992.8	112,086	6.89	6.03
B.B.C.T. #4 TOTAL	**56**	**1,626**	**4.0**	**80.4**	**92.2**	**11,681**	**GAS**	**18,602**	**1,021,000**	**18,992.8**	**112,086**	**6.89**	**6.03**
BIG BEND STATION TOTAL	**1,598**	**594,099**	**51.6**	**55.9**	**92.8**	**10,480**	**-**	**-**	**-**	**6,231,385.8**	**22,380,057**	**3.77**	**-**
POLK #1 GASIFIER	220	154,209	98.1	98.6	98.1	9,641	COAL	55,339	27,061,186	1,497,539.2	4,456,092	2.89	80.52
POLK #1 CT (GAS)	218	1,883	1.2	100.0	21.7	6,845	GAS	15,699	1,021,000	12,890.0	107,036	5.68	6.82
POLK #1 TOTAL	**220**	**156,092**	**99.2**	**100.0**	**99.2**	**9,608**	**-**	**-**	**-**	**1,510,429.2**	**4,563,128**	**2.92**	**-**
POLK #2 CT (GAS) [4]	151	(113)	0.0	0.7	0.0	0	GAS	0	0	0.0	(730)	0.65	0.00
POLK #2 CT (OIL)	159	0	0.0	0.7	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**151**	**(113)**	**0.0**	**0.7**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**(730)**	**0.65**	**-**
POLK #3 CT (GAS)	151	2,352	2.2	95.4	68.9	15,180	GAS	34,970	1,021,000	35,704.0	240,450	10.22	6.88
POLK #3 CT (OIL)	159	0	0.0	95.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**2,352**	**2.2**	**95.4**	**68.9**	**15,180**	**-**	**-**	**-**	**35,704.0**	**240,450**	**10.22**	**-**
POLK #4 (GAS)	**151**	**1,479**	**1.4**	**100.0**	**68.4**	**15,835**	GAS	**22,938**	**1,021,000**	**23,420.0**	**157,785**	**10.67**	**6.88**
POLK #5 (GAS)	**151**	**1,157**	**1.1**	**100.0**	**64.6**	**15,604**	GAS	**17,683**	**1,021,000**	**18,054.0**	**121,577**	**10.51**	**6.88**
POLK STATION TOTAL	**824**	**160,967**	**27.3**	**81.0**	**97.8**	**9,795**	**-**	**-**	**-**	**1,587,607.2**	**5,082,210**	**3.16**	**-**
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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	233	85,346	50.9	89.0	57.2	-		-	-	-	-	-	-
BAYSIDE CT1A	156	40,598	36.1	94.7	88.1	11,255	GAS	447,525	1,021,000	456,923.0	2,606,165	6.42	5.82
BAYSIDE CT1B	156	66,482	59.2	100.0	85.6	11,348	GAS	738,902	1,021,000	754,419.0	4,303,001	6.47	5.82
BAYSIDE CT1C	156	53,825	47.9	100.0	84.8	10,827	GAS	570,757	1,021,000	582,743.0	3,323,808	6.18	5.82
BAYSIDE UNIT 1 TOTAL	**701**	**246,251**	**48.8**	**87.2**	**54.8**	**7,286**	**GAS**	**1,757,184**	**1,021,000**	**1,794,085.0**	**10,232,974**	**4.16**	**5.82**
BAYSIDE ST 2	305	141,448	64.4	100.0	64.4	-		-	-	-	-	-	-
BAYSIDE CT2A	156	90,415	80.5	100.0	86.6	11,213	GAS	993,010	1,021,000	1,013,862.0	5,779,360	6.39	5.82
BAYSIDE CT2B	156	57,542	51.2	98.8	87.8	11,473	GAS	646,587	1,021,000	660,165.0	3,763,164	6.54	5.82
BAYSIDE CT2C	156	52,228	46.5	100.0	87.8	11,350	GAS	580,613	1,021,000	592,806.0	3,379,192	6.47	5.82
BAYSIDE CT2D	156	67,036	59.7	98.7	86.7	11,397	GAS	748,311	1,021,000	764,026.0	4,355,202	6.50	5.82
BAYSIDE UNIT 2 TOTAL	**929**	**408,669**	**61.1**	**99.4**	**61.1**	**7,416**	**GAS**	**2,968,521**	**1,021,000**	**3,030,859.0**	**17,276,918**	**4.23**	**5.82**
BAYSIDE UNIT 3 TOTAL	**56**	**610**	**1.5**	**76.0**	**91.5**	**11,623**	**GAS**	**6,944**	**1,021,000**	**7,090.0**	**40,453**	**6.63**	**5.83**
BAYSIDE UNIT 4 TOTAL	**56**	**366**	**0.9**	**81.4**	**85.4**	**11,637**	**GAS**	**4,171**	**1,021,000**	**4,259.0**	**24,180**	**6.61**	**5.80**
BAYSIDE UNIT 5 TOTAL	**56**	**982**	**2.4**	**78.0**	**93.5**	**11,393**	**GAS**	**10,958**	**1,021,000**	**11,188.0**	**63,726**	**6.49**	**5.82**
BAYSIDE UNIT 6 TOTAL	**56**	**1,556**	**3.9**	**87.4**	**92.6**	**10,958**	**GAS**	**16,699**	**1,021,000**	**17,050.0**	**97,233**	**6.25**	**5.82**
BAYSIDE STATION TOTAL	**1,854**	**658,434**	**49.3**	**92.5**	**58.7**	**7,388**	**GAS**	**4,764,477**	**1,021,000**	**4,864,531.0**	**27,735,484**	**4.21**	**5.82**
SYSTEM	**4,276**	**1,413,500**	**45.9**	**76.6**	**73.3**	**8,969**	**-**	**-**	**-**	**12,683,524.0**	**55,197,751**	**3.91**	**-**

Footnotes:

[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] City of Tampa on Long Term Reserve Stand-by.
[4] Station Service

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 9 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2014

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)
B.B.#1		385	215,829	75.3	78.2	91.1	10,543	COAL	93,994	24,210,000	2,275,583.1	7,352,116	3.41	78.22
B.B.#2		385	264,251	92.3	96.5	92.7	10,291	COAL	115,420	23,560,000	2,719,295.7	9,028,036	3.42	78.22
B.B.#3		365	277,407	102.2	98.1	103.4	10,282	COAL	123,477	23,100,000	2,852,326.6	9,658,247	3.48	78.22
B.B.#4	[4],[5]	407	(6)	0.0	0.0	0.0	0	COAL	4,102	24,082,000	98,215.0	320,854	(5,347.57)	78.22
B.B. IGNITION		-	-	-	-	-	-	LGT.OIL	2,186	5,746,989	12,561.1	290,337	-	132.82
B.B. COAL		**1,542**	**757,481**	**66.0**	**66.8**	**95.9**	**10,461**	**-**	**-**	**-**	**-**	**26,649,590**	**3.52**	**-**
B.B.C.T.#4 (GAS)		56	387	0.9	99.0	75.3	16,066	GAS	6,084	1,022,000	6,217.7	36,257	9.37	5.96
B.B.C.T. #4 TOTAL		**56**	**387**	**0.9**	**99.0**	**75.3**	**16,066**	**GAS**	**6,084**	**1,022,000**	**6,217.7**	**36,257**	**9.37**	**5.96**
BIG BEND STATION TOTAL		**1,598**	**757,868**	**63.7**	**68.0**	**95.9**	**10,464**	**-**	**-**	**-**	**7,951,638.1**	**26,685,847**	**3.52**	**-**
POLK #1 GASIFIER		220	146,916	90.7	87.4	96.2	10,546	COAL	56,362	27,777,860	1,565,622.4	4,704,543	3.20	83.47
POLK #1 CT (GAS)		218	9,771	6.0	99.0	29.1	7,943	GAS	81,090	1,022,000	77,607.0	441,909	4.52	5.45
POLK #1 TOTAL		**220**	**156,687**	**96.7**	**99.0**	**97.7**	**10,385**	**-**	**-**	**-**	**1,643,229.4**	**5,146,452**	**3.28**	**-**
POLK #2 CT (GAS)		151	5,065	4.5	78.1	83.5	11,148	GAS	55,249	1,022,000	56,464.0	304,825	6.02	5.52
POLK #2 CT (OIL)		159	0	0.0	78.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**151**	**5,065**	**4.5**	**78.1**	**83.5**	**11,148**	**-**	**-**	**-**	**56,464.0**	**304,825**	**6.02**	**-**
POLK #3 CT (GAS)	[4]	151	(63)	0.0	1.0	0.0	0	GAS	0	0	0.0	(1,072)	1.70	0.00
POLK #3 CT (OIL)		159	0	0.0	1.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**151**	**(63)**	**0.0**	**1.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**(1,072)**	**1.70**	**-**
POLK #4 (GAS)		**151**	**3,844**	**3.4**	**100.0**	**74.7**	**12,957**	GAS	**48,733**	**1,022,000**	**49,806.0**	**269,174**	**7.00**	**5.52**
POLK #5 (GAS)		**151**	**5,814**	**5.2**	**98.7**	**72.4**	**12,169**	GAS	**69,227**	**1,022,000**	**70,750.0**	**380,442**	**6.54**	**5.50**
POLK STATION TOTAL		**824**	**171,347**	**28.2**	**77.3**	**95.4**	**10,529**	**-**	**-**	**-**	**1,820,249.4**	**6,099,821**	**3.56**	**-**
COT 1		0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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		233	100,427	57.9	88.7	65.3	-		-	-	-	-	-	-
BAYSIDE CT1A		156	75,171	64.8	100.0	83.5	11,252	GAS	827,590	1,022,000	845,797.0	4,863,688	6.47	5.88
BAYSIDE CT1B		156	61,882	53.3	99.8	84.8	11,240	GAS	680,593	1,022,000	695,566.0	3,999,797	6.46	5.88
BAYSIDE CT1C		156	51,864	44.7	99.8	84.6	11,381	GAS	577,552	1,022,000	590,258.0	3,394,232	6.54	5.88
BAYSIDE UNIT 1 TOTAL		**701**	**289,344**	**55.5**	**88.6**	**62.5**	**7,367**	**GAS**	**2,085,735**	**1,022,000**	**2,131,621.0**	**12,257,717**	**4.24**	**5.88**
BAYSIDE ST 2		305	145,309	64.0	97.7	65.5	-		-	-	-	-	-	-
BAYSIDE CT2A		156	73,822	63.6	97.1	86.7	11,075	GAS	800,018	1,022,000	817,618.0	4,711,588	6.38	5.89
BAYSIDE CT2B		156	60,976	52.5	97.4	88.2	11,331	GAS	676,063	1,022,000	690,936.0	3,981,573	6.53	5.89
BAYSIDE CT2C		156	77,697	66.9	97.4	86.2	11,284	GAS	857,880	1,022,000	876,753.0	5,052,358	6.50	5.89
BAYSIDE CT2D		156	62,892	54.2	93.4	86.2	11,246	GAS	692,062	1,022,000	707,287.0	4,075,797	6.48	5.89
BAYSIDE UNIT 2 TOTAL		**929**	**420,696**	**60.9**	**94.0**	**62.3**	**7,351**	**GAS**	**3,026,023**	**1,022,000**	**3,092,594.0**	**17,821,316**	**4.24**	**5.89**
BAYSIDE UNIT 3 TOTAL		**56**	**1,321**	**3.2**	**100.0**	**92.3**	**10,975**	**GAS**	**14,185**	**1,022,000**	**14,498.0**	**83,926**	**6.35**	**5.92**
BAYSIDE UNIT 4 TOTAL		**56**	**424**	**1.0**	**100.0**	**88.9**	**11,491**	**GAS**	**4,767**	**1,022,000**	**4,872.0**	**27,105**	**6.39**	**5.69**
BAYSIDE UNIT 5 TOTAL		**56**	**613**	**1.5**	**100.0**	**88.9**	**11,793**	**GAS**	**7,073**	**1,022,000**	**7,229.0**	**41,773**	**6.81**	**5.91**
BAYSIDE UNIT 6 TOTAL		**56**	**1,741**	**4.2**	**100.0**	**93.6**	**10,686**	**GAS**	**18,204**	**1,022,000**	**18,604.0**	**107,165**	**6.16**	**5.89**
BAYSIDE STATION TOTAL		**1,854**	**714,139**	**51.8**	**92.7**	**62.5**	**7,379**	**GAS**	**5,155,987**	**1,022,000**	**5,269,418.0**	**30,339,002**	**4.25**	**5.88**
SYSTEM		**4,276**	**1,643,354**	**51.7**	**80.5**	**77.7**	**9,140**	**-**	**-**	**-**	**15,041,305.5**	**63,124,670**	**3.84**	**-**

Footnotes:

[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] City of Tampa on Long Term Reserve Stand-by.
[4] Station Service
[5] Includes Big Bend Unit 4 adjustment of 898 tons and $73,961.02 for March 2014 previously adjusted in April for 232 tons and $19,135.55 for a total adjustment of 1,130 tons and $93,096.57
Adjustments to mmbtu's are 21,056.3 and 5,440.0 previously adjusted in April for a total adjustment of 26,496.3 mmbtu's for March.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 140001-EI
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2014

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)
B.B.#1	385	251,586	90.8	94.6	90.8	10,442	COAL	109,129	24,072,000	2,626,953.0	8,778,986	3.49	80.45
B.B.#2	385	180,418	65.1	69.1	86.7	10,378	COAL	77,770	24,076,000	1,872,390.5	6,256,281	3.47	80.45
B.B.#3	365	272,116	103.5	99.9	103.5	10,298	COAL	118,859	23,576,000	2,802,219.5	9,561,725	3.51	80.45
B.B.#4	407	213,862	73.0	73.9	92.4	9,929	COAL	88,958	23,870,000	2,123,427.2	7,156,310	3.35	80.45
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	6,924	5,748,889	39,807.0	940,035	-	135.76
B.B. COAL	**1,542**	**917,982**	**82.7**	**84.0**	**93.7**	**10,267**	**-**	**-**	**-**	**-**	**32,693,337**	**3.56**	**-**
B.B.C.T.#4 (GAS)	56	1,602	4.0	100.0	90.3	11,929	GAS	18,717	1,021,000	19,109.6	107,618	6.72	5.75
B.B.C.T. #4 TOTAL	**56**	**1,602**	**4.0**	**100.0**	**90.3**	**11,929**	**GAS**	**18,717**	**1,021,000**	**19,109.6**	**107,618**	**6.72**	**5.75**
BIG BEND STATION TOTAL	**1,598**	**919,584**	**79.9**	**84.6**	**93.7**	**10,270**	**-**	**-**	**-**	**9,444,099.8**	**32,800,955**	**3.57**	**-**
POLK #1 GASIFIER	220	131,882	84.2	85.0	93.3	10,413	COAL	49,915	27,819,204	1,388,596.7	4,220,928	3.20	84.56
POLK #1 CT (GAS)	218	18,225	11.6	99.4	39.5	7,151	GAS	133,467	1,021,000	130,331.0	758,107	4.16	5.68
POLK #1 TOTAL	**220**	**150,107**	**95.7**	**99.4**	**96.3**	**10,021**	**-**	**-**	**-**	**1,518,927.7**	**4,979,035**	**3.32**	**-**
POLK #2 CT (GAS)	151	2,377	2.2	100.0	81.8	12,048	GAS	28,050	1,021,000	28,639.0	159,326	6.70	5.68
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**	**2,377**	**2.2**	**100.0**	**81.8**	**12,048**	**-**	**-**	**-**	**28,639.0**	**159,326**	**6.70**	**-**
POLK #3 CT (GAS)	151	3,448	3.2	100.0	71.2	11,744	GAS	39,662	1,021,000	40,495.0	225,285	6.53	5.68
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**	**3,448**	**3.2**	**100.0**	**71.2**	**11,744**	**-**	**-**	**-**	**40,495.0**	**225,285**	**6.53**	**-**
POLK #4 (GAS)	**151**	**96**	**0.1**	**100.0**	**27.2**	**32,229**	GAS	**3,030**	**1,021,000**	**3,094.0**	**17,213**	**17.93**	**5.68**
POLK #5 (GAS)	**151**	**6,057**	**5.6**	**99.4**	**71.8**	**10,657**	GAS	**63,220**	**1,021,000**	**64,548.0**	**359,098**	**5.93**	**5.68**
POLK STATION TOTAL	**824**	**162,085**	**27.6**	**99.7**	**94.0**	**10,123**	**-**	**-**	**-**	**1,655,703.7**	**5,739,957**	**3.54**	**-**
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
COT 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	233	97,408	58.1	97.2	59.8	-		-	-	-	-	-	-
BAYSIDE CT1A	156	55,770	49.7	89.1	85.0	11,284	GAS	616,367	1,021,000	629,311.0	3,537,281	6.34	5.74
BAYSIDE CT1B	156	61,024	54.3	94.1	85.9	11,262	GAS	673,098	1,021,000	687,233.0	3,862,856	6.33	5.74
BAYSIDE CT1C	156	67,973	60.5	94.5	82.7	11,544	GAS	768,552	1,021,000	784,691.0	4,410,659	6.49	5.74
BAYSIDE UNIT 1 TOTAL	**701**	**282,175**	**55.9**	**89.5**	**57.5**	**7,447**	**GAS**	**2,058,017**	**1,021,000**	**2,101,235.0**	**11,810,796**	**4.19**	**5.74**
BAYSIDE ST 2	305	142,511	64.9	100.0	64.9	-		-	-	-	-	-	-
BAYSIDE CT2A	156	63,673	56.7	96.9	91.5	11,148	GAS	695,195	1,021,000	709,794.0	3,989,670	6.27	5.74
BAYSIDE CT2B	156	79,997	71.2	95.8	86.0	11,600	GAS	908,848	1,021,000	927,934.0	5,215,808	6.52	5.74
BAYSIDE CT2C	156	58,608	52.2	100.0	88.8	11,247	GAS	645,621	1,021,000	659,179.0	3,705,168	6.32	5.74
BAYSIDE CT2D	156	65,814	58.6	100.0	86.1	11,342	GAS	731,091	1,021,000	746,444.0	4,195,674	6.38	5.74
BAYSIDE UNIT 2 TOTAL	**929**	**410,603**	**61.4**	**98.2**	**61.4**	**7,412**	**GAS**	**2,980,755**	**1,021,000**	**3,043,351.0**	**17,106,320**	**4.17**	**5.74**
BAYSIDE UNIT 3 TOTAL	**56**	**2,093**	**5.2**	**99.9**	**99.7**	**11,129**	**GAS**	**22,815**	**1,021,000**	**23,294.0**	**130,562**	**6.24**	**5.72**
BAYSIDE UNIT 4 TOTAL	**56**	**562**	**1.4**	**99.8**	**84.3**	**11,447**	**GAS**	**6,301**	**1,021,000**	**6,433.0**	**36,057**	**6.42**	**5.72**
BAYSIDE UNIT 5 TOTAL	**56**	**290**	**0.7**	**81.9**	**72.9**	**12,683**	**GAS**	**3,602**	**1,021,000**	**3,678.0**	**20,615**	**7.11**	**5.72**
BAYSIDE UNIT 6 TOTAL	**56**	**1,435**	**3.6**	**99.9**	**89.2**	**11,225**	**GAS**	**15,777**	**1,021,000**	**16,108.0**	**90,284**	**6.29**	**5.72**
BAYSIDE STATION TOTAL	**1,854**	**697,158**	**52.2**	**94.6**	**59.9**	**7,450**	**GAS**	**5,087,267**	**1,021,000**	**5,194,099.0**	**29,194,634**	**4.19**	**5.74**
SYSTEM	**4,276**	**1,778,827**	**57.8**	**91.8**	**76.7**	**9,160**	**-**	**-**	**-**	**16,293,902.5**	**67,735,546**	**3.81**	**-**

Footnotes:
[1] **As burned fuel cost system total includes ignition oil.** [2] **Fuel burned (MM BTU) system total excludes ignition oil.**
[3] **City of Tampa on Long Term Reserve Stand-by.**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2014

(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. B.B.#1	385	236,140	82.4	85.1	93.6	10,126	COAL	102,880	23,241,155	2,391,050.0	7,849,124	3.32	76.29
2. B.B.#2	385	244,300	85.3	87.9	95.1	10,204	COAL	107,240	23,246,177	2,492,920.0	8,181,760	3.35	76.29
3. B.B.#3	395	252,300	85.9	88.0	94.6	10,376	COAL	115,690	22,627,885	2,617,820.0	8,826,443	3.50	76.29
4. B.B.#4	407	264,340	87.3	86.2	98.4	10,113	COAL	121,190	22,058,421	2,673,260.0	9,246,060	3.50	76.29
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,770	-	10,290.0	243,641	-	137.65
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,572**	**997,080**	**85.3**	**86.8**	**95.5**	**10,205**	**-**	**-**	**-**	**-**	**34,347,028**	**3.44**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.2	12,000	LGT OIL	20	6,000,000	120.0	2,753	27.53	137.65
9. B.B.C.T.#4 GAS	56	1,270	3.0	-	84.0	11,134	GAS	13,750	1,028,364	14,140.0	79,894	6.29	5.81
10. B.B.C.T.#4 TOTAL	**56**	**1,280**	**3.1**	**99.4**	**65.3**	**11,141**	**-**	**-**	**-**	**14,260.0**	**82,647**	**6.46**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**998,360**	**82.4**	**87.2**	**95.4**	**10,206**	**-**	**-**	**-**	**10,189,310.0**	**34,429,675**	**3.45**	**-**
12. POLK #1 GASIFIER	220	137,360	83.9	-	97.4	10,163	COAL	52,200	26,744,061	1,396,040.0	4,419,672	3.22	84.67
13. POLK #1 CT GAS	195	6,790	4.7	-	96.7	7,938	GAS	54,770	984,115	53,900.0	304,702	4.49	5.56
14. POLK #1 TOTAL	**220**	**144,150**	**88.1**	**92.4**	**97.4**	**10,059**	**-**	**-**	**-**	**1,449,940.0**	**4,724,374**	**3.28**	**-**
15. POLK #2 CT GAS	151	24,480	21.8	-	95.4	10,844	GAS	258,220	1,027,999	265,450.0	1,500,388	6.13	5.81
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	5,099	25.50	127.48
17. POLK #2 TOTAL	**151**	**24,500**	**21.8**	**98.2**	**92.6**	**10,844**	**-**	**-**	**-**	**265,690.0**	**1,505,487**	**6.14**	**-**
18. POLK #3 CT GAS	151	17,520	15.5	-	96.4	10,803	GAS	184,110	1,027,972	189,260.0	1,069,770	6.11	5.81
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	5,099	25.50	127.48
20. POLK #3 TOTAL	**151**	**17,540**	**15.6**	**98.2**	**92.5**	**10,804**	**-**	**-**	**-**	**189,500.0**	**1,074,869**	**6.13**	**-**
21. POLK #4 CT GAS	**151**	**12,230**	**10.9**	**98.8**	**97.8**	**10,773**	**GAS**	**128,170**	**1,027,932**	**131,750.0**	**744,731**	**6.09**	**5.81**
22. POLK #5 CT GAS	**151**	**6,410**	**5.7**	**98.9**	**98.7**	**10,757**	**GAS**	**67,070**	**1,028,030**	**68,950.0**	**389,710**	**6.08**	**5.81**
23. POLK STATION TOTAL	**824**	**204,830**	**33.4**	**96.9**	**96.4**	**10,281**	**-**	**-**	**-**	**2,105,830.0**	**8,439,171**	**4.12**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	248,800	47.7	89.1	57.7	7,357	GAS	1,780,560	1,027,997	1,830,410.0	10,345,938	4.16	5.81
26. BAYSIDE #2	929	406,960	58.9	89.0	63.7	7,325	GAS	2,899,700	1,027,999	2,980,890.0	16,848,697	4.14	5.81
27. BAYSIDE #3	56	2,830	6.8	97.7	82.8	11,053	GAS	30,430	1,027,933	31,280.0	176,813	6.25	5.81
28. BAYSIDE #4	56	2,150	5.2	99.4	81.7	11,116	GAS	23,250	1,027,957	23,900.0	135,094	6.28	5.81
29. BAYSIDE #5	56	4,830	11.6	99.6	88.0	10,952	GAS	51,460	1,027,983	52,900.0	299,008	6.19	5.81
30. BAYSIDE #6	56	3,740	9.0	99.9	87.9	10,941	GAS	39,800	1,028,141	40,920.0	231,258	6.18	5.81
31. BAYSIDE TOTAL	**1,854**	**669,310**	**48.5**	**90.3**	**61.6**	**7,411**	**GAS**	**4,825,200**	**1,027,999**	**4,960,300.0**	**28,036,808**	**4.19**	**5.81**
32. SYSTEM	**4,306**	**1,872,500**	**58.4**	**90.4**	**79.9**	**9,215**	**-**	**-**	**-**	**17,255,440.0**	**70,905,654**	**3.79**	**-**

LEGEND:
B.B. = BIG BEND
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.

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 12 of 25

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2014

(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. B.B.#1	385	236,430	82.5	85.1	93.8	10,125	COAL	102,980	23,244,902	2,393,760.0	7,931,615	3.35	77.02
2. B.B.#2	385	244,380	85.3	87.9	95.2	10,204	COAL	107,280	23,243,475	2,493,560.0	8,262,805	3.38	77.02
3. B.B.#3	395	254,110	86.5	88.0	95.3	10,368	COAL	116,430	22,628,189	2,634,600.0	8,967,550	3.53	77.02
4. B.B.#4	407	264,360	87.3	86.2	98.4	10,113	COAL	121,200	22,058,416	2,673,480.0	9,334,937	3.53	77.02
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,770	-	10,290.0	243,641	-	137.65
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,572**	**999,280**	**85.4**	**86.8**	**95.7**	**10,203**	**-**	**-**	**-**	**-**	**34,740,548**	**3.48**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	10,000	LGT OIL	20	5,000,000	100.0	2,753	27.53	137.65
9. B.B.C.T.#4 GAS	56	1,960	4.7	-	85.4	11,036	GAS	21,040	1,028,042	21,630.0	117,550	6.00	5.59
10. B.B.C.T.#4 TOTAL	**56**	**1,970**	**4.7**	**99.4**	**74.8**	**11,030**	**-**	**-**	**-**	**21,730.0**	**120,303**	**6.11**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**1,001,250**	**82.7**	**87.2**	**95.6**	**10,204**	**-**	**-**	**-**	**10,217,130.0**	**34,860,851**	**3.48**	**-**
12. POLK #1 GASIFIER	220	137,360	83.9	-	97.4	10,163	COAL	52,200	26,744,253	1,396,050.0	4,479,064	3.26	85.81
13. POLK #1 CT GAS	195	2,610	1.8	-	83.7	7,931	GAS	22,470	921,228	20,700.0	112,522	4.31	5.01
14. POLK #1 TOTAL	**220**	**139,970**	**85.5**	**92.4**	**97.1**	**10,122**	**-**	**-**	**-**	**1,416,750.0**	**4,591,586**	**3.28**	**-**
15. POLK #2 CT GAS	151	16,490	14.7	-	97.5	10,780	GAS	172,930	1,027,988	177,770.0	966,159	5.86	5.59
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,824	19.12	127.47
17. POLK #2 TOTAL	**151**	**16,510**	**14.7**	**98.2**	**94.1**	**10,779**	**-**	**-**	**-**	**177,960.0**	**969,983**	**5.88**	**-**
18. POLK #3 CT GAS	151	12,950	11.5	-	98.3	10,746	GAS	135,380	1,027,921	139,160.0	756,368	5.84	5.59
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,824	19.12	127.47
20. POLK #3 TOTAL	**151**	**12,970**	**11.5**	**98.2**	**93.9**	**10,744**	**-**	**-**	**-**	**139,350.0**	**760,192**	**5.86**	**-**
21. POLK #4 CT GAS	**151**	**6,620**	**5.9**	**98.8**	**99.9**	**10,716**	**GAS**	**69,010**	**1,027,967**	**70,940.0**	**385,559**	**5.82**	**5.59**
22. POLK #5 CT GAS	**151**	**5,280**	**4.7**	**98.9**	**99.9**	**10,701**	**GAS**	**54,960**	**1,028,020**	**56,500.0**	**307,061**	**5.82**	**5.59**
23. POLK STATION TOTAL	**824**	**181,350**	**29.6**	**96.9**	**96.8**	**10,265**	**-**	**-**	**-**	**1,861,500.0**	**7,014,381**	**3.87**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	265,040	50.8	89.1	57.8	7,368	GAS	1,899,480	1,028,013	1,952,690.0	10,612,391	4.00	5.59
26. BAYSIDE #2	929	404,690	58.6	89.0	63.3	7,326	GAS	2,884,140	1,027,994	2,964,880.0	16,113,685	3.98	5.59
27. BAYSIDE #3	56	3,210	7.7	97.7	88.2	10,857	GAS	33,890	1,028,327	34,850.0	189,343	5.90	5.59
28. BAYSIDE #4	56	2,720	6.5	99.4	86.7	10,915	GAS	28,880	1,028,047	29,690.0	161,352	5.93	5.59
29. BAYSIDE #5	56	4,730	11.4	99.6	93.8	10,799	GAS	49,690	1,027,973	51,080.0	277,618	5.87	5.59
30. BAYSIDE #6	56	4,290	10.3	99.9	90.1	10,867	GAS	45,350	1,028,004	46,620.0	253,370	5.91	5.59
31. BAYSIDE TOTAL	**1,854**	**684,680**	**49.6**	**90.3**	**61.5**	**7,419**	**GAS**	**4,941,430**	**1,028,004**	**5,079,810.0**	**27,607,759**	**4.03**	**5.59**
32. SYSTEM	**4,306**	**1,867,280**	**58.3**	**90.4**	**79.5**	**9,189**	**-**	**-**	**-**	**17,158,440.0**	**69,482,991**	**3.72**	**-**

LEGEND:
B.B. = BIG BEND
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.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2014

(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. B.B.#1	385	227,390	82.0	85.1	93.2	10,131	COAL	99,110	23,242,761	2,303,590.0	7,682,918	3.38	77.52
2. B.B.#2	385	235,040	84.8	87.9	94.7	10,210	COAL	103,240	23,243,510	2,399,660.0	8,003,077	3.40	77.52
3. B.B.#3	395	241,040	84.8	88.0	93.4	10,389	COAL	110,660	22,629,044	2,504,130.0	8,578,263	3.56	77.52
4. B.B.#4	407	253,500	86.5	86.2	97.5	10,124	COAL	116,340	22,059,309	2,566,380.0	9,018,578	3.56	77.52
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,550	-	20,580.0	493,159	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,572**	**956,970**	**84.5**	**86.8**	**94.7**	**10,213**	**-**	**-**	**-**	**-**	**33,775,995**	**3.53**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.6	10,000	LGT OIL	20	5,000,000	100.0	4,378	43.78	218.90
9. B.B.C.T.#4 GAS	56	1,010	2.5	-	90.2	10,990	GAS	10,800	1,027,778	11,100.0	63,815	6.32	5.91
10. B.B.C.T.#4 TOTAL	**56**	**1,020**	**2.5**	**99.4**	**72.9**	**10,980**	**-**	**-**	**-**	**11,200.0**	**68,193**	**6.69**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**957,990**	**81.7**	**87.2**	**94.7**	**10,214**	**-**	**-**	**-**	**9,784,960.0**	**33,844,188**	**3.53**	**-**
12. POLK #1 GASIFIER	220	132,850	83.9	-	97.4	10,164	COAL	50,490	26,744,900	1,350,350.0	4,387,623	3.30	86.90
13. POLK #1 CT GAS	195	3,500	2.5	-	89.7	8,254	GAS	30,440	949,080	28,890.0	166,096	4.75	5.46
14. POLK #1 TOTAL	**220**	**136,350**	**86.1**	**92.4**	**97.2**	**10,115**	**-**	**-**	**-**	**1,379,240.0**	**4,553,719**	**3.34**	**-**
15. POLK #2 CT GAS	151	18,950	17.4	-	95.8	10,846	GAS	199,950	1,027,957	205,540.0	1,181,462	6.23	5.91
16. POLK #2 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**18,970**	**17.4**	**98.2**	**92.9**	**10,846**	**-**	**-**	**-**	**205,740.0**	**1,185,037**	**6.25**	**-**
18. POLK #3 CT GAS	151	10,390	9.5	-	98.0	10,765	GAS	108,800	1,028,033	111,850.0	642,876	6.19	5.91
19. POLK #3 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**10,410**	**9.5**	**98.2**	**92.6**	**10,764**	**-**	**-**	**-**	**112,050.0**	**646,451**	**6.21**	**-**
21. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**824**	**165,730**	**27.9**	**60.7**	**96.4**	**10,240**	**-**	**-**	**-**	**1,697,030.0**	**6,385,207**	**3.85**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	218,020	43.2	89.1	54.3	7,374	GAS	1,563,920	1,028,000	1,607,710.0	9,240,870	4.24	5.91
26. BAYSIDE #2	929	390,350	58.4	89.0	63.2	7,335	GAS	2,785,340	1,028,004	2,863,340.0	16,457,980	4.22	5.91
27. BAYSIDE #3	56	2,730	6.8	97.7	90.3	10,908	GAS	28,970	1,027,960	29,780.0	171,178	6.27	5.91
28. BAYSIDE #4	56	1,870	4.6	99.4	92.8	10,872	GAS	19,780	1,027,806	20,330.0	116,876	6.25	5.91
29. BAYSIDE #5	56	4,150	10.3	99.6	87.2	11,019	GAS	44,490	1,027,871	45,730.0	262,882	6.33	5.91
30. BAYSIDE #6	56	3,720	9.2	99.9	91.0	10,898	GAS	39,430	1,028,151	40,540.0	232,983	6.26	5.91
31. BAYSIDE TOTAL	**1,854**	**620,840**	**46.5**	**90.3**	**60.1**	**7,421**	**GAS**	**4,481,930**	**1,028,001**	**4,607,430.0**	**26,482,769**	**4.27**	**5.91**
32. SYSTEM	**4,306**	**1,744,560**	**56.3**	**83.5**	**78.7**	**9,223**	**-**	**-**	**-**	**16,089,420.0**	**66,712,164**	**3.82**	**-**

LEGEND:
B.B. = BIG BEND
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.

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2014

(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. B.B.#1	385	181,000	63.2	85.1	92.5	10,141	COAL	78,980	23,240,820	1,835,560.0	6,199,026	3.42	78.49
2. B.B.#2	385	194,820	68.0	87.9	94.1	10,221	COAL	85,660	23,245,389	1,991,200.0	6,723,329	3.45	78.49
3. B.B.#3	395	168,320	57.3	59.6	93.2	10,391	COAL	77,300	22,626,261	1,749,010.0	6,067,158	3.60	78.49
4. B.B.#4	407	263,640	87.1	69.5	98.1	10,116	COAL	120,910	22,058,225	2,667,060.0	9,490,043	3.60	78.49
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	21,020.0	504,273	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,572**	**807,780**	**69.1**	**75.3**	**94.8**	**10,204**	**-**	**-**	**-**	**-**	**28,983,829**	**3.59**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.6	10,000	LGT OIL	20	5,000,000	100.0	2,778	27.78	138.90
9. B.B.C.T.#4 GAS	56	550	1.3	-	75.5	11,600	GAS	6,210	1,027,375	6,380.0	36,048	6.55	5.80
10. B.B.C.T.#4 TOTAL	**56**	**560**	**1.3**	**99.4**	**55.6**	**11,571**	**-**	**-**	**-**	**6,480.0**	**38,826**	**6.93**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**808,340**	**66.7**	**76.2**	**94.8**	**10,205**	**-**	**-**	**-**	**8,249,310.0**	**29,022,655**	**3.59**	**-**
12. POLK #1 GASIFIER	220	137,350	83.9	-	97.4	10,164	COAL	52,200	26,742,720	1,395,970.0	4,559,157	3.32	87.34
13. POLK #1 CT GAS	195	2,610	1.8	-	83.7	7,762	GAS	22,040	919,238	20,260.0	114,412	4.38	5.19
14. POLK #1 TOTAL	**220**	**139,960**	**85.5**	**77.5**	**97.1**	**10,119**	**-**	**-**	**-**	**1,416,230.0**	**4,673,569**	**3.34**	**-**
15. POLK #2 CT GAS	151	14,680	13.1	-	89.2	11,063	GAS	157,970	1,028,043	162,400.0	916,977	6.25	5.80
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**14,700**	**13.1**	**98.2**	**86.0**	**11,061**	**-**	**-**	**-**	**162,590.0**	**920,552**	**6.26**	**-**
18. POLK #3 CT GAS	151	9,980	8.9	-	91.5	10,974	GAS	106,540	1,027,971	109,520.0	618,439	6.20	5.80
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**10,000**	**8.9**	**98.2**	**86.6**	**10,971**	**-**	**-**	**-**	**109,710.0**	**622,014**	**6.22**	**-**
21. POLK #4 CT GAS	**151**	**2,050**	**1.8**	**57.4**	**97.2**	**10,849**	**GAS**	**21,640**	**1,027,726**	**22,240.0**	**125,615**	**6.13**	**5.80**
22. POLK #5 CT GAS	**151**	**1,500**	**1.3**	**86.1**	**99.3**	**10,760**	**GAS**	**15,700**	**1,028,025**	**16,140.0**	**91,135**	**6.08**	**5.80**
23. POLK STATION TOTAL	**824**	**168,210**	**27.4**	**83.0**	**95.4**	**10,266**	**-**	**-**	**-**	**1,726,910.0**	**6,432,885**	**3.82**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	206,090	39.5	89.1	57.5	7,352	GAS	1,474,000	1,027,999	1,515,270.0	8,556,212	4.15	5.80
26. BAYSIDE #2	929	415,510	60.1	89.0	65.0	7,333	GAS	2,963,810	1,028,001	3,046,800.0	17,204,199	4.14	5.80
27. BAYSIDE #3	56	1,840	4.4	97.7	82.1	11,082	GAS	19,830	1,028,240	20,390.0	115,108	6.26	5.80
28. BAYSIDE #4	56	1,230	3.0	99.4	78.4	11,236	GAS	13,450	1,027,509	13,820.0	78,074	6.35	5.80
29. BAYSIDE #5	56	2,620	6.3	99.6	85.1	11,057	GAS	28,180	1,028,034	28,970.0	163,578	6.24	5.80
30. BAYSIDE #6	56	1,630	3.9	99.9	83.2	11,025	GAS	17,480	1,028,032	17,970.0	101,467	6.22	5.80
31. BAYSIDE TOTAL	**1,854**	**628,920**	**45.6**	**90.3**	**62.5**	**7,383**	**GAS**	**4,516,750**	**1,028,000**	**4,643,220.0**	**26,218,638**	**4.17**	**5.80**
32. SYSTEM	**4,306**	**1,605,470**	**50.1**	**83.5**	**78.9**	**9,106**	**-**	**-**	**-**	**14,619,440.0**	**61,674,178**	**3.84**	**-**

LEGEND:
B.B. = BIG BEND
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.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2014

(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. B.B.#1	385	196,760	71.0	85.1	89.5	10,180	COAL	86,180	23,241,819	2,002,980.0	6,795,205	3.45	78.85
2. B.B.#2	385	190,380	68.7	87.9	88.5	10,308	COAL	84,420	23,245,321	1,962,370.0	6,656,428	3.50	78.85
3. B.B.#3	395	221,740	78.0	88.0	86.0	10,484	COAL	102,730	22,628,638	2,324,640.0	8,100,157	3.65	78.85
4. B.B.#4	407	246,510	84.1	74.7	94.8	10,157	COAL	113,510	22,059,026	2,503,920.0	8,950,146	3.63	78.85
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,920	-	22,730.0	544,559	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,572**	**855,390**	**75.6**	**83.8**	**89.8**	**10,281**	**-**	**-**	**-**	**-**	**31,046,495**	**3.63**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.6	13,000	LGT OIL	20	6,500,000	130.0	2,778	27.78	138.90
9. B.B.C.T.#4 GAS	56	530	1.3	-	94.6	10,906	GAS	5,620	1,028,470	5,780.0	35,057	6.61	6.24
10. B.B.C.T.#4 TOTAL	**56**	**540**	**1.3**	**99.4**	**56.7**	**10,944**	**-**	**-**	**-**	**5,910.0**	**37,835**	**7.01**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**855,930**	**73.0**	**84.3**	**89.7**	**10,281**	**-**	**-**	**-**	**8,799,820.0**	**31,084,330**	**3.63**	**-**
12. POLK #1 GASIFIER	220	110,700	69.9	-	97.3	10,202	COAL	42,080	26,838,641	1,129,370.0	3,741,853	3.38	88.92
13. POLK #1 CT GAS	195	5,920	4.2	-	84.3	8,083	GAS	52,390	913,342	47,850.0	290,375	4.90	5.54
14. POLK #1 TOTAL	**220**	**116,620**	**73.6**	**92.4**	**96.6**	**10,094**	**-**	**-**	**-**	**1,177,220.0**	**4,032,228**	**3.46**	**-**
15. POLK #2 CT GAS	151	9,550	8.8	-	91.7	10,950	GAS	101,720	1,028,018	104,570.0	634,521	6.64	6.24
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**9,570**	**8.8**	**98.2**	**85.3**	**10,953**	**-**	**-**	**-**	**104,820.0**	**639,288**	**6.68**	**-**
18. POLK #3 CT GAS	151	7,570	6.9	-	94.3	10,855	GAS	79,930	1,028,025	82,170.0	498,596	6.59	6.24
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
20. POLK #3 TOTAL	**151**	**7,590**	**7.0**	**98.2**	**86.0**	**10,859**	**-**	**-**	**-**	**82,420.0**	**503,363**	**6.63**	**-**
21. POLK #4 CT GAS	**151**	**3,310**	**3.1**	**75.8**	**99.9**	**10,722**	**GAS**	**34,530**	**1,027,802**	**35,490.0**	**215,395**	**6.51**	**6.24**
22. POLK #5 CT GAS	**151**	**1,500**	**1.4**	**98.9**	**99.3**	**10,733**	**GAS**	**15,660**	**1,028,097**	**16,100.0**	**97,686**	**6.51**	**6.24**
23. POLK STATION TOTAL	**824**	**138,590**	**23.4**	**92.7**	**95.2**	**10,218**	**-**	**-**	**-**	**1,416,050.0**	**5,487,960**	**3.96**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	153,200	30.4	68.3	55.8	7,428	GAS	1,106,990	1,028,004	1,137,990.0	6,905,307	4.51	6.24
26. BAYSIDE #2	929	177,970	26.6	68.2	41.1	7,474	GAS	1,293,840	1,028,010	1,330,080.0	8,070,862	4.53	6.24
27. BAYSIDE #3	56	1,000	2.5	97.7	89.3	11,050	GAS	10,750	1,027,907	11,050.0	67,058	6.71	6.24
28. BAYSIDE #4	56	100	0.2	99.4	89.3	10,900	GAS	1,060	1,028,302	1,090.0	6,612	6.61	6.24
29. BAYSIDE #5	56	1,640	4.1	99.6	86.1	11,043	GAS	17,620	1,027,809	18,110.0	109,912	6.70	6.24
30. BAYSIDE #6	56	1,250	3.1	99.9	93.0	10,896	GAS	13,250	1,027,925	13,620.0	82,652	6.61	6.24
31. BAYSIDE TOTAL	**1,854**	**335,160**	**25.1**	**72.0**	**47.1**	**7,495**	**GAS**	**2,443,510**	**1,028,005**	**2,511,940.0**	**15,242,403**	**4.55**	**6.24**
32. SYSTEM	**4,306**	**1,329,680**	**42.9**	**80.6**	**73.4**	**9,572**	**-**	**-**	**-**	**12,727,810.0**	**51,814,693**	**3.90**	**-**

LEGEND:
B.B. = BIG BEND
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.

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 16 of 25

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2014

(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. B.B.#1	395	232,240	79.0	57.7	89.8	10,061	COAL	100,530	23,243,012	2,336,620.0	7,930,788	3.41	78.89
2. B.B.#2	395	238,520	81.2	59.5	90.5	10,225	COAL	104,920	23,244,758	2,438,840.0	8,277,109	3.47	78.89
3. B.B.#3	400	234,770	78.9	88.0	87.0	10,428	COAL	108,190	22,628,616	2,448,190.0	8,535,085	3.64	78.89
4. B.B.#4	417	173,970	56.1	86.2	93.1	10,105	COAL	79,700	22,057,716	1,758,000.0	6,287,512	3.61	78.89
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,550	-	20,590.0	493,159	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,607**	**879,500**	**73.6**	**73.1**	**89.8**	**10,212**	**-**	**-**	**-**	**-**	**31,523,653**	**3.58**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.3	10,000	LGT OIL	20	5,000,000	100.0	4,378	43.78	218.90
9. B.B.C.T.#4 GAS	61	790	1.7	-	92.5	10,962	GAS	8,420	1,028,504	8,660.0	52,899	6.70	6.28
10. B.B.C.T.#4 TOTAL	**61**	**800**	**1.8**	**99.4**	**62.5**	**10,950**	**-**	**-**	**-**	**8,760.0**	**57,277**	**7.16**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**880,300**	**70.9**	**74.0**	**89.8**	**10,213**	**-**	**-**	**-**	**8,990,410.0**	**31,580,930**	**3.59**	**-**
12. POLK #1 GASIFIER	220	137,340	83.9	-	97.4	10,164	COAL	52,200	26,741,188	1,395,890.0	4,598,181	3.35	88.09
13. POLK #1 CT GAS	205	3,390	2.2	-	78.7	8,829	GAS	31,450	951,669	29,930.0	182,949	5.40	5.82
14. POLK #1 TOTAL	**220**	**140,730**	**86.0**	**92.4**	**96.8**	**10,132**	**-**	**-**	**-**	**1,425,820.0**	**4,781,130**	**3.40**	**-**
15. POLK #2 CT GAS	183	19,340	14.2	-	85.9	10,660	GAS	200,540	1,028,024	206,160.0	1,259,913	6.51	6.28
16. POLK #2 CT OIL	187	20	0.0	-	2.1	10,500	LGT OIL	40	5,250,000	210.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**19,360**	**14.2**	**98.2**	**82.6**	**10,660**	**-**	**-**	**-**	**206,370.0**	**1,264,680**	**6.53**	**-**
18. POLK #3 CT GAS	183	12,200	8.9	-	91.1	10,538	GAS	125,060	1,027,987	128,560.0	785,702	6.44	6.28
19. POLK #3 CT OIL	187	20	0.0	-	2.1	10,500	LGT OIL	40	5,250,000	210.0	4,767	23.84	119.18
20. POLK #3 TOTAL	**183**	**12,220**	**9.0**	**98.2**	**85.3**	**10,538**	**-**	**-**	**-**	**128,770.0**	**790,469**	**6.47**	**-**
21. POLK #4 CT GAS	**183**	**4,780**	**3.5**	**98.8**	**97.0**	**10,450**	**GAS**	**48,580**	**1,028,201**	**49,950.0**	**305,209**	**6.39**	**6.28**
22. POLK #5 CT GAS	**183**	**2,860**	**2.1**	**98.9**	**97.7**	**10,437**	**GAS**	**29,030**	**1,028,247**	**29,850.0**	**182,384**	**6.38**	**6.28**
23. POLK STATION TOTAL	**952**	**179,950**	**25.4**	**97.1**	**94.2**	**10,229**	**-**	**-**	**-**	**1,840,760.0**	**7,323,872**	**4.07**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	80,090	13.6	89.1	34.0	7,483	GAS	583,000	1,028,027	599,340.0	3,662,756	4.57	6.28
26. BAYSIDE #2	1,047	243,330	31.2	89.0	33.8	7,336	GAS	1,736,440	1,027,994	1,785,050.0	10,909,357	4.48	6.28
27. BAYSIDE #3	61	1,870	4.1	97.7	95.8	10,487	GAS	19,070	1,028,317	19,610.0	119,809	6.41	6.28
28. BAYSIDE #4	61	880	1.9	99.4	90.2	10,875	GAS	9,320	1,026,824	9,570.0	58,554	6.65	6.28
29. BAYSIDE #5	61	2,440	5.4	99.6	97.6	10,557	GAS	25,060	1,027,933	25,760.0	157,442	6.45	6.28
30. BAYSIDE #6	61	2,070	4.6	99.9	99.8	10,406	GAS	20,950	1,028,162	21,540.0	131,620	6.36	6.28
31. BAYSIDE TOTAL	**2,083**	**330,680**	**21.3**	**90.2**	**34.3**	**7,442**	**GAS**	**2,393,840**	**1,028,001**	**2,460,870.0**	**15,039,538**	**4.55**	**6.28**
32. SYSTEM	**4,703**	**1,390,930**	**39.8**	**85.9**	**65.2**	**9,556**	**-**	**-**	**-**	**13,292,040.0**	**53,944,340**	**3.88**	**-**

LEGEND:
B.B. = BIG BEND
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.

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E5

	ACTUAL					
	Jan-14	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
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)	1,783	1,421	6,223	0	8,901	11,469
16. UNIT COST ($/BBL)	131.38	136.56	132.83	0.00	145.25	142.02
17. AMOUNT ($)	234,255	194,057	826,608	0	1,292,881	1,628,816
18. BURNED:						
19. UNITS (BBL)	0	0	0	0	0	0
20. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
21. AMOUNT ($)	0	0	0	0	0	0
22. ENDING INVENTORY:						
23. UNITS (BBL)	74,495	73,909	76,869	73,859	79,990	84,104
24. UNIT COST ($/BBL)	129.29	129.35	129.50	129.37	131.02	132.11
25. AMOUNT ($)	9,631,152	9,559,905	9,954,253	9,555,506	10,480,635	11,110,888
26. DAYS SUPPLY: NORMAL	438	441	471	462	493	528
27. DAYS SUPPLY: EMERGENCY	11	11	11	11	11	12
COAL						
28. PURCHASES:						
29. UNITS (TONS)	490,121	242,955	284,625	434,559	465,285	341,400
30. UNIT COST ($/TON)	76.98	79.93	79.83	80.94	81.18	81.69
31. AMOUNT ($)	37,728,110	19,419,095	22,722,441	35,174,838	37,773,929	27,888,933
32. BURNED:						
33. UNITS (TONS)	479,132	376,564	273,928	315,633	393,355	444,631
34. UNIT COST ($/TON)	78.01	81.37	84.83	84.67	79.71	83.02
35. AMOUNT ($)	37,375,651	30,641,723	23,236,564	26,724,063	31,354,133	36,914,265
36. ENDING INVENTORY:						
37. UNITS (TONS)	579,298	445,689	456,386	575,312	647,242	544,011
38. UNIT COST ($/TON)	77.34	76.71	77.42	78.89	80.65	81.23
39. AMOUNT ($)	44,803,323	34,188,102	35,335,652	45,384,896	52,201,313	44,191,255
40. DAYS SUPPLY:	44	37	37	43	44	35
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	3,381,158	3,026,968	4,505,608	5,096,231	5,614,612	5,410,415
43. UNIT COST ($/MCF)	6.17	5.81	5.66	5.76	5.80	5.71
44. AMOUNT ($)	20,865,627	17,590,653	25,480,736	29,355,476	32,567,574	30,898,758
45. BURNED:						
46. UNITS (MCF)	3,334,922	3,102,784	4,532,946	4,874,369	5,416,370	5,373,413
47. UNIT COST ($/MCF)	6.11	5.55	5.76	5.84	5.87	5.74
48. AMOUNT ($)	20,389,287	17,233,819	26,095,864	28,473,688	31,770,537	30,821,281
49. ENDING INVENTORY:						
50. UNITS (MCF)	637,222	561,406	534,068	755,930	954,172	991,174
51. UNIT COST ($/MCF)	4.76	6.03	5.19	4.83	4.66	4.65
52. AMOUNT ($)	3,030,625	3,387,459	2,772,331	3,654,119	4,451,156	4,610,530
53. DAYS SUPPLY:	4	4	4	5	6	7
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-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

SCHEDULE E5

	Estimated						
	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	0	0	0	0	0	0	29,797
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	140.17
17. AMOUNT ($)	0	0	0	0	0	0	4,176,617
18. BURNED:							
19. UNITS (BBL)	1,870	1,850	3,630	3,710	4,020	3,650	18,730
20. UNIT COST ($/BBL)	6.93	5.62	3.18	2.68	3.06	3.81	3.79
21. AMOUNT ($)	12,951	10,401	11,528	9,928	12,312	13,912	71,032
22. ENDING INVENTORY:							
23. UNITS (BBL)	82,234	80,384	76,754	73,044	69,024	65,374	65,374
24. UNIT COST ($/BBL)	131.99	131.87	131.55	131.19	130.77	130.34	130.34
25. AMOUNT ($)	10,854,295	10,600,252	10,097,164	9,582,963	9,026,092	8,520,622	8,520,622
26. DAYS SUPPLY: NORMAL	1,033	1,055	1,055	1,158	1,299	1,544	-
27. DAYS SUPPLY: EMERGENCY	12	11	11	10	10	9	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	558,333	489,000	483,333	435,000	443,333	431,000	5,098,944
30. UNIT COST ($/TON)	78.34	79.54	77.07	77.70	77.42	77.42	78.86
31. AMOUNT ($)	43,739,739	38,895,063	37,249,112	33,800,577	34,322,267	33,369,736	402,083,840
32. BURNED:							
33. UNITS (TONS)	499,200	500,090	479,840	415,050	428,920	445,540	5,051,883
34. UNIT COST ($/TON)	77.66	78.43	79.53	80.82	81.11	81.07	80.53
35. AMOUNT ($)	38,766,700	39,219,612	38,163,618	33,542,986	34,788,348	36,121,834	406,849,497
36. ENDING INVENTORY:							
37. UNITS (TONS)	603,144	592,054	595,547	615,497	629,910	615,370	615,370
38. UNIT COST ($/TON)	82.21	83.85	82.89	81.74	80.26	78.73	78.73
39. AMOUNT ($)	49,586,111	49,645,859	49,365,417	50,312,444	50,558,817	48,445,730	48,445,730
40. DAYS SUPPLY:	38	39	41	44	43	59	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	5,707,431	5,417,220	4,831,920	4,846,850	2,441,531	2,836,920	53,116,864
43. UNIT COST ($/MCF)	5.76	5.48	5.91	5.81	6.51	6.31	5.83
44. AMOUNT ($)	32,857,010	29,682,796	28,554,385	28,145,589	15,902,062	17,892,532	309,793,198
45. BURNED:							
46. UNITS (MCF)	5,531,290	5,417,220	4,831,920	4,846,850	2,733,360	2,836,920	52,832,364
47. UNIT COST ($/MCF)	5.81	5.58	5.91	5.80	6.22	6.28	5.84
48. AMOUNT ($)	32,126,003	30,252,978	28,537,018	28,121,264	17,014,033	17,808,594	308,644,366
49. ENDING INVENTORY:							
50. UNITS (MCF)	1,167,315	1,167,315	1,167,315	1,167,315	875,487	875,487	875,487
51. UNIT COST ($/MCF)	4.56	4.06	4.07	4.08	4.12	4.20	4.20
52. AMOUNT ($)	5,328,000	4,744,800	4,748,400	4,759,200	3,610,800	3,680,100	3,680,100
53. DAYS SUPPLY:	9	9	9	9	7	7	-
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-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
POWER SOLD
ACTUAL FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E6

(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 MARKET BASED SALES
ACTUAL											
Jan-14	SEMINOLE	JURISD.	SCH. - D	3,134.1	0.0	3,134.1	3.148	3.462	98,647.38	108,512.12	7,090.95
	VARIOUS	JURISD.	SCH. - C	19.0	0.0	19.0	2.543	3.264	483.23	620.08	105.84
	VARIOUS	JURISD.	SCH. - CB	1,393.0	0.0	1,393.0	3.314	3.930	46,163.00	54,747.18	4,978.19
	VARIOUS	JURISD.	SCH. - MA	38,944.0	0.0	38,944.0	3.929	9.374	1,530,233.09	3,650,508.61	1,756,509.45
	TOTAL			**43,490.1**	**0.0**	**43,490.1**	**3.853**	**8.771**	**1,675,526.70**	**3,814,387.99**	**1,768,684.43**
ACTUAL											
Feb-14	SEMINOLE	JURISD.	SCH. - D	2,849.6	0.0	2,849.6	3.564	3.921	101,570.67	111,727.74	6,934.70
	VARIOUS	JURISD.	SCH. - C	475.0	0.0	475.0	3.664	4.851	17,403.10	23,041.58	3,545.58
	VARIOUS	JURISD.	SCH. - CB	6,503.0	0.0	6,503.0	4.020	4.618	261,441.52	300,324.47	17,687.13
	VARIOUS	JURISD.	SCH. - MA	41,511.0	0.0	41,511.0	3.575	4.987	1,484,078.59	2,070,044.94	398,001.09
	TOTAL			**51,338.6**	**0.0**	**51,338.6**	**3.632**	**4.880**	**1,864,493.88**	**2,505,138.73**	**426,168.50**
ACTUAL											
Mar-14	SEMINOLE	JURISD.	SCH. - D	2,476.2	0.0	2,476.2	3.550	3.905	87,907.84	96,698.62	6,098.37
	VARIOUS	JURISD.	SCH. - C	8.0	0.0	8.0	3.031	3.756	242.46	300.49	26.33
	VARIOUS	JURISD.	SCH. - CB	2,664.0	0.0	2,664.0	3.088	3.679	82,271.84	98,009.67	6,969.46
	VARIOUS	JURISD.	SCH. - MA	6,447.0	0.0	6,447.0	3.645	4.609	234,996.79	297,116.76	38,285.58
	TOTAL			**11,595.2**	**0.0**	**11,595.2**	**3.496**	**4.244**	**405,418.93**	**492,125.54**	**51,379.74**
ACTUAL											
Apr-14	SEMINOLE	JURISD.	SCH. - D	1,819.0	0.0	1,819.0	3.118	3.430	56,720.81	62,392.89	3,569.11
	VARIOUS	JURISD.	SCH. - C	233.0	0.0	233.0	2.923	3.699	6,810.20	8,618.54	967.67
	VARIOUS	JURISD.	SCH. - CB	6,807.0	0.0	6,807.0	3.325	3.929	226,346.18	267,449.38	19,384.51
	VARIOUS	JURISD.	SCH. - MA	2,921.0	0.0	2,921.0	3.102	4.101	90,613.53	119,781.89	17,583.76
	TOTAL			**11,780.0**	**0.0**	**11,780.0**	**3.230**	**3.890**	**380,490.72**	**458,242.70**	**41,505.05**
ACTUAL											
May-14	SEMINOLE	JURISD.	SCH. - D	2,220.1	0.0	2,220.1	3.001	3.301	66,620.32	73,282.35	3,927.19
	VARIOUS	JURISD.	SCH. - C	60.0	0.0	60.0	2.804	3.482	1,682.60	2,088.97	235.61
	VARIOUS	JURISD.	SCH. - CB	965.0	0.0	965.0	2.779	3.335	26,814.70	32,184.99	2,295.95
	VARIOUS	JURISD.	SCH. - MA	508.0	0.0	508.0	3.329	3.944	16,910.74	20,035.96	1,841.46
	TOTAL			**3,753.1**	**0.0**	**3,753.1**	**2.985**	**3.400**	**112,028.36**	**127,592.27**	**8,300.21**
ACTUAL											
Jun-14	SEMINOLE	JURISD.	SCH. - D	2,430.0	0.0	2,430.0	2.966	3.262	72,067.55	79,274.31	4,163.74
	VARIOUS	JURISD.	SCH. - C	58.0	0.0	58.0	2.848	3.476	1,652.12	2,015.84	173.12
	VARIOUS	JURISD.	SCH. - CB	4,055.0	0.0	4,055.0	3.748	4.357	151,995.03	176,658.05	12,431.10
	VARIOUS	JURISD.	SCH. - MA	4,206.0	0.0	4,206.0	3.199	4.364	134,558.83	183,564.46	31,212.44
	TOTAL			**10,749.0**	**0.0**	**10,749.0**	**3.352**	**4.107**	**360,273.53**	**441,512.66**	**47,980.40**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

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-14	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.518	3.746	35,530.00	37,835.00	2,305.00
	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	13,460.0	0.0	13,460.0	3.330	3.664	448,264.26	493,140.00	44,875.74
	TOTAL			**14,470.0**	**0.0**	**14,470.0**	**3.343**	**3.669**	**483,794.26**	**530,975.00**	**47,180.74**
ESTIMATED											
Aug-14	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	3.225	3.434	31,930.00	34,001.00	2,071.00
	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	9,580.0	0.0	9,580.0	3.173	3.490	303,933.24	334,360.00	30,426.76
	TOTAL			**10,570.0**	**0.0**	**10,570.0**	**3.178**	**3.485**	**335,863.24**	**368,361.00**	**32,497.76**
ESTIMATED											
Sep-14	SEMINOLE	JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.225	3.434	32,250.00	34,342.00	2,092.00
	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	16,610.0	0.0	16,610.0	3.346	3.681	555,798.96	611,440.00	55,641.04
	TOTAL			**17,610.0**	**0.0**	**17,610.0**	**3.339**	**3.667**	**588,048.96**	**645,782.00**	**57,733.04**
ESTIMATED											
Oct-14	SEMINOLE	JURISD.	SCH. - D	740.0	0.0	740.0	3.085	3.285	22,830.00	24,311.00	1,481.00
	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	11,470.0	0.0	11,470.0	2.945	3.240	337,848.03	371,670.00	33,821.97
	TOTAL			**12,210.0**	**0.0**	**12,210.0**	**2.954**	**3.243**	**360,678.03**	**395,981.00**	**35,302.97**
ESTIMATED											
Nov-14	SEMINOLE	JURISD.	SCH. - D	650.0	0.0	650.0	3.028	3.224	19,680.00	20,957.00	1,277.00
	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	34,070.0	0.0	34,070.0	3.241	3.566	1,104,362.28	1,214,920.00	110,557.72
	TOTAL			**34,720.0**	**0.0**	**34,720.0**	**3.237**	**3.560**	**1,124,042.28**	**1,235,877.00**	**111,834.72**
ESTIMATED											
Dec-14	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	3.131	3.334	18,160.00	19,338.00	1,178.00
	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	11,650.0	0.0	11,650.0	2.975	3.273	346,583.52	381,280.00	34,696.48
	TOTAL			**12,230.0**	**0.0**	**12,230.0**	**2.982**	**3.276**	**364,743.52**	**400,618.00**	**35,874.48**
TOTAL	SEMINOLE	JURISD.	SCH. - D	19,899.0	0.0	19,899.0	3.236	3.531	643,914.57	702,672.03	42,188.06
Jan-14	VARIOUS	JURISD.	SCH. - C	853.0	0.0	853.0	3.315	4.301	28,273.71	36,685.50	5,054.15
THRU	VARIOUS	JURISD.	SCH. - CB	22,387.0	0.0	22,387.0	3.551	4.151	795,032.27	929,373.74	63,746.34
Dec-14	VARIOUS	JURISD.	SCH. - MA	191,377.0	0.0	191,377.0	3.443	5.094	6,588,181.86	9,747,862.62	2,553,453.49
	TOTAL			**234,516.0**	**0.0**	**234,516.0**	**3.435**	**4.868**	**8,055,402.41**	**11,416,593.89**	**2,664,442.04**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ACTUAL FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL Jan-14									
	OLEANDER	SCH. - D	800.0	0.0	0.0	800.0	7.909	7.909	63,274.91
	CALPINE	SCH. - D	585.0	0.0	0.0	585.0	8.997	8.997	52,633.41
	PASCO COGEN	SCH. - D	13,155.0	0.0	0.0	13,155.0	6.169	6.169	811,500.90
	VARIOUS	OATT	917.0	0.0	0.0	917.0	3.079	3.079	28,232.08
	TOTAL		**15,457.0**	**0.0**	**0.0**	**15,457.0**	**6.183**	**6.183**	**955,641.30**
ACTUAL Feb-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	(10,796.57)
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	(7,936.19)
	PASCO COGEN	SCH. - D	7,346.0	0.0	0.0	7,346.0	6.860	6.860	503,961.29
	VARIOUS	OATT	294.0	0.0	0.0	294.0	3.399	3.399	9,993.41
	TOTAL		**7,640.0**	**0.0**	**0.0**	**7,640.0**	**6.482**	**6.482**	**495,221.94**
ACTUAL Mar-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	3,269.49
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	17,351.0	0.0	0.0	17,351.0	5.584	5.584	968,875.29
	VARIOUS	OATT	637.0	0.0	0.0	637.0	3.766	3.766	23,986.69
	TOTAL		**17,988.0**	**0.0**	**0.0**	**17,988.0**	**5.538**	**5.538**	**996,131.47**
ACTUAL Apr-14									
	OLEANDER	SCH. - D	800.0	0.0	0.0	800.0	8.107	8.107	64,856.94
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	9,461.0	0.0	0.0	9,461.0	5.713	5.713	540,462.03
	VARIOUS	OATT	944.0	0.0	0.0	944.0	3.470	3.470	32,753.61
	TOTAL		**11,205.0**	**0.0**	**0.0**	**11,205.0**	**5.695**	**5.695**	**638,072.58**
ACTUAL May-14									
	OLEANDER	SCH. - D	2,240.0	0.0	0.0	2,240.0	7.364	7.364	164,956.64
	CALPINE	SCH. - D	1,150.0	0.0	0.0	1,150.0	8.083	8.083	92,959.96
	PASCO COGEN	SCH. - D	18,933.0	0.0	0.0	18,933.0	5.335	5.335	1,010,001.75
	VARIOUS	OATT	1,148.0	0.0	0.0	1,148.0	4.080	4.080	46,834.94
	TOTAL		**23,471.0**	**0.0**	**0.0**	**23,471.0**	**5.602**	**5.602**	**1,314,753.29**
ACTUAL Jun-14									
	OLEANDER	SCH. - D	1,280.0	0.0	0.0	1,280.0	6.113	6.113	78,243.45
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	21,843.0	0.0	0.0	21,843.0	5.669	5.669	1,238,372.76
	VARIOUS	OATT	532.0	0.0	0.0	532.0	3.878	3.878	20,632.41
	TOTAL		**23,655.0**	**0.0**	**0.0**	**23,655.0**	**5.653**	**5.653**	**1,337,248.62**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

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-14									
	OLEANDER	SCH. - D	1,880.0	0.0	0.0	1,880.0	5.812	5.812	109,270.00
	CALPINE	SCH. - D	1,280.0	0.0	0.0	1,280.0	6.977	6.977	89,310.00
	PASCO COGEN	SCH. - D	16,200.0	0.0	0.0	16,200.0	4.443	4.443	719,780.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**19,360.0**	**0.0**	**0.0**	**19,360.0**	**4.744**	**4.744**	**918,360.00**
ESTIMATED Aug-14									
	OLEANDER	SCH. - D	2,040.0	0.0	0.0	2,040.0	5.819	5.819	118,700.00
	CALPINE	SCH. - D	1,440.0	0.0	0.0	1,440.0	5.855	5.855	84,310.00
	PASCO COGEN	SCH. - D	14,990.0	0.0	0.0	14,990.0	3.983	3.983	597,020.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**18,470.0**	**0.0**	**0.0**	**18,470.0**	**4.332**	**4.332**	**800,030.00**
ESTIMATED Sep-14									
	OLEANDER	SCH. - D	5,940.0	0.0	0.0	5,940.0	6.132	6.132	364,250.00
	CALPINE	SCH. - D	2,580.0	0.0	0.0	2,580.0	6.380	6.380	164,610.00
	PASCO COGEN	SCH. - D	17,960.0	0.0	0.0	17,960.0	3.993	3.993	717,120.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**26,480.0**	**0.0**	**0.0**	**26,480.0**	**4.705**	**4.705**	**1,245,980.00**
ESTIMATED Oct-14									
	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	7,710.0	0.0	0.0	7,710.0	3.997	3.997	308,160.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**7,710.0**	**0.0**	**0.0**	**7,710.0**	**3.997**	**3.997**	**308,160.00**
ESTIMATED Nov-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	680.0	0.0	0.0	680.0	5.766	5.766	39,210.00
	PASCO COGEN	SCH. - D	7,120.0	0.0	0.0	7,120.0	4.008	4.008	285,360.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**7,800.0**	**0.0**	**0.0**	**7,800.0**	**4.161**	**4.161**	**324,570.00**
ESTIMATED Dec-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	800.0	0.0	0.0	800.0	7.478	7.478	59,820.00
	PASCO COGEN	SCH. - D	4,320.0	0.0	0.0	4,320.0	4.116	4.116	177,820.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**5,120.0**	**0.0**	**0.0**	**5,120.0**	**4.641**	**4.641**	**237,640.00**
TOTAL									
Jan-14	OLEANDER	SCH. - D	14,980.0	0.0	0.0	14,980.0	6.382	6.382	956,024.86
THRU	CALPINE	SCH. - D	8,515.0	0.0	0.0	8,515.0	6.752	6.752	574,917.18
Dec-14	PASCO COGEN	SCH. - D	156,389.0	0.0	0.0	156,389.0	5.038	5.038	7,878,434.02
	VARIOUS	OATT	4,472.0	0.0	0.0	4,472.0	3.632	3.632	162,433.14
	TOTAL		**184,356.0**	**0.0**	**0.0**	**184,356.0**	**5.192**	**5.192**	**9,571,809.20**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	VARIOUS	CO-GEN.							
Jan-14		FIRM	5,131.0	0.0	0.0	5,131.0	2.912	2.912	149,436.40
		AS AVAIL.	15,099.0	0.0	0.0	15,099.0	3.190	3.190	481,668.94
	TOTAL		**20,230.0**	**0.0**	**0.0**	**20,230.0**	**3.120**	**3.120**	**631,105.34**
ACTUAL	VARIOUS	CO-GEN.							
Feb-14		FIRM	5,152.0	0.0	0.0	5,152.0	3.035	3.035	156,351.45
		AS AVAIL.	12,735.0	0.0	0.0	12,735.0	3.521	3.521	448,387.23
	TOTAL		**17,887.0**	**0.0**	**0.0**	**17,887.0**	**3.381**	**3.381**	**604,738.68**
ACTUAL	VARIOUS	CO-GEN.							
Mar-14		FIRM	5,555.0	0.0	0.0	5,555.0	3.448	3.448	191,527.73
		AS AVAIL.	18,213.0	0.0	0.0	18,213.0	3.584	3.584	652,786.96
	TOTAL		**23,768.0**	**0.0**	**0.0**	**23,768.0**	**3.552**	**3.552**	**844,314.69**
ACTUAL	VARIOUS	CO-GEN.							
Apr-14		FIRM	7,590.0	0.0	0.0	7,590.0	3.188	3.188	241,944.36
		AS AVAIL.	19,999.0	0.0	0.0	19,999.0	3.266	3.266	653,078.34
	TOTAL		**27,589.0**	**0.0**	**0.0**	**27,589.0**	**3.244**	**3.244**	**895,022.70**
ACTUAL	VARIOUS	CO-GEN.							
May-14		FIRM	7,337.0	0.0	0.0	7,337.0	3.237	3.237	237,465.34
		AS AVAIL.	20,618.0	0.0	0.0	20,618.0	3.226	3.226	665,132.66
	TOTAL		**27,955.0**	**0.0**	**0.0**	**27,955.0**	**3.229**	**3.229**	**902,598.00**
ACTUAL	VARIOUS	CO-GEN.							
Jun-14		FIRM	7,590.0	0.0	0.0	7,590.0	3.233	3.233	245,409.08
		AS AVAIL.	15,317.0	0.0	0.0	15,317.0	3.214	3.214	492,262.64
	TOTAL		**22,907.0**	**0.0**	**0.0**	**22,907.0**	**3.220**	**3.220**	**737,671.72**
ESTIMATED	VARIOUS	CO-GEN.							
Jul-14		FIRM	6,420.0	0.0	0.0	6,420.0	3.411	3.411	219,010.00
		AS AVAIL.	12,900.0	0.0	0.0	12,900.0	4.456	4.456	574,820.00
	TOTAL		**19,320.0**	**0.0**	**0.0**	**19,320.0**	**4.109**	**4.109**	**793,830.00**
ESTIMATED	VARIOUS	CO-GEN.							
Aug-14		FIRM	6,420.0	0.0	0.0	6,420.0	3.400	3.400	218,310.00
		AS AVAIL.	12,810.0	0.0	0.0	12,810.0	3.612	3.612	462,750.00
	TOTAL		**19,230.0**	**0.0**	**0.0**	**19,230.0**	**3.542**	**3.542**	**681,060.00**
ESTIMATED	VARIOUS	CO-GEN.							
Sep-14		FIRM	6,210.0	0.0	0.0	6,210.0	2.612	2.612	162,210.00
		AS AVAIL.	12,790.0	0.0	0.0	12,790.0	2.871	2.871	367,160.00
	TOTAL		**19,000.0**	**0.0**	**0.0**	**19,000.0**	**2.786**	**2.786**	**529,370.00**
ESTIMATED	VARIOUS	CO-GEN.							
Oct-14		FIRM	6,420.0	0.0	0.0	6,420.0	2.987	2.987	191,740.00
		AS AVAIL.	12,980.0	0.0	0.0	12,980.0	3.253	3.253	422,220.00
	TOTAL		**19,400.0**	**0.0**	**0.0**	**19,400.0**	**3.165**	**3.165**	**613,960.00**
ESTIMATED	VARIOUS	CO-GEN.							
Nov-14		FIRM	6,210.0	0.0	0.0	6,210.0	3.197	3.197	198,530.00
		AS AVAIL.	12,720.0	0.0	0.0	12,720.0	3.439	3.439	437,490.00
	TOTAL		**18,930.0**	**0.0**	**0.0**	**18,930.0**	**3.360**	**3.360**	**636,020.00**
ESTIMATED	VARIOUS	CO-GEN.							
Dec-14		FIRM	5,700.0	0.0	0.0	5,700.0	1.998	1.998	113,910.00
		AS AVAIL.	12,830.0	0.0	0.0	12,830.0	2.330	2.330	298,930.00
	TOTAL		**18,530.0**	**0.0**	**0.0**	**18,530.0**	**2.228**	**2.228**	**412,840.00**
TOTAL	VARIOUS	CO-GEN.							
Jan-14		FIRM	75,735.0	0.0	0.0	75,735.0	3.071	3.071	2,325,844.36
THRU		AS AVAIL.	179,011.0	0.0	0.0	179,011.0	3.328	3.328	5,956,686.77
Dec-14	TOTAL		**254,746.0**	**0.0**	**0.0**	**254,746.0**	**3.251**	**3.251**	**8,282,531.13**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

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-14	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	14,229.0	0.0	14,229.0	4.441	631,870.00	5.773	821,417.48	189,547.48
	TOTAL		**14,229.0**	**0.0**	**14,229.0**	**4.441**	**631,870.00**	**5.773**	**821,417.48**	**189,547.48**
ACTUAL	VARIOUS	SCH. - REB	130.0	0.0	130.0	4.125	5,363.00	5.198	6,756.99	1,393.99
Feb-14	VARIOUS	SCH. - C	150.0	0.0	150.0	5.668	8,502.00	7.016	10,524.00	2,022.00
	VARIOUS	SCH. - J	22,062.0	0.0	22,062.0	4.833	1,066,274.00	6.302	1,390,353.39	324,079.39
	TOTAL		**22,342.0**	**0.0**	**22,342.0**	**4.835**	**1,080,139.00**	**6.300**	**1,407,634.38**	**327,495.38**
ACTUAL	VARIOUS	SCH. - REB	1,440.0	0.0	1,440.0	4.422	63,680.00	4.988	71,822.40	8,142.40
Mar-14	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	83,985.0	0.0	83,985.0	4.483	3,764,943.00	5.979	5,021,639.36	1,256,696.36
	TOTAL		**85,425.0**	**0.0**	**85,425.0**	**4.482**	**3,828,623.00**	**5.962**	**5,093,461.76**	**1,264,838.76**
ACTUAL	VARIOUS	SCH. - REB	150.0	0.0	150.0	7.000	10,500.00	7.939	11,908.50	1,408.50
Apr-14	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	35,299.0	0.0	35,299.0	4.602	1,624,613.00	5.611	1,980,536.72	355,923.72
	TOTAL		**35,449.0**	**0.0**	**35,449.0**	**4.613**	**1,635,113.00**	**5.621**	**1,992,445.22**	**357,332.22**
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
May-14	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	46,967.0	0.0	46,967.0	4.897	2,300,097.50	5.685	2,670,103.89	370,006.39
	TOTAL		**46,967.0**	**0.0**	**46,967.0**	**4.897**	**2,300,097.50**	**5.685**	**2,670,103.89**	**370,006.39**
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Jun-14	VARIOUS	SCH. - C	112.0	0.0	112.0	5.309	5,945.93	6.013	6,735.11	789.18
	VARIOUS	SCH. - J	41,285.0	0.0	41,285.0	4.964	2,049,538.50	5.767	2,381,091.11	331,552.61
	TOTAL		**41,397.0**	**0.0**	**41,397.0**	**4.965**	**2,055,484.43**	**5.768**	**2,387,826.22**	**332,341.79**
ESTIMATED	VARIOUS	ECONOMY	53,650.0	0.0	53,650.0	3.951	2,119,750.00	5.946	3,190,270.00	1,070,520.00
Jul-14	**TOTAL**		**53,650.0**	**0.0**	**53,650.0**	**3.951**	**2,119,750.00**	**5.946**	**3,190,270.00**	**1,070,520.00**
ESTIMATED	VARIOUS	ECONOMY	51,930.0	0.0	51,930.0	3.691	1,916,600.00	5.608	2,911,980.00	995,380.00
Aug-14	**TOTAL**		**51,930.0**	**0.0**	**51,930.0**	**3.691**	**1,916,600.00**	**5.608**	**2,911,980.00**	**995,380.00**
ESTIMATED	VARIOUS	ECONOMY	50,920.0	0.0	50,920.0	3.673	1,870,170.00	5.693	2,898,630.00	1,028,460.00
Sep-14	**TOTAL**		**50,920.0**	**0.0**	**50,920.0**	**3.673**	**1,870,170.00**	**5.693**	**2,898,630.00**	**1,028,460.00**
ESTIMATED	VARIOUS	ECONOMY	41,820.0	0.0	41,820.0	3.066	1,282,210.00	5.261	2,200,130.00	917,920.00
Oct-14	**TOTAL**		**41,820.0**	**0.0**	**41,820.0**	**3.066**	**1,282,210.00**	**5.261**	**2,200,130.00**	**917,920.00**
ESTIMATED	VARIOUS	ECONOMY	38,670.0	0.0	38,670.0	3.128	1,209,630.00	5.281	2,042,100.00	832,470.00
Nov-14	**TOTAL**		**38,670.0**	**0.0**	**38,670.0**	**3.128**	**1,209,630.00**	**5.281**	**2,042,100.00**	**832,470.00**
ESTIMATED	VARIOUS	ECONOMY	35,000.0	0.0	35,000.0	2.925	1,023,610.00	4.912	1,719,080.00	695,470.00
Dec-14	**TOTAL**		**35,000.0**	**0.0**	**35,000.0**	**2.925**	**1,023,610.00**	**4.912**	**1,719,080.00**	**695,470.00**
TOTAL	VARIOUS	SCH. - REB	1,720.0	0.0	1,720.0	4.625	79,543.00	5.261	90,487.89	10,944.89
Jan-14	VARIOUS	SCH. - C	262.0	0.0	262.0	5.514	14,447.93	6.587	17,259.11	2,811.18
THRU	VARIOUS	SCH. - J	243,827.0	0.0	243,827.0	4.691	11,437,336.00	5.851	14,265,141.95	2,827,805.95
Dec-14	VARIOUS	ECONOMY	271,990.0	0.0	271,990.0	3.464	9,421,970.00	5.501	14,962,190.00	5,540,220.00
	TOTAL		**517,799.0**	**0.0**	**517,799.0**	**4.047**	**20,953,296.93**	**5.665**	**29,335,078.95**	**8,381,782.02**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2014 THROUGH DECEMBER 2014

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2014 THROUGH DECEMBER 2014

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2013 THROUGH DECEMBER 2013	($8,074)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2014 THROUGH DECEMBER 2014	(25,452)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2015 THROUGH DECEMBER 2015	($33,526)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2014 THROUGH DECEMBER 2014

	Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	Total
1 UNIT POWER CAPACITY CHARGES	1,514,522	1,532,630	1,482,474	1,438,377	1,561,019	1,607,610	1,501,890	1,501,890	1,501,890	1,501,890	1,501,890	1,501,890	18,147,972
2 CAPACITY PAYMENTS TO COGENERATORS	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,330	1,186,330	1,186,350	1,186,330	1,186,350	1,186,330	14,236,060
3 (UNIT POWER CAPACITY REVENUES)	(319,291)	(354,157)	(66,194)	(92,254)	(48,051)	(80,762)	(79,411)	(79,411)	(79,411)	(79,411)	(79,411)	(79,408)	(1,437,172)
4 TOTAL CAPACITY DOLLARS	2,381,571	2,364,813	2,602,620	2,532,463	2,699,308	2,713,188	2,608,809	2,608,809	2,608,829	2,608,809	2,608,829	2,608,812	30,946,860
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	2,381,571	2,364,813	2,602,620	2,532,463	2,699,308	2,713,188	2,608,809	2,608,809	2,608,829	2,608,809	2,608,829	2,608,812	30,946,860
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,418,172	2,403,121	2,189,324	2,197,626	2,583,032	2,990,707	3,104,802	3,039,102	3,119,945	2,817,246	2,378,745	2,271,599	31,513,421
8 PRIOR PERIOD TRUE-UP PROVISION	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,314)	(49,311)	(591,765)
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	2,368,858	2,353,807	2,140,010	2,148,312	2,533,718	2,941,393	3,055,488	2,989,788	3,070,631	2,767,932	2,329,431	2,222,288	30,921,656
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	(12,713)	(11,006)	(462,610)	(384,151)	(165,590)	228,205	446,679	380,979	461,802	159,123	(279,398)	(386,524)	(25,204)
11 INTEREST PROVISION FOR MONTH	(35)	(27)	(37)	(66)	(67)	(50)	(69)	(44)	8	56	63	20	(248)
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	(599,839)	(563,273)	(524,992)	(938,325)	(1,273,228)	(1,389,571)	(1,112,102)	(616,178)	(185,929)	325,195	533,688	303,667	(599,839)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	49,314	49,314	49,314	49,314	49,314	49,314	49,314	49,314	49,314	49,314	49,314	49,311	591,765
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	**(563,273)**	**(524,992)**	**(938,325)**	**(1,273,228)**	**(1,389,571)**	**(1,112,102)**	**(616,178)**	**(185,929)**	**325,195**	**533,688**	**303,667**	**(33,526)**	**(33,526)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2014 THROUGH DECEMBER 2014

	Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	Total
1 BEGINNING TRUE-UP AMOUNT	(599,839)	(563,273)	(524,992)	(938,325)	(1,273,228)	(1,389,571)	(1,112,102)	(616,178)	(185,929)	325,195	533,688	303,667	(599,839)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(563,238)	(524,965)	(938,288)	(1,273,162)	(1,389,504)	(1,112,052)	(616,109)	(185,885)	325,187	533,632	303,604	(33,546)	(33,278)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(1,163,077)	(1,088,238)	(1,463,280)	(2,211,487)	(2,662,732)	(2,501,623)	(1,728,211)	(802,063)	139,258	858,827	837,292	270,121	(633,117)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(581,539)	(544,119)	(731,640)	(1,105,744)	(1,331,366)	(1,250,812)	(864,106)	(401,032)	69,629	429,414	418,646	135,061	(316,559)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.080	0.070	0.060	0.070	0.080	0.040	0.060	0.130	0.130	0.130	0.180	0.180	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.070	0.060	0.070	0.080	0.040	0.060	0.130	0.130	0.130	0.180	0.180	0.180	NA
7 TOTAL (LINE 5 + LINE 6)	0.150	0.130	0.130	0.150	0.120	0.100	0.190	0.260	0.260	0.310	0.360	0.360	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.075	0.065	0.065	0.075	0.060	0.050	0.095	0.130	0.130	0.155	0.180	0.180	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.006	0.005	0.005	0.006	0.005	0.004	0.008	0.011	0.011	0.013	0.015	0.015	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(35)	(27)	(37)	(66)	(67)	(50)	(69)	(44)	8	56	63	20	(248)

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E12

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	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
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	160.0	160.0	160.0	160.0	160.0	160.0	157.0	157.0	157.0	157.0	157.0	157.0
SEMINOLE ELECTRIC	7.1	7.6	3.7	3.0	4.8	4.7	1.5	1.7	1.4	1.4	1.2	1.2

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 ($)
													-
ORANGE COGEN LP	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,330	1,186,330	1,186,350	1,186,330	1,186,350	1,186,330	14,236,060
TOTAL COGENERATION	**$ 1,186,340**	**$ 1,186,340**	**$ 1,186,340**	**$ 1,186,340**	**$ 1,186,340**	**$ 1,186,340**	**$ 1,186,330**	**$ 1,186,330**	**$ 1,186,350**	**$ 1,186,330**	**$ 1,186,350**	**$ 1,186,330**	**$ 14,236,060**

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E12
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													
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													
VARIOUS - MA													
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)	$ 1,195,231	$ 1,178,473	$ 1,416,280	$ 1,346,123	$ 1,512,968	$ 1,526,848	$ 1,422,479	$ 1,422,479	$ 1,422,479	$ 1,422,479	$ 1,422,479	$ 1,422,482	$ 16,710,800
TOTAL CAPACITY	$ 2,381,571	$ 2,364,813	$ 2,602,620	$ 2,532,463	$ 2,699,308	$ 2,713,188	$ 2,608,809	$ 2,608,809	$ 2,608,829	$ 2,608,809	$ 2,608,829	$ 2,608,812	$ 30,946,860

Docket No. 140001-EI
Exhibit No. ____ (PAR-2)
Document No. 2, Page 5 of 5

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

POLK UNIT 1 IGNITION OIL CONVERSION

ACTUAL/ESTIMATED

JANUARY 2014 - DECEMBER 2014

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2014 THROUGH DECEMBER 2014

		ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ESTIMATED JULY	ESTIMATED AUGUST	ESTIMATED SEPTEMBER	ESTIMATED OCTOBER	ESTIMATED NOVEMBER	ESTIMATED DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 16,139,139	$ 16,143,307	$ 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	$ 16,139,139
2	ADD INVESTMENT	4,169	643	-	-	-	-	-	-	-	-	-	-	4,812
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	16,143,307	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	16,141,223	16,143,629	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	269,020	269,060	269,066	269,066	269,066	269,066	269,225	269,225	269,225	269,225	269,225	269,225	3,229,695
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	1,606,803	1,875,823	2,144,884	2,413,950	2,683,016	2,952,082	3,221,147	3,490,372	3,759,598	4,028,823	4,298,048	4,567,273	1,606,803
12	ENDING BALANCE DEPRECIATION	1,875,823	2,144,884	2,413,950	2,683,016	2,952,082	3,221,147	3,490,372	3,759,598	4,028,823	4,298,048	4,567,273	4,836,498	4,836,498
13														
14														
15	ENDING NET INVESTMENT	14,267,484	13,999,067	13,730,001	13,460,935	13,191,869	12,922,803	12,653,578	12,384,353	12,115,128	11,845,903	11,576,678	11,307,453	11,307,453
16														
17														
18	AVERAGE INVESTMENT	$ 14,399,910	$ 14,133,275	$ 13,864,534	$ 13,595,468	$ 13,326,402	$ 13,057,336	$ 12,788,191	$ 12,518,966	$ 12,249,741	$ 11,980,516	$ 11,711,291	$ 11,442,065	
19	ALLOWED EQUITY RETURN	.36884%	.36884%	.36884%	.36884%	.36884%	.36884%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	
20	EQUITY COMPONENT AFTER-TAX	53,113	52,129	51,138	50,146	49,153	48,161	46,255	45,281	44,307	43,334	42,360	41,386	566,763
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	86,691	85,085	83,467	81,848	80,228	78,608	75,497	73,908	72,318	70,730	69,140	67,550	925,070
23														
24	ALLOWED DEBT RETURN	.18418%	.18418%	.18418%	.18418%	.18418%	.18418%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	
25	DEBT COMPONENT	$26,521	$26,030	$25,535	$25,039	$24,544	$24,048	$21,679	$21,223	$20,766	$20,310	$19,854	$19,397	$274,946
26														
27	TOTAL RETURN REQUIREMENTS	$113,212	$111,115	$109,002	$106,887	$104,772	$102,656	$97,176	$95,131	$93,084	$91,040	$88,994	$86,947	$1,200,016
28	PRIOR MONTH TRUE-UP	205	5											
29	TOTAL DEPRECIATION & RETURN	$382,437	$380,180	$378,068	$375,953	$373,838	$371,722	$366,401	$364,356	$362,309	$360,265	$358,219	$356,172	$4,429,920
30														
31	ESTIMATED FUEL SAVINGS	$4,813,066	$643,679	$4,657,919	$6,122	$1,446,381	$3,393,860	$1,426,579	$386,541	$459,550	$352,350	$1,121,248	$625,116	$19,332,410
32	TOTAL DEPRECIATION & RETURN	$382,437	$380,180	$378,068	$375,953	$373,838	$371,722	$366,401	$364,356	$362,309	$360,265	$358,219	$356,172	$4,429,920
33	NET BENEFIT (COST) TO RATEPAYER	$4,430,628	$263,499	$4,279,851	($369,831)	$1,072,543	$3,022,138	$1,060,178	$22,185	$97,241	($7,915)	$763,029	$268,944	$14,902,490

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD AND ADJUSTED BEGINNING IN JULY 2014 TO ACCOUNT FOR ADDITIONAL INVESTMENT DURING THE FIRST 12 MONTHS OF SERVICE.

35 FOR JANUARY THROUGH JUNE, RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.4343% (EQUITY 7.2242% , DEBT 2.2101%). THESE RATES ARE EFFECTIVE JANUARY 1, 2014, PER THE RATE CASE SETTLEMENT (SEPTEMBER 2013).

36 FOR JULY THROUGH DECEMBER, RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.1187% (EQUITY 7.0844% , DEBT 2.0343%). THE RATES ARE FROM THE MAY 2014 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 to June 2014 Actual/Estimated Period

	(1) Jurisdictional Rate Base Actual May 2013 Capital Structure ($000)	(2) Adjusted per Base Rates Settlement * Jurisdictional Rate Base Actual May 2013 Capital Structure ($000)	(3) Ratio %	(4) Cost Rate %	(5) Weighted Cost Rate %
Long Term Debt	$ 1,425,239	$ 1,413,339	36.69%	5.78%	2.12%
Short Term Debt	0	0	0.00%	0.66%	0.00%
Preferred Stock	0	0	0.00%	0.00%	0.00%
Customer Deposits	106,560	106,560	2.77%	2.91%	0.08%
Common Equity	1,647,409	1,659,309	43.08%	10.25%	4.42%
Deferred ITC - Weighted Cost	8,381	8,381	0.22%	8.71%	0.02%
Accumulated Deferred Income Taxes & Zero Cost ITCs	664,214	664,214	17.24%	0.00%	0.00%
Total		$ 3,851,803	100.00%		6.64%

ITC split between Debt and Equity:

Long Term Debt	$ 1,413,339	Long Term Debt	46.00%
Short Term Debt	0	Short Term Debt	0.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,659,309	Equity - Common	54.00%
Total	$ 3,072,648	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0192% * 46.00%	0.0088%
Equity = .0192% * 54.00%	0.0104%
Weighted Cost	0.0192%

Total Equity Cost Rate:		**Monthly Rate:**
Preferred Stock	0.0000%	
Common Equity	4.4157%	
Deferred ITC - Weighted Cost	0.0104%	
	4.4261%	0.36884%
Times Tax Multiplier	1.632200	
Total Equity Component	7.2242%	

Total Debt Cost Rate:		**Monthly Rate:**
Long Term Debt	2.1207%	
Short Term Debt	0.0000%	
Customer Deposits	0.0806%	
Deferred ITC - Weighted Cost	0.0088%	
Total Debt Component	2.2101%	0.18418%
Total Weighted Cost:	9.4343%	

Notes:

* Adjusted to 54% equity, per Base Rates Settlement Agreement Dated September 6, 2013.

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.

Column (2) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.

Column (3) - Column (2) / Total Column (2)

Column (4) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.

Column (5) - Column (3) x Column (4)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
for Cost Recovery Clauses

July to December 2014 Actual/Estimated Period

	(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%	1.96%
Short Term Debt	25,222	0.62%	0.61%	0.00%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	107,785	2.67%	2.25%	0.06%
Common Equity	1,707,776	42.26%	10.25%	4.33%
Deferred ITC - Weighted Cost	8,027	0.20%	8.05%	0.02%
Accumulated Deferred Income Taxes & Zero Cost ITCs	763,143	18.88%	0.00%	0.00%
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:		**Monthly Rate:**
Preferred Stock	0.0000%	
Common Equity	4.3317%	
Deferred ITC - Weighted Cost	0.0087%	
	4.3404%	0.36170%
Times Tax Multiplier	1.632200	
Total Equity Component	7.0844%	

Total Debt Cost Rate:		**Monthly 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%	0.16953%
Total Weighted Cost:	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)

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2015 - DECEMBER 2015

AND

SCHEDULE E12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 45
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-3

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	54.04%	8,713,087	1,841	1.07665	1.05525	9,194,470	1,982	46.92%	56.36%	55.64%
GS, TS	60.65%	1,047,683	197	1.07665	1.05523	1,105,551	212	5.64%	6.03%	6.00%
GSD Optional	3.58%	357,148	53	1.07236	1.05157	375,566	57	1.92%	1.62%	1.64%
GSD, SBF	73.67%	7,345,405	1,085	1.07236	1.05157	7,724,211	1,164	39.41%	33.11%	33.59%
IS,SBI	113.14%	949,661	96	1.02745	1.01946	968,139	98	4.94%	2.79%	2.96%
LS1	808.37%	217,416	3	1.07665	1.05525	229,428	3	1.17%	0.09%	0.17%
TOTAL		18,630,400	3,275			19,597,365	3,516	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2014 projected calendar data.
(2) Projected MWH sales for the period January 2015 thru December 2015.
(3) Based on 12 months average CP at meter.
(4) Based on 2014 projected demand losses.
(5) Based on 2014 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

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	18,211,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
3	(UNIT POWER CAPACITY REVENUES)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,757)	(1,437,172)
4	TOTAL CAPACITY DOLLARS	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,633	$31,915,558
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,633	$31,915,558
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2014 - DEC. 2014													33,526
8	TOTAL													$31,949,084
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,972,087

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
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	46.92%	56.36%	1,153,601	16,633,771	17,787,372	8,713,087	8,713,087				0.00204
GS, CS	5.64%	6.03%	138,668	1,779,660	1,918,328	1,047,683	1,047,683				0.00183
GSD, SBF											
Secondary						6,038,291	6,038,291			0.63	
Primary						1,299,355	1,286,361			0.62	
Transmission						7,759	7,604			0.62	
GSD, SBF - Standard	39.41%	33.11%	968,955	9,771,898	10,740,853	7,345,405	7,332,256	58.57%	17,148,546		
GSD - Optional	1.92%	1.62%	47,206	478,118	525,324						
Secondary						342,215	342,215				0.00147
Primary						14,933	14,784				0.00146
IS, SBI											
Primary						254,684	252,137			0.41	
Transmission						694,977	681,077			0.40	
Total IS, SBI	4.94%	2.79%	121,457	823,425	944,882	949,661	933,214	55.82%	2,290,004		
LS1	1.17%	0.09%	28,766	26,562	55,328	217,416	217,416				0.00025
TOTAL	100.00%	100.00%	2,458,653	29,513,434	31,972,087	18,630,400	18,600,655				0.00172

(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 2015 through December 2015.
(7) Projected kWh sales at secondary for the period January 2015 through December 2015.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2015 through December 2015.
(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 2015 THROUGH DECEMBER 2015

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
ORANGE COGEN LP	4/17/1989	12/31/2015	QF
CALPINE	11/1/2011	12/31/2016	LT
PASCO COGEN	1/1/2009	12/31/2018	LT
OLEANDER	1/1/2013	12/31/2015	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
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	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	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
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 ($)
ORANGE COGEN LP	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
TOTAL COGENERATION	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
CALPINE - D	[redacted]												
PASCO COGEN - D													
OLEANDER - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,863	16,774,268
TOTAL CAPACITY	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,633**	**$31,915,558**

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EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2015 - DECEMBER 2015

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2015 - DEC. 2015)
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	(")
26-27	Schedule E7 Purchased Power	(")
28	Schedule E8 Energy Payment to Qualifying Facilities	(")
29	Schedule E9 Economy Energy Purchases	(")
30	Schedule E10 Residential Bill Comparison	(")
31	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2012-2015)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	698,913,664	18,831,670	3.71137
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	3,310,090	18,831,670 (1)	0.01758
4b.	Polk 1 Conversion Depreciation & ROI	4,114,495	18,831,670 (1)	0.02185
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**706,338,249**	**18,831,670**	**3.75080**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	6,810,170	154,460	4.40902
7.	Energy Cost of Economy Purchases (E9)	16,990,090	509,460	3.33492
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	8,238,900	256,140	3.21656
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**32,039,160**	**920,060**	**3.48229**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,751,730	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	321,850	10,330	3.11568
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,644,499	178,480	3.16254
14.	Gains on Sales	581,933	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**6,548,282**	**188,810**	**3.46819**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		3,197	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**731,829,127**	**19,559,723**	**3.74151**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,230,208 (1)	32,880	0.00660
22.	T & D Losses	33,540,507 (1)	896,443	0.18003
23.	System MWH Sales	731,829,127	18,630,400	3.92815
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	731,829,127	18,630,400	3.92815
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	731,829,127	18,630,400	3.92815
28.	True-up (2)	(13,386,207)	18,630,400	(0.07185)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	718,442,920	18,630,400	3.85629
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	718,960,199	18,630,400	3.85907
32.	GPIF Adjusted for Taxes (2)	1,689,728	18,630,400	0.00907
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	720,649,927	18,630,400	3.86814
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.868**

(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 2015 THROUGH DECEMBER 2015

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2014 - December 2014 (6 months actual, 6 months estimated)	($10,166,001)
2.	FINAL TRUE-UP (January 2013 - December 2013) (Per True-Up filed March 3, 2014)	23,552,208
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2015 through December 2015 (Schedule E1, line 28)	$13,386,207
4.	JURISDICTIONAL MWH SALES (Projected January 2015 through December 2015)	18,630,400
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0719)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2015 through December 2015)	$1,689,728	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2014 through December 2014)	$13,386,207	
2.	TOTAL SALES (January 2015 through December 2015)	18,630,400	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0091**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0719)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1-D

		NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK		30.01	$32.37
OFF PEAK		69.99	$29.68
		100.00	1.0906

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$731,829,127		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,630,400		
2a	Effective MWH Sales (Jurisd)		18,600,655		
3	Cost Per KWH Sold	(line 1 / line 2)	3.9281		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($13,386,207)		
7	TOTAL	(line 1 x line 4)+line 6	$718,442,920		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.8652		
10	GPIF Factor	(Sch E1-C line 3a)	0.0091		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.8743	4.1135	3.7717
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.874	4.114	3.772

13	Hours: ON PEAK	25.01%
14	OFF PEAK	74.99%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,358,692	16,358,692
Distribution Primary	1,568,972	1,553,282
Transmission	702,736	688,681
Total	18,630,400	18,600,655

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.874	4.114	3.772
Distribution Primary	3.835	4.073	3.734
Transmission	3.797	4.032	3.697
RS 1st Tier	3.559		
RS 2nd Tier	4.559		
Lighting	3.830		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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)		3.559	4.559
Distribution Secondary	3.874		
Distribution Primary	3.835		
Transmission	3.797		
Lighting Service (1)	3.830		
TIME-OF-USE			
Distribution Secondary - On-Peak	4.114		
Distribution Secondary - Off-Peak	3.772		
Distribution Primary - On-Peak	4.073		
Distribution Primary - Off-Peak	3.734		
Transmission - On-Peak	4.032		
Transmission - Off-Peak	3.697		

(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 2015 THROUGH DECEMBER 2015

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
							ESTIMATED							TOTAL
		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	PERIOD
1.	Fuel Cost of System Net Generation	54,277,329	48,284,354	51,702,083	54,615,201	62,932,967	66,631,475	68,738,093	69,019,911	64,016,194	57,959,486	48,824,166	51,912,405	698,913,664
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	521,643	727,839	775,317	789,700	663,497	491,251	526,973	152,799	75,512	235,080	1,133,837	454,834	6,548,282
4.	Fuel Cost of Purchased Power	8,860	132,500	263,610	426,840	697,470	564,370	631,130	1,106,720	1,256,320	1,196,990	309,560	215,800	6,810,170
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	664,130	585,300	568,030	731,910	758,720	569,650	667,160	759,940	822,540	756,620	639,940	714,960	8,238,900
7.	Energy Cost of Economy Purchases	1,017,820	1,048,640	1,112,500	1,050,600	1,584,350	1,678,360	1,695,010	1,725,610	2,195,180	1,831,370	978,410	1,072,240	16,990,090
8.	Big Bend Units 1-4 Igniters Conversion Project	0	0	33,035	225,368	318,929	394,762	392,682	390,603	388,523	386,443	384,363	395,382	3,310,090
9.	Polk 1 Conversion Depreciation & ROI	354,126	352,080	350,036	347,990	345,943	343,897	341,851	339,806	337,761	335,714	333,668	331,623	4,114,495
10.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**55,800,622**	**49,675,035**	**53,253,977**	**56,608,209**	**65,974,882**	**69,691,263**	**71,938,953**	**73,189,791**	**68,941,006**	**62,231,543**	**50,336,270**	**54,187,576**	**731,829,127**
11.	Jurisdictional MWH Sold	1,460,709	1,327,839	1,307,319	1,375,861	1,504,829	1,754,329	1,814,047	1,805,882	1,862,609	1,649,232	1,398,249	1,369,495	18,630,400
12.	Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13.	Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	55,800,622	49,675,035	53,253,977	56,608,209	65,974,882	69,691,263	71,938,953	73,189,791	68,941,006	62,231,543	50,336,270	54,187,576	731,829,127
14.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15.	**JURISD. TOTAL FUEL & NET PWR. TRANS.** Adjusted for Line Losses (Line 13 * Line 14)	**55,800,622**	**49,675,035**	**53,253,977**	**56,608,209**	**65,974,882**	**69,691,263**	**71,938,953**	**73,189,791**	**68,941,006**	**62,231,543**	**50,336,270**	**54,187,576**	**731,829,127**
16.	Cost Per kWh Sold (Cents/kWh)	3.8201	3.7410	4.0735	4.1144	4.3842	3.9725	3.9657	4.0529	3.7013	3.7734	3.6000	3.9568	3.9281
17.	True-up (Cents/kWh) [2]	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)
18.	Total (Cents/kWh) (Line 16+17)	3.7482	3.6691	4.0016	4.0425	4.3123	3.9006	3.8938	3.9810	3.6294	3.7015	3.5281	3.8849	3.8562
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)	3.7509	3.6717	4.0045	4.0454	4.3154	3.9034	3.8966	3.9839	3.6320	3.7042	3.5306	3.8877	3.8590
21.	GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
22.	**TOTAL RECOVERY FACTOR (LINE 20+21)**	**3.7600**	**3.6808**	**4.0136**	**4.0545**	**4.3245**	**3.9125**	**3.9057**	**3.9930**	**3.6411**	**3.7133**	**3.5397**	**3.8968**	**3.8681**
23.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.760**	**3.681**	**4.014**	**4.055**	**4.325**	**3.913**	**3.906**	**3.993**	**3.641**	**3.713**	**3.540**	**3.897**	**3.868**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
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TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

SCHEDULE E3

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	12,871	12,871	10,488	5,721	12,871	12,871
3. COAL	38,661,568	31,408,363	31,000,156	31,499,413	33,195,265	36,519,675
4. NATURAL GAS	15,602,890	16,863,120	20,691,439	23,110,067	29,724,831	30,098,929
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**54,277,329**	**48,284,354**	**51,702,083**	**54,615,201**	**62,932,967**	**66,631,475**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	50	50	50	10	50	50
10. COAL	1,112,580	916,860	905,060	921,320	984,550	1,097,650
11. NATURAL GAS	309,360	364,930	472,990	529,960	709,930	717,580
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,421,990**	**1,281,840**	**1,378,100**	**1,451,290**	**1,694,530**	**1,815,280**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	1,940	2,830	1,920	1,520	1,510	620
17. COAL (TON)	486,010	398,200	398,730	409,260	432,630	480,700
18. NATURAL GAS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,266,450	5,372,220
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	550	530	480	200	600	630
23. COAL	11,316,900	9,301,200	9,212,920	9,404,330	10,060,890	11,193,900
24. NATURAL GAS	2,292,410	2,672,450	3,501,010	3,987,940	5,398,660	5,508,930
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,609,860**	**11,974,180**	**12,714,410**	**13,392,470**	**15,460,150**	**16,703,460**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00
30. COAL	78.24	71.53	65.68	63.48	58.10	60.47
31. NATURAL GAS	21.76	28.47	34.32	36.52	41.90	39.53
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	6.63	4.55	5.46	3.76	8.52	20.76
37. COAL ($/TON)	79.55	78.88	77.75	76.97	76.73	75.97
38. NATURAL GAS ($/MCF)	6.99	6.48	6.06	5.94	5.64	5.60
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	23.40	24.28	21.85	28.61	21.45	20.43
43. COAL	3.42	3.38	3.36	3.35	3.30	3.26
44. NATURAL GAS	6.81	6.31	5.91	5.79	5.51	5.46
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)	**3.99**	**4.03**	**4.07**	**4.08**	**4.07**	**3.99**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,000	10,600	9,600	20,000	12,000	12,600
50. COAL	10,172	10,145	10,179	10,207	10,219	10,198
51. NATURAL GAS	7,410	7,323	7,402	7,525	7,604	7,677
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,571**	**9,341**	**9,226**	**9,228**	**9,124**	**9,202**
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	25.74	25.74	20.98	57.21	25.74	25.74
57. COAL	3.47	3.43	3.43	3.42	3.37	3.33
58. NATURAL GAS	5.04	4.62	4.37	4.36	4.19	4.19
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)	**3.82**	**3.77**	**3.75**	**3.76**	**3.71**	**3.67**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

SCHEDULE E3

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	10,488	10,488	12,871	10,488	10,488	12,871	135,387
3.	COAL	37,466,150	35,217,466	28,714,269	27,220,227	31,731,776	34,370,993	397,005,321
4.	NATURAL GAS	31,261,455	33,791,957	35,289,054	30,728,771	17,081,902	17,528,541	301,772,956
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**68,738,093**	**69,019,911**	**64,016,194**	**57,959,486**	**48,824,166**	**51,912,405**	**698,913,664**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	50	50	50	50	50	50	560
10.	COAL	1,133,800	1,059,460	866,580	822,050	947,010	1,030,580	11,797,500
11.	NATURAL GAS	737,250	820,750	865,120	745,760	379,970	380,010	7,033,610
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**1,871,100**	**1,880,260**	**1,731,750**	**1,567,860**	**1,327,030**	**1,410,640**	**18,831,670**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	600	600	100	80	80	100	11,900
17.	COAL (TON)	496,540	464,500	381,340	362,230	416,530	448,890	5,175,560
18.	NATURAL GAS (MCF)	5,566,610	6,166,160	6,543,190	5,624,300	2,806,550	2,801,060	52,285,140
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	480	480	630	480	500	550	6,110
23.	COAL	11,558,520	10,806,170	8,856,790	8,405,290	9,698,720	10,498,820	120,314,450
24.	NATURAL GAS	5,712,400	6,326,150	6,716,300	5,758,400	2,865,810	2,856,080	53,596,540
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,271,400**	**17,132,800**	**15,573,720**	**14,164,170**	**12,565,030**	**13,355,450**	**173,917,100**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30.	COAL	60.60	56.35	50.04	52.43	71.37	73.06	62.65
31.	NATURAL GAS	39.40	43.65	49.96	47.57	28.63	26.94	37.35
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	17.48	17.48	128.71	131.10	131.10	128.71	11.38
37.	COAL ($/TON)	75.45	75.82	75.30	75.15	76.18	76.57	76.71
38.	NATURAL GAS ($/MCF)	5.62	5.48	5.39	5.46	6.09	6.26	5.77
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	21.85	21.85	20.43	21.85	20.98	23.40	22.16
43.	COAL	3.24	3.26	3.24	3.24	3.27	3.27	3.30
44.	NATURAL GAS	5.47	5.34	5.25	5.34	5.96	6.14	5.63
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)**	**3.98**	**4.03**	**4.11**	**4.09**	**3.89**	**3.89**	**4.02**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	9,600	9,600	12,600	9,600	10,000	11,000	10,911
50.	COAL	10,194	10,200	10,220	10,225	10,241	10,187	10,198
51.	NATURAL GAS	7,748	7,708	7,763	7,722	7,542	7,516	7,620
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,231**	**9,112**	**8,993**	**9,034**	**9,469**	**9,468**	**9,235**
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	20.98	20.98	25.74	20.98	20.98	25.74	24.18
57.	COAL	3.30	3.32	3.31	3.31	3.35	3.34	3.37
58.	NATURAL GAS	4.24	4.12	4.08	4.12	4.50	4.61	4.29
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)**	**3.67**	**3.67**	**3.70**	**3.70**	**3.68**	**3.68**	**3.71**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2015

(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. B.B.#1	395	237,300	80.7	85.1	92.3	10,026	COAL	101,350	23,474,494	2,379,140.0	7,927,767	3.34	78.22
2. B.B.#2	395	236,280	80.4	84.8	90.2	10,227	COAL	102,930	23,476,635	2,416,450.0	8,051,363	3.41	78.22
3. B.B.#3	400	233,190	78.4	83.2	90.1	10,389	COAL	107,040	22,633,221	2,422,660.0	8,372,850	3.59	78.22
4. B.B.#4	417	270,980	87.3	88.1	97.6	10,059	COAL	123,410	22,088,323	2,725,920.0	9,653,342	3.56	78.22
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,840	-	10,710.0	255,609	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,607**	**977,750**	**81.8**	**85.3**	**92.6**	**10,170**	**-**	**-**	**-**	**-**	**34,260,931**	**3.50**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.7	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
10. B.B.C.T.#4 TOTAL	**61**	**10**	**0.0**	**98.2**	**2.7**	**11,000**	**-**	**-**	**-**	**110.0**	**3,338**	**33.38**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**977,760**	**78.8**	**85.8**	**92.6**	**10,170**	**-**	**-**	**-**	**9,944,280.0**	**34,264,269**	**3.50**	**-**
12. POLK #1 GASIFIER	220	134,830	82.4	-	97.1	10,181	COAL	51,280	26,769,306	1,372,730.0	4,400,637	3.26	85.82
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	3,500	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**134,830**	**82.4**	**81.5**	**97.1**	**10,181**	**-**	**-**	**-**	**1,372,730.0**	**4,400,637**	**3.26**	**-**
15. POLK #2 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
16. POLK #2 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**20**	**0.0**	**97.7**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,767**	**23.84**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**97.7**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**134,870**	**19.0**	**56.4**	**95.9**	**10,181**	**-**	**-**	**-**	**1,373,170.0**	**4,410,170**	**3.27**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	161,060	27.3	91.5	36.7	7,361	GAS	1,153,300	1,028,007	1,185,600.0	8,069,640	5.01	7.00
26. BAYSIDE #2	1,047	148,240	19.0	93.2	20.6	7,462	GAS	1,076,000	1,028,020	1,106,150.0	7,528,772	5.08	7.00
27. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
28. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. BAYSIDE #5	61	60	0.1	98.6	98.4	11,000	GAS	640	1,031,250	660.0	4,478	7.46	7.00
30. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BAYSIDE TOTAL	**2,083**	**309,360**	**20.0**	**84.5**	**26.7**	**7,410**	**GAS**	**2,229,940**	**1,028,014**	**2,292,410.0**	**15,602,890**	**5.04**	**7.00**
32. SYSTEM	**4,703**	**1,421,990**	**40.6**	**79.3**	**60.4**	**9,571**	**-**	**-**	**-**	**13,609,860.0**	**54,277,329**	**3.82**	**-**

LEGEND:
B.B. = BIG BEND
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] Units burned are ignition associated with Polk #1 Gasifier.

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2015

(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. B.B.#1	395	220,270	83.0	85.1	94.8	10,011	COAL	93,940	23,472,961	2,205,050.0	7,243,410	3.29	77.11
2. B.B.#2	395	217,720	82.0	84.8	92.0	10,211	COAL	94,700	23,475,290	2,223,110.0	7,302,007	3.35	77.11
3. B.B.#3	400	112,260	41.8	46.0	86.6	10,431	COAL	51,740	22,631,620	1,170,960.0	3,989,500	3.55	77.11
4. B.B.#4	417	244,770	87.3	88.1	97.5	10,061	COAL	111,480	22,090,151	2,462,610.0	8,595,866	3.51	77.11
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,730	-	15,860.0	379,246	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,607**	**795,020**	**73.6**	**76.1**	**93.6**	**10,140**	**-**	**-**	**-**	**-**	**27,510,029**	**3.46**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.7	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	470	1.1	-	70.0	10,936	GAS	5,000	1,028,000	5,140.0	32,434	6.90	6.49
10. B.B.C.T.#4 TOTAL	**61**	**480**	**1.2**	**98.2**	**46.3**	**10,938**	**-**	**-**	**-**	**5,250.0**	**35,772**	**7.45**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**795,500**	**71.0**	**76.9**	**93.5**	**10,141**	**-**	**-**	**-**	**8,066,980.0**	**27,545,801**	**3.46**	**-**
12. POLK #1 GASIFIER	220	121,840	82.4	-	97.2	10,173	COAL	46,340	26,747,303	1,239,470.0	3,898,334	3.20	84.12
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**121,840**	**82.4**	**58.2**	**97.2**	**10,173**	**-**	**-**	**-**	**1,239,470.0**	**3,898,334**	**3.20**	**-**
15. POLK #2 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
16. POLK #2 CT OIL	187	20	0.0	-	2.7	10,500	LGT OIL	40	5,250,000	210.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**20**	**0.0**	**83.8**	**2.7**	**10,500**	**-**	**-**	**-**	**210.0**	**4,767**	**23.84**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.7	10,500	LGT OIL	40	5,250,000	210.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**83.8**	**2.7**	**10,500**	**-**	**-**	**-**	**210.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**121,880**	**19.1**	**45.7**	**96.0**	**10,173**	**-**	**-**	**-**	**1,239,890.0**	**3,907,867**	**3.21**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	162,160	30.5	55.6	52.4	7,267	GAS	1,146,250	1,027,996	1,178,340.0	7,435,395	4.59	6.49
26. BAYSIDE #2	1,047	199,020	28.3	79.9	31.8	7,307	GAS	1,414,640	1,028,014	1,454,270.0	9,176,364	4.61	6.49
27. BAYSIDE #3	61	790	1.9	98.6	99.6	10,418	GAS	8,010	1,027,466	8,230.0	51,959	6.58	6.49
28. BAYSIDE #4	61	620	1.5	98.6	84.7	10,839	GAS	6,540	1,027,523	6,720.0	42,423	6.84	6.49
29. BAYSIDE #5	61	950	2.3	98.6	91.6	10,589	GAS	9,780	1,028,630	10,060.0	63,440	6.68	6.49
30. BAYSIDE #6	61	920	2.2	98.6	94.3	10,533	GAS	9,420	1,028,662	9,690.0	61,105	6.64	6.49
31. BAYSIDE TOTAL	**2,083**	**364,460**	**26.0**	**72.8**	**38.8**	**7,319**	**GAS**	**2,594,640**	**1,028,008**	**2,667,310.0**	**16,830,686**	**4.62**	**6.49**
32. SYSTEM	**4,703**	**1,281,840**	**40.6**	**68.8**	**66.9**	**9,341**	**-**	**-**	**-**	**11,974,180.0**	**48,284,354**	**3.77**	**-**

LEGEND:
B.B. = BIG BEND
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] Units burned are ignition associated with Polk #1 Gasifier.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 11 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2015

(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. B.B.#1	395	243,350	82.8	85.1	94.6	10,010	COAL	103,780	23,472,731	2,436,000.0	7,957,092	3.27	76.67
2. B.B.#2	395	241,320	82.1	84.8	92.1	10,205	COAL	104,910	23,474,311	2,462,690.0	8,043,732	3.33	76.67
3. B.B.#3	400	243,120	81.7	85.9	91.0	10,379	COAL	111,490	22,633,061	2,523,360.0	8,548,238	3.52	76.67
4. B.B.#4	417	146,800	47.3	48.3	96.4	10,074	COAL	66,950	22,088,424	1,478,820.0	5,133,235	3.50	76.67
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,840	-	10,710.0	255,609	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	30,439	-	6.08
7. B.B. COAL	**1,607**	**874,590**	**73.2**	**75.7**	**93.2**	**10,177**	**-**	**-**	**-**	**-**	**29,968,345**	**3.43**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	3.3	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	280	0.6	-	91.8	10,643	GAS	2,900	1,027,586	2,980.0	17,619	6.29	6.08
10. B.B.C.T.#4 TOTAL	**61**	**290**	**0.6**	**98.2**	**47.5**	**10,621**	**-**	**-**	**-**	**3,080.0**	**20,957**	**7.23**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**874,880**	**70.5**	**76.5**	**93.2**	**10,177**	**-**	**-**	**-**	**8,903,950.0**	**29,989,302**	**3.43**	**-**
12. POLK #1 GASIFIER	220	30,470	18.6	-	96.9	10,241	COAL	11,600	26,900,862	312,050.0	1,031,811	3.39	88.95
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**30,470**	**18.6**	**26.3**	**96.9**	**10,241**	**-**	**-**	**-**	**312,050.0**	**1,031,811**	**3.39**	**-**
15. POLK #2 CT GAS	183	11,180	8.2	-	92.6	10,513	GAS	114,330	1,027,989	117,530.0	694,618	6.21	6.08
16. POLK #2 CT OIL	187	20	0.0	-	2.7	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**183**	**11,200**	**8.2**	**22.1**	**87.3**	**10,511**	**-**	**-**	**-**	**117,720.0**	**698,193**	**6.23**	**-**
18. POLK #3 CT GAS	183	1,870	1.4	-	92.7	10,465	GAS	19,040	1,027,836	19,570.0	115,678	6.19	6.08
19. POLK #3 CT OIL	187	20	0.0	-	2.7	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**183**	**1,890**	**1.4**	**22.1**	**68.3**	**10,455**	**-**	**-**	**-**	**19,760.0**	**119,253**	**6.31**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**43,560**	**6.1**	**14.6**	**92.6**	**10,320**	**-**	**-**	**-**	**449,530.0**	**1,849,257**	**4.25**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	290,960	49.4	91.5	54.5	7,238	GAS	2,048,630	1,028,004	2,106,000.0	12,446,554	4.28	6.08
26. BAYSIDE #2	1,047	161,610	20.7	69.1	30.3	7,297	GAS	1,147,100	1,027,984	1,179,200.0	6,969,263	4.31	6.08
27. BAYSIDE #3	61	1,800	4.0	82.7	84.3	10,772	GAS	18,870	1,027,557	19,390.0	114,646	6.37	6.08
28. BAYSIDE #4	61	280	0.6	70.0	91.8	10,821	GAS	2,950	1,027,119	3,030.0	17,923	6.40	6.08
29. BAYSIDE #5	61	2,270	5.0	70.0	93.0	10,604	GAS	23,420	1,027,754	24,070.0	142,289	6.27	6.08
30. BAYSIDE #6	61	2,740	6.0	98.6	88.1	10,672	GAS	28,450	1,027,768	29,240.0	172,849	6.31	6.08
31. BAYSIDE TOTAL	**2,083**	**459,660**	**29.7**	**79.0**	**42.7**	**7,312**	**GAS**	**3,269,420**	**1,027,990**	**3,360,930.0**	**19,863,524**	**4.32**	**6.08**
32. SYSTEM	**4,703**	**1,378,100**	**39.4**	**65.0**	**66.8**	**9,226**	**-**	**-**	**-**	**12,714,410.0**	**51,702,083**	**3.75**	**-**

LEGEND:
B.B. = BIG BEND
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] Units burned are ignition associated with Polk #1 Gasifier.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 12 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2015

(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. B.B.#1	385	186,590	67.3	68.1	96.2	10,094	COAL	80,240	23,471,461	1,883,350.0	6,090,552	3.26	75.90
2. B.B.#2	385	194,890	70.3	70.6	94.6	10,212	COAL	84,770	23,477,527	1,990,190.0	6,434,399	3.30	75.90
3. B.B.#3	395	243,480	85.6	85.9	95.3	10,368	COAL	111,530	22,634,538	2,524,430.0	8,465,588	3.48	75.90
4. B.B.#4	407	257,090	87.7	88.1	98.1	10,119	COAL	117,780	22,087,112	2,601,420.0	8,939,996	3.48	75.90
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,480	-	8,580.0	205,599	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	5,000	-	5,140.0	29,786	-	5.96
7. B.B. COAL	**1,572**	**882,050**	**77.9**	**78.4**	**96.1**	**10,203**	**-**	**-**	**-**	**-**	**30,165,920**	**3.42**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	4.5	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	620	1.5	-	100.6	10,677	GAS	6,440	1,027,950	6,620.0	38,365	6.19	5.96
10. B.B.C.T.#4 TOTAL	**56**	**630**	**1.6**	**81.8**	**75.0**	**10,667**	**-**	**-**	**-**	**6,720.0**	**41,703**	**6.62**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**882,680**	**75.3**	**78.5**	**96.1**	**10,203**	**-**	**-**	**-**	**9,006,110.0**	**30,207,623**	**3.42**	**-**
12. POLK #1 GASIFIER	220	39,270	24.8	-	97.0	10,312	COAL	14,940	27,104,418	404,940.0	1,333,493	3.40	89.26
13. POLK #1 CT GAS	218	1,540	1.0	-	88.3	7,929	GAS	17,720	689,052	12,210.0	70,772	4.60	3.99
14. POLK #1 TOTAL	**220**	**40,810**	**25.8**	**81.5**	**96.7**	**10,222**	**-**	**-**	**-**	**417,150.0**	**1,404,265**	**3.44**	**-**
15. POLK #2 CT GAS	151	5,380	4.9	-	93.8	10,857	GAS	56,820	1,027,983	58,410.0	338,491	6.29	5.96
16. POLK #2 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	10	5,000,000	50.0	1,192	0.00	119.20
17. POLK #2 TOTAL	**151**	**5,380**	**4.9**	**97.7**	**91.2**	**10,866**	**-**	**-**	**-**	**58,460.0**	**339,683**	**6.31**	**-**
18. POLK #3 CT GAS	151	3,180	2.9	-	95.4	10,814	GAS	33,450	1,028,102	34,390.0	199,270	6.27	5.96
19. POLK #3 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	10	5,000,000	50.0	1,191	0.00	119.10
20. POLK #3 TOTAL	**151**	**3,180**	**2.9**	**97.7**	**91.1**	**10,830**	**-**	**-**	**-**	**34,440.0**	**200,461**	**6.30**	**-**
21. POLK #4 CT GAS	**151**	**5,320**	**4.9**	**98.6**	**95.5**	**10,878**	**GAS**	**56,300**	**1,027,886**	**57,870.0**	**335,393**	**6.30**	**5.96**
22. POLK #5 CT GAS	**151**	**2,810**	**2.6**	**98.6**	**97.9**	**10,769**	**GAS**	**29,440**	**1,027,853**	**30,260.0**	**175,381**	**6.24**	**5.96**
23. POLK STATION TOTAL	**824**	**57,500**	**9.7**	**93.7**	**95.7**	**10,403**	**-**	**-**	**-**	**598,180.0**	**2,455,183**	**4.27**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	149,690	29.7	91.5	49.7	7,365	GAS	1,072,410	1,028,012	1,102,450.0	6,388,611	4.27	5.96
26. BAYSIDE #2	929	354,880	53.1	93.2	57.4	7,369	GAS	2,543,850	1,028,001	2,615,080.0	15,154,342	4.27	5.96
27. BAYSIDE #3	56	1,650	4.1	98.6	95.0	10,788	GAS	17,310	1,028,307	17,800.0	103,120	6.25	5.96
28. BAYSIDE #4	56	900	2.2	98.6	84.6	11,033	GAS	9,660	1,027,950	9,930.0	57,547	6.39	5.96
29. BAYSIDE #5	56	2,120	5.3	98.6	94.6	10,811	GAS	22,300	1,027,803	22,920.0	132,847	6.27	5.96
30. BAYSIDE #6	56	1,870	4.6	69.0	98.2	10,695	GAS	19,460	1,027,749	20,000.0	115,928	6.20	5.96
31. BAYSIDE TOTAL	**1,854**	**511,110**	**38.3**	**92.3**	**55.2**	**7,412**	**GAS**	**3,684,990**	**1,028,003**	**3,788,180.0**	**21,952,395**	**4.30**	**5.96**
32. SYSTEM	**4,306**	**1,451,290**	**46.8**	**87.4**	**76.2**	**9,228**	**-**	**-**	**-**	**13,392,470.0**	**54,615,201**	**3.76**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 13 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2015

(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. B.B.#1	385	175,080	61.1	63.1	94.2	10,114	COAL	75,450	23,470,113	1,770,820.0	5,673,948	3.24	75.20
2. B.B.#2	385	165,570	57.8	60.1	91.3	10,257	COAL	72,330	23,478,363	1,698,190.0	5,439,319	3.29	75.20
3. B.B.#3	395	243,410	82.8	85.9	92.2	10,403	COAL	111,880	22,633,625	2,532,250.0	8,413,534	3.46	75.20
4. B.B.#4	407	265,570	87.7	88.1	98.0	10,120	COAL	121,670	22,088,025	2,687,450.0	9,149,751	3.45	75.20
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,410	-	8,150.0	195,875	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	12,510	-	12,860.0	70,808	-	5.66
7. B.B. COAL	**1,572**	**849,630**	**72.6**	**74.6**	**94.2**	**10,226**	**-**	**-**	**-**	**-**	**28,943,235**	**3.41**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	12,000	LGT OIL	20	6,000,000	120.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,060	2.5	-	99.6	11,000	GAS	11,340	1,028,219	11,660.0	64,186	6.06	5.66
10. B.B.C.T.#4 TOTAL	**56**	**1,070**	**2.6**	**98.2**	**76.4**	**11,009**	**-**	**-**	**-**	**11,780.0**	**67,524**	**6.31**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**850,700**	**70.2**	**75.4**	**94.1**	**10,227**	**-**	**-**	**-**	**8,700,490.0**	**29,010,759**	**3.41**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,748,148	1,372,180.0	4,252,030	3.15	82.89
13. POLK #1 CT GAS	218	5,300	3.3	-	86.8	8,025	GAS	43,700	973,227	42,530.0	234,160	4.42	5.36
14. POLK #1 TOTAL	**220**	**140,220**	**85.7**	**81.5**	**96.8**	**10,089**	**-**	**-**	**-**	**1,414,710.0**	**4,486,190**	**3.20**	**-**
15. POLK #2 CT GAS	151	18,100	16.1	-	93.6	10,905	GAS	192,010	1,027,967	197,380.0	1,086,804	6.00	5.66
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**18,120**	**16.1**	**97.7**	**90.0**	**10,906**	**-**	**-**	**-**	**197,620.0**	**1,091,571**	**6.02**	**-**
18. POLK #3 CT GAS	151	8,810	7.8	-	95.4	10,831	GAS	92,810	1,028,122	95,420.0	525,317	5.96	5.66
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**8,830**	**7.8**	**97.7**	**88.0**	**10,834**	**-**	**-**	**-**	**95,660.0**	**530,083**	**6.00**	**-**
21. POLK #4 CT GAS	**151**	**6,690**	**6.0**	**98.6**	**94.5**	**10,865**	**GAS**	**70,710**	**1,028,002**	**72,690.0**	**400,228**	**5.98**	**5.66**
22. POLK #5 CT GAS	**151**	**4,190**	**3.7**	**98.6**	**92.5**	**10,900**	**GAS**	**44,420**	**1,028,140**	**45,670.0**	**251,423**	**6.00**	**5.66**
23. POLK STATION TOTAL	**824**	**178,050**	**29.0**	**93.7**	**95.4**	**10,258**	**-**	**-**	**-**	**1,826,350.0**	**6,759,495**	**3.80**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	244,410	46.9	91.5	56.2	7,366	GAS	1,751,320	1,028,002	1,800,360.0	9,912,711	4.06	5.66
26. BAYSIDE #2	929	408,550	59.1	93.2	64.0	7,332	GAS	2,914,020	1,027,996	2,995,600.0	16,493,752	4.04	5.66
27. BAYSIDE #3	56	3,140	7.5	98.6	100.1	10,707	GAS	32,700	1,028,135	33,620.0	185,086	5.89	5.66
28. BAYSIDE #4	56	1,790	4.3	98.6	99.9	10,760	GAS	18,740	1,027,748	19,260.0	106,071	5.93	5.66
29. BAYSIDE #5	56	4,310	10.3	98.6	100.0	10,703	GAS	44,880	1,027,852	46,130.0	254,027	5.89	5.66
30. BAYSIDE #6	56	3,580	8.6	98.6	99.9	10,709	GAS	37,290	1,028,158	38,340.0	211,066	5.90	5.66
31. BAYSIDE TOTAL	**1,854**	**665,780**	**48.3**	**93.2**	**61.3**	**7,410**	**GAS**	**4,798,950**	**1,027,998**	**4,933,310.0**	**27,162,713**	**4.08**	**5.66**
32. SYSTEM	**4,306**	**1,694,530**	**52.9**	**86.6**	**77.9**	**9,124**	**-**	**-**	**-**	**15,460,150.0**	**62,932,967**	**3.71**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 14 OF 31

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2015

(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. B.B.#1	385	234,290	84.5	85.1	96.6	10,087	COAL	100,670	23,474,719	2,363,200.0	7,536,258	3.22	74.86
2. B.B.#2	385	233,590	84.3	84.8	94.5	10,213	COAL	101,620	23,476,678	2,385,700.0	7,607,375	3.26	74.86
3. B.B.#3	395	242,120	85.1	85.9	94.7	10,374	COAL	110,980	22,632,997	2,511,810.0	8,308,074	3.43	74.86
4. B.B.#4	407	257,080	87.7	88.1	98.1	10,119	COAL	117,770	22,088,308	2,601,340.0	8,816,370	3.43	74.86
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	42,125	-	5.62
7. B.B. COAL	**1,572**	**967,080**	**85.4**	**86.0**	**96.0**	**10,198**	**-**	**-**	**-**	**-**	**32,382,439**	**3.35**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	13,000	LGT OIL	20	6,500,000	130.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,160	2.9	-	98.6	10,948	GAS	12,360	1,027,508	12,700.0	69,422	5.98	5.62
10. B.B.C.T.#4 TOTAL	**56**	**1,170**	**2.9**	**98.2**	**77.4**	**10,966**	**-**	**-**	**-**	**12,830.0**	**72,760**	**6.22**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**968,250**	**82.6**	**86.4**	**96.0**	**10,199**	**-**	**-**	**-**	**9,874,880.0**	**32,455,199**	**3.35**	**-**
12. POLK #1 GASIFIER	220	130,570	82.4	-	97.1	10,200	COAL	49,660	26,819,372	1,331,850.0	4,137,236	3.17	83.31
13. POLK #1 CT GAS	218	3,500	2.2	-	73.0	8,346	GAS	34,260	852,598	29,210.0	159,625	4.56	4.66
14. POLK #1 TOTAL	**220**	**134,070**	**84.6**	**81.5**	**96.3**	**10,152**	**-**	**-**	**-**	**1,361,060.0**	**4,296,861**	**3.20**	**-**
15. POLK #2 CT GAS	151	18,270	16.8	-	96.8	10,790	GAS	191,770	1,028,002	197,140.0	1,077,105	5.90	5.62
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**18,290**	**16.8**	**97.7**	**93.0**	**10,792**	**-**	**-**	**-**	**197,390.0**	**1,081,872**	**5.92**	**-**
18. POLK #3 CT GAS	151	16,110	14.8	-	96.7	10,790	GAS	169,080	1,028,034	173,820.0	949,662	5.89	5.62
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**16,130**	**14.8**	**97.7**	**92.4**	**10,792**	**-**	**-**	**-**	**174,070.0**	**954,428**	**5.92**	**-**
21. POLK #4 CT GAS	**151**	**12,900**	**11.9**	**98.6**	**98.5**	**10,765**	**GAS**	**135,080**	**1,028,057**	**138,870.0**	**758,696**	**5.88**	**5.62**
22. POLK #5 CT GAS	**151**	**8,820**	**8.1**	**98.6**	**99.0**	**10,749**	**GAS**	**92,230**	**1,027,974**	**94,810.0**	**518,023**	**5.87**	**5.62**
23. POLK STATION TOTAL	**824**	**190,210**	**32.1**	**93.7**	**95.9**	**10,337**	**-**	**-**	**-**	**1,966,200.0**	**7,609,880**	**4.00**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	238,140	47.2	91.5	53.4	7,369	GAS	1,706,990	1,028,003	1,754,790.0	9,587,558	4.03	5.62
26. BAYSIDE #2	929	405,830	60.7	93.2	65.7	7,316	GAS	2,888,050	1,027,998	2,968,910.0	16,221,152	4.00	5.62
27. BAYSIDE #3	56	2,690	6.7	98.6	94.2	10,836	GAS	28,350	1,028,219	29,150.0	159,232	5.92	5.62
28. BAYSIDE #4	56	2,000	5.0	98.6	94.0	10,885	GAS	21,180	1,027,856	21,770.0	118,961	5.95	5.62
29. BAYSIDE #5	56	4,950	12.3	98.6	98.2	10,725	GAS	51,650	1,027,880	53,090.0	290,100	5.86	5.62
30. BAYSIDE #6	56	3,210	8.0	98.6	97.2	10,801	GAS	33,720	1,028,173	34,670.0	189,393	5.90	5.62
31. BAYSIDE TOTAL	**1,854**	**656,820**	**49.2**	**93.2**	**61.0**	**7,403**	**GAS**	**4,729,940**	**1,028,000**	**4,862,380.0**	**26,566,396**	**4.04**	**5.62**
32. SYSTEM	**4,306**	**1,815,280**	**58.6**	**90.7**	**79.5**	**9,202**	**-**	**-**	**-**	**16,703,460.0**	**66,631,475**	**3.67**	**-**

LEGEND:
B.B. = BIG BEND
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.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2015

(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. B.B.#1	385	241,400	84.3	85.1	96.3	10,089	COAL	103,760	23,472,726	2,435,530.0	7,712,993	3.20	74.33
2. B.B.#2	385	241,270	84.2	84.8	94.5	10,213	COAL	104,960	23,475,419	2,463,980.0	7,802,196	3.23	74.33
3. B.B.#3	395	250,300	85.2	85.9	94.9	10,373	COAL	114,710	22,633,162	2,596,250.0	8,526,962	3.41	74.33
4. B.B.#4	407	265,910	87.8	88.1	98.1	10,118	COAL	121,810	22,088,416	2,690,590.0	9,054,755	3.41	74.34
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	42,194	-	5.63
7. B.B. COAL	**1,572**	**998,880**	**85.4**	**86.0**	**96.0**	**10,198**	**-**	**-**	**-**	**-**	**33,211,337**	**3.32**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.6	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,150	2.8	-	93.3	11,296	GAS	12,640	1,027,690	12,990.0	71,110	6.18	5.63
10. B.B.C.T.#4 TOTAL	**56**	**1,160**	**2.8**	**98.2**	**71.4**	**11,284**	**-**	**-**	**-**	**13,090.0**	**74,448**	**6.42**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**1,000,040**	**82.6**	**86.4**	**95.9**	**10,199**	**-**	**-**	**-**	**10,199,440.0**	**33,285,785**	**3.33**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,254,813	3.15	82.94
13. POLK #1 CT GAS	218	3,390	2.1	-	74.0	8,115	GAS	29,090	945,686	27,510.0	150,547	4.44	5.18
14. POLK #1 TOTAL	**220**	**138,310**	**84.5**	**81.5**	**96.5**	**10,120**	**-**	**-**	**-**	**1,399,680.0**	**4,405,360**	**3.19**	**-**
15. POLK #2 CT GAS	151	28,120	25.0	-	95.5	10,836	GAS	296,420	1,027,967	304,710.0	1,667,606	5.93	5.63
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**28,140**	**25.0**	**97.7**	**93.5**	**10,835**	**-**	**-**	**-**	**304,900.0**	**1,671,181**	**5.94**	**-**
18. POLK #3 CT GAS	151	20,870	18.5	-	96.4	10,812	GAS	219,500	1,028,018	225,650.0	1,234,868	5.92	5.63
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**20,890**	**18.5**	**97.7**	**93.7**	**10,811**	**-**	**-**	**-**	**225,840.0**	**1,238,443**	**5.93**	**-**
21. POLK #4 CT GAS	**151**	**15,320**	**13.7**	**98.6**	**97.8**	**10,790**	**GAS**	**160,800**	**1,028,047**	**165,310.0**	**904,632**	**5.90**	**5.63**
22. POLK #5 CT GAS	**151**	**4,490**	**4.0**	**98.6**	**99.1**	**10,808**	**GAS**	**47,200**	**1,028,178**	**48,530.0**	**265,539**	**5.91**	**5.63**
23. POLK STATION TOTAL	**824**	**207,150**	**33.8**	**93.7**	**95.9**	**10,351**	**-**	**-**	**-**	**2,144,260.0**	**8,485,155**	**4.10**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	251,690	48.3	91.5	56.0	7,380	GAS	1,806,770	1,028,011	1,857,380.0	10,164,567	4.04	5.63
26. BAYSIDE #2	929	397,670	57.5	93.2	62.3	7,325	GAS	2,833,600	1,028,003	2,912,950.0	15,941,329	4.01	5.63
27. BAYSIDE #3	56	3,490	8.4	98.6	97.4	10,834	GAS	36,780	1,028,004	37,810.0	206,918	5.93	5.63
28. BAYSIDE #4	56	2,570	6.2	98.6	95.6	10,938	GAS	27,350	1,027,788	28,110.0	153,866	5.99	5.63
29. BAYSIDE #5	56	4,700	11.3	98.6	98.7	10,753	GAS	49,160	1,028,072	50,540.0	276,565	5.88	5.63
30. BAYSIDE #6	56	3,790	9.1	98.6	98.1	10,794	GAS	39,800	1,027,889	40,910.0	223,908	5.91	5.63
31. BAYSIDE TOTAL	**1,854**	**663,910**	**48.1**	**93.2**	**60.2**	**7,422**	**GAS**	**4,793,460**	**1,028,005**	**4,927,700.0**	**26,967,153**	**4.06**	**5.63**
32. SYSTEM	**4,306**	**1,871,100**	**58.4**	**90.7**	**79.3**	**9,231**	**-**	**-**	**-**	**17,271,400.0**	**68,738,093**	**3.67**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 16 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2015

(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. B.B.#1	385	164,840	57.5	57.6	97.1	10,083	COAL	70,810	23,473,379	1,662,150.0	5,286,000	3.21	74.65
2. B.B.#2	385	242,810	84.8	84.8	95.1	10,206	COAL	105,560	23,476,127	2,478,140.0	7,880,104	3.25	74.65
3. B.B.#3	395	252,160	85.8	85.9	95.6	10,365	COAL	115,480	22,632,144	2,613,560.0	8,620,636	3.42	74.65
4. B.B.#4	407	264,730	87.4	88.1	97.7	10,124	COAL	121,350	22,086,115	2,680,150.0	9,058,828	3.42	74.65
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	10,010	-	10,290.0	54,967	-	5.49
7. B.B. COAL	**1,572**	**924,540**	**79.0**	**79.3**	**96.3**	**10,204**	**-**	**-**	**-**	**-**	**30,972,772**	**3.35**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,180	2.8	-	100.3	10,780	GAS	12,370	1,028,294	12,720.0	67,926	5.76	5.49
10. B.B.C.T.#4 TOTAL	**56**	**1,190**	**2.9**	**98.2**	**78.7**	**10,773**	**-**	**-**	**-**	**12,820.0**	**71,264**	**5.99**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**925,730**	**76.4**	**79.9**	**96.3**	**10,205**	**-**	**-**	**-**	**9,446,820.0**	**31,044,036**	**3.35**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,244,694	3.15	82.74
13. POLK #1 CT GAS	218	6,770	4.2	-	86.3	8,092	GAS	55,620	984,898	54,780.0	292,627	4.32	5.26
14. POLK #1 TOTAL	**220**	**141,690**	**86.6**	**81.5**	**96.6**	**10,071**	**-**	**-**	**-**	**1,426,950.0**	**4,537,321**	**3.20**	**-**
15. POLK #2 CT GAS	151	31,710	28.2	-	95.0	10,847	GAS	334,590	1,028,004	343,960.0	1,837,306	5.79	5.49
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**31,730**	**28.2**	**97.7**	**93.3**	**10,846**	**-**	**-**	**-**	**344,150.0**	**1,840,881**	**5.80**	**-**
18. POLK #3 CT GAS	151	21,470	19.1	-	95.1	10,838	GAS	226,350	1,028,010	232,690.0	1,242,937	5.79	5.49
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**21,490**	**19.1**	**97.7**	**92.6**	**10,837**	**-**	**-**	**-**	**232,880.0**	**1,246,512**	**5.80**	**-**
21. POLK #4 CT GAS	**151**	**14,800**	**13.2**	**98.6**	**99.3**	**10,739**	**GAS**	**154,590**	**1,028,074**	**158,930.0**	**848,887**	**5.74**	**5.49**
22. POLK #5 CT GAS	**151**	**4,200**	**3.7**	**98.6**	**99.3**	**10,743**	**GAS**	**43,890**	**1,028,025**	**45,120.0**	**241,009**	**5.74**	**5.49**
23. POLK STATION TOTAL	**824**	**213,910**	**34.9**	**93.7**	**95.9**	**10,322**	**-**	**-**	**-**	**2,208,030.0**	**8,714,610**	**4.07**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	282,360	54.1	91.5	58.9	7,336	GAS	2,014,940	1,028,006	2,071,370.0	11,064,472	3.92	5.49
26. BAYSIDE #2	929	439,720	63.6	93.2	68.9	7,295	GAS	3,120,590	1,028,001	3,207,970.0	17,135,835	3.90	5.49
27. BAYSIDE #3	56	4,700	11.3	98.6	99.9	10,706	GAS	48,950	1,027,988	50,320.0	268,795	5.72	5.49
28. BAYSIDE #4	56	3,140	7.5	98.6	100.1	10,748	GAS	32,830	1,028,023	33,750.0	180,277	5.74	5.49
29. BAYSIDE #5	56	5,880	14.1	98.6	100.0	10,709	GAS	61,260	1,027,914	62,970.0	336,392	5.72	5.49
30. BAYSIDE #6	56	4,820	11.6	98.6	100.1	10,699	GAS	50,170	1,027,905	51,570.0	275,494	5.72	5.49
31. BAYSIDE TOTAL	**1,854**	**740,620**	**53.7**	**93.2**	**65.2**	**7,396**	**GAS**	**5,328,740**	**1,028,001**	**5,477,950.0**	**29,261,265**	**3.95**	**5.49**
32. SYSTEM	**4,306**	**1,880,260**	**58.7**	**88.3**	**81.0**	**9,112**	**-**	**-**	**-**	**17,132,800.0**	**69,019,911**	**3.67**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 17 OF 31

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2015

(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. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	234,950	84.8	84.8	95.1	10,207	COAL	102,160	23,474,941	2,398,200.0	7,567,027	3.22	74.07
3. B.B.#3	395	243,970	85.8	85.9	95.5	10,366	COAL	111,740	22,632,182	2,528,920.0	8,276,622	3.39	74.07
4. B.B.#4	407	257,090	87.7	88.1	98.1	10,119	COAL	117,780	22,087,112	2,601,420.0	8,724,007	3.39	74.07
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	40,510	-	5.40
7. B.B. COAL	**1,572**	**736,010**	**65.0**	**65.2**	**96.2**	**10,229**	**-**	**-**	**-**	**-**	**24,608,166**	**3.34**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.6	13,000	LGT OIL	20	6,500,000	130.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,720	4.3	-	99.1	10,820	GAS	18,100	1,028,177	18,610.0	97,765	5.68	5.40
10. B.B.C.T.#4 TOTAL	**56**	**1,730**	**4.3**	**98.2**	**81.3**	**10,832**	**-**	**-**	**-**	**18,740.0**	**101,103**	**5.84**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**737,740**	**62.9**	**66.3**	**96.2**	**10,230**	**-**	**-**	**-**	**7,547,280.0**	**24,709,269**	**3.35**	**-**
12. POLK #1 GASIFIER	220	130,570	82.4	-	97.1	10,173	COAL	49,660	26,746,879	1,328,250.0	4,106,103	3.14	82.68
13. POLK #1 CT GAS	218	5,460	3.5	-	73.7	8,148	GAS	45,610	975,444	44,490.0	233,771	4.28	5.13
14. POLK #1 TOTAL	**220**	**136,030**	**85.9**	**81.5**	**95.9**	**10,091**	**-**	**-**	**-**	**1,372,740.0**	**4,339,874**	**3.19**	**-**
15. POLK #2 CT GAS	151	32,080	29.5	-	97.0	10,786	GAS	336,590	1,027,987	346,010.0	1,818,045	5.67	5.40
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**32,100**	**29.5**	**97.7**	**94.8**	**10,787**	**-**	**-**	**-**	**346,260.0**	**1,822,812**	**5.68**	**-**
18. POLK #3 CT GAS	151	27,760	25.5	-	97.5	10,765	GAS	290,700	1,028,001	298,840.0	1,570,177	5.66	5.40
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**27,780**	**25.5**	**97.7**	**94.9**	**10,766**	**-**	**-**	**-**	**299,090.0**	**1,574,943**	**5.67**	**-**
21. POLK #4 CT GAS	**151**	**23,640**	**21.8**	**98.6**	**98.1**	**10,771**	**GAS**	**247,690**	**1,028,019**	**254,630.0**	**1,337,864**	**5.66**	**5.40**
22. POLK #5 CT GAS	**151**	**14,320**	**13.2**	**98.6**	**98.8**	**10,755**	**GAS**	**149,810**	**1,028,036**	**154,010.0**	**809,178**	**5.65**	**5.40**
23. POLK STATION TOTAL	**824**	**233,870**	**39.4**	**93.7**	**96.0**	**10,376**	**-**	**-**	**-**	**2,426,730.0**	**9,884,671**	**4.23**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	282,530	56.0	91.5	61.0	7,314	GAS	2,010,160	1,027,998	2,066,440.0	10,857,605	3.84	5.40
26. BAYSIDE #2	929	460,020	68.8	93.2	74.5	7,270	GAS	3,253,150	1,028,004	3,344,250.0	17,571,446	3.82	5.40
27. BAYSIDE #3	56	3,790	9.4	98.6	99.5	10,752	GAS	39,640	1,028,002	40,750.0	214,110	5.65	5.40
28. BAYSIDE #4	56	2,730	6.8	98.6	99.5	10,751	GAS	28,550	1,028,021	29,350.0	154,209	5.65	5.40
29. BAYSIDE #5	56	6,310	15.6	98.6	99.7	10,729	GAS	65,860	1,027,938	67,700.0	355,734	5.64	5.40
30. BAYSIDE #6	56	4,760	11.8	98.6	100.0	10,761	GAS	49,830	1,027,895	51,220.0	269,150	5.65	5.40
31. BAYSIDE TOTAL	**1,854**	**760,140**	**56.9**	**93.2**	**69.2**	**7,367**	**GAS**	**5,447,190**	**1,028,000**	**5,599,710.0**	**29,422,254**	**3.87**	**5.40**
32. SYSTEM	**4,306**	**1,731,750**	**55.9**	**83.1**	**82.1**	**8,993**	**-**	**-**	**-**	**15,573,720.0**	**64,016,194**	**3.70**	**-**

LEGEND:
B.B. = BIG BEND
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.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2015

(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. B.B.#1	385	6,050	2.1	2.7	74.8	10,486	COAL	2,700	23,496,296	63,440.0	198,601	3.28	73.56
2. B.B.#2	385	163,020	56.9	57.4	94.3	10,217	COAL	70,950	23,475,969	1,665,620.0	5,218,747	3.20	73.56
3. B.B.#3	395	252,150	85.8	85.9	95.6	10,365	COAL	115,470	22,633,325	2,613,470.0	8,493,428	3.37	73.56
4. B.B.#4	407	265,910	87.8	88.1	98.1	10,118	COAL	121,810	22,088,416	2,690,590.0	8,959,758	3.37	73.56
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	20,440	-	21,010.0	112,130	-	5.49
7. B.B. COAL	**1,572**	**687,130**	**58.8**	**59.1**	**96.0**	**10,236**	**-**	**-**	**-**	**-**	**22,982,664**	**3.34**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	4.5	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	2,920	7.0	-	94.8	10,863	GAS	30,860	1,027,868	31,720.0	169,291	5.80	5.49
10. B.B.C.T.#4 TOTAL	**56**	**2,930**	**7.0**	**98.2**	**88.7**	**10,860**	**-**	**-**	**-**	**31,820.0**	**172,629**	**5.89**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**690,060**	**57.0**	**60.5**	**96.0**	**10,238**	**-**	**-**	**-**	**7,064,940.0**	**23,155,293**	**3.36**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,237,563	3.14	82.60
13. POLK #1 CT GAS	218	3,390	2.1	-	86.4	7,944	GAS	28,520	944,250	26,930.0	143,673	4.24	5.04
14. POLK #1 TOTAL	**220**	**138,310**	**84.5**	**81.5**	**96.9**	**10,116**	**-**	**-**	**-**	**1,399,100.0**	**4,381,236**	**3.17**	**-**
15. POLK #2 CT GAS	151	25,040	22.3	-	97.0	10,785	GAS	262,690	1,028,018	270,050.0	1,441,060	5.76	5.49
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**25,060**	**22.3**	**97.7**	**94.7**	**10,784**	**-**	**-**	**-**	**270,240.0**	**1,444,635**	**5.76**	**-**
18. POLK #3 CT GAS	151	18,080	16.0	-	97.0	10,769	GAS	189,400	1,028,036	194,710.0	1,039,007	5.75	5.49
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**18,100**	**16.1**	**97.7**	**93.9**	**10,768**	**-**	**-**	**-**	**194,900.0**	**1,042,582**	**5.76**	**-**
21. POLK #4 CT GAS	**151**	**12,140**	**10.8**	**98.6**	**99.5**	**10,715**	**GAS**	**126,540**	**1,027,975**	**130,080.0**	**694,171**	**5.72**	**5.49**
22. POLK #5 CT GAS	**151**	**10,670**	**9.5**	**98.6**	**99.5**	**10,698**	**GAS**	**111,040**	**1,028,008**	**114,150.0**	**609,141**	**5.71**	**5.49**
23. POLK STATION TOTAL	**824**	**204,280**	**33.3**	**93.7**	**96.6**	**10,321**	**-**	**-**	**-**	**2,108,470.0**	**8,171,765**	**4.00**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	231,490	44.4	91.5	54.7	7,326	GAS	1,649,650	1,028,006	1,695,850.0	9,049,620	3.91	5.49
26. BAYSIDE #2	929	423,080	61.2	93.2	66.3	7,304	GAS	3,005,950	1,027,998	3,090,110.0	16,489,985	3.90	5.49
27. BAYSIDE #3	56	4,450	10.7	85.9	95.7	10,822	GAS	46,850	1,027,962	48,160.0	257,009	5.78	5.49
28. BAYSIDE #4	56	3,890	9.3	98.6	95.2	10,892	GAS	41,210	1,028,149	42,370.0	226,069	5.81	5.49
29. BAYSIDE #5	56	6,280	15.1	98.6	95.8	10,780	GAS	65,860	1,027,938	67,700.0	361,294	5.75	5.49
30. BAYSIDE #6	56	4,330	10.4	85.9	99.1	10,755	GAS	45,290	1,028,262	46,570.0	248,451	5.74	5.49
31. BAYSIDE TOTAL	**1,854**	**673,520**	**48.8**	**92.4**	**62.3**	**7,410**	**GAS**	**4,854,810**	**1,028,003**	**4,990,760.0**	**26,632,428**	**3.95**	**5.49**
32. SYSTEM	**4,306**	**1,567,860**	**48.9**	**80.6**	**77.9**	**9,034**	**-**	**-**	**-**	**14,164,170.0**	**57,959,486**	**3.70**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 19 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2015

(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. B.B.#1	385	223,040	80.5	85.1	92.0	10,144	COAL	96,390	23,472,767	2,262,540.0	7,242,384	3.25	75.14
2. B.B.#2	385	218,400	78.8	84.8	88.4	10,312	COAL	95,930	23,475,972	2,252,050.0	7,207,823	3.30	75.14
3. B.B.#3	395	140,360	49.4	57.3	82.4	10,534	COAL	65,330	22,632,481	1,478,580.0	4,908,651	3.50	75.14
4. B.B.#4	407	256,630	87.6	88.1	97.9	10,118	COAL	117,560	22,086,424	2,596,480.0	8,833,018	3.44	75.14
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	12,930	-	13,290.0	79,228	-	6.13
7. B.B. COAL	**1,572**	**838,430**	**74.1**	**78.8**	**90.9**	**10,245**	**-**	**-**	**-**	**-**	**28,271,104**	**3.37**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.6	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	60	0.1	-	107.1	10,833	GAS	630	1,031,746	650.0	3,860	6.43	6.13
10. B.B.C.T.#4 TOTAL	**56**	**70**	**0.2**	**98.2**	**20.8**	**10,714**	**-**	**-**	**-**	**750.0**	**7,198**	**10.28**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**838,500**	**71.5**	**79.5**	**90.9**	**10,245**	**-**	**-**	**-**	**8,590,400.0**	**28,278,302**	**3.37**	**-**
12. POLK #1 GASIFIER	220	108,580	68.5	-	97.0	10,214	COAL	41,320	26,840,997	1,109,070.0	3,460,672	3.19	83.75
13. POLK #1 CT GAS	218	10,100	6.4	-	82.7	8,049	GAS	84,930	957,141	81,290.0	484,618	4.80	5.71
14. POLK #1 TOTAL	**220**	**118,680**	**74.9**	**67.9**	**95.6**	**10,030**	**-**	**-**	**-**	**1,190,360.0**	**3,945,290**	**3.32**	**-**
15. POLK #2 CT GAS	151	5,350	4.9	-	90.8	10,987	GAS	57,180	1,027,982	58,780.0	350,367	6.55	6.13
16. POLK #2 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**5,370**	**4.9**	**97.7**	**82.3**	**10,983**	**-**	**-**	**-**	**58,980.0**	**353,942**	**6.59**	**-**
18. POLK #3 CT GAS	151	2,550	2.3	-	93.5	10,886	GAS	27,000	1,028,148	27,760.0	165,440	6.49	6.13
19. POLK #3 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**2,570**	**2.4**	**97.7**	**76.4**	**10,879**	**-**	**-**	**-**	**27,960.0**	**169,015**	**6.58**	**-**
21. POLK #4 CT GAS	**151**	**300**	**0.3**	**98.6**	**99.6**	**10,933**	**GAS**	**3,190**	**1,028,213**	**3,280.0**	**19,546**	**6.52**	**6.13**
22. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**824**	**126,920**	**21.4**	**72.0**	**94.5**	**10,090**	**-**	**-**	**-**	**1,280,580.0**	**4,487,793**	**3.54**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	172,000	34.1	82.3	46.4	7,487	GAS	1,252,730	1,027,987	1,287,790.0	7,676,004	4.46	6.13
26. BAYSIDE #2	929	187,660	28.1	43.5	53.6	7,378	GAS	1,346,780	1,028,008	1,384,500.0	8,252,288	4.40	6.13
27. BAYSIDE #3	56	500	1.2	98.6	99.2	11,140	GAS	5,420	1,027,675	5,570.0	33,211	6.64	6.13
28. BAYSIDE #4	56	110	0.3	98.6	98.2	11,364	GAS	1,220	1,024,590	1,250.0	7,475	6.80	6.13
29. BAYSIDE #5	56	780	1.9	98.6	99.5	11,256	GAS	8,540	1,028,103	8,780.0	52,328	6.71	6.13
30. BAYSIDE #6	56	560	1.4	98.6	100.0	11,000	GAS	6,000	1,026,667	6,160.0	36,765	6.57	6.13
31. BAYSIDE TOTAL	**1,854**	**361,610**	**27.1**	**64.8**	**50.0**	**7,450**	**GAS**	**2,620,690**	**1,027,993**	**2,694,050.0**	**16,058,071**	**4.44**	**6.13**
32. SYSTEM	**4,306**	**1,327,030**	**42.8**	**71.7**	**74.6**	**9,469**	**-**	**-**	**-**	**12,565,030.0**	**48,824,166**	**3.68**	**-**

LEGEND:
B.B. = BIG BEND
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.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 20 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2015

(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. B.B.#1	395	239,420	81.5	85.1	93.1	10,026	COAL	102,260	23,473,206	2,400,370.0	7,716,288	3.22	75.46
2. B.B.#2	395	235,840	80.3	84.8	90.1	10,235	COAL	102,810	23,477,677	2,413,740.0	7,757,790	3.29	75.46
3. B.B.#3	400	240,110	80.7	85.9	89.9	10,392	COAL	110,240	22,633,618	2,495,130.0	8,318,440	3.46	75.46
4. B.B.#4	417	180,320	58.1	59.7	95.9	10,080	COAL	82,280	22,090,423	1,817,600.0	6,208,644	3.44	75.46
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	20,450	-	21,020.0	129,022	-	6.31
7. B.B. COAL	**1,607**	**895,690**	**74.9**	**78.6**	**91.9**	**10,190**	**-**	**-**	**-**	**-**	**30,130,184**	**3.36**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.0	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	120	0.3	-	65.6	11,750	GAS	1,370	1,029,197	1,410.0	8,643	7.20	6.31
10. B.B.C.T.#4 TOTAL	**61**	**130**	**0.3**	**98.2**	**19.4**	**11,692**	**-**	**-**	**-**	**1,520.0**	**11,981**	**9.22**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**895,820**	**72.2**	**79.3**	**91.9**	**10,190**	**-**	**-**	**-**	**9,128,360.0**	**30,142,165**	**3.36**	**-**
12. POLK #1 GASIFIER	220	134,890	82.4	-	97.2	10,171	COAL	51,300	26,744,250	1,371,980.0	4,240,809	3.14	82.67
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**134,890**	**82.4**	**81.5**	**97.2**	**10,171**	**-**	**-**	**-**	**1,371,980.0**	**4,240,809**	**3.14**	**-**
15. POLK #2 CT GAS	183	7,950	5.8	-	90.5	10,560	GAS	81,660	1,028,043	83,950.0	515,204	6.48	6.31
16. POLK #2 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**7,970**	**5.9**	**88.3**	**82.0**	**10,561**	**-**	**-**	**-**	**84,170.0**	**519,971**	**6.52**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**88.3**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**5,580**	**4.1**	**89.1**	**92.6**	**10,507**	**GAS**	**57,030**	**1,028,055**	**58,630.0**	**359,810**	**6.45**	**6.31**
22. POLK #5 CT GAS	**183**	**320**	**0.2**	**92.2**	**87.4**	**10,500**	**GAS**	**3,270**	**1,027,523**	**3,360.0**	**20,631**	**6.45**	**6.31**
23. POLK STATION TOTAL	**952**	**148,780**	**21.0**	**87.6**	**95.5**	**10,205**	**-**	**-**	**-**	**1,518,360.0**	**5,145,987**	**3.46**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	153,120	26.0	67.9	45.3	7,400	GAS	1,102,150	1,028,009	1,133,020.0	6,953,612	4.54	6.31
26. BAYSIDE #2	1,047	209,600	26.9	93.2	29.1	7,348	GAS	1,498,210	1,028,007	1,540,170.0	9,452,408	4.51	6.31
27. BAYSIDE #3	61	550	1.2	98.6	90.2	10,600	GAS	5,680	1,026,408	5,830.0	35,836	6.52	6.31
28. BAYSIDE #4	61	320	0.7	98.6	87.4	10,594	GAS	3,300	1,027,273	3,390.0	20,820	6.51	6.31
29. BAYSIDE #5	61	1,590	3.5	98.6	96.5	10,686	GAS	16,530	1,027,828	16,990.0	104,290	6.56	6.31
30. BAYSIDE #6	61	860	1.9	98.6	82.9	10,849	GAS	9,080	1,027,533	9,330.0	57,287	6.66	6.31
31. BAYSIDE TOTAL	**2,083**	**366,040**	**23.6**	**84.2**	**34.5**	**7,400**	**GAS**	**2,634,950**	**1,028,001**	**2,708,730.0**	**16,624,253**	**4.54**	**6.31**
32. SYSTEM	**4,703**	**1,410,640**	**40.3**	**83.2**	**64.4**	**9,468**	**-**	**-**	**-**	**13,355,450.0**	**51,912,405**	**3.68**	**-**

LEGEND:
B.B. = BIG BEND
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] Units burned are ignition associated with Polk #1 Gasifier.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 21 OF 31

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0
18. BURNED:						
19. UNITS (BBL)	1,940	2,830	1,920	1,520	1,510	620
20. UNIT COST ($/BBL)	6.63	4.55	5.46	3.76	8.52	20.76
21. AMOUNT ($)	12,871	12,871	10,488	5,721	12,871	12,871
22. ENDING INVENTORY:						
23. UNITS (BBL)	63,434	60,604	58,684	57,164	55,654	55,034
24. UNIT COST ($/BBL)	130.10	129.71	129.43	129.19	128.95	128.87
25. AMOUNT ($)	8,252,700	7,861,142	7,595,605	7,384,844	7,176,659	7,092,110
26. DAYS SUPPLY: NORMAL	1,946	1,843	1,775	3,867	5,029	7,688
27. DAYS SUPPLY: EMERGENCY	9	9	8	8	8	8
COAL						
28. PURCHASES:						
29. UNITS (TONS)	449,082	389,999	429,082	374,999	469,082	493,082
30. UNIT COST ($/TON)	75.68	75.02	75.19	74.67	75.35	74.39
31. AMOUNT ($)	33,985,185	29,257,489	32,264,783	27,999,684	35,346,459	36,681,971
32. BURNED:						
33. UNITS (TONS)	486,010	398,200	398,730	409,260	432,630	480,700
34. UNIT COST ($/TON)	79.55	78.88	77.75	76.97	76.73	75.97
35. AMOUNT ($)	38,661,568	31,408,363	31,000,156	31,499,413	33,195,265	36,519,675
36. ENDING INVENTORY:						
37. UNITS (TONS)	578,442	570,241	600,593	566,332	602,784	615,166
38. UNIT COST ($/TON)	76.40	74.63	73.66	72.70	72.53	71.76
39. AMOUNT ($)	44,195,308	42,555,656	44,236,849	41,173,907	43,719,834	44,144,655
40. DAYS SUPPLY:	107	30	26	39	39	39
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,558,279	5,372,220
43. UNIT COST ($/MCF)	7.02	6.48	6.06	5.90	5.57	5.62
44. AMOUNT ($)	15,684,980	16,866,534	20,673,034	22,962,243	30,944,627	30,211,055
45. BURNED:						
46. UNITS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,266,450	5,372,220
47. UNIT COST ($/MCF)	6.99	6.48	6.06	5.94	5.64	5.60
48. AMOUNT ($)	15,602,890	16,863,120	20,691,439	23,110,067	29,724,831	30,098,929
49. ENDING INVENTORY:						
50. UNITS (MCF)	875,486	875,486	875,486	875,486	1,167,315	1,167,315
51. UNIT COST ($/MCF)	4.27	4.26	4.18	3.94	3.93	3.96
52. AMOUNT ($)	3,737,700	3,726,000	3,663,000	3,450,600	4,586,400	4,623,600
53. DAYS SUPPLY:	6	6	5	6	8	8
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 2015 THROUGH DECEMBER 2015

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	0	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0	0
18.	BURNED:							
19.	UNITS (BBL)	600	600	100	80	80	100	11,900
20.	UNIT COST ($/BBL)	17.48	17.48	128.71	131.10	131.10	128.71	11.38
21.	AMOUNT ($)	10,488	10,488	12,871	10,488	10,488	12,871	135,387
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	54,434	53,834	53,734	53,654	53,574	53,474	53,474
24.	UNIT COST ($/BBL)	128.78	128.69	128.70	128.70	128.71	128.72	128.72
25.	AMOUNT ($)	7,009,944	6,927,778	6,915,466	6,905,537	6,895,610	6,883,298	6,883,298
26.	DAYS SUPPLY: NORMAL	9,487	12,470	18,553	18,526	18,498	18,464	-
27.	DAYS SUPPLY: EMERGENCY	8	8	8	8	8	8	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	472,082	458,082	416,082	383,082	362,082	407,098	5,103,834
30.	UNIT COST ($/TON)	73.50	75.18	75.43	75.99	75.33	75.87	75.10
31.	AMOUNT ($)	34,695,876	34,437,295	31,383,234	29,109,574	27,273,836	30,887,725	383,323,111
32.	BURNED:							
33.	UNITS (TONS)	496,540	464,500	381,340	362,230	416,530	448,890	5,175,560
34.	UNIT COST ($/TON)	75.45	75.82	75.30	75.15	76.18	76.57	76.71
35.	AMOUNT ($)	37,466,150	35,217,466	28,714,269	27,220,227	31,731,776	34,370,993	397,005,321
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	590,708	584,290	619,032	639,884	585,436	543,644	543,644
38.	UNIT COST ($/TON)	70.52	70.40	71.03	72.12	71.60	71.18	71.18
39.	AMOUNT ($)	41,656,032	41,132,972	43,971,644	46,147,015	41,919,699	38,695,520	38,695,520
40.	DAYS SUPPLY:	40	44	49	48	41	38	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	5,566,610	6,166,160	6,543,190	5,429,748	2,563,359	2,801,060	52,139,226
43.	UNIT COST ($/MCF)	5.63	5.49	5.40	5.54	6.35	6.35	5.79
44.	AMOUNT ($)	31,355,157	33,868,119	35,321,749	30,095,683	16,270,414	17,796,013	302,049,608
45.	BURNED:							
46.	UNITS (MCF)	5,566,610	6,166,160	6,543,190	5,624,300	2,806,550	2,801,060	52,285,140
47.	UNIT COST ($/MCF)	5.62	5.48	5.39	5.46	6.09	6.26	5.77
48.	AMOUNT ($)	31,261,455	33,791,957	35,289,054	30,728,771	17,081,902	17,528,541	301,772,956
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 ($/MCF)	3.99	4.00	3.98	4.00	4.06	4.23	4.23
52.	AMOUNT ($)	4,662,000	4,670,400	4,650,000	3,892,000	2,965,500	3,089,250	3,089,250
53.	DAYS SUPPLY:	8	8	8	7	5	5	-
	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
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-15	SEMINOLE	JURISD. SCH. - D	810.0	0.0	810.0	2.917	3.107	23,630.00	25,163.00	1,533.00
	VARIOUS	JURISD. MKT. BASE	15,310.0	0.0	15,310.0	2.948	3.243	451,300.32	496,480.00	45,179.68
	TOTAL		**16,120.0**	**0.0**	**16,120.0**	**2.946**	**3.236**	**474,930.32**	**521,643.00**	**46,712.68**
Feb-15	SEMINOLE	JURISD. SCH. - D	670.0	0.0	670.0	3.034	3.231	20,330.00	21,649.00	1,319.00
	VARIOUS	JURISD. MKT. BASE	21,460.0	0.0	21,460.0	2.991	3.291	641,926.71	706,190.00	64,263.29
	TOTAL		**22,130.0**	**0.0**	**22,130.0**	**2.993**	**3.289**	**662,256.71**	**727,839.00**	**65,582.29**
Mar-15	SEMINOLE	JURISD. SCH. - D	880.0	0.0	880.0	3.078	3.278	27,090.00	28,847.00	1,757.00
	VARIOUS	JURISD. MKT. BASE	20,490.0	0.0	20,490.0	3.312	3.643	678,541.23	746,470.00	67,928.77
	TOTAL		**21,370.0**	**0.0**	**21,370.0**	**3.302**	**3.628**	**705,631.23**	**775,317.00**	**69,685.77**
Apr-15	SEMINOLE	JURISD. SCH. - D	1,090.0	0.0	1,090.0	2.970	3.162	32,370.00	34,470.00	2,100.00
	VARIOUS	JURISD. MKT. BASE	23,590.0	0.0	23,590.0	2.910	3.201	686,504.07	755,230.00	68,725.93
	TOTAL		**24,680.0**	**0.0**	**24,680.0**	**2.913**	**3.200**	**718,874.07**	**789,700.00**	**70,825.93**
May-15	SEMINOLE	JURISD. SCH. - D	920.0	0.0	920.0	3.061	3.259	28,160.00	29,987.00	1,827.00
	VARIOUS	JURISD. MKT. BASE	15,350.0	0.0	15,350.0	3.752	4.127	575,860.59	633,510.00	57,649.41
	TOTAL		**16,270.0**	**0.0**	**16,270.0**	**3.712**	**4.078**	**604,020.59**	**663,497.00**	**59,476.41**
Jun-15	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	3.055	3.253	30,240.00	32,201.00	1,961.00
	VARIOUS	JURISD. MKT. BASE	13,320.0	0.0	13,320.0	3.133	3.446	417,276.45	459,050.00	41,773.55
	TOTAL		**14,310.0**	**0.0**	**14,310.0**	**3.127**	**3.433**	**447,516.45**	**491,251.00**	**43,734.55**

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
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SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
		TYPE		TOTAL	WHEELED FROM	MWH	(A)	(B)	TOTAL $		
MONTH	SOLD TO	& SCHEDULE		MWH SOLD	OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jul-15	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.134	3.337	31,650.00	33,703.00	2,053.00
	VARIOUS	JURISD.	MKT. BASE	13,950.0	0.0	13,950.0	3.214	3.536	448,382.43	493,270.00	44,887.57
	TOTAL			**14,960.0**	**0.0**	**14,960.0**	**3.209**	**3.523**	**480,032.43**	**526,973.00**	**46,940.57**
Aug-15	SEMINOLE	JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.360	3.578	33,600.00	35,779.00	2,179.00
	VARIOUS	JURISD.	MKT. BASE	3,770.0	0.0	3,770.0	2.822	3.104	106,371.18	117,020.00	10,648.82
	TOTAL			**4,770.0**	**0.0**	**4,770.0**	**2.934**	**3.203**	**139,971.18**	**152,799.00**	**12,827.82**
Sep-15	SEMINOLE	JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.272	3.484	32,720.00	34,842.00	2,122.00
	VARIOUS	JURISD.	MKT. BASE	1,310.0	0.0	1,310.0	2.822	3.105	36,969.03	40,670.00	3,700.97
	TOTAL			**2,310.0**	**0.0**	**2,310.0**	**3.017**	**3.269**	**69,689.03**	**75,512.00**	**5,822.97**
Oct-15	SEMINOLE	JURISD.	SCH. - D	730.0	0.0	730.0	3.400	3.621	24,820.00	26,430.00	1,610.00
	VARIOUS	JURISD.	MKT. BASE	6,660.0	0.0	6,660.0	2.848	3.133	189,662.85	208,650.00	18,987.15
	TOTAL			**7,390.0**	**0.0**	**7,390.0**	**2.902**	**3.181**	**214,482.85**	**235,080.00**	**20,597.15**
Nov-15	SEMINOLE	JURISD.	SCH. - D	650.0	0.0	650.0	3.006	3.201	19,540.00	20,807.00	1,267.00
	VARIOUS	JURISD.	MKT. BASE	30,060.0	0.0	30,060.0	3.366	3.703	1,011,744.27	1,113,030.00	101,285.73
	TOTAL			**30,710.0**	**0.0**	**30,710.0**	**3.358**	**3.692**	**1,031,284.27**	**1,133,837.00**	**102,552.73**
Dec-15	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	3.052	3.250	17,700.00	18,848.00	1,148.00
	VARIOUS	JURISD.	MKT. BASE	13,210.0	0.0	13,210.0	3.028	3.331	399,960.00	440,000.00	36,026.00
	TOTAL			**13,790.0**	**0.0**	**13,790.0**	**3.029**	**3.327**	**417,660.00**	**458,848.00**	**37,174.00**
TOTAL	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**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

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-15									
	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	200.0	0.0	0.0	200.0	4.430	4.430	8,860.00
	TOTAL		**200.0**	**0.0**	**0.0**	**200.0**	**4.430**	**4.430**	**8,860.00**
Feb-15									
	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	3,140.0	0.0	0.0	3,140.0	4.220	4.220	132,500.00
	TOTAL		**3,140.0**	**0.0**	**0.0**	**3,140.0**	**4.220**	**4.220**	**132,500.00**
Mar-15									
	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	6,490.0	0.0	0.0	6,490.0	4.062	4.062	263,610.00
	TOTAL		**6,490.0**	**0.0**	**0.0**	**6,490.0**	**4.062**	**4.062**	**263,610.00**
Apr-15									
	OLEANDER	SCH. - D	1,570.0	0.0	0.0	1,570.0	5.252	5.252	82,450.00
	CALPINE	SCH. - D	1,150.0	0.0	0.0	1,150.0	6.369	6.369	73,240.00
	PASCO COGEN	SCH. - D	6,840.0	0.0	0.0	6,840.0	3.964	3.964	271,150.00
	TOTAL		**9,560.0**	**0.0**	**0.0**	**9,560.0**	**4.465**	**4.465**	**426,840.00**
May-15									
	OLEANDER	SCH. - D	1,410.0	0.0	0.0	1,410.0	5.279	5.279	74,430.00
	CALPINE	SCH. - D	1,150.0	0.0	0.0	1,150.0	6.312	6.312	72,590.00
	PASCO COGEN	SCH. - D	13,930.0	0.0	0.0	13,930.0	3.952	3.952	550,450.00
	TOTAL		**16,490.0**	**0.0**	**0.0**	**16,490.0**	**4.230**	**4.230**	**697,470.00**
Jun-15									
	OLEANDER	SCH. - D	530.0	0.0	0.0	530.0	8.404	8.404	44,540.00
	CALPINE	SCH. - D	330.0	0.0	0.0	330.0	8.079	8.079	26,660.00
	PASCO COGEN	SCH. - D	12,470.0	0.0	0.0	12,470.0	3.955	3.955	493,170.00
	TOTAL		**13,330.0**	**0.0**	**0.0**	**13,330.0**	**4.234**	**4.234**	**564,370.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER **SCHEDULE E7**
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

(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
Jul-15									
	OLEANDER	SCH. - D	310.0	0.0	0.0	310.0	6.471	6.471	20,060.00
	CALPINE	SCH. - D	530.0	0.0	0.0	530.0	7.170	7.170	38,000.00
	PASCO COGEN	SCH. - D	14,340.0	0.0	0.0	14,340.0	3.996	3.996	573,070.00
	TOTAL		**15,180.0**	**0.0**	**0.0**	**15,180.0**	**4.158**	**4.158**	**631,130.00**
Aug-15									
	OLEANDER	SCH. - D	3,070.0	0.0	0.0	3,070.0	6.730	6.730	206,620.00
	CALPINE	SCH. - D	2,020.0	0.0	0.0	2,020.0	6.617	6.617	133,660.00
	PASCO COGEN	SCH. - D	19,290.0	0.0	0.0	19,290.0	3.973	3.973	766,440.00
	TOTAL		**24,380.0**	**0.0**	**0.0**	**24,380.0**	**4.539**	**4.539**	**1,106,720.00**
Sep-15									
	OLEANDER	SCH. - D	4,370.0	0.0	0.0	4,370.0	5.519	5.519	241,160.00
	CALPINE	SCH. - D	3,190.0	0.0	0.0	3,190.0	6.220	6.220	198,420.00
	PASCO COGEN	SCH. - D	20,690.0	0.0	0.0	20,690.0	3.948	3.948	816,740.00
	TOTAL		**28,250.0**	**0.0**	**0.0**	**28,250.0**	**4.447**	**4.447**	**1,256,320.00**
Oct-15									
	OLEANDER	SCH. - D	6,060.0	0.0	0.0	6,060.0	5.964	5.964	361,440.00
	CALPINE	SCH. - D	4,190.0	0.0	0.0	4,190.0	6.432	6.432	269,480.00
	PASCO COGEN	SCH. - D	14,280.0	0.0	0.0	14,280.0	3.964	3.964	566,070.00
	TOTAL		**24,530.0**	**0.0**	**0.0**	**24,530.0**	**4.880**	**4.880**	**1,196,990.00**
Nov-15									
	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	7,640.0	0.0	0.0	7,640.0	4.052	4.052	309,560.00
	TOTAL		**7,640.0**	**0.0**	**0.0**	**7,640.0**	**4.052**	**4.052**	**309,560.00**
Dec-15									
	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	5,270.0	0.0	0.0	5,270.0	4.095	4.095	215,800.00
	TOTAL		**5,270.0**	**0.0**	**0.0**	**5,270.0**	**4.095**	**4.095**	**215,800.00**
TOTAL	OLEANDER	SCH. - D	17,320.0	0.0	0.0	17,320.0	5.951	5.951	1,030,700.00
Jan-15	CALPINE	SCH. - D	12,560.0	0.0	0.0	12,560.0	6.465	6.465	812,050.00
THRU	PASCO COGEN	SCH. - D	124,580.0	0.0	0.0	124,580.0	3.987	3.987	4,967,420.00
Dec-15	**TOTAL**		**154,460.0**	**0.0**	**0.0**	**154,460.0**	**4.409**	**4.409**	**6,810,170.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES **SCHEDULE E8**
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJUST-MENT
Jan-15	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	2.959	2.959	168,670.00
		AS AVAIL.	15,370.0	0.0	0.0	15,370.0	3.224	3.224	495,460.00
	TOTAL		21,070.0	0.0	0.0	21,070.0	3.152	3.152	664,130.00
Feb-15	VARIOUS	CO-GEN.							
		FIRM	5,150.0	0.0	0.0	5,150.0	2.677	2.677	137,870.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	2.940	2.940	447,430.00
	TOTAL		20,370.0	0.0	0.0	20,370.0	2.873	2.873	585,300.00
Mar-15	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	2.492	2.492	142,030.00
		AS AVAIL.	15,320.0	0.0	0.0	15,320.0	2.781	2.781	426,000.00
	TOTAL		21,020.0	0.0	0.0	21,020.0	2.702	2.702	568,030.00
Apr-15	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.229	3.229	200,520.00
		AS AVAIL.	15,320.0	0.0	0.0	15,320.0	3.469	3.469	531,390.00
	TOTAL		21,530.0	0.0	0.0	21,530.0	3.399	3.399	731,910.00
May-15	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.343	3.343	214,650.00
		AS AVAIL.	15,170.0	0.0	0.0	15,170.0	3.586	3.586	544,070.00
	TOTAL		21,590.0	0.0	0.0	21,590.0	3.514	3.514	758,720.00
Jun-15	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	2.433	2.433	151,090.00
		AS AVAIL.	15,360.0	0.0	0.0	15,360.0	2.725	2.725	418,560.00
	TOTAL		21,570.0	0.0	0.0	21,570.0	2.641	2.641	569,650.00
Jul-15	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	2.918	2.918	187,310.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	3.153	3.153	479,850.00
	TOTAL		21,640.0	0.0	0.0	21,640.0	3.083	3.083	667,160.00
Aug-15	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.319	3.319	213,110.00
		AS AVAIL.	15,260.0	0.0	0.0	15,260.0	3.583	3.583	546,830.00
	TOTAL		21,680.0	0.0	0.0	21,680.0	3.505	3.505	759,940.00
Sep-15	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.307	3.307	205,360.00
		AS AVAIL.	15,340.0	0.0	0.0	15,340.0	4.023	4.023	617,180.00
	TOTAL		21,550.0	0.0	0.0	21,550.0	3.817	3.817	822,540.00
Oct-15	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.294	3.294	211,500.00
		AS AVAIL.	15,310.0	0.0	0.0	15,310.0	3.561	3.561	545,120.00
	TOTAL		21,730.0	0.0	0.0	21,730.0	3.482	3.482	756,620.00
Nov-15	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	2.809	2.809	174,440.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	3.058	3.058	465,500.00
	TOTAL		21,430.0	0.0	0.0	21,430.0	2.986	2.986	639,940.00
Dec-15	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.220	3.220	183,560.00
		AS AVAIL.	15,260.0	0.0	0.0	15,260.0	3.482	3.482	531,400.00
	TOTAL		20,960.0	0.0	0.0	20,960.0	3.411	3.411	714,960.00
TOTAL	VARIOUS	CO-GEN.							
Jan-14		FIRM	72,770.0	0.0	0.0	72,770.0	3.010	3.010	2,190,110.00
THRU		AS AVAIL.	183,370.0	0.0	0.0	183,370.0	3.299	3.299	6,048,790.00
Dec-14	TOTAL		256,140.0	0.0	0.0	256,140.0	3.217	3.217	8,238,900.00

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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-15	VARIOUS	ECONOMY	35,870.0	0.0	35,870.0	2.838	1,017,820.00	5.444	1,952,880.00	935,060.00
Feb-15	VARIOUS	ECONOMY	34,940.0	0.0	34,940.0	3.001	1,048,640.00	4.896	1,710,630.00	661,990.00
Mar-15	VARIOUS	ECONOMY	35,020.0	0.0	35,020.0	3.177	1,112,500.00	5.005	1,752,600.00	640,100.00
Apr-15	VARIOUS	ECONOMY	35,320.0	0.0	35,320.0	2.975	1,050,600.00	5.194	1,834,410.00	783,810.00
May-15	VARIOUS	ECONOMY	44,600.0	0.0	44,600.0	3.552	1,584,350.00	5.827	2,598,650.00	1,014,300.00
Jun-15	VARIOUS	ECONOMY	51,190.0	0.0	51,190.0	3.279	1,678,360.00	5.491	2,810,650.00	1,132,290.00
Jul-15	VARIOUS	ECONOMY	51,150.0	0.0	51,150.0	3.314	1,695,010.00	5.599	2,863,830.00	1,168,820.00
Aug-15	VARIOUS	ECONOMY	47,210.0	0.0	47,210.0	3.655	1,725,610.00	5.694	2,688,040.00	962,430.00
Sep-15	VARIOUS	ECONOMY	57,800.0	0.0	57,800.0	3.798	2,195,180.00	5.820	3,363,990.00	1,168,810.00
Oct-15	VARIOUS	ECONOMY	47,520.0	0.0	47,520.0	3.854	1,831,370.00	5.501	2,614,210.00	782,840.00
Nov-15	VARIOUS	ECONOMY	32,670.0	0.0	32,670.0	2.995	978,410.00	5.417	1,769,740.00	791,330.00
Dec-15	VARIOUS	ECONOMY	36,170.0	0.0	36,170.0	2.964	1,072,240.00	4.985	1,803,023.00	730,783.00
TOTAL	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**

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 29 OF 31

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current	Step Increase	Difference		Projected	Difference	
	Jan 14 - Oct 14	Nov 14 - Dec 14	$	%	Jan 15 - Oct 15	$	%
Base Rate Revenue *	60.98	61.50	0.52	0.9%	61.50	0.00	0.0%
Fuel Recovery Revenue	36.09	36.09	0.00	0.0%	35.59	(0.50)	-1.4%
Conservation Revenue	2.95	2.95	0.00	0.0%	2.47	(0.48)	-16.3%
Capacity Revenue	2.02	2.02	0.00	0.0%	2.04	0.02	1.0%
Environmental Revenue	4.83	4.83	0.00	0.0%	4.08	(0.75)	-15.5%
Florida Gross Receipts Tax Revenue	2.74	2.75	0.01	0.4%	2.71	(0.04)	-1.5%
TOTAL REVENUE	**$109.61**	**$110.14**	**$0.53**	**0.5%**	**$108.39**	**($1.75)**	**-1.6%**

*** Base rate change effective November 1, 2014.**

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 30 OF 31

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2012	ACTUAL 2013	ACT/EST 2014	EST 2015	DIFFERENCE (%) 2013-2012	2014-2013	2015-2014
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	4,902,843	2,070,617	71,032	135,387	-57.8%	-96.6%	90.6%
3 COAL	395,142,292	380,570,736	406,849,497	397,005,321	-3.7%	6.9%	-2.4%
4 NATURAL GAS	305,701,892	300,114,267	308,644,366	301,772,956	-1.8%	2.8%	-2.2%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**705,747,027**	**682,755,620**	**715,564,895**	**698,913,664**	**-3.3%**	**4.8%**	**-2.3%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	20,242	8,475	300	560	-58.1%	-96.5%	86.7%
10 COAL	10,690,533	10,821,031	11,585,990	11,797,500	1.2%	7.1%	1.8%
11 NATURAL GAS	7,567,891	7,601,115	7,130,215	7,033,610	0.4%	-6.2%	-1.4%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**18,278,666**	**18,430,621**	**18,716,505**	**18,831,670**	**0.8%**	**1.6%**	**0.6%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	40,791	16,398	18,730	11,900	-59.8%	14.2%	-36.5%
17 COAL (TON)	4,671,399	4,702,698	5,051,883	5,175,560	0.7%	7.4%	2.4%
18 NATURAL GAS (MCF)	56,591,885	56,560,899	52,832,364	52,285,140	-0.1%	-6.6%	-1.0%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL [1]	208,086	83,760	3,210	6,110	-59.7%	-96.2%	90.3%
23 COAL	112,307,550	113,471,450	119,403,945	120,314,450	1.0%	5.2%	0.8%
24 NATURAL GAS	57,395,050	57,416,563	54,047,903	53,596,540	0.0%	-5.9%	-0.8%
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)	**169,910,686**	**170,971,773**	**173,455,058**	**173,917,100**	**0.6%**	**1.5%**	**0.3%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL [1]	0.11	0.05	0.00	0.00	-54.5%	-100.0%	0.0%
30 COAL	58.49	58.71	61.90	62.65	0.4%	5.4%	1.2%
31 NATURAL GAS	41.40	41.24	38.10	37.35	-0.4%	-7.6%	-2.0%
32 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	120.19	126.27	3.79	11.38	5.1%	-97.0%	200.3%
37 COAL ($/TON)	84.59	80.93	80.53	76.71	-4.3%	-0.5%	-4.7%
38 NATURAL GAS ($/MCF)	5.40	5.31	5.84	5.77	-1.7%	10.0%	-1.2%
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]	23.56	24.72	22.13	22.16	4.9%	-10.5%	0.1%
43 COAL	3.52	3.35	3.41	3.30	-4.8%	1.8%	-3.2%
44 NATURAL GAS	5.33	5.23	5.71	5.63	-1.9%	9.2%	-1.4%
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)	**4.15**	**3.99**	**4.13**	**4.02**	**-3.9%**	**3.5%**	**-2.7%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	10,280	9,883	10,700	10,911	-3.9%	8.3%	2.0%
50 COAL	10,505	10,486	10,306	10,198	-0.2%	-1.7%	-1.0%
51 NATURAL GAS	7,584	7,554	7,580	7,620	-0.4%	0.3%	0.5%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	**9,296**	**9,277**	**9,267**	**9,235**	**-0.2%**	**-0.1%**	**-0.3%**
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]	24.22	24.43	23.68	24.18	0.9%	-3.1%	2.1%
57 COAL	3.70	3.52	3.51	3.37	-4.9%	-0.3%	-4.0%
58 NATURAL GAS	4.04	3.95	4.33	4.29	-2.2%	9.6%	-0.9%
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)	**3.86**	**3.70**	**3.82**	**3.71**	**-4.1%**	**3.2%**	**-2.9%**

[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 2015 - DECEMBER 2015

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2015 through December 2015

	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	3,198,584	3.874	123,913,152	3.559	113,837,612
TIER II (Over 1,000) kWh	1,470,882	3.874	56,981,961	4.559	67,057,501
Total	4,669,466		180,895,113		180,895,113

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2015 - DECEMBER 2015

POLK 1 CONVERSION
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%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	
20	EQUITY COMPONENT AFTER-TAX	40,412	39,438	38,465	37,491	36,517	35,543	34,569	33,596	32,622	31,648	30,674	29,701	420,676
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	56,424	54,835	53,246	51,656	50,066	48,478	686,628
23														
24	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	
25	DEBT COMPONENT	$ 18,941	$ 18,484	$ 18,028	$ 17,572	$ 17,115	$ 16,659	16,202	15,746	15,290	14,833	14,377	13,920	197,167
26														
27	TOTAL RETURN REQUIREMENTS	$ 84,901	$ 82,855	$ 80,811	$ 78,765	$ 76,718	$ 74,672	72,626	70,581	68,536	66,489	64,443	62,398	883,795
28														
29	TOTAL DEPRECIATION & RETURN	$ 354,126	$ 352,080	$ 350,036	$ 347,990	$ 345,943	$ 343,897	341,851	339,806	337,761	335,714	333,668	331,623	4,114,495
30														
31	ESTIMATED FUEL SAVINGS	$0	$0	$0	$20,944	$1,029,260	$674,800	$455,616	$918,012	$1,067,976	$462,396	$1,321,080	$0	$5,950,084
32	TOTAL DEPRECIATION & RETURN	$ 354,126	$ 352,080	$ 350,036	$ 347,990	$ 345,943	$ 343,897	$ 341,851	$ 339,806	$ 337,761	$ 335,714	$ 333,668	$ 331,623	4,114,495
33	NET BENEFIT (COST) TO RATEPAYER	($354,126)	($352,080)	($350,036)	($327,046)	$683,317	$330,903	$113,765	$578,206	$730,215	$126,682	$987,412	($331,623)	$1,835,588

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.1187% (EQUITY 7.0844% , DEBT 2.0343%).
36 THE RATES ARE FROM THE MAY 2014 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.

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	$ -	$ -	$ -	$ 8,694,457	$ 12,627,359	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568
2	ADD INVESTMENT	-	-	8,694,457	3,932,902	3,795,209	-	$ -	-	-	-	-	$ 3,447,732	19,870,300
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	-	-	8,694,457	12,627,359	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	19,870,300	19,870,300
5														
6	AVERAGE BALANCE	-	-	-	8,694,457	12,627,359	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	
7	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%	
8	DEPRECIATION EXPENSE	-	-	-	144,908	210,456	273,709	273,709	273,709	273,709	273,709	273,709	273,709	2,271,330
9	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
10	BEGINNING BALANCE DEPRECIATION	-	-	-	-	144,908	355,364	629,073	902,783	1,176,492	1,450,201	1,723,911	1,997,620	-
11	ENDING BALANCE DEPRECIATION	-	-	-	144,908	355,364	629,073	902,783	1,176,492	1,450,201	1,723,911	1,997,620	2,271,330	2,271,330
12														
13	ENDING NET INVESTMENT	-	-	8,694,457	12,482,451	16,067,204	15,793,495	15,519,785	15,246,076	14,972,367	14,698,657	14,424,948	17,598,970	
14														
15	AVERAGE INVESTMENT	$ -	$ -	$ 4,347,229	$ 10,588,454	$ 14,274,828	$ 15,930,350	$ 15,656,640	$ 15,382,931	$ 15,109,221	$ 14,835,512	$ 14,561,802	$ 16,011,959	
16	ALLOWED EQUITY RETURN	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	
17	EQUITY COMPONENT AFTER-TAX	-	-	15,724	38,298	51,632	57,620	56,630	55,640	54,650	53,660	52,670	57,915	494,439
18	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	
19	EQUITY COMPONENT PRE-TAX	-	-	25,665	62,510	84,274	94,047	92,431	90,816	89,200	87,584	85,968	94,529	807,024
20														
21	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	
22	DEBT COMPONENT	$ -	$ -	$ 7,370	$ 17,950	$ 24,199	$ 27,006	$ 26,542	$ 26,078	$ 25,614	$ 25,150	$ 24,686	$ 27,144	$ 231,739
23														
24	TOTAL RETURN REQUIREMENTS	$ -	$ -	$ 33,035	$ 80,460	$ 108,473	$ 121,053	$ 118,973	$ 116,894	$ 114,814	$ 112,734	$ 110,654	$ 121,673	$ 1,038,763
25														
26	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ 33,035	$ 225,368	$ 318,929	$ 394,762	$ 392,682	$ 390,603	$ 388,523	$ 386,443	$ 384,363	$ 395,382	$ 3,310,090
27														
28	ESTIMATED FUEL SAVINGS	$ -	$ -	$ 204,769	$ 205,004	$ 407,735	$ 405,018	$ 302,181	$ 301,197	$ 401,370	$ 300,313	$ 708,156	$ 403,760	$ 3,639,503
29	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ 33,035	$ 225,368	$ 318,929	$ 394,762	$ 392,682	$ 390,603	$ 388,523	$ 386,443	$ 384,363	$ 395,382	$ 3,310,090
30	CURRENT PERIOD NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ 171,734	$ (20,364)	$ 88,806	$ 10,256	$ (90,501)	$ (89,406)	$ 12,847	$ (86,130)	$ 323,793	$ 8,378	$ 329,413

31 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD

32 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.1187% (EQUITY 7.0844% , DEBT 2.0343%).

33 THE RATES ARE FROM THE MAY 2014 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
for Cost Recovery Clauses

January to December 2015 Estimated Period

	(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%	1.96%
Short Term Debt	25,222	0.62%	0.61%	0.00%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	107,785	2.67%	2.25%	0.06%
Common Equity	1,707,776	42.26%	10.25%	4.33%
Deferred ITC - Weighted Cost	8,027	0.20%	8.05%	0.02%
Accumulated Deferred Income Taxes & Zero Cost ITCs	763,143	18.88%	0.00%	0.00%
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:		**Monthly Rate:**
Preferred Stock	0.0000%	
Common Equity	4.3317%	
Deferred ITC - Weighted Cost	0.0087%	
	4.3404%	0.36170%
Times Tax Multiplier	1.632200	
Total Equity Component	7.0844%	

Total Debt Cost Rate:		**Monthly 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%	0.16953%
Total Weighted Cost:	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)

GENERATING PERFORMANCE INCENTIVE FACTOR

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2	Actual Unit Performance Data	43

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 46
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Brian S. Buckley BSB-1

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
GPIF 2013 FINAL TRUE-UP
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 140001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2013 – DECEMBER 2013

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2013 - DECEMBER 2013
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2013 - DECEMBER 2013

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	24,217.6	8,157.1
+9	21,795.8	7,341.4
+8	19,374.1	6,525.7
+7	16,952.3	5,710.0
+6	14,530.6	4,894.3
+5	12,108.8	4,078.6
+4	9,687.0	3,262.8
+3	7,265.3	2,447.1
+2	4,843.5	1,631.4
+1	2,421.8	815.7
0	0.0	0.0
-1	(2,331.6)	(815.7)
-2	(4,663.1)	(1,631.4)
-3	(6,994.7)	(2,447.1)
-4	(9,326.2)	(3,262.8)
-5	(11,657.8)	(4,078.6)
-6	(13,989.3)	(4,894.3)
-7	(16,320.9)	(5,710.0)
-8	(18,652.4)	(6,525.7)
-9	(20,984.0)	(7,341.4)
-10	(23,315.5)	(8,157.1)

GPI POINTS 2.071

REWARD DOLLARS $1,689,728

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2013 - DECEMBER 2013

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,986,054,000
Line 2	Month of January	2013	$	1,995,423,000
Line 3	Month of February	2013	$	1,956,106,000
Line 4	Month of March	2013	$	1,969,017,000
Line 5	Month of April	2013	$	1,981,529,000
Line 6	Month of May	2013	$	1,981,379,000
Line 7	Month of June	2013	$	2,002,294,000
Line 8	Month of July	2013	$	1,982,587,000
Line 9	Month of August	2013	$	2,008,001,000
Line 10	Month of September	2013	$	2,028,500,000
Line 11	Month of October	2013	$	1,977,112,000
Line 12	Month of November	2013	$	2,037,631,000
Line 13	Month of December	2013	$	2,039,111,000
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,995,749,538
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.17%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	8,157,103
Line 18	Jurisdictional Sales			18,417,662 MWH
Line 19	Total Sales			18,417,662 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)**		**$**	**8,157,103**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2013 - DECEMBER 2013

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	74.9%	EAF	11.53%	10.000	1.153
BIG BEND 2	75.2%	EAF	4.04%	1.073	0.043
BIG BEND 3	70.0%	EAF	2.73%	10.000	0.273
BIG BEND 4	76.1%	EAF	5.26%	-10.000	-0.526
POLK 1	85.0%	EAF	1.08%	10.000	0.108
BAYSIDE 1	87.7%	EAF	1.50%	-10.000	-0.150
BAYSIDE 2	82.5%	EAF	0.80%	-10.000	-0.080
BIG BEND 1	10,565	ANOHR	17.14%	0.000	0.000
BIG BEND 2	10,343	ANOHR	5.75%	-5.009	-0.288
BIG BEND 3	10,697	ANOHR	10.33%	-0.262	-0.027
BIG BEND 4	10,552	ANOHR	10.78%	0.000	0.000
POLK 1	10,419	ANOHR	13.39%	0.000	0.000
BAYSIDE 1	7,024	ANOHR	8.45%	10.000	0.845
BAYSIDE 2	7,174	ANOHR	7.21%	10.000	0.721
			100.00%		2.071

GPIF REWARD **$ 1,689,728**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

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)
BIG BEND 1	11.53%	64.20	70.4	51.9	2,791.3	(851.7)	74.9%	851.7
BIG BEND 2	4.04%	74.76	78.8	66.7	978.4	(106.6)	75.2%	11.4
BIG BEND 3	2.73%	60.78	65.5	51.4	662.2	(2,199.0)	70.0%	2,199.0
BIG BEND 4	5.26%	83.64	85.9	79.1	1,274.6	(1,160.2)	76.1%	(1,160.2)
POLK 1	1.08%	75.13	78.7	68.1	261.8	(473.0)	85.0%	473.0
BAYSIDE 1	1.50%	94.11	94.5	93.2	364.1	(772.8)	87.7%	(772.8)
BAYSIDE 2	0.80%	93.25	93.8	92.2	193.5	(60.5)	82.5%	(60.5)
GPIF SYSTEM	**26.95%**				**6,525.8**	**(5,623.8)**		

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	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	17.14%	10,530	85.1	9,876	11,183	4,150.0	(4,150.0)	10,565	0.0
BIG BEND 2	5.75%	10,199	87.9	9,986	10,412	1,393.2	(1,393.2)	10,343	(697.8)
BIG BEND 3	10.33%	10,614	84.2	10,226	11,001	2,502.4	(2,502.4)	10,697	(65.5)
BIG BEND 4	10.78%	10,536	83.6	10,124	10,947	2,611.5	(2,611.5)	10,552	0.0
POLK 1	13.39%	10,437	95.3	9,832	11,042	3,242.8	(3,242.8)	10,419	0.0
BAYSIDE 1	8.45%	7,177	83.4	7,027	7,327	2,046.5	(2,046.5)	7,024	2,046.5
BAYSIDE 2	7.21%	7,325	83.1	7,196	7,454	1,745.4	(1,745.4)	7,174	1,745.4
GPIF SYSTEM	**73.05%**					**17,691.8**	**(17,691.8)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2013 - DECEMBER 2013

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	71.5	3.4	74.9
BIG BEND 2	75.6	-0.4	75.2
BIG BEND 3	66.5	3.5	70.0
BIG BEND 4	77.6	-1.5	76.1
POLK 1	79.6	5.4	85.0
BAYSIDE 1	88.6	-0.9	87.7
BAYSIDE 2	83.7	-1.2	82.5

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,530	35	10,565
BIG BEND 2	10,324	19	10,343
BIG BEND 3	10,508	189	10,697
BIG BEND 4	10,454	98	10,552
POLK 1	10,587	-168	10,419
BAYSIDE 1	7,315	-291	7,024
BAYSIDE 2	7,456	-282	7,174

(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 2013 - DECEMBER 2013

WEIGHTING FACTOR = 11.53%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	64.2	71.5	74.9
POH	576.0	950.1	576.0
FOH + EFOH	2,442.0	1,328.1	1,391.7
MOH + EMOH	117.9	218.1	228.5
POF	6.6	10.8	6.6
EFOF	27.9	15.2	15.9
EMOF	1.3	2.5	2.6
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 950.1} \times (1328.1 + 218.1) = 1{,}620.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1620.3}{8760.0} \times 100 = 74.9$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 4.04%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	74.8	75.6	75.2
POH	576.0	531.2	576.0
FOH + EFOH	1,324.2	1,042.3	1,036.6
MOH + EMOH	310.5	559.6	556.6
POF	6.6	6.1	6.6
EFOF	15.1	11.9	11.8
EMOF	3.5	6.4	6.4
	1.073	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 531.2} \times (1042.3 + 559.6) = 1{,}593.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1593.2}{8760.0} \times 100 = 75.2$$

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 2013 - DECEMBER 2013

WEIGHTING FACTOR = 2.73%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	60.8	66.5	70.0
POH	1,847.0	2,188.3	1,847.0
FOH + EFOH	1,450.8	352.1	370.4
MOH + EMOH	137.6	390.2	410.5
POF	21.1	25.0	21.1
EFOF	16.6	4.0	4.2
EMOF	1.6	4.5	4.7
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1847}{8760 - 2188.3} \times (352.1 + 390.2) = 780.9$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 21.1 - \frac{780.9}{8760.0} \times 100 = 70.0$$

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 2013 - DECEMBER 2013

WEIGHTING FACTOR = 5.26%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	83.6	77.6	76.1
POH	576.0	422.1	576.0
FOH + EFOH	704.6	1,312.1	1,287.9
MOH + EMOH	152.1	231.3	227.0
POF	6.6	4.8	6.6
EFOF	8.0	15.0	14.7
EMOF	1.7	2.6	2.6
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 422.1} \times (1312.1 + 231.3) = 1{,}514.9$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1514.9}{8760.0} \times 100 = 76.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 1.08%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**	**ADJUSTED ACTUAL PERFORMANCE**
PH	8,760.0	8,760.0	8,760.0
EAF	75.1	79.6	85.0
POH	841.0	1,337.2	841.0
FOH + EFOH	1,200.5	191.0	203.8
MOH + EMOH	137.5	256.2	273.3
POF	9.6	15.3	9.6
EFOF	13.7	2.2	2.3
EMOF	1.6	2.9	3.1
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 841}{8760 - 1337.2} \times (191 + 256.2) = 477.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 9.6 - \frac{477.1}{8760.0} \times 100 = 85.0$$

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
BAYSIDE UNIT NO. 1
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 1.50%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	94.1	88.6	87.7
POH	432.0	334.6	432.0
FOH + EFOH	0.0	132.7	131.2
MOH + EMOH	84.3	527.3	521.2
POF	4.9	3.8	4.9
EFOF	0.0	1.5	1.5
EMOF	1.0	6.0	5.9

-10.000 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 432}{8760 - 334.6} \times (132.7 + 527.3) = 652.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 4.9 - \frac{652.4}{8760.0} \times 100 = 87.7$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 0.80%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	93.2	83.7	82.5
POH	480.0	357.4	480.0
FOH + EFOH	40.2	751.6	740.6
MOH + EMOH	71.3	316.8	312.2
POF	5.5	4.1	5.5
EFOF	0.5	8.6	8.5
EMOF	0.8	3.6	3.6

-10.000 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 480}{8760 - 357.4} \times (751.6 + 316.8) = 1{,}052.8$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.5 - \frac{1052.8}{8760.0} \times 100 = 82.5$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 17.14%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,530	10,530
NET GENERATION (GWH)	2,050.9	2,297.9
OPERATING BTU (10^9)	21,426.6	24,197.9
NET OUTPUT FACTOR	85.1	88.0

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-12) + 11551.39 = ANOHR

88 * (-12) + 11551.39 = 10,495

10530 - 10495 = 35

10530 + 35 = 10,565 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 5.75%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,199	10,324
NET GENERATION (GWH)	2,491.6	2,430.5
OPERATING BTU (10^9)	25,256.1	25,091.6
NET OUTPUT FACTOR	87.9	89.5

-5.009 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-11.39) + 11200.35 = ANOHR

89.5 * (-11.39) + 11200.35 = 10,181

10324 - 10181 = 143

10199 + 143 = 10,343 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 10.33%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,614	10,508
NET GENERATION (GWH)	1,716.4	2,140.6
OPERATING BTU (10^9)	17,647.3	22,492.9
NET OUTPUT FACTOR	84.2	92.9

-0.262 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-21.68) + 12438.71 = ANOHR

92.9 * (-21.68) + 12438.71 = 10,425

10508 - 10425 = 83

10614 + 83 = 10,697 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 10.78%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,536	10,454
NET GENERATION (GWH)	2,713.9	2,664.1
OPERATING BTU (10^9)	28,415.1	27,851.2
NET OUTPUT FACTOR	83.6	87.6

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-24.58) + 12591.32 = ANOHR

87.6 * (-24.58) + 12591.32 = 10,438

10454 - 10438 = 16

10536 + 16 = 10,552 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 13.39%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,437	10,587
NET GENERATION (GWH)	1,414.6	1,376.0
OPERATING BTU (10^9)	14,408.9	14,568.2
NET OUTPUT FACTOR	95.3	94.0

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-130.47) + 22869.35 = ANOHR

94 * (-130.47) + 22869.35 = 10,605

10587 - 10605 = -18

10437 + -18 = 10,419 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 8.45%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	7,177	7,315
NET GENERATION (GWH)	3,271.7	3,106.1
OPERATING BTU (10^9)	24,432.0	22,720.8
NET OUTPUT FACTOR	83.4	59.2

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-12) + 11551.39 = ANOHR

59.2 * (-12.03) + 8180.22 = 7,468

7315 - 7468 = -153

7177 + -153 = 7,024 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2013 - DECEMBER 2013

WEIGHTING FACTOR = 7.21%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	7,325	7,456
NET GENERATION (GWH)	4,703.6	4,157.4
OPERATING BTU (10^9)	35,167.3	30,998.7
NET OUTPUT FACTOR	83.1	52.9

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-12) + 11551.39 = ANOHR

52.9 * (-9.35) + 8101.44 = 7,607

7456 - 7607 = -151

7325 + -151 = 7,174 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

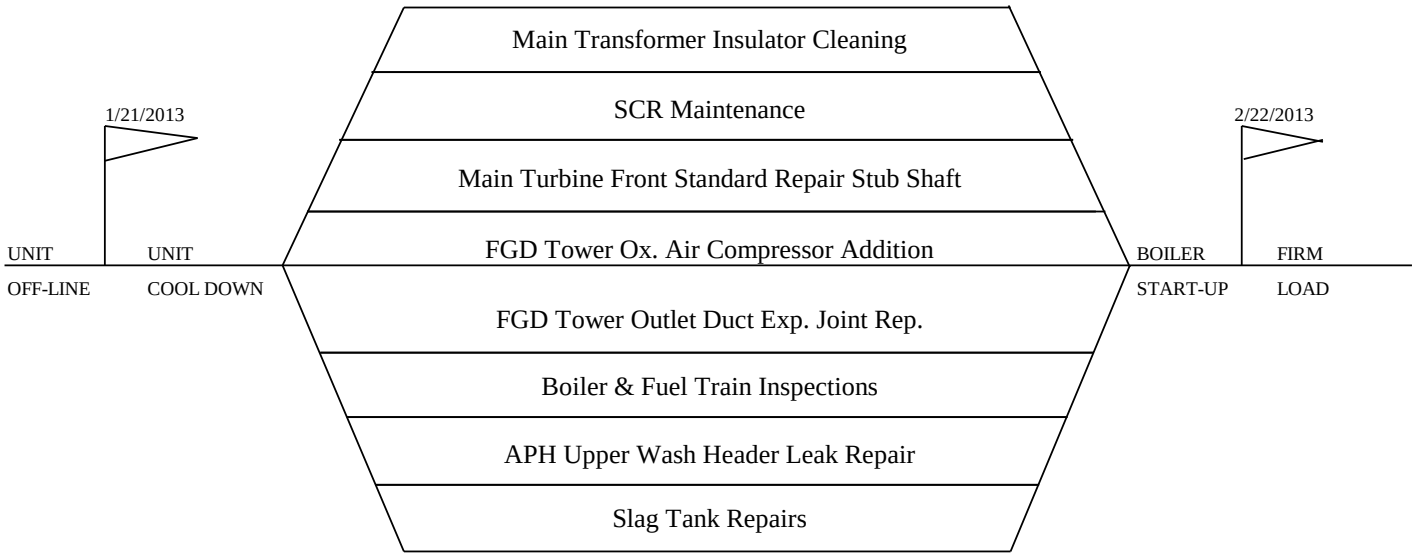
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2013 - DECEMBER 2013

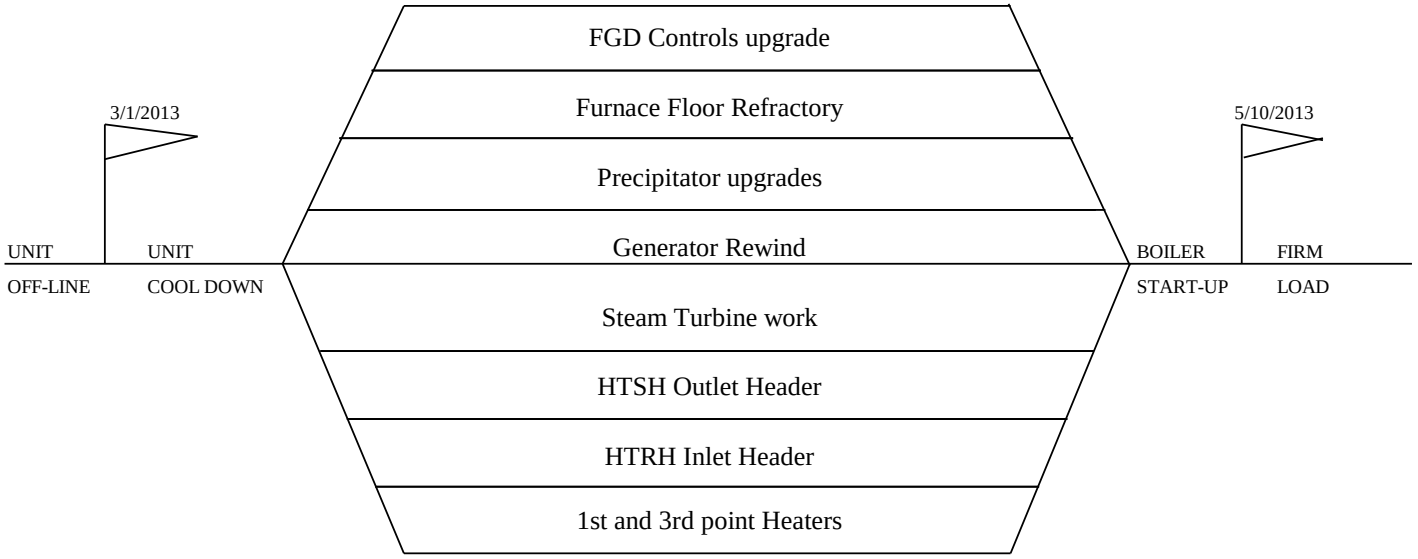
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Jan 21	-	Feb 22	FGD Tower Ox. Air Compressor Addition, FGD Tower Outlet Duct Exp. Joint Rep., Main Turbine Front Standard Repair Stub Shaft, Main Transformer Insulator Cleaning, SCR Maintenance, Boiler & Fuel Train Inspections, APH Upper Wash Header Leak Repair, Slag Tank Repairs
	BIG BEND 2	Jan 22	-	Feb 09	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 3	Mar 01	-	May 10	Generator Rewind, Precipitator upgrades, HTSH Outlet Header, HTRH Inlet Header, Steam Turbine work, 1st and 3rd point Heaters, Furnace Floor Refractory, Slag Tank Necks, FGD Controls upgrade, FGD Inlet & Outlet Duct work
		Oct 24	-	Nov 05	Fuel System Cleanup
	BIG BEND 4	Feb 11	-	Mar 01	Fuel System Cleanup and FGD/SCR work
		Sep 26	-	Oct 13	Fuel System Cleanup
+	POLK 1	Apr 14	-	Jun 08	CT and Gasifier Inspection, Replace MAC Motor, Replace Gox Motor and Compressor Wheel, Replace ASU Dgan Motor, Natural Gas S/U Fuel Conversion, Replace Catalyst and clean towers, Aux Boiler Natural Gas Conversion, Geho Pump Inspection; added MkVIe Controls Upgrade
	BAYSIDE 1	Mar 10	-	Mar 18	Fuel System Cleanup
		Nov 17	-	Nov 24	Fuel System Cleanup
	BAYSIDE 2	Mar 31	-	Apr 08	Fuel System Cleanup
		Nov 08	-	Nov 15	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 2013 - DECEMBER 2013

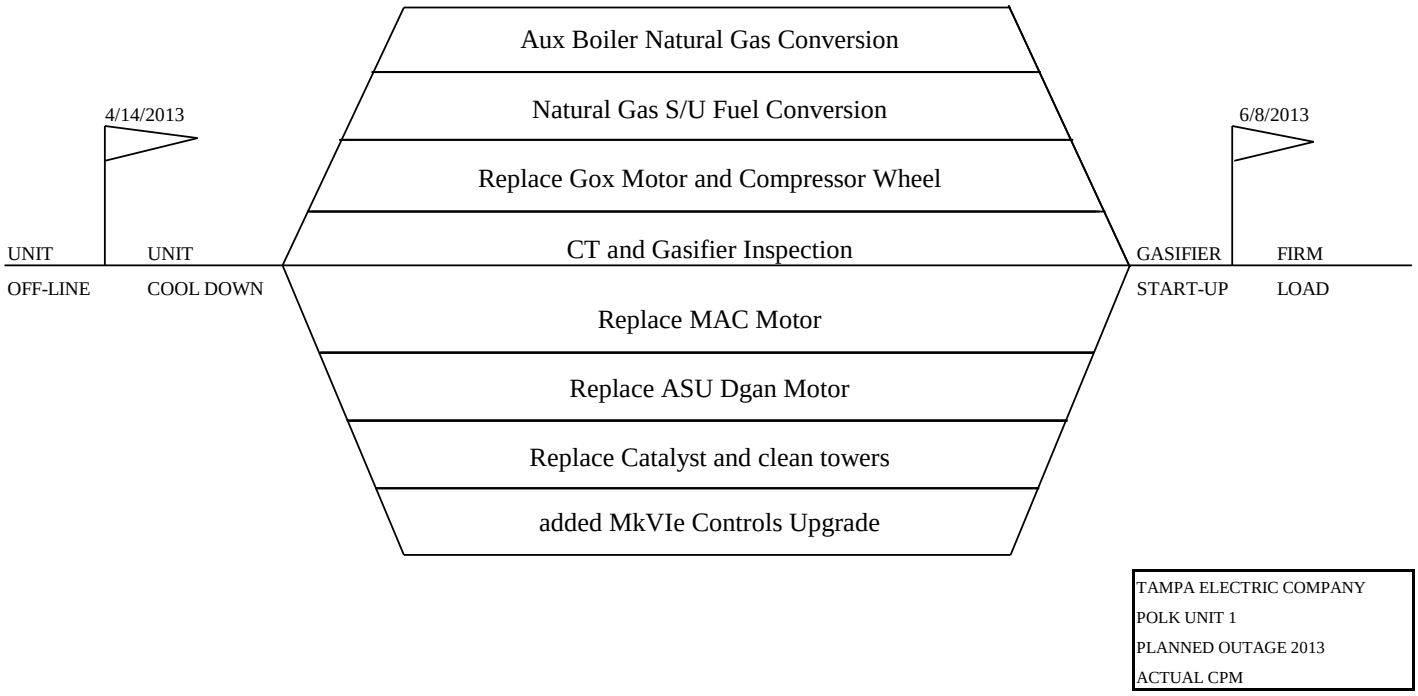


TAMPA ELECTRIC COMPANY
BIG BEND UNIT 1
PLANNED OUTAGE 2013
ACTUAL CPM



TAMPA ELECTRIC COMPANY
BIG BEND UNIT 3
PLANNED OUTAGE 2013
ACTUAL CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2013 - DECEMBER 2013



TAMPA ELECTRIC COMPANY
POLK UNIT 1
PLANNED OUTAGE 2013
ACTUAL CPM

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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 ← **EAF POINTS 10.000**	2,791.3	**Adjusted EAF 74.9** → 70.4	+10	4,150.0	9,876
+9	2,512.1	69.8	+9	3,735.0	9,934
+8	2,233.0	69.1	+8	3,320.0	9,992
+7	1,953.9	68.5	+7	2,905.0	10,050
+6	1,674.8	67.9	+6	2,490.0	10,108
+5	1,395.6	67.3	+5	2,075.0	10,166
+4	1,116.5	66.7	+4	1,660.0	10,223
+3	837.4	66.1	+3	1,245.0	10,281
+2	558.3	65.4	+2	830.0	10,339
+1	279.1	64.8	+1	415.0	10,397
					10,455
0	0.0	64.2	0 ← **AHR POINTS 0.000**	0.0	**Adjusted ANOHR 10,565** → 10,530
					10,605
-1	(85.2)	63.0	-1	(415.0)	10,662
-2	(170.3)	61.7	-2	(830.0)	10,720
-3	(255.5)	60.5	-3	(1,245.0)	10,778
-4	(340.7)	59.3	-4	(1,660.0)	10,836
-5	(425.8)	58.0	-5	(2,075.0)	10,894
-6	(511.0)	56.8	-6	(2,490.0)	10,952
-7	(596.2)	55.6	-7	(2,905.0)	11,009
-8	(681.3)	54.3	-8	(3,320.0)	11,067
-9	(766.5)	53.1	-9	(3,735.0)	11,125
-10	(851.7)	51.9	-10	(4,150.0)	11,183
Weighting Factor =		11.53%	Weighting Factor =		17.14%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	978.4	78.8	+10	1,393.2	9,986
+9	880.5	78.4	+9	1,253.8	10,000
+8	782.7	78.0	+8	1,114.5	10,014
+7	684.9	77.6	+7	975.2	10,028
+6	587.0	77.2	+6	835.9	10,041
+5	489.2	76.8	+5	696.6	10,055
+4	391.3	76.4	+4	557.3	10,069
+3	293.5	76.0	+3	417.9	10,083
+2	195.7	75.6	+2	278.6	10,097
+1	97.8	75.2	+1	139.3	10,110
					10,124
0	0.0	74.8	0	0.0	10,199
					10,274
-1	(10.7)	74.0	-1	(139.3)	10,288
-2	(21.3)	73.1	-2	(278.6)	10,302
-3	(32.0)	72.3	-3	(417.9)	10,315
-4	(42.6)	71.5	-4	(557.3)	10,329
-5	(53.3)	70.7	-5	(696.6)	10,343
-6	(64.0)	69.9	-6	(835.9)	10,357
-7	(74.6)	69.1	-7	(975.2)	10,370
-8	(85.3)	68.3	-8	(1,114.5)	10,384
-9	(95.9)	67.5	-9	(1,253.8)	10,398
-10	(106.6)	66.7	-10	(1,393.2)	10,412

EAF POINTS 1.073

Adjusted EAF 75.2

AHR POINTS -5.009

Adjusted ANOHR 10,343

Weighting Factor = 4.04%

Weighting Factor = 5.75%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	662.2	65.5	+10	2,502.4	10,226
+9	596.0	65.0	+9	2,252.2	10,257
+8	529.8	64.5	+8	2,001.9	10,289
+7	463.6	64.1	+7	1,751.7	10,320
+6	397.3	63.6	+6	1,501.5	10,351
+5	331.1	63.1	+5	1,251.2	10,383
+4	264.9	62.7	+4	1,001.0	10,414
+3	198.7	62.2	+3	750.7	10,445
+2	132.4	61.7	+2	500.5	10,476
+1	66.2	61.3	+1	250.2	10,508
					10,539
0	0.0	60.8	0	0.0	10,614
					10,689
-1	(219.9)	59.8	-1	(250.2)	10,720
-2	(439.8)	58.9	-2	(500.5)	10,751
-3	(659.7)	58.0	-3	(750.7)	10,783
-4	(879.6)	57.0	-4	(1,001.0)	10,814
-5	(1,099.5)	56.1	-5	(1,251.2)	10,845
-6	(1,319.4)	55.2	-6	(1,501.5)	10,876
-7	(1,539.3)	54.2	-7	(1,751.7)	10,908
-8	(1,759.2)	53.3	-8	(2,001.9)	10,939
-9	(1,979.1)	52.4	-9	(2,252.2)	10,970
-10	(2,199.0)	51.4	-10	(2,502.4)	11,001

EAF POINTS 10.000

Adjusted EAF 70.0

AHR POINTS -0.262

Adjusted ANOHR 10,697

Weighting Factor = 2.73%

Weighting Factor = 10.33%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	1,274.6	85.9	+10	2,611.5	10,124
+9	1,147.1	85.7	+9	2,350.3	10,157
+8	1,019.7	85.5	+8	2,089.2	10,191
+7	892.2	85.2	+7	1,828.0	10,225
+6	764.8	85.0	+6	1,566.9	10,258
+5	637.3	84.8	+5	1,305.7	10,292
+4	509.8	84.6	+4	1,044.6	10,326
+3	382.4	84.3	+3	783.4	10,360
+2	254.9	84.1	+2	522.3	10,393
+1	127.5	83.9	+1	261.1	10,427
					10,461
0	0.0	83.6	0	0.0	10,536
					10,611
-1	(116.0)	83.2	-1	(261.1)	10,644
-2	(232.0)	82.7	-2	(522.3)	10,678
-3	(348.0)	82.3	-3	(783.4)	10,712
-4	(464.1)	81.8	-4	(1,044.6)	10,745
-5	(580.1)	81.4	-5	(1,305.7)	10,779
-6	(696.1)	80.9	-6	(1,566.9)	10,813
-7	(812.1)	80.4	-7	(1,828.0)	10,846
-8	(928.1)	80.0	-8	(2,089.2)	10,880
-9	(1,044.1)	79.5	-9	(2,350.3)	10,914
-10	(1,160.2)	79.1	-10	(2,611.5)	10,947

EAF POINTS -10.000

Adjusted EAF 76.1

AHR POINTS 0.000

Adjusted ANOHR 10,552

Weighting Factor = 5.26%

Weighting Factor = 10.78%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	**EAF POINTS 10.000**	261.8	**Adjusted EAF 85.0**	78.7	+10		3,242.8		9,832
+9		235.6		78.3	+9		2,918.5		9,885
+8		209.4		78.0	+8		2,594.2		9,938
+7		183.3		77.6	+7		2,270.0		9,991
+6		157.1		77.2	+6		1,945.7		10,044
+5		130.9		76.9	+5		1,621.4		10,097
+4		104.7		76.5	+4		1,297.1		10,150
+3		78.5		76.2	+3		972.8		10,203
+2		52.4		75.8	+2		648.6		10,256
+1		26.2		75.5	+1		324.3		10,309
									10,362
0		0.0		75.1	0	**AHR POINTS 0.000**	0.0	**Adjusted ANOHR 10,419**	10,437
									10,512
-1		(47.3)		74.4	-1		(324.3)		10,565
-2		(94.6)		73.7	-2		(648.6)		10,618
-3		(141.9)		73.0	-3		(972.8)		10,671
-4		(189.2)		72.3	-4		(1,297.1)		10,724
-5		(236.5)		71.6	-5		(1,621.4)		10,777
-6		(283.8)		70.9	-6		(1,945.7)		10,830
-7		(331.1)		70.2	-7		(2,270.0)		10,883
-8		(378.4)		69.5	-8		(2,594.2)		10,936
-9		(425.7)		68.8	-9		(2,918.5)		10,989
-10		(473.0)		68.1	-10		(3,242.8)		11,042

Weighting Factor = 1.08%

Weighting Factor = 13.39%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	364.1	94.5	+10	2,046.5	7,027
+9	327.7	94.5	+9	1,841.8	7,034
+8	291.3	94.5	+8	1,637.2	7,042
+7	254.9	94.4	+7	1,432.5	7,049
+6	218.4	94.4	+6	1,227.9	7,057
+5	182.0	94.3	+5	1,023.2	7,064
+4	145.6	94.3	+4	818.6	7,072
+3	109.2	94.2	+3	613.9	7,079
+2	72.8	94.2	+2	409.3	7,087
+1	36.4	94.2	+1	204.6	7,094
					7,102
0	0.0	94.1	0	0.0	7,177
					7,252
-1	(77.3)	94.0	-1	(204.6)	7,259
-2	(154.6)	93.9	-2	(409.3)	7,267
-3	(231.8)	93.8	-3	(613.9)	7,274
-4	(309.1)	93.8	-4	(818.6)	7,282
-5	(386.4)	93.7	-5	(1,023.2)	7,289
-6	(463.7)	93.6	-6	(1,227.9)	7,297
-7	(541.0)	93.5	-7	(1,432.5)	7,304
-8	(618.3)	93.4	-8	(1,637.2)	7,312
-9	(695.5)	93.3	-9	(1,841.8)	7,319
-10	(772.8)	93.2	-10	(2,046.5)	7,327

EAF POINTS -10.000

Adjusted EAF 87.7

AHR POINTS 10.000

Adjusted ANOHR 7,024

Weighting Factor = 1.50%

Weighting Factor = 8.45%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2013 - DECEMBER 2013

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	193.5	93.8	+10	1,745.4	7,196
+9	174.2	93.7	+9	1,570.9	7,201
+8	154.8	93.7	+8	1,396.3	7,207
+7	135.5	93.6	+7	1,221.8	7,212
+6	116.1	93.6	+6	1,047.3	7,218
+5	96.8	93.5	+5	872.7	7,223
+4	77.4	93.5	+4	698.2	7,228
+3	58.1	93.4	+3	523.6	7,234
+2	38.7	93.4	+2	349.1	7,239
+1	19.4	93.3	+1	174.5	7,244
					7,250
0	0.0	93.2	0	0.0	7,325
					7,400
-1	(6.1)	93.1	-1	(174.5)	7,405
-2	(12.1)	93.0	-2	(349.1)	7,411
-3	(18.2)	92.9	-3	(523.6)	7,416
-4	(24.2)	92.8	-4	(698.2)	7,421
-5	(30.3)	92.7	-5	(872.7)	7,427
-6	(36.3)	92.6	-6	(1,047.3)	7,432
-7	(42.4)	92.5	-7	(1,221.8)	7,437
-8	(48.4)	92.4	-8	(1,396.3)	7,443
-9	(54.5)	92.3	-9	(1,570.9)	7,448
-10	(60.5)	92.2	-10	(1,745.4)	7,454

EAF POINTS -10.000

Adjusted EAF 82.5

AHR POINTS 10.000

Adjusted ANOHR 7,174

Weighting Factor = 0.80%

Weighting Factor = 7.21%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 13 - DEC 13 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 13 - DEC 13 POF	EUOF	EUOR
BIG BEND 1	11.53%	42.8%	6.6	29.2	31.3	10.8	17.6	19.8
BIG BEND 2	4.04%	15.0%	6.6	18.7	20.0	6.1	18.3	19.5
BIG BEND 3	2.73%	10.1%	21.1	18.1	23.0	25.0	8.5	11.3
BIG BEND 4	5.26%	19.5%	6.6	9.8	10.5	4.8	17.6	18.5
POLK 1	1.08%	4.0%	9.6	15.3	16.9	15.3	5.1	6.0
BAYSIDE 1	1.50%	5.6%	4.9	15.3	16.1	15.3	5.1	6.0
BAYSIDE 2	0.80%	3.0%	5.5	15.3	16.2	15.3	5.1	6.0
GPIF SYSTEM	**26.9%**	**100.0%**	**8.0**	**21.0**	**22.8**	**10.9**	**15.2**	**16.9**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (% **71.0** **73.8**

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
8.6	**16.5**	**18.1**	**74.9**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 13 - DEC 13	ADJUSTED ACTUAL HEAT RATE JAN 13 - DEC 13
BIG BEND 1	17.14%	23.5%	10,530	10,565
BIG BEND 2	5.75%	7.9%	10,199	10,343
BIG BEND 3	10.33%	14.1%	10,614	10,697
BIG BEND 4	10.78%	14.8%	10,536	10,552
POLK 1	13.39%	18.3%	10,437	10,419
BAYSIDE 1	8.45%	11.6%	7,177	7,024
BAYSIDE 2	7.21%	9.9%	7,325	7,174
GPIF SYSTEM	**73.1%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) **9,795** **9,793**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2013 - DECEMBER 2013

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 = 11.53% * (BB 1 EAP) + 4.04% * (BB 2 EAP) + 2.73% * (BB 3 EAP)
+ 5.26% * (BB 4 EAP) + 1.08% * (PK 1 EAP) + 1.50% * (BAY 1 EAP)
+ 0.80% * (BAY 2 EAP) + 17.14% * (BB 1 AHRP) + 5.75% * (BB 2 AHRP)
+ 10.33% * (BB 3 AHRP) + 10.78% * (BB 4 AHRP) + 13.39% * (PK 1 AHRP)
+ 8.45% * (BAY 1 AHRP) + 7.21% * (BAY 2 AHRP)

GPIP = 11.53% * 10.000 + 4.04% * 1.073 + 2.73% * 10.000
+ 5.26% * -10.000 + 1.08% * 10.000 + 1.50% * -10.000
+ 0.80% * -10.000 + 17.14% * 0.000 + 5.75% * -5.009
+ 10.33% * -0.262 + 10.78% * 0.000 + 13.39% * 0.000
+ 8.45% * 10.000 + 7.21% * 10.000

GPIP = 1.153 + 0.043 + 0.273
+ -0.526 + 0.108 + -0.150
+ -0.080 + 0.000 + -0.288
+ -0.027 + 0.000 + 0.000
+ 0.845 + 0.721

GPIP = 2.071 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 PENALTY = $1,689,728

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 140001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2013 – DECEMBER 2013

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.13A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	16.4	14.3	78.8	87.3	88.0	80.1	93.2	97.2	90.6	69.5	74.9	64.1	71.5
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	122.4	159.0	663.7	651.8	659.0	601.3	716.6	744.0	700.4	563.9	559.5	601.7	6,743.3
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	621.6	513.0	79.3	68.2	85.0	118.8	27.4	0.0	19.6	180.1	161.5	142.3	2,016.7
6. POH	257.0	513.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.1	0.0	0.0	950.1
7. FOH	364.6	0.0	79.3	68.2	85.0	118.8	27.4	0.0	19.6	0.0	143.5	0.0	906.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	142.3	160.3
9. PFOH	26.3	148.0	299.7	76.9	40.2	129.0	229.8	206.9	599.0	354.9	323.2	304.6	2,738.5
10. LR PF (MW)	7.7	168.1	98.8	115.9	18.1	25.0	21.2	23.9	26.5	43.5	23.5	155.9	59.8
11. PMOH	0.8	0.0	22.9	1.7	8.0	81.7	23.5	21.3	18.3	21.2	0.3	16.5	216.4
12. LR PM (MW)	0.0	0.0	50.1	0.0	120.4	76.8	170.8	138.6	147.4	117.5	0.0	114.5	103.7
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	387.3
14. OPR BTU(GBTU)	487.1	374.1	2,297.4	2,468.5	2,545.9	2,244.6	2,606.3	2,833.7	2,540.1	1,988.0	2,055.1	1,757.0	24,197.9
15. NET GEN (MWH)	45,745	32,994	218,329	237,862	240,612	212,558	251,543	270,885	241,178	187,132	195,527	163,530	2,297,894
16. ANOHR (BTU/KWH)	10,648.1	11,337.2	10,522.5	10,377.8	10,581.1	10,559.9	10,361.3	10,461.0	10,532.1	10,623.7	10,510.8	10,744.3	10,530.0
17. NOF (%)	94.6	52.5	83.3	94.8	94.8	91.8	91.2	94.6	89.4	86.2	90.8	68.8	88.0
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(-12.004)+ 11,551												

EXHIBIT NO. _____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 140001 - EI
DOCUMENT NO. 2
PAGE 1 OF 7

ORIGINAL SHEET NO. 8.401.13A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	36.5	50.3	96.8	76.3	98.6	96.5	92.1	63.9	95.1	85.2	58.3	56.7	75.6
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	278.2	433.3	743.0	577.4	744.0	720.0	744.0	494.9	720.0	644.1	422.9	481.0	7,002.8
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	465.8	238.7	0.0	142.6	0.0	0.0	0.0	249.1	0.0	99.9	298.1	263.0	1,757.2
6. POH	217.4	213.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.9	0.0	0.0	531.2
7. FOH	248.4	24.8	0.0	0.0	0.0	0.0	0.0	249.1	0.0	0.0	187.5	0.0	709.8
8. MOH	0.0	0.0	0.0	142.6	0.0	0.0	0.0	0.0	0.0	0.0	110.6	263.0	516.2
9. PFOH	93.6	296.0	97.4	116.7	47.1	370.4	702.6	193.9	404.7	72.0	11.3	193.8	2,599.4
10. LR PF (MW)	26.4	127.1	74.4	93.0	53.4	23.3	25.6	33.0	22.2	54.6	28.2	114.4	49.7
11. PMOH	15.0	0.7	16.2	1.6	12.8	5.6	35.7	9.1	35.5	6.0	4.7	14.1	157.0
12. LR PM (MW)	4.7	0.0	138.4	0.0	125.5	191.2	128.3	114.9	129.0	0.0	123.5	76.2	107.3
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	387.8
14. OPR BTU(GBTU)	1,011.8	1,335.0	2,762.7	2,053.6	2,862.9	2,660.5	2,623.3	1,788.9	2,594.5	2,348.5	1,525.6	1,524.1	25,091.6
15. NET GEN (MWH)	101,821	119,862	271,581	202,976	278,394	259,235	249,537	172,064	249,411	228,133	149,104	148,376	2,430,494
16. ANOHR (BTU/KWH)	9,937.2	11,138.1	10,172.7	10,117.6	10,283.6	10,262.9	10,512.8	10,397.0	10,402.6	10,294.4	10,231.7	10,272.2	10,324.0
17. NOF (%)	92.6	70.0	92.5	91.3	97.2	93.5	87.1	90.3	90.0	92.0	91.6	78.1	89.5
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(-11.395) + 11,200

ORIGINAL SHEET NO. 8.401.13A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	84.0	79.0	2.1	0.0	32.8	87.8	89.6	95.3	81.5	73.3	83.2	90.7	66.5
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	672.0	21.1	0.0	254.6	644.7	744.0	726.2	648.3	552.1	602.4	703.9	6,313.3
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	721.9	720.0	489.4	75.3	0.0	17.8	71.7	191.9	118.6	40.1	2,446.7
6. POH	0.0	0.0	721.9	720.0	435.9	0.0	0.0	0.0	0.0	191.9	118.6	0.0	2,188.3
7. FOH	0.0	0.0	0.0	0.0	27.5	0.0	0.0	17.8	71.7	0.0	0.0	0.0	117.0
8. MOH	0.0	0.0	0.0	0.0	26.0	75.3	0.0	0.0	0.0	0.0	0.0	40.1	141.4
9. PFOH	342.2	23.0	0.0	0.0	52.7	36.8	171.7	37.7	212.2	4.0	3.9	74.4	958.5
10. LR PF (MW)	58.5	113.4	0.0	0.0	56.5	99.5	153.8	68.5	80.7	83.5	101.5	130.9	89.5
11. PMOH	401.8	649.0	21.1	0.0	4.3	10.1	22.1	32.7	56.0	22.5	11.6	9.6	1,240.7
12. LR PM (MW)	58.6	75.5	88.9	0.0	205.9	101.7	82.2	112.7	94.8	98.7	51.4	87.4	73.2
13. NSC (MW)	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0
14. OPR BTU(GBTU)	2,382.3	2,039.7	50.5	0.0	877.5	2,378.6	2,624.3	2,801.3	2,265.4	2,122.2	2,355.5	2,595.6	22,492.9
15. NET GEN (MWH)	220,461	188,638	4,505	0	86,122	232,486	249,965	266,551	214,246	203,784	225,988	247,829	2,140,575
16. ANOHR BTU/KWH	10,806.2	10,812.5	11,206.8	0.0	10,189.1	10,231.2	10,498.7	10,509.5	10,573.7	10,414.1	10,422.9	10,473.5	10,508.0
17. NOF (%)	81.2	76.9	58.5	0.0	92.7	98.8	92.0	100.6	90.5	101.1	102.8	96.5	92.9
18. NPC (MW)	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0

19. ANOHR EQUATION ANOHR = NOF(-21.678) + 12,439

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 140001 - EI
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ORIGINAL SHEET NO. 8.401.13A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	56.7	22.4	92.4	99.5	85.0	55.1	92.3	92.1	70.3	94.2	76.5	89.9	77.6
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	261.8	722.1	720.0	671.8	409.3	690.5	694.7	507.1	703.9	573.0	710.5	7,408.6
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	410.3	20.9	0.0	72.2	310.7	53.5	49.3	212.9	40.1	148.0	33.5	1,351.4
6. POH	0.0	410.3	11.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	422.1
7. FOH	0.0	0.0	9.0	0.0	72.2	310.7	53.5	49.3	212.9	0.0	22.8	4.3	734.7
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.1	125.3	29.2	194.6
9. PFOH	738.5	261.8	269.5	30.7	593.0	111.5	0.0	94.2	15.2	2.0	287.2	296.0	2,699.6
10. LR PF (MW)	180.4	177.3	43.9	4.6	25.2	16.1	0.0	41.5	22.6	170.5	30.6	51.1	87.8
11. PMOH	5.5	0.0	16.0	9.6	14.8	12.0	10.0	3.0	1.3	7.1	0.2	12.8	92.1
12. LR PM (MW)	222.4	0.0	193.2	141.2	77.6	282.1	164.6	0.0	0.0	143.3	0.0	172.4	163.4
13. NSC (MW)	417.0	417.0	417.0	407.0	407.0	407.0	407.0	407.0	407.0	407.0	407.0	417.0	410.3
14. OPR BTU(GBTU)	1,903.3	658.7	2,742.5	2,996.5	2,680.7	1,637.3	2,723.2	2,843.7	2,031.2	2,821.6	2,182.0	2,630.5	27,851.2
15. NET GEN (MWH)	172,056	60,827	269,732	288,798	253,441	155,428	260,830	269,066	196,987	273,149	208,937	254,826	2,664,076
16. ANOHR BTU/KWH	11,062.4	10,829.7	10,167.4	10,375.6	10,577.1	10,534.3	10,440.4	10,568.9	10,311.5	10,329.9	10,443.1	10,322.8	10,454.0
17. NOF (%)	55.5	55.7	89.6	98.6	92.7	93.3	92.8	95.2	95.5	95.3	89.6	86.0	87.6
18. NPC (MW)	417.0	417.0	417.0	407.0	407.0	407.0	407.0	407.0	407.0	407.0	407.0	417.0	410.3

19. ANOHR EQUATION ANOHR = NOF(-24.581) + 12,591

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	93.9	85.7	98.7	43.3	0.0	55.1	96.6	99.5	100.0	98.7	84.1	99.3	79.6
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	698.6	443.5	717.9	184.9	0.0	396.8	695.2	740.0	720.0	734.6	583.3	739.1	6,653.9
4. RSH	0.0	132.3	15.3	127.1	0.0	0.0	23.6	0.0	0.0	0.0	23.4	0.0	321.6
5. UH	45.4	96.1	9.8	408.0	744.0	323.2	25.2	4.0	0.0	9.4	114.3	4.9	1,784.4
6. POH	0.0	0.0	0.0	408.0	744.0	185.3	0.0	0.0	0.0	0.0	0.0	0.0	1,337.2
7. FOH	45.4	20.0	9.8	0.0	0.0	62.2	25.2	4.0	0.0	9.4	10.0	4.9	191.0
8. MOH	0.0	76.1	0.0	0.0	0.0	75.8	0.0	0.0	0.0	0.0	104.3	0.0	256.2
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)	1,627.8	1,004.0	1,587.9	410.2	0.0	759.3	1,499.4	1,631.2	1,593.8	1,609.3	1,203.8	1,641.7	14,568.2
15. NET GEN (MWH)	152,120	92,880	153,212	34,073	-4,609	59,478	139,297	161,894	153,099	160,558	113,507	160,486	1,375,996
16. ANOHR BTU/KWH	10,700.7	10,809.2	10,364.0	12,038.4	0.0	12,765.9	10,763.7	10,075.5	10,410.2	10,023.1	10,605.2	10,229.8	10,587.0
17. NOF (%)	99.0	95.2	97.0	83.7	0.0	68.1	91.1	99.4	96.7	99.4	88.5	98.7	94.0
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(-130.472) + 22,869

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	99.9	100.0	72.8	100.0	99.6	99.1	99.0	96.6	95.9	86.3	51.0	63.5	88.6
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	564.4	672.0	571.5	720.0	744.0	720.0	744.0	744.0	702.0	664.2	408.9	0.0	7,255.0
4. RSH	179.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	481.3	809.8
5. UH	0.0	0.0	171.5	0.0	0.0	0.0	0.0	0.0	18.0	79.8	163.1	262.7	695.2
6. POH	0.0	0.0	171.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	163.1	0.0	334.6
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	79.8	0.0	8.6	106.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.1	254.1
9. PFOH	2.8	0.0	0.0	1.0	4.5	19.5	0.8	0.0	11.9	14.1	0.0	27.6	82.1
10. LR PF (MW)	264.0	0.0	0.0	233.7	233.7	233.7	233.7	0.0	216.2	185.2	0.0	264.0	234.1
11. PMOH	0.0	0.0	101.0	0.0	4.4	0.0	22.6	75.9	22.7	55.2	570.3	0.0	852.0
12. LR PM (MW)	0.0	0.0	240.5	0.0	233.7	0.0	233.7	233.7	233.7	233.7	233.7	0.0	234.5
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	723.7
14. OPR BTU(GBTU)	2,068.9	2,603.5	1,412.2	2,422.6	2,282.6	2,451.6	2,089.2	2,295.2	2,081.7	1,747.6	1,265.7	0.0	22,720.8
15. NET GEN (MWH)	283,302	361,640	190,076	331,371	312,471	336,597	284,611	315,569	283,891	236,579	170,850	-830	3,106,128
16. ANOHR (BTU/KWH)	7,302.9	7,199.1	7,429.9	7,310.8	7,305.1	7,283.4	7,340.4	7,273.1	7,332.7	7,386.9	7,408.5	0.0	7,315.0
17. NOF (%)	63.4	67.9	42.0	65.7	59.9	66.7	54.6	60.5	57.7	50.8	59.6	0.0	59.2
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(-12.033) + 8,180

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

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 13	FEB 13	MAR 13	APR 13	MAY 13	JUN 13	JUL 13	AUG 13	SEP 13	OCT 13	NOV 13	DEC 13	2013
1. EAF (%)	72.4	75.0	71.6	62.9	98.0	99.7	98.2	93.4	99.7	98.2	38.3	99.5	83.7
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	485.0	672.0	741.3	537.5	734.8	718.2	744.0	744.0	720.0	744.0	540.9	744.0	8,125.8
4. RSH	259.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	259.0
5. UH	0.0	0.0	1.7	182.5	9.2	1.8	0.0	0.0	0.0	0.0	180.1	0.0	375.2
6. POH	0.0	0.0	1.7	175.6	0.0	0.0	0.0	0.0	0.0	0.0	180.1	0.0	357.4
7. FOH	0.0	0.0	0.0	0.0	9.2	1.8	0.0	0.0	0.0	0.0	0.0	0.0	11.0
8. MOH	0.0	0.0	0.0	6.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8
9. PFOH	744.0	672.0	743.0	337.8	22.5	1.5	0.7	16.0	10.0	29.2	132.0	14.2	2,722.8
10. LR PF (MW)	289.2	262.1	261.8	232.3	232.3	232.3	232.3	232.3	232.3	232.3	232.3	261.8	263.4
11. PMOH	0.0	0.0	95.0	0.0	0.0	0.0	54.0	181.5	0.0	23.0	721.0	0.0	1,074.5
12. LR PM (MW)	0.0	0.0	261.8	0.0	0.0	0.0	232.3	232.3	0.0	232.3	298.5	0.0	279.3
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	967.4
14. OPR BTU(GBTU)	1,988.5	2,594.3	2,257.4	2,174.8	2,954.1	3,426.1	2,588.2	2,919.5	2,840.5	2,616.2	1,723.4	2,915.5	30,998.7
15. NET GEN (MWH)	268,566	351,353	298,785	291,047	396,114	464,273	345,463	392,830	381,200	347,775	228,574	391,459	4,157,439
16. ANOHR (BTU/KWH)	7,404.1	7,383.7	7,555.3	7,472.5	7,457.7	7,379.5	7,492.1	7,431.9	7,451.5	7,522.7	7,539.9	7,447.9	7,456.0
17. NOF (%)	52.9	49.9	38.5	58.3	58.0	69.6	50.0	56.8	57.0	50.3	45.5	50.3	52.9
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(-9.350) + 8,101

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GPIF 2015 PROJECTION FILING
EXHIBIT NO. ____ (BSB-2)
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2015 – DECEMBER 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 47
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Brian S. Buckley BSB-2

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2015 - DECEMBER 2015
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
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
JANUARY 2015 - DECEMBER 2015

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,168,605,000	
Line 2	Month of January	2015	$	2,115,059,000	
Line 3	Month of February	2015	$	2,134,887,678	
Line 4	Month of March	2015	$	2,154,902,250	
Line 5	Month of April	2015	$	2,188,807,209	
Line 6	Month of May	2015	$	2,209,327,276	
Line 7	Month of June	2015	$	2,230,039,719	
Line 8	Month of July	2015	$	2,175,808,872	
Line 9	Month of August	2015	$	2,196,207,081	
Line 10	Month of September	2015	$	2,216,796,522	
Line 11	Month of October	2015	$	2,250,822,187	
Line 12	Month of November	2015	$	2,271,923,645	
Line 13	Month of December	2015	$	2,293,222,929	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,200,493,028	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.17%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	8,993,880	
Line 18	Jurisdictional Sales			18,630,400	MWH
Line 19	Total Sales			18,630,400	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)**		**$**	**8,993,880**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2015 - DECEMBER 2015

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	7.78%	61.2	65.5	52.6	1,197.9	(284.9)
BIG BEND 2	2.04%	75.2	79.2	67.3	314.8	(548.1)
BIG BEND 3	1.49%	79.2	82.4	72.9	229.3	(572.6)
BIG BEND 4	4.13%	80.3	83.2	74.4	635.7	(1,103.8)
POLK 1	0.60%	77.1	79.6	72.0	91.9	(222.1)
BAYSIDE 1	3.39%	89.9	91.2	87.3	522.4	(908.6)
BAYSIDE 2	10.11%	86.6	88.4	83.0	1,556.9	(64.2)
GPIF SYSTEM	**29.53%**					

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	8.43%	10,563	94.8	10,368	10,757	1,299.3	(1,299.3)
BIG BEND 2	11.29%	10,379	92.7	10,149	10,609	1,739.7	(1,739.7)
BIG BEND 3	8.97%	10,495	92.5	10,326	10,664	1,382.3	(1,382.3)
BIG BEND 4	8.86%	10,416	97.6	10,245	10,587	1,365.4	(1,365.4)
POLK 1	16.65%	10,552	96.6	10,020	11,085	2,564.5	(2,564.5)
BAYSIDE 1	6.02%	7,414	52.3	7,322	7,505	928.0	(928.0)
BAYSIDE 2	10.24%	7,447	51.7	7,351	7,542	1,576.8	(1,576.8)
GPIF SYSTEM	**70.47%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	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 13 - DEC 13 POF	ACTUAL PERFORMANCE JAN 13 - DEC 13 EUOF	ACTUAL PERFORMANCE JAN 13 - DEC 13 EUOR	ACTUAL PERFORMANCE JAN 12 - DEC 12 POF	ACTUAL PERFORMANCE JAN 12 - DEC 12 EUOF	ACTUAL PERFORMANCE JAN 12 - DEC 12 EUOR	ACTUAL PERFORMANCE JAN 11 - DEC 11 POF	ACTUAL PERFORMANCE JAN 11 - DEC 11 EUOF	ACTUAL PERFORMANCE JAN 11 - DEC 11 EUOR
BIG BEND 1	7.78%	26.3%	23.0	15.8	20.5	10.8	17.6	19.8	6.8	26.2	28.3	5.8	13.5	14.4
BIG BEND 2	2.04%	6.9%	6.6	18.2	19.5	6.1	18.3	19.5	4	17.9	18.7	17.1	25.4	30.6
BIG BEND 3	1.49%	5.0%	6.6	14.2	15.2	25.0	8.5	11.3	2.8	25	25.7	8.6	17.9	19.5
BIG BEND 4	4.13%	14.0%	6.6	13.1	14.1	4.8	17.6	18.5	8.2	16.2	17.6	9.4	15.1	16.7
POLK 1	0.60%	2.0%	13.7	9.2	10.7	15.3	6.7	8.8	12.7	17.3	21.0	4.4	17.3	17.6
BAYSIDE 1	3.39%	11.5%	4.9	5.2	5.5	3.8	7.5	8.7	1.9	3.0	2.0	21.0	3.3	2.0
BAYSIDE 2	10.11%	34.2%	6.0	7.4	7.9	4.1	12.2	13.1	16.5	7.5	2.9	3.7	7.4	3.2
GPIF SYSTEM	**29.53%**	**100.0%**	**10.7**	**11.3**	**13.0**	**7.3**	**14.0**	**15.4**	**9.5**	**14.9**	**14.2**	**8.2**	**11.6**	**10.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**78.1**			**78.7**			**75.6**			**80.2**	

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
8.3	**13.5**	**13.5**	**78.2**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 13 - DEC 13	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 11 - DEC 11
BIG BEND 1	8.43%	12.0%	10,563	10,546	10,485	10,719
BIG BEND 2	11.29%	16.0%	10,379	10,303	10,362	10,254
BIG BEND 3	8.97%	12.7%	10,495	10,516	10,468	10,346
BIG BEND 4	8.86%	12.6%	10,416	10,445	10,427	10,310
POLK 1	16.65%	23.6%	10,552	10,465	10,503	10,364
BAYSIDE 1	6.02%	8.5%	7,414	7,403	7,382	7,348
BAYSIDE 2	10.24%	14.5%	7,447	7,464	7,401	7,409
GPIF SYSTEM	**70.47%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,782**	**9,755**	**9,747**	**9,693**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2015 - DECEMBER 2015
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	596,119.8	594,921.9	1,197.9	7.78%
EA_2 BIG BEND 2	596,119.8	595,805.1	314.8	2.04%
EA_3 BIG BEND 3	596,119.8	595,890.5	229.3	1.49%
EA_4 BIG BEND 4	596,119.8	595,484.2	635.7	4.13%
EA_5 POLK 1	596,119.8	596,028.0	91.9	0.60%
EA_6 BAYSIDE 1	596,119.8	595,597.4	522.4	3.39%
EA_7 BAYSIDE 2	596,119.8	594,562.9	1,556.9	10.11%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	596,119.8	594,820.5	1,299.3	8.43%
AHR_2 BIG BEND 2	596,119.8	594,380.1	1,739.7	11.29%
AHR_3 BIG BEND 3	596,119.8	594,737.5	1,382.3	8.97%
AHR_4 BIG BEND 4	596,119.8	594,754.4	1,365.4	8.86%
AHR_5 POLK 1	596,119.8	593,555.3	2,564.5	16.65%
AHR_6 BAYSIDE 1	596,119.8	595,191.8	928.0	6.02%
AHR_7 BAYSIDE 2	596,119.8	594,543.0	1,576.8	10.24%
TOTAL SAVINGS			**15,405.1**	**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 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
	Weighting Factor =	7.78%		Weighting Factor =	8.43%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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	0.0	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	(548.1)	67.3	-10	(1,739.7)	10,609
	Weighting Factor =	2.04%		Weighting Factor =	11.29%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	1.49%		Weighting Factor =	8.97%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	4.13%		Weighting Factor =	8.86%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	0.60%		Weighting Factor =	16.65%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	3.39%		Weighting Factor =	6.02%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	10.11%		Weighting Factor =	10.24%

TAMPA ELECTRIC COMPANY

ESTIMATED 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 (%)	79.5	79.5	79.5	63.6	59.0	79.5	79.5	53.9	0.0	2.6	79.5	79.5	61.2
2. POF	0.0	0.0	0.0	20.0	25.8	0.0	0.0	32.3	100.0	96.8	0.0	0.0	23.0
3. EUOF	20.5	20.5	20.5	16.4	15.2	20.5	20.5	13.9	0.0	0.7	20.5	20.5	15.8
4. EUOR	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	0.0	20.5	20.5	20.5	20.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	651	588	651	504	483	630	651	441	0	21	630	651	5,901
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	93	84	92	216	261	90	93	303	720	723	91	93	2,859
9. POH	0	0	0	144	192	0	0	240	720	720	0	0	2,016
10. EFOH	137	124	137	106	102	132	137	93	0	4	133	137	1,240
11. EMOH	16	14	16	12	12	15	16	11	0	1	15	16	141
12. OPER BTU (GBTU)	2,505	2,327	2,570	1,971	1,849	2,476	2,551	1,742	0	64	2,354	2,528	22,938
13. NET GEN (MWH)	237,300	220,270	243,350	186,590	175,080	234,290	241,400	164,840	0	6,050	223,040	239,420	2,171,630
14. ANOHR (Btu/kwh)	10,557	10,563	10,562	10,566	10,561	10,567	10,566	10,568	0	10,516	10,556	10,559	10,563
15. NOF (%)	92.3	94.8	94.6	96.2	94.2	96.6	96.3	97.1	0.0	74.8	92.0	93.1	94.8
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	2.316	) +	10,343									

TAMPA ELECTRIC COMPANY

ESTIMATED 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 (%)	80.5	80.5	80.5	67.1	57.1	80.5	80.5	80.5	80.5	54.5	80.5	80.5	75.2
2. POF	0.0	0.0	0.0	16.7	29.0	0.0	0.0	0.0	0.0	32.3	0.0	0.0	6.6
3. EUOF	19.5	19.5	19.5	16.3	13.8	19.5	19.5	19.5	19.5	13.2	19.5	19.5	18.2
4. EUOR	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	663	599	663	535	471	642	663	663	642	449	642	663	7,295
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	81	73	80	185	273	78	81	81	78	295	79	81	1,465
9. POH	0	0	0	120	216	0	0	0	0	240	0	0	576
10. EFOH	112	101	112	90	79	108	112	112	108	76	108	112	1,231
11. EMOH	33	30	33	27	24	32	33	33	32	22	32	33	365
12. OPER BTU (GBTU)	2,456	2,261	2,505	2,020	1,720	2,422	2,501	2,516	2,435	1,690	2,273	2,452	27,251
13. NET GEN (MWH)	236,280	217,720	241,320	194,890	165,570	233,590	241,270	242,810	234,950	163,020	218,400	235,840	2,625,660
14. ANOHR (Btu/kwh)	10,395	10,383	10,382	10,366	10,388	10,367	10,367	10,363	10,363	10,368	10,407	10,396	10,379
15. NOF (%)	90.2	92.0	92.1	94.6	91.3	94.5	94.5	95.1	95.1	94.3	88.4	90.1	92.7
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	-6.562	) +	10,987									

TAMPA ELECTRIC COMPANY

ESTIMATED 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 (%)	82.1	45.4	84.8	84.8	84.8	84.8	84.8	84.8	84.8	84.8	56.6	84.8	79.2
2. POF	3.2	46.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	14.7	8.1	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	10.1	15.2	14.2
4. EUOR	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	647	324	668	647	668	647	668	668	647	668	431	668	7,351
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	97	348	75	73	76	73	76	76	73	76	290	76	1,409
9. POH	24	312	0	0	0	0	0	0	0	0	240	0	576
10. EFOH	84	42	87	84	87	84	87	87	84	87	56	87	955
11. EMOH	25	13	26	25	26	25	26	26	25	26	17	26	288
12. OPER BTU (GBTU)	2,459	1,191	2,559	2,542	2,556	2,530	2,615	2,631	2,546	2,631	1,501	2,533	28,302
13. NET GEN (MWH)	233,190	112,260	243,120	243,480	243,410	242,120	250,300	252,160	243,970	252,150	140,360	240,110	2,696,630
14. ANOHR (Btu/kwh)	10,543	10,613	10,526	10,439	10,500	10,450	10,448	10,433	10,435	10,433	10,697	10,548	10,495
15. NOF (%)	90.1	86.6	91.0	95.3	92.2	94.7	94.9	95.6	95.5	95.6	82.4	89.9	92.5
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397
17. ANOHR EQUATION	ANOHR = NOF(	-20.119	) +	12,356									

TAMPA ELECTRIC COMPANY

ESTIMATED 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 (%)	85.9	85.9	47.1	85.9	85.9	85.9	85.9	85.9	85.9	85.9	85.9	58.2	80.3
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	14.1	14.1	7.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	9.5	13.1
4. EUOR	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	666	602	365	644	666	644	666	666	644	666	644	451	7,324
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	78	70	378	76	78	76	78	78	76	78	77	293	1,436
9. POH	0	0	336	0	0	0	0	0	0	0	0	240	576
10. EFOH	77	70	42	75	77	75	77	77	75	77	75	52	847
11. EMOH	28	25	15	27	28	27	28	28	27	28	27	19	303
12. OPER BTU (GBTU)	2,823	2,550	1,529	2,678	2,766	2,678	2,770	2,757	2,678	2,770	2,673	1,878	30,549
13. NET GEN (MWH)	270,980	244,770	146,800	257,090	265,570	257,080	265,910	264,730	257,090	265,910	256,630	180,320	2,932,880
14. ANOHR (Btu/kwh)	10,416	10,416	10,417	10,415	10,416	10,415	10,415	10,416	10,415	10,415	10,416	10,418	10,416
15. NOF (%)	97.6	97.5	96.4	98.1	98.0	98.1	98.1	97.7	98.1	98.1	97.9	95.9	97.6
16. NPC (MW)	417	417	417	407	407	407	407	407	407	407	407	417	410
17. ANOHR EQUATION	ANOHR = NOF(	-0.940	) +	10,508									

TAMPA ELECTRIC COMPANY

ESTIMATED 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 (%)	89.3	89.3	20.1	26.8	89.3	89.3	89.3	89.3	89.3	89.3	74.5	89.3	77.1
2. POF	0.0	0.0	77.5	70.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	13.7
3. EUOF	10.7	10.7	2.4	3.2	10.7	10.7	10.7	10.7	10.7	10.7	8.9	10.7	9.2
4. EUOR	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	631	570	143	192	659	633	652	667	645	649	565	631	6,637
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	113	102	600	528	85	87	92	77	75	95	156	113	2,123
9. POH	0	0	576	504	0	0	0	0	0	0	120	0	1,200
10. EFOH	61	55	14	18	61	59	61	61	59	61	49	61	619
11. EMOH	19	17	4	5	19	18	19	19	18	19	15	19	188
12. OPER BTU (GBTU)	1,419	1,282	321	431	1,479	1,417	1,460	1,495	1,440	1,458	1,258	1,420	14,880
13. NET GEN (MWH)	134,830	121,840	30,470	40,810	140,220	134,070	138,310	141,690	136,030	138,310	118,680	134,890	1,410,150
14. ANOHR (Btu/kwh)	10,526	10,524	10,539	10,550	10,545	10,566	10,559	10,553	10,586	10,538	10,604	10,524	10,552
15. NOF (%)	97.1	97.2	96.9	96.6	96.7	96.3	96.4	96.6	95.9	96.9	95.5	97.2	96.6
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(	-47.266	) +	15,117									

TAMPA ELECTRIC COMPANY

ESTIMATED 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 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 (%)	94.5	64.1	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	91.4	70.1	89.9
2. POF	0.0	32.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	25.8	4.9
3. EUOF	5.5	3.7	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.3	4.1	5.2
4. EUOR	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	554	391	674	430	620	636	641	684	661	604	529	427	6,851
7. RSH	149	40	28	251	83	45	62	19	20	99	130	95	1,021
8. UH	41	241	41	39	41	39	41	41	39	41	62	222	888
9. POH	0	216	0	0	0	0	0	0	0	0	24	192	432
10. EFOH	8	5	8	7	8	7	8	8	7	8	7	6	84
11. EMOH	33	20	33	32	33	32	33	33	32	33	31	25	372
12. OPER BTU (GBTU)	1,226	1,202	2,149	1,115	1,800	1,762	1,854	2,070	2,063	1,709	1,288	1,149	19,422
13. NET GEN (MWH)	161,060	162,160	290,960	149,690	244,410	238,140	251,690	282,360	282,530	231,490	172,000	153,120	2,619,610
14. ANOHR (Btu/kwh)	7,614	7,413	7,386	7,448	7,363	7,400	7,366	7,329	7,303	7,383	7,490	7,504	7,414
15. NOF (%)	36.7	52.4	54.5	49.7	56.2	53.4	56.0	58.9	61.0	54.7	46.4	45.3	52.3
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(	-12.819	) +	8,084									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

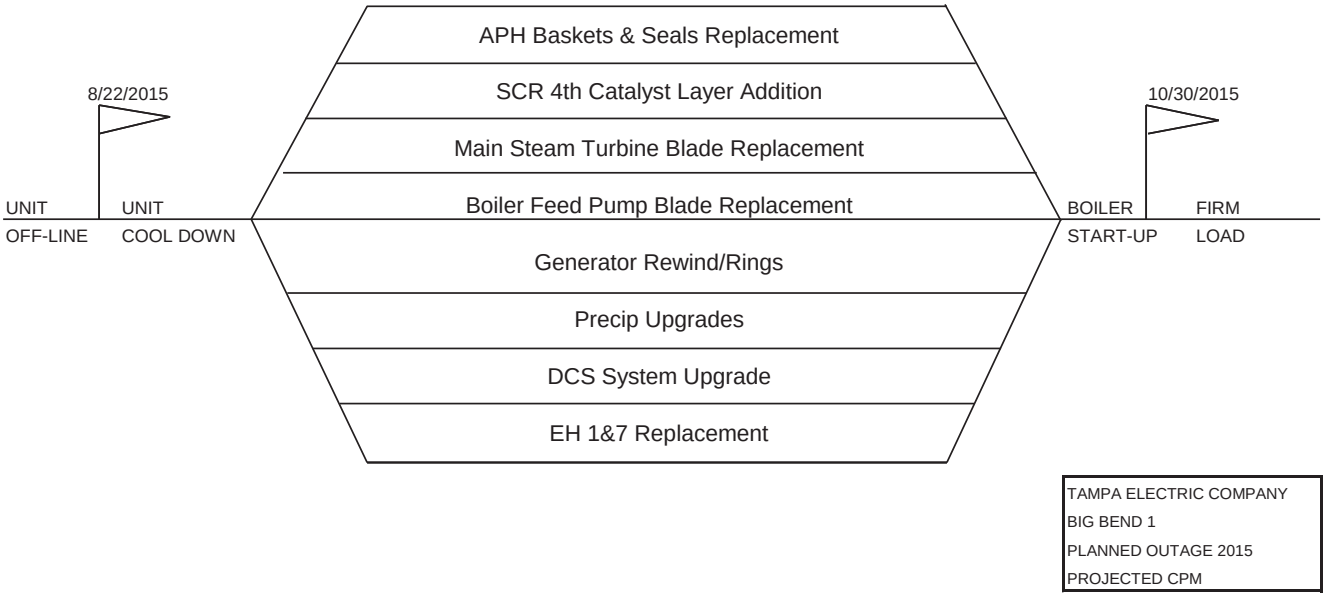
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	92.1	88.9	68.3	92.1	92.1	92.1	92.1	92.1	92.1	92.1	52.3	92.1	86.6
2. POF	0.0	3.6	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.3	0.0	6.0
3. EUOF	7.9	7.6	5.8	7.9	7.9	7.9	7.9	7.9	7.9	7.9	4.5	7.9	7.4
4. EUOR	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	686	597	508	664	686	664	686	686	664	686	377	686	7,586
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	58	75	235	57	58	57	58	58	57	58	344	58	1,174
9. POH	0	24	192	0	0	0	0	0	0	0	312	0	528
10. EFOH	26	23	19	25	26	25	26	26	25	26	14	26	291
11. EMOH	32	28	24	31	32	31	32	32	31	32	18	32	355
12. OPER BTU (GBTU)	1,136	1,510	1,228	2,628	3,007	2,982	2,931	3,221	3,351	3,107	1,395	1,594	28,267
13. NET GEN (MWH)	148,240	199,020	161,610	354,880	408,550	405,830	397,670	439,720	460,020	423,080	187,660	209,600	3,795,880
14. ANOHR (Btu/kwh)	7,666	7,587	7,597	7,405	7,359	7,347	7,371	7,324	7,285	7,343	7,433	7,605	7,447
15. NOF (%)	20.7	31.8	30.4	57.6	64.1	65.8	62.4	69.0	74.6	66.4	53.6	29.2	51.7
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(		-7.052	) +		7,811							

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2015 - DECEMBER 2015

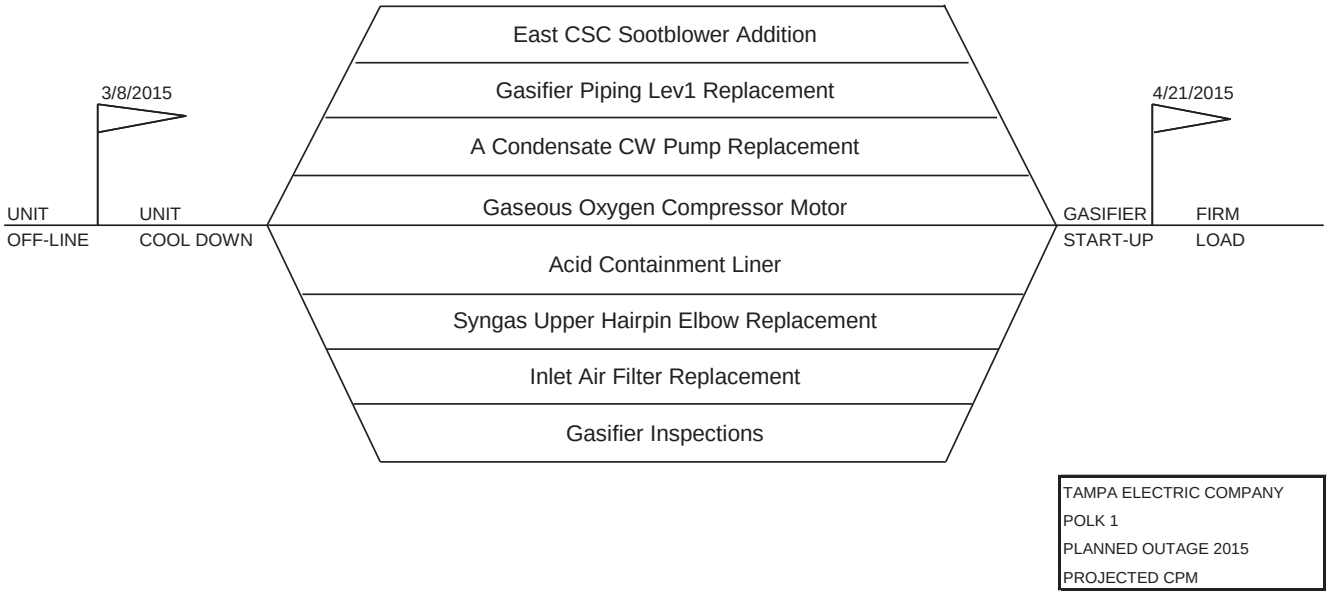
	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
+	BIG BEND 1	Apr 25 - May 09	Fuel System Cleanup and FGD/SCR work
		Aug 22 - Oct 30	APH Baskets & Seals Replacement, BFP Turbine Blade Repl, DCS Syst Soft-Hardware Upgrades, EH1&7 Repl, Generator Rewind/Rings, Main Steam Turbine Blade Replac, Precip Upgrades, SCR 4th Catalyst Layer Addition
	BIG BEND 2	Apr 26 - May 09	Fuel System Cleanup and FGD/SCR work
		Oct 17 - Oct 26	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Jan 31 - Feb 13	Fuel System Cleanup and FGD/SCR work
		Nov 02 - Nov 11	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Mar 14 - Mar 27	Fuel System Cleanup and FGD/SCR work
		Dec 05 - Dec 14	Fuel System Cleanup and FGD/SCR work
+	POLK 1	Mar 08 - Apr 21	Gaseous Oxygen Compressor Mtr, Acid Containment Liner, East CSC Sootblower Addition, A Condensate CW Pump Repl, Syngas Upper Hairpin Elbow R, Gasifier Piping Lev1 replace, Inlet Air Filter Replacement
		Nov 01 - Nov 05	Gasifier Outage
	BAYSIDE 1	Feb 16 - Feb 24	Fuel System Cleanup
		Nov 30 - Dec 08	Fuel System Cleanup
	BAYSIDE 2	Feb 28 - Mar 08	Fuel System Cleanup
		Nov 10 - Nov 22	Fuel System Cleanup

+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

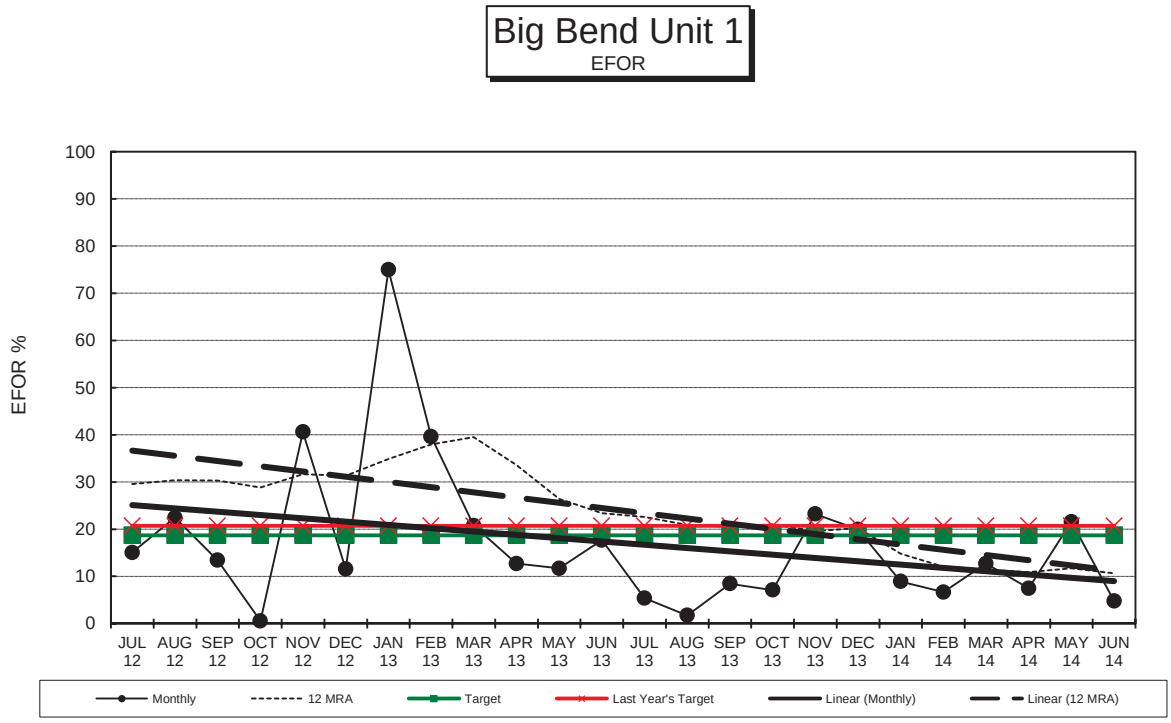
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2015 - DECEMBER 2015



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2015 - DECEMBER 2015



TAMPA ELECTRIC COMPANY
POLK 1
PLANNED OUTAGE 2015
PROJECTED CPM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EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
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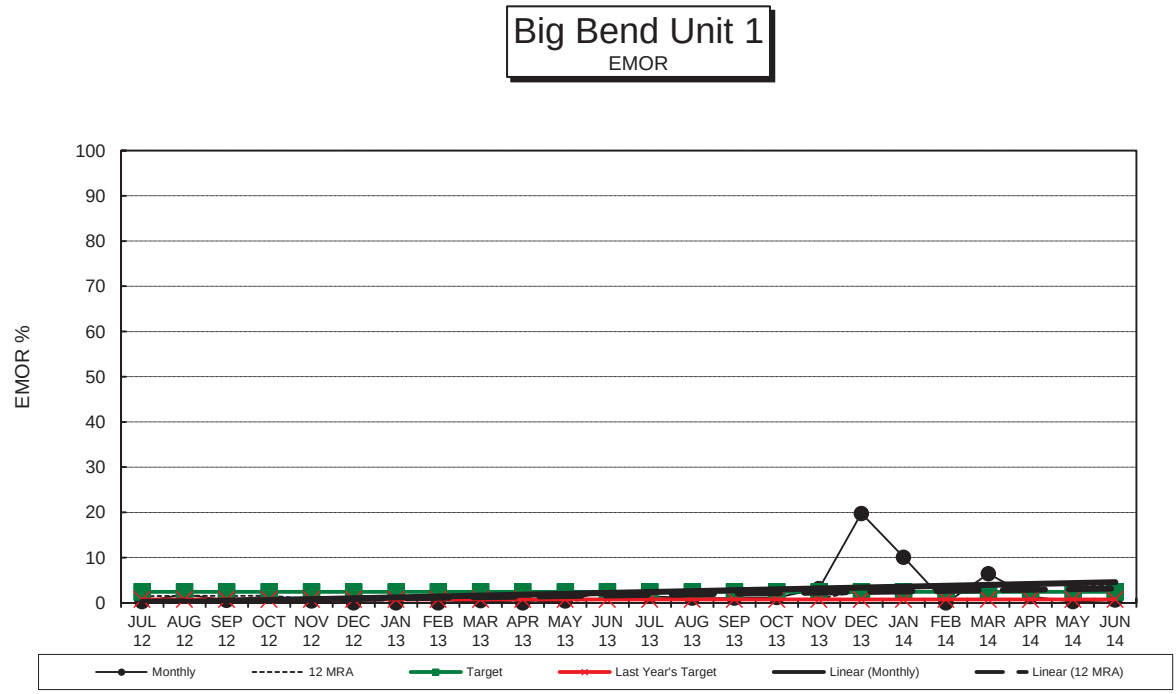
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR %
100
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AUG 12
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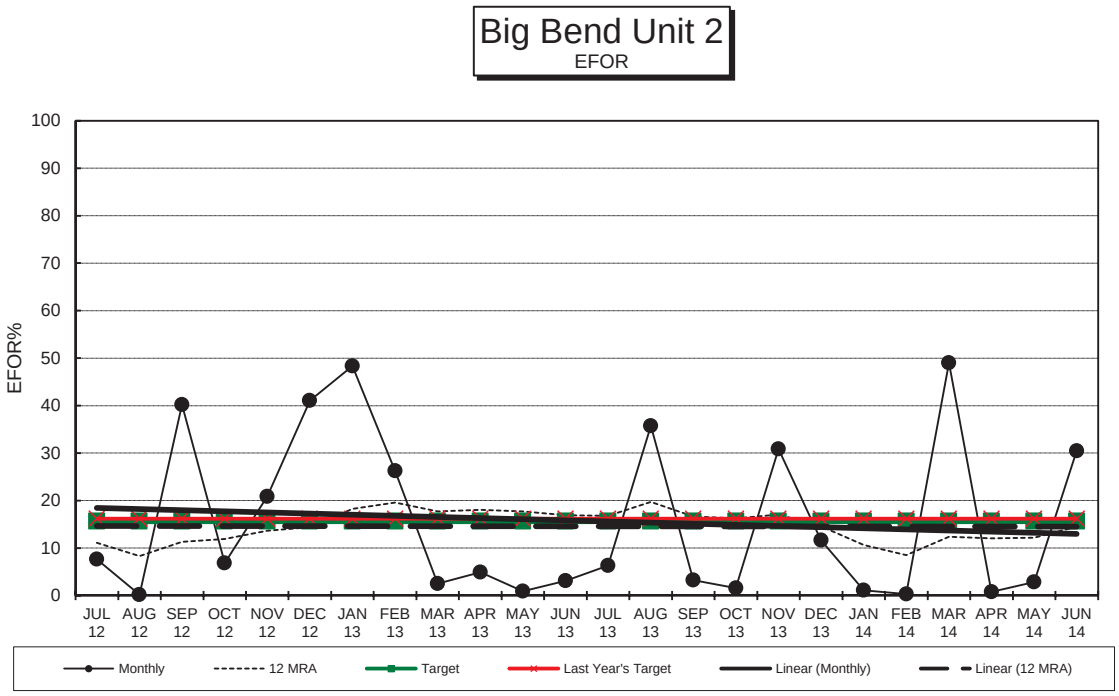
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR%
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60
50
40
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20
10
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AUG 12
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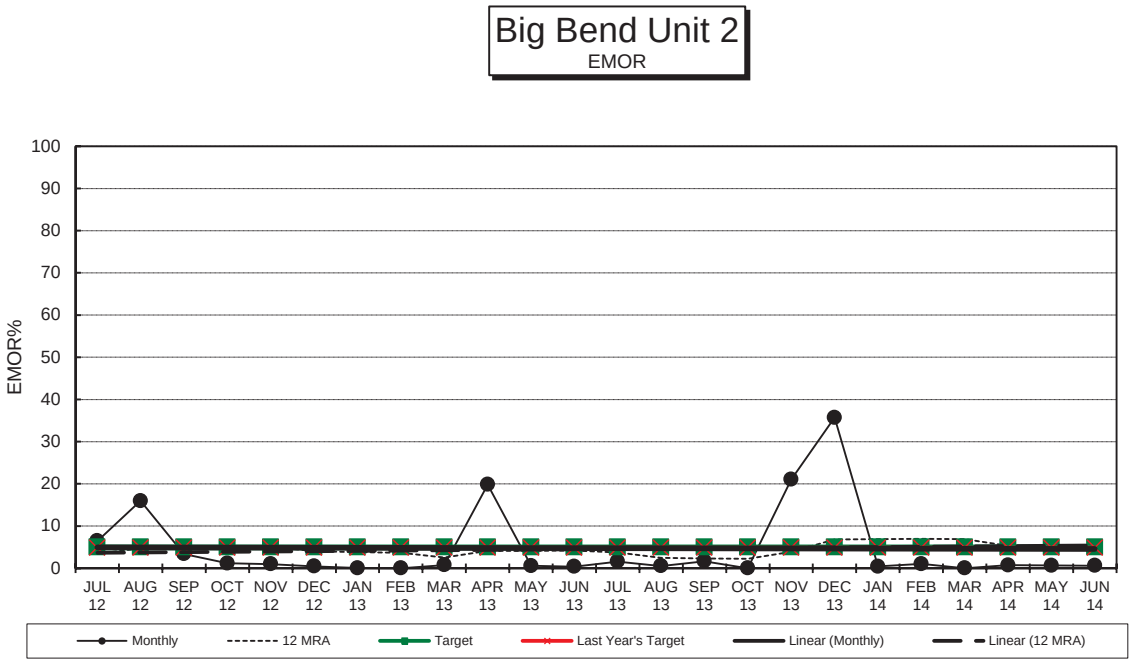
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
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EMOR%
100
90
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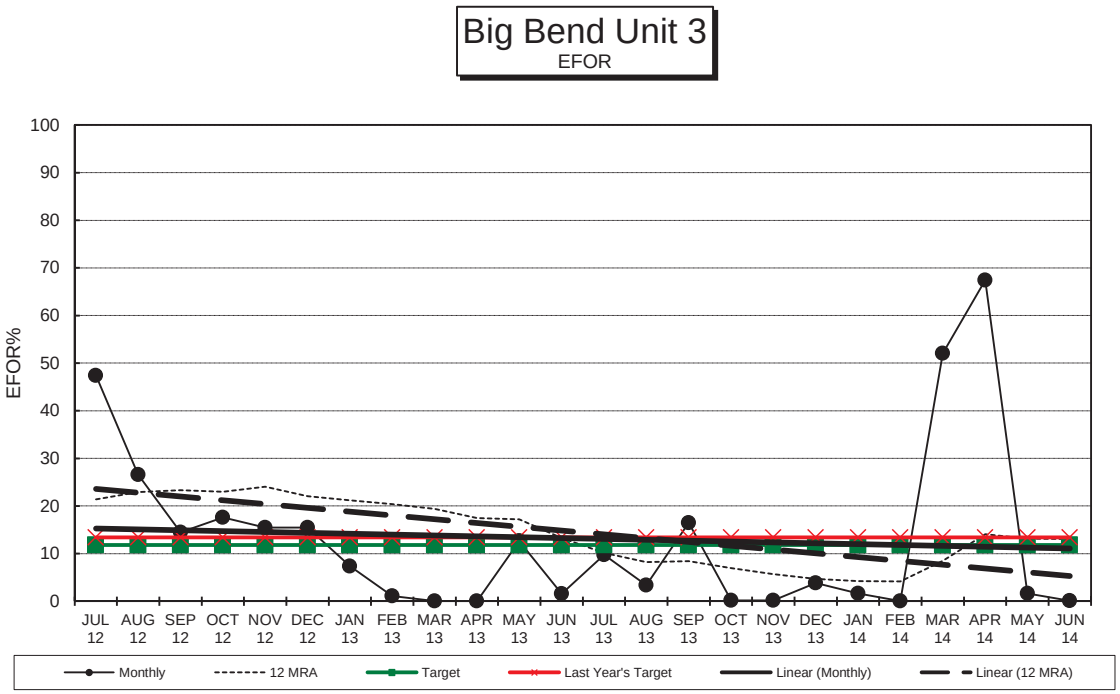
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
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AUG 12
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OCT 12
NOV 12
DEC 12
JAN 13
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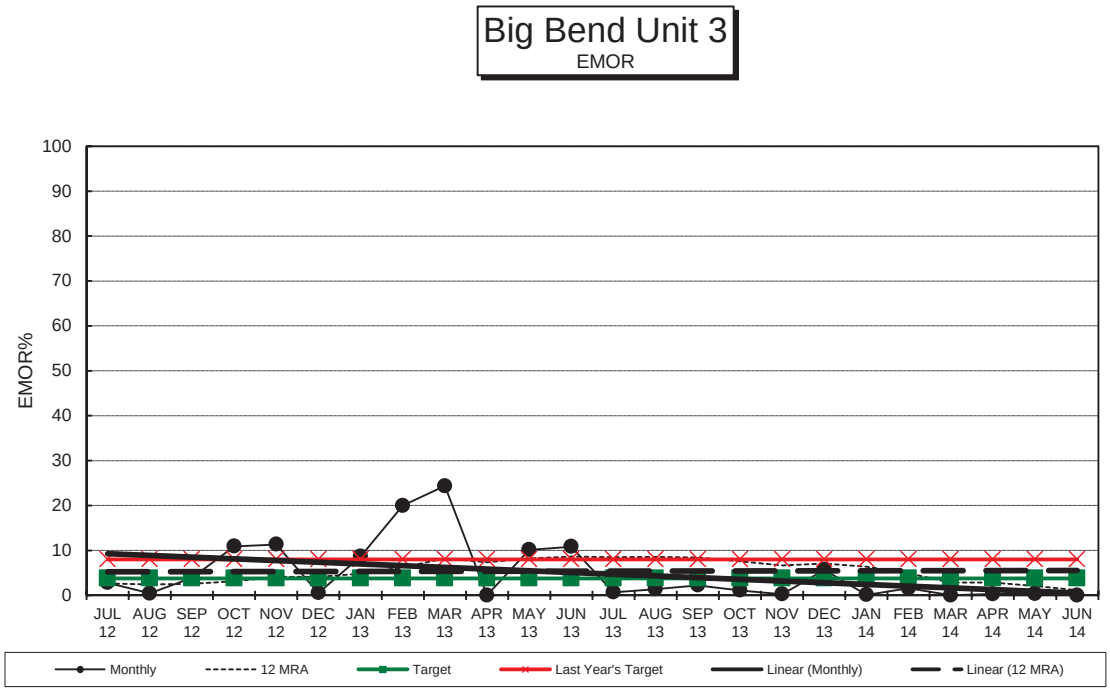
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR%
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NOV 13
DEC 13
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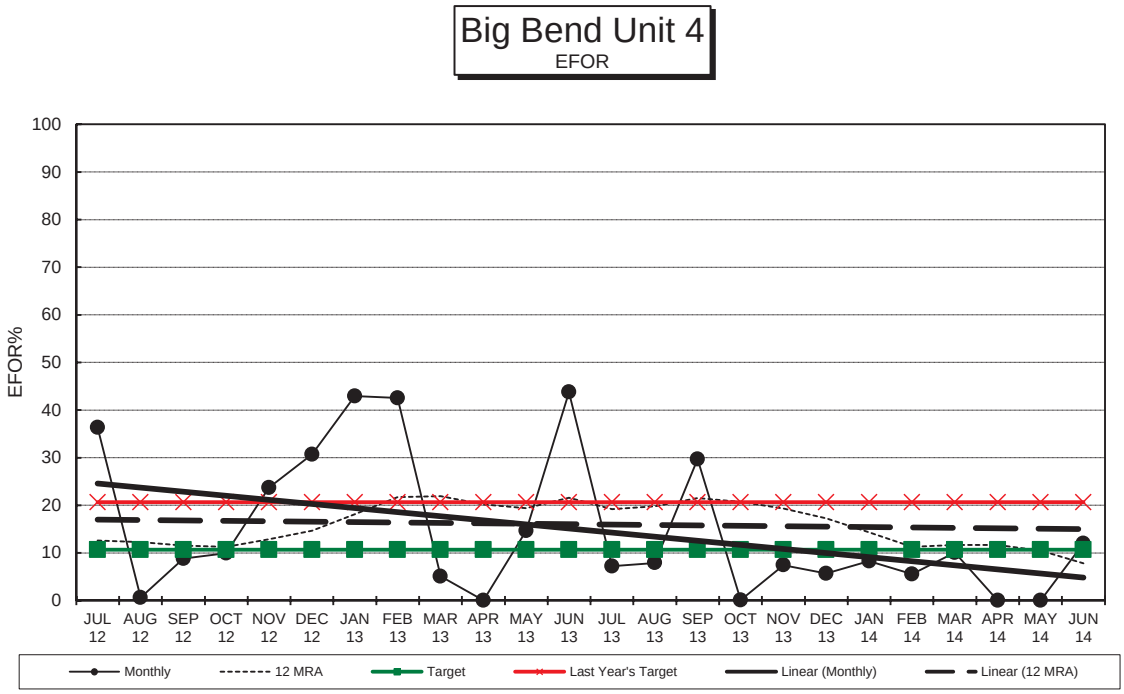
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR%
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80
70
60
50
40
30
20
10
0
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AUG 12
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NOV 13
DEC 13
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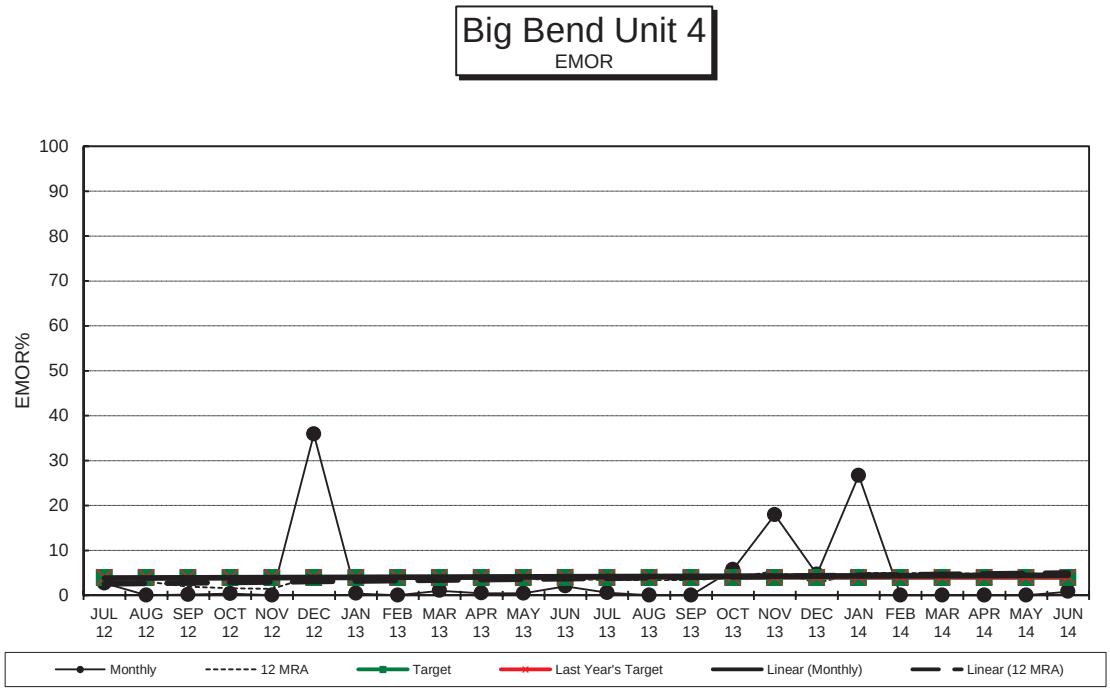
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
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AUG 13
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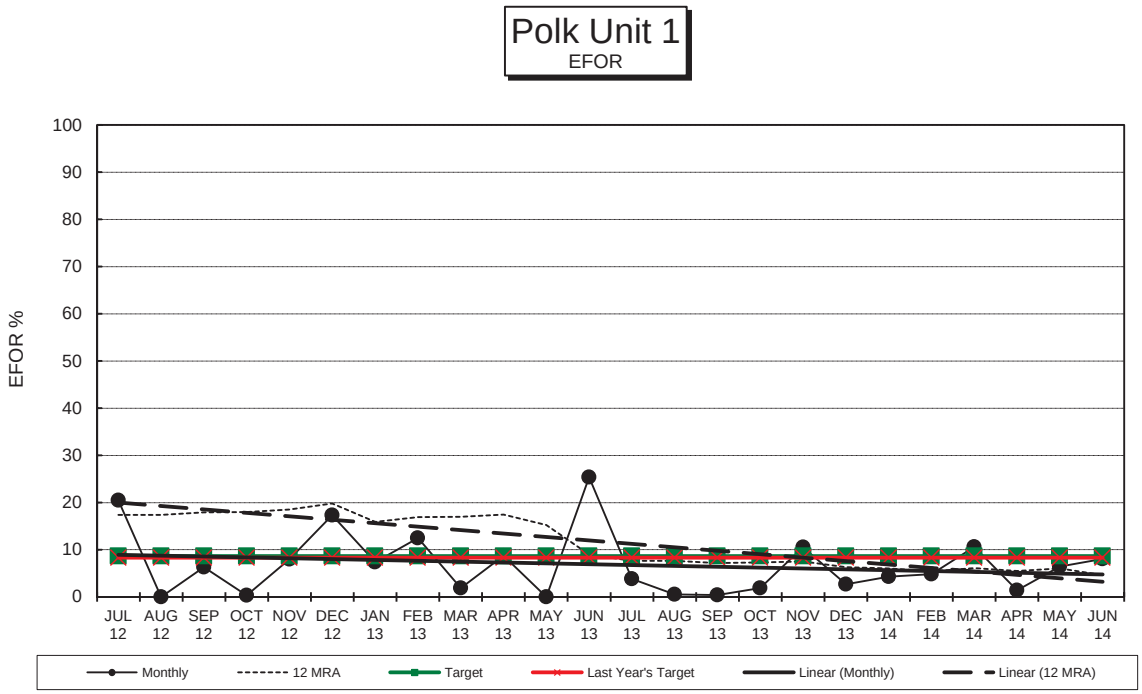
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
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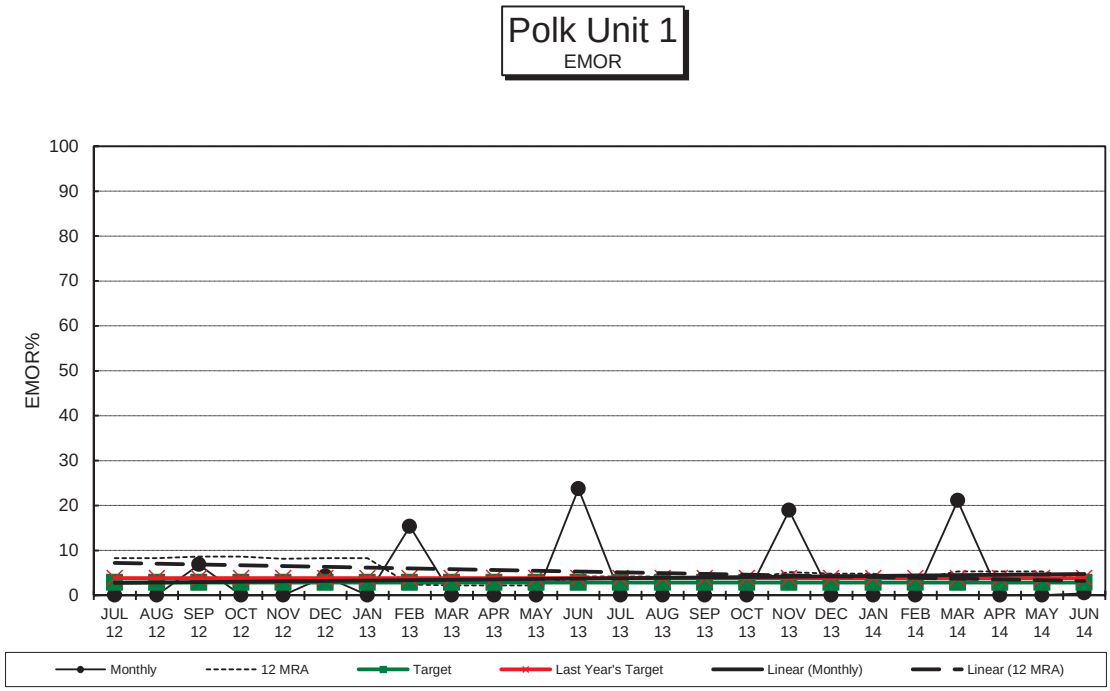
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
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JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
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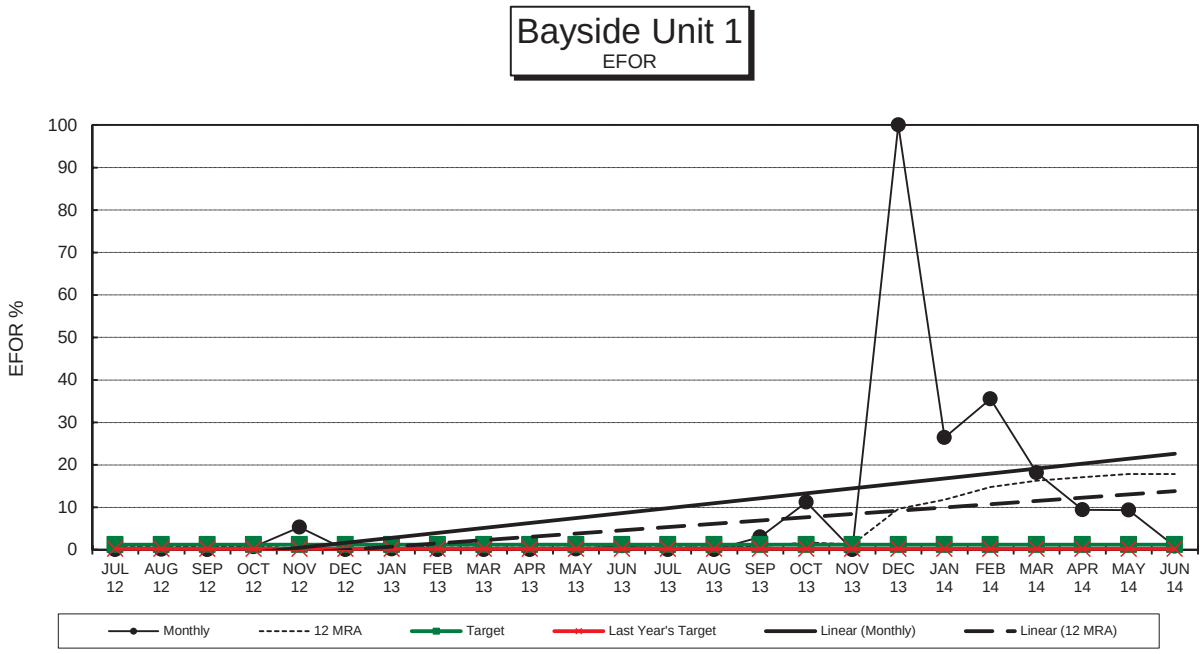
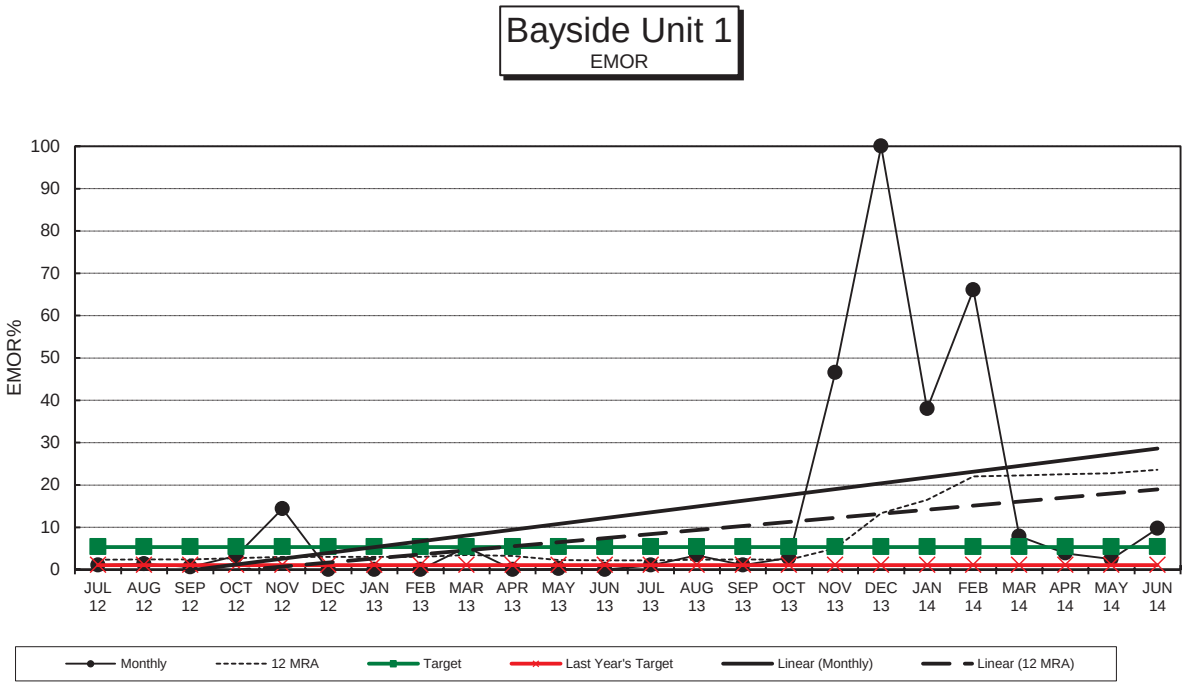
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
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SEP 12
OCT 12
NOV 12
DEC 12
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FEB 13
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APR 13
MAY 13
JUN 13
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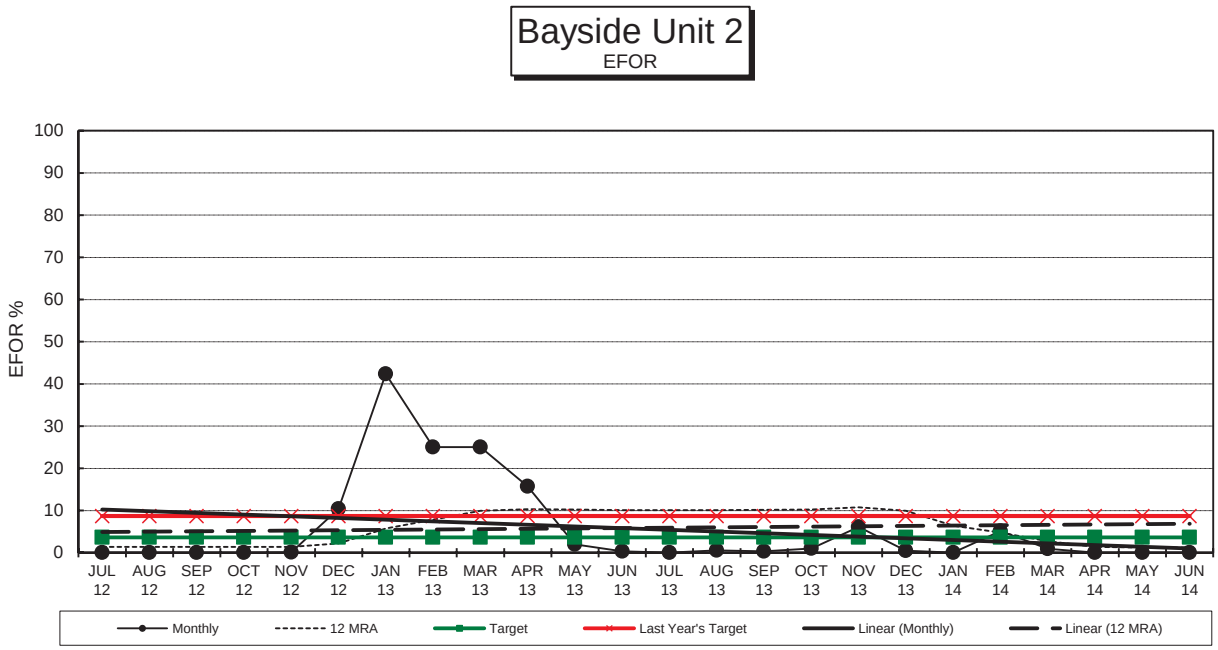
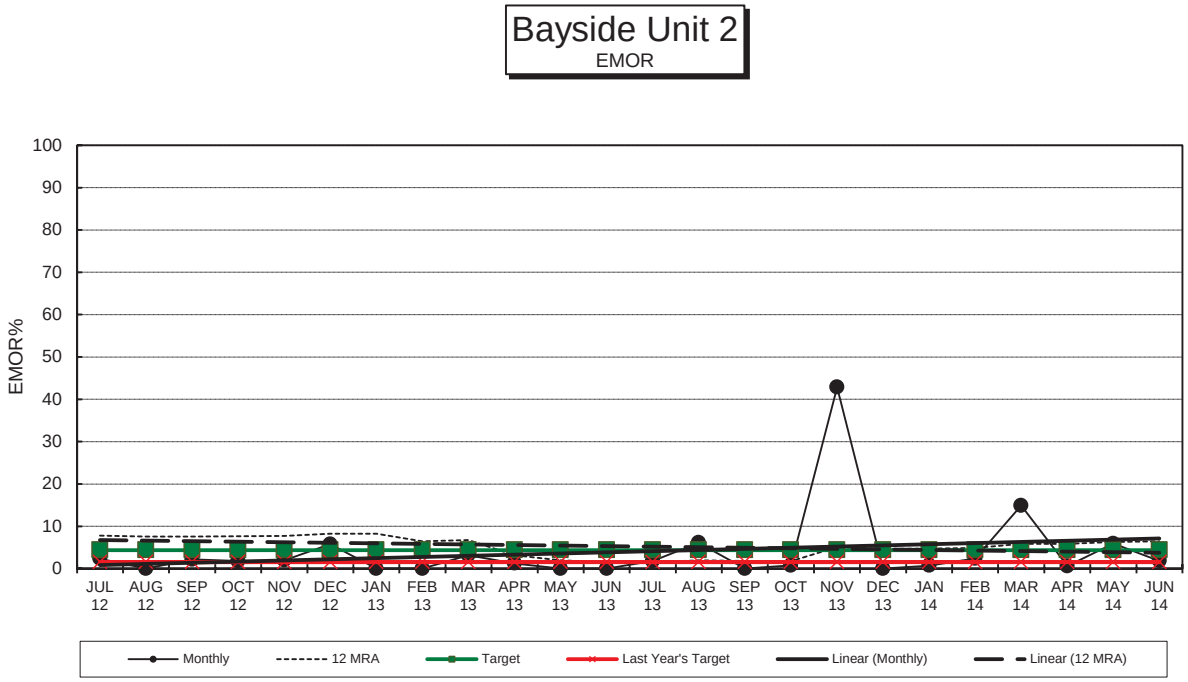
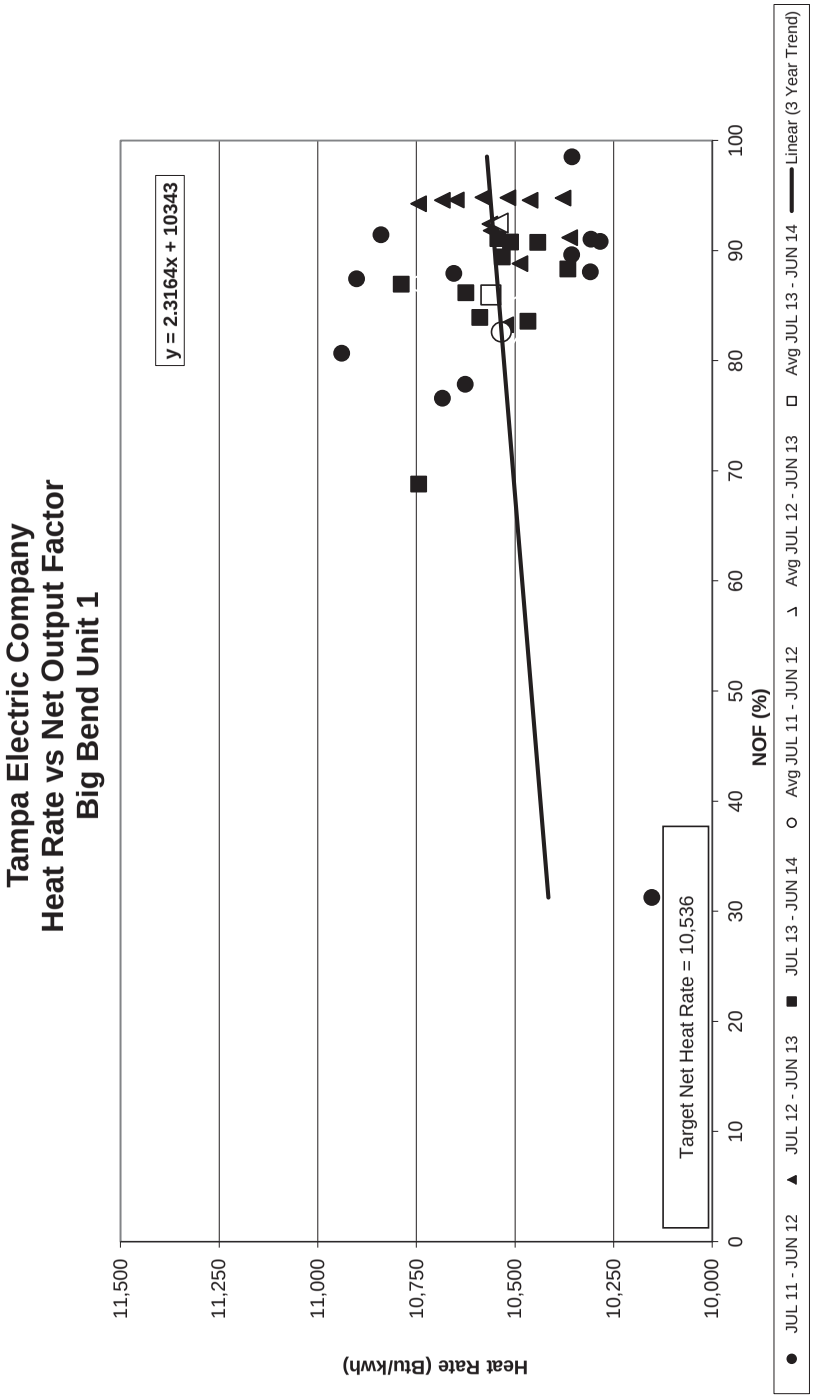
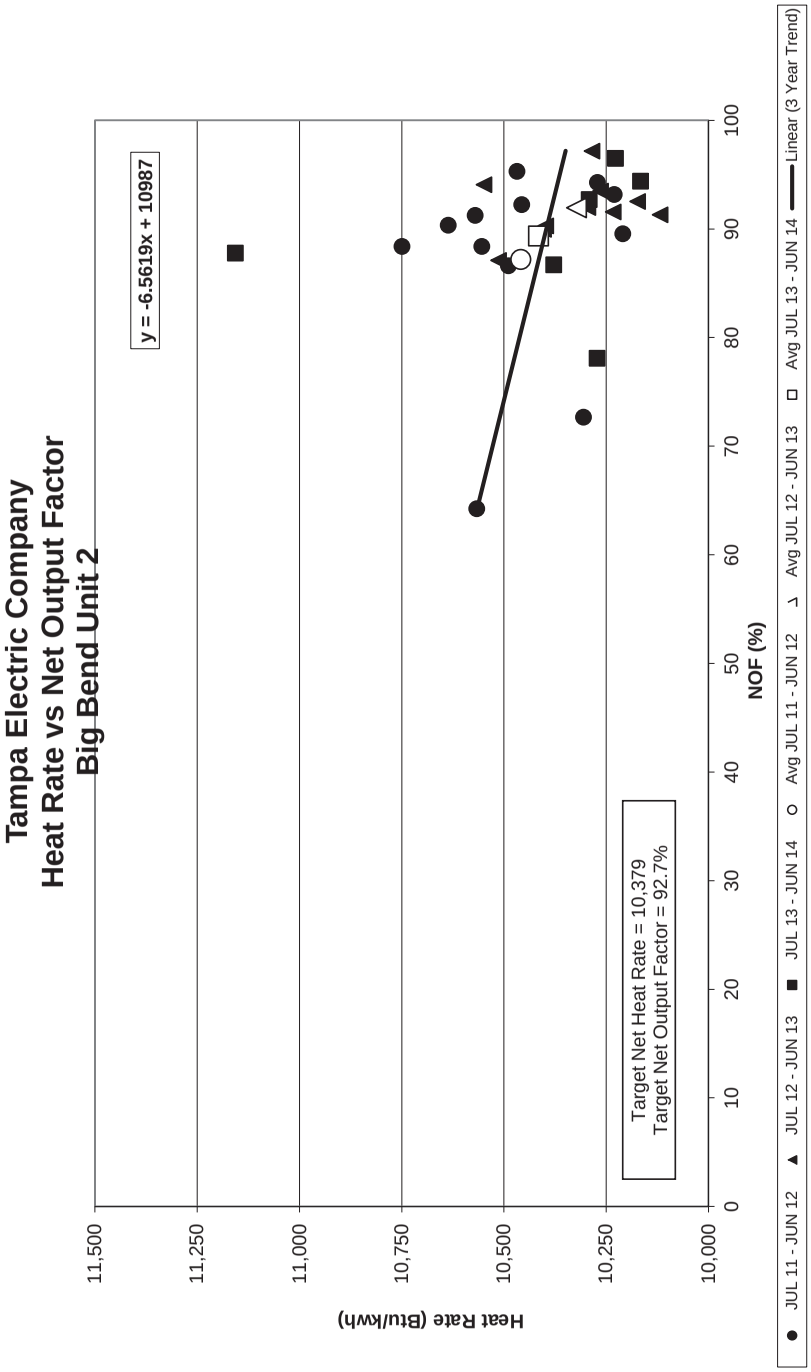
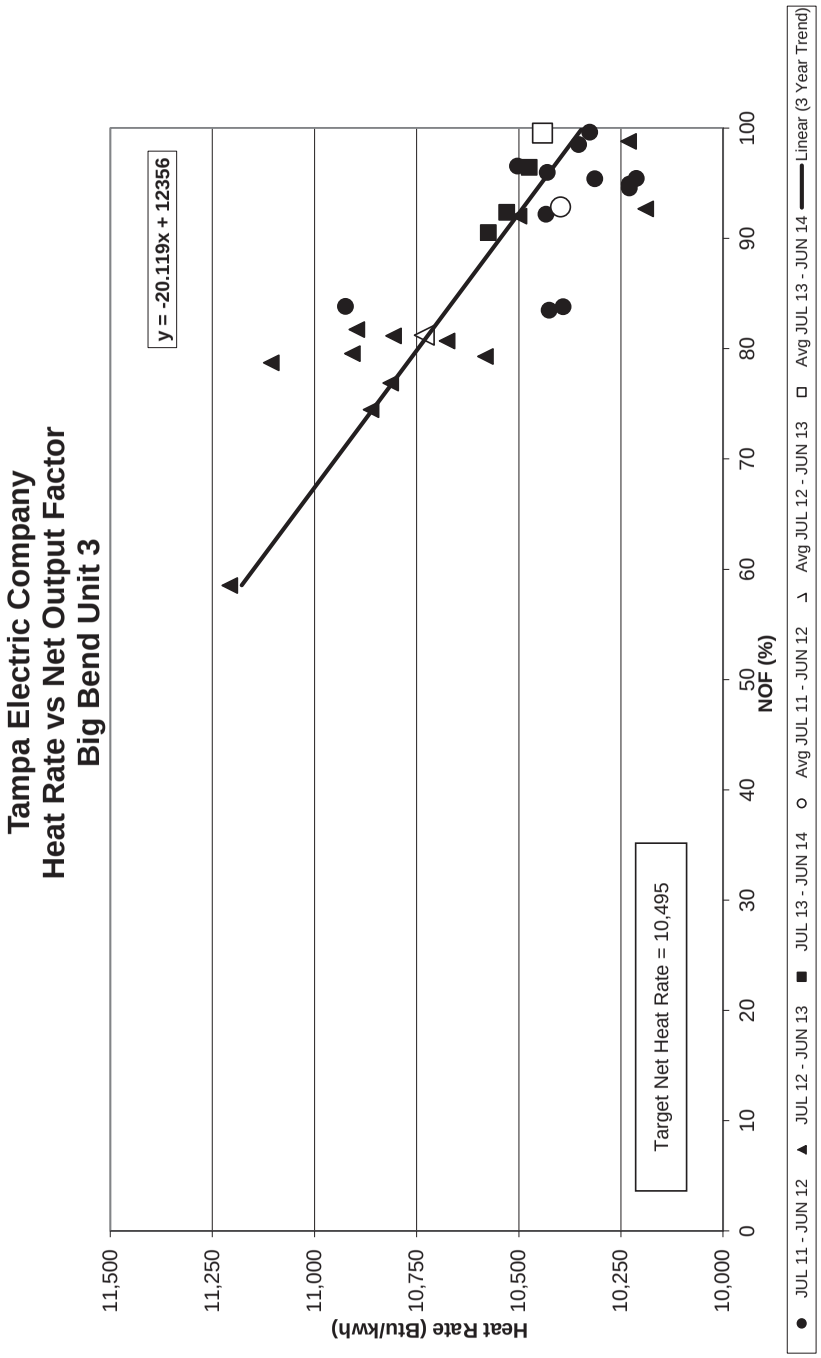
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

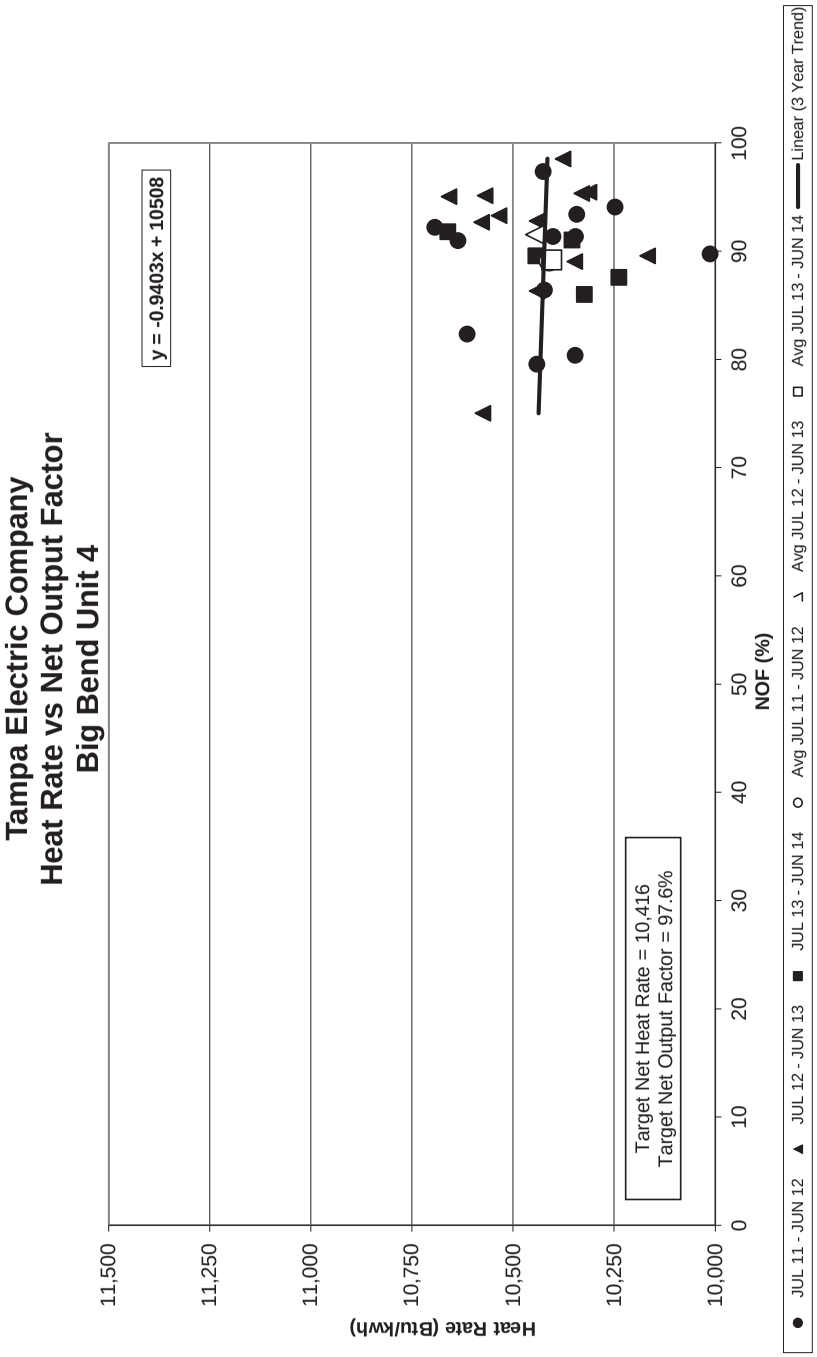

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

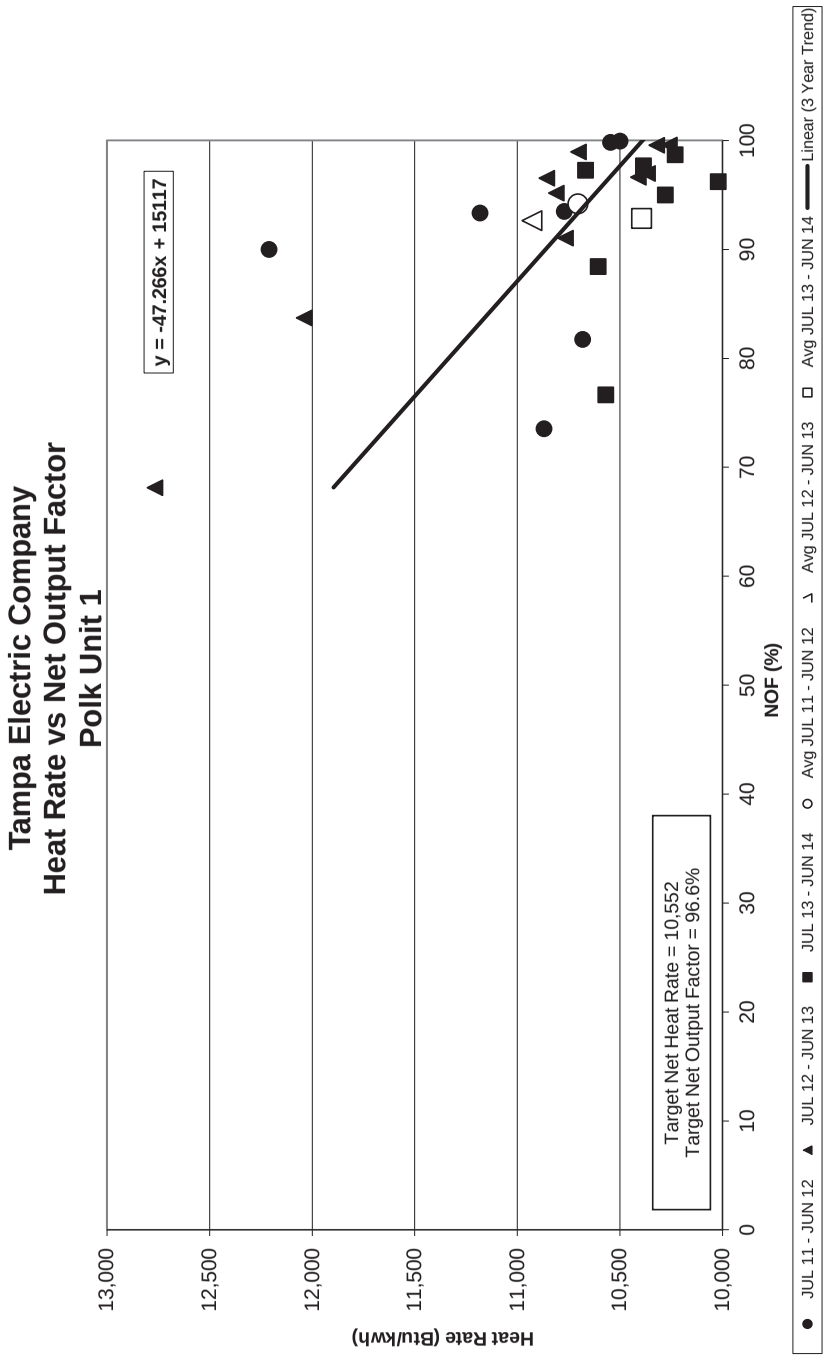

Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

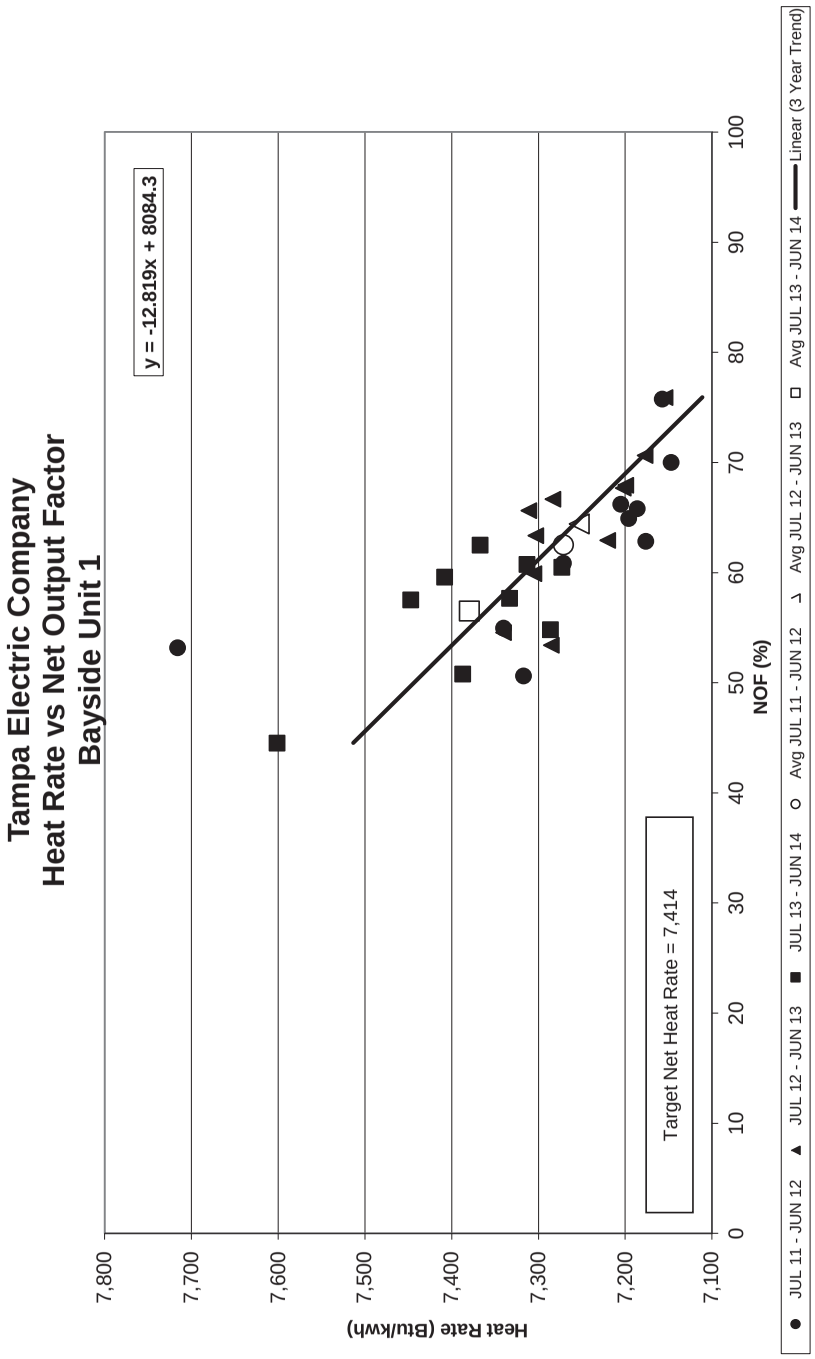

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1
y = 2.3164x + 10343
Target Net Heat Rate = 10,536
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)

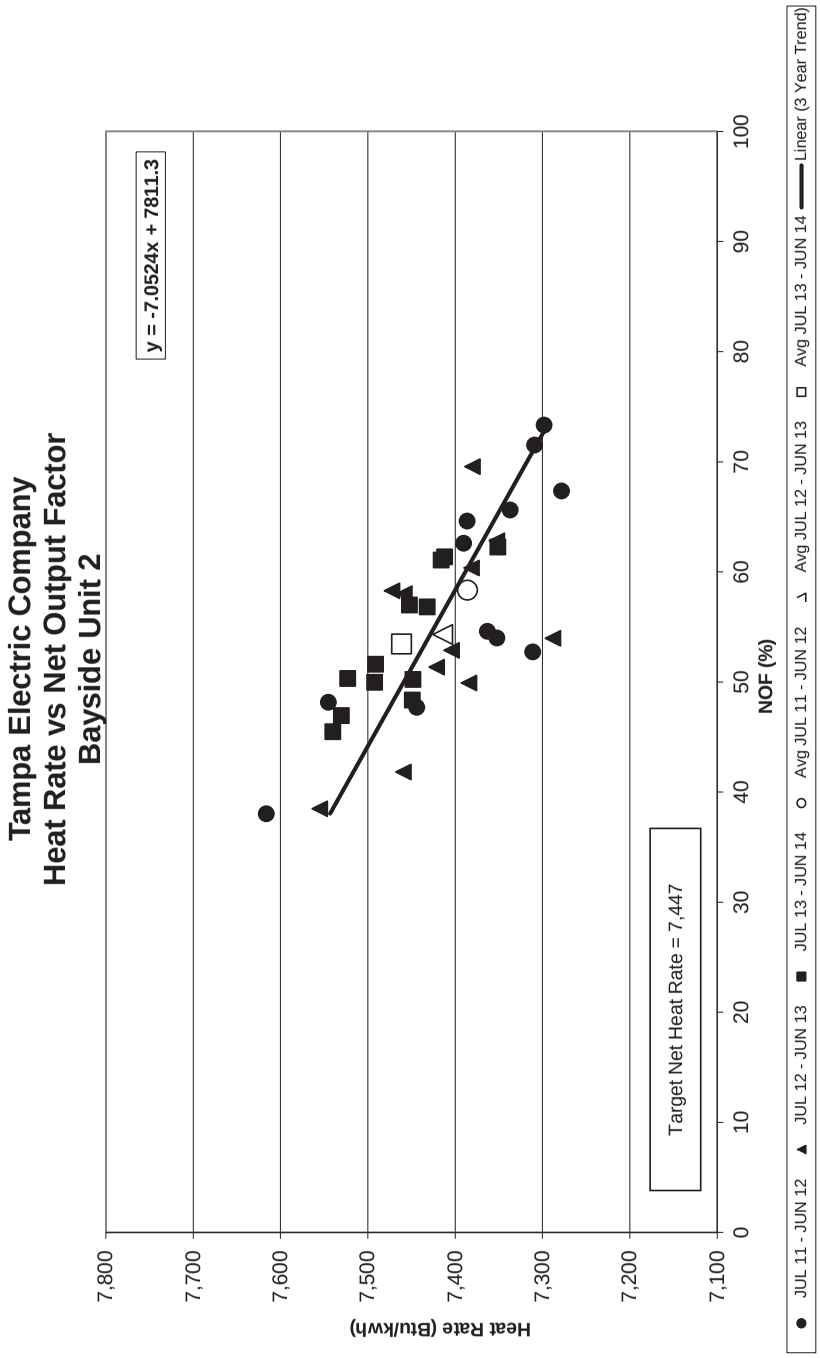

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
y = -6.5619x + 10987
Target Net Heat Rate = 10,379
Target Net Output Factor = 92.7%
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
y = -20.119x + 12356
Target Net Heat Rate = 10,495
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 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4
y = -0.9403x + 10508
Target Net Heat Rate = 10,416
Target Net Output Factor = 97.6%
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 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1
y = -47.266x + 15117
Target Net Heat Rate = 10,552
Target Net Output Factor = 96.6%
Heat Rate (Btu/kwh)
NOF (%)
13,000
12,500
12,000
11,500
11,000
10,500
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
y = -12.819x + 8084.3
Target Net Heat Rate = 7,414
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 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -7.0524x + 7811.3
Target Net Heat Rate = 7,447
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 11 - JUN 12
JUL 12 - JUN 13
JUL 13 - JUN 14
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Avg JUL 13 - JUN 14
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2015 - DECEMBER 2015

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		443	410
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,701	3,503
	SYSTEM TOTAL	**4,645**	**4,439**
	% OF SYSTEM TOTAL	**79.7%**	**78.9%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2015 - DECEMBER 2015

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		443	410
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,750	1,641
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,645**	**4,439**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2015 - DECEMBER 2015

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	3,795,880	20.16%	20.16%
BIG BEND	4	2,932,880	15.57%	35.73%
BIG BEND	3	2,696,630	14.32%	50.05%
BIG BEND	2	2,625,660	13.94%	63.99%
BAYSIDE	1	2,619,610	13.91%	77.90%
BIG BEND	1	2,171,630	11.53%	89.44%
POLK	1	1,410,150	7.49%	96.92%
POLK	2	183,400	0.97%	97.90%
POLK	3	120,920	0.64%	98.54%
POLK	4	96,690	0.51%	99.05%
POLK	5	49,820	0.26%	99.32%
BAYSIDE	5	40,200	0.21%	99.53%
BAYSIDE	6	31,440	0.17%	99.70%
BAYSIDE	3	27,550	0.15%	99.84%
BAYSIDE	4	18,350	0.10%	99.94%
BIG BEND CT	4	10,860	0.06%	100.00%
TOTAL GENERATION		18,831,670	100.00%	

GENERATION BY COAL UNITS: 11,836,950 MWH
% GENERATION BY COAL UNITS 62.86%

GENERATION BY NATURAL GAS UNITS: 6,994,720 MWH
% GENERATION BY NATURAL GAS UNITS: 37.14%

GENERATION BY OIL UNITS: - MWH
% GENERATION BY OIL UNITS: 0.00%

GENERATION BY GPIF UNITS: 18,252,440 MWH
% GENERATION BY GPIF UNITS: 96.92%

DOCKET NO. 140001-EI
GPIF 2015 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 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2015 - DECEMBER 2015

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	61.2	23.0	15.8	10,563
Big Bend 2[2]	75.2	6.6	18.2	10,379
Big Bend 3[3]	79.2	6.6	14.2	10,495
Big Bend 4[4]	80.3	6.6	13.1	10,416
Polk 1[5]	77.1	13.7	9.2	10,552
Bayside 1[6]	89.9	4.9	5.2	7,414
Bayside 2[7]	86.6	6.0	7.4	7,447

1 Original Sheet 8.401.15E, Page 14

2 Original Sheet 8.401.15E, Page 15

3 Original Sheet 8.401.15E, Page 16

4 Original Sheet 8.401.15E, Page 17

5 Original Sheet 8.401.15E, Page 18

6 Original Sheet 8.401.15E, Page 19

7 Original Sheet 8.401.15E, Page 20

J. BRENT CALDWELL

EXHIBIT

2013 HEDGING ACTIVITY TRUE-UP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 48
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Brent C. Caldwell JBC-1

Tampa Electric
2013 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.

2013 Risk Management Activities
The company's activities in 2013 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 2013 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 59 percent of the electricity the company generated in 2013.

- 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.

- Natural Gas Purchases

  In 2013, approximately 41 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 2013 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, 2013 through December 31, 2013

Contract	Type of Hedge	Mark-to-Market Savings/(Loss)	Hedged Volume (MMBtu)	Consumption (MMBtu)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-13	Swap	($1,482,130)	[redacted]	4,355,657	[redacted]	[redacted]	[redacted]	$3.35
Feb-13	Swap	($1,744,150)	[redacted]	5,362,808	[redacted]	[redacted]	[redacted]	$3.23
Mar-13	Swap	($828,170)	[redacted]	3,761,758	[redacted]	[redacted]	[redacted]	$3.43
Apr-13	Swap	$1,127,945	[redacted]	4,873,898	[redacted]	[redacted]	[redacted]	$3.98
May-13	Swap	$1,794,365	[redacted]	5,474,303	[redacted]	[redacted]	[redacted]	$4.15
Jun-13	Swap	$1,902,130	[redacted]	6,500,554	[redacted]	[redacted]	[redacted]	$4.15
Jul-13	Swap	($190,245)	[redacted]	4,881,959	[redacted]	[redacted]	[redacted]	$3.71
Aug-13	Swap	($1,208,040)	[redacted]	5,620,214	[redacted]	[redacted]	[redacted]	$3.46
Sep-13	Swap	($710,690)	[redacted]	5,251,411	[redacted]	[redacted]	[redacted]	$3.57
Oct-13	Swap	($871,990)	[redacted]	4,622,892	[redacted]	[redacted]	[redacted]	$3.50
Nov-13	Swap	($756,725)	[redacted]	3,467,202	[redacted]	[redacted]	[redacted]	$3.50
Dec-13	Swap	($288,670)	[redacted]	3,243,907	[redacted]	[redacted]	[redacted]	$3.82
Total		($3,256,370)	[redacted]	57,416,563	[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 2013. For 2013, the calendar year net position for natural gas hedges was slightly above the closing price of natural gas, resulting in a mark-to-market net loss of $3.3 million. The closing price was less than the fixed hedge price primarily due to a reduction in the price of natural gas during 2013. The price decline was driven primarily by a supply surplus due to higher supply from non-conventional production of shale gas and reduced demand due to mild weather and continued economic weakness.

Tampa Electric maintains natural gas storage capacity of 1,250,000 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 $3.3 million in 2013; however, Tampa Electric was successful in reducing price uncertainty and maintaining fuel supply reliability for customers for both its physical and financial hedges.

2013 Market Pricing

Tampa Electric provides a comparison of 2013 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 2013 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 (Mine)	Contract ($/MMBtu)	Market Indicator ($/MMBtu)	Difference	Market Indicator Source	Note
Knight Hawk Coal	[redacted]	$3.07	[redacted]	GEN-2009-01 (issued 12/.7/07) (RFP)	1
Warrior Coal	[redacted]	$3.00	[redacted]	GEN-2009-01 (issued 12/7/07) (RFP)	1
Glencore Ltd.	[redacted]	$4.43	[redacted]	Polk-LS-2013 (issued 9/27/12) (RFP)	1
Valero Marketing	[redacted]	$2.82	[redacted]	Polk-PC-2013 (issued 9/24/12) (RFP)	1
Patriot Dodge Hill Mine	[redacted]	$3.56	[redacted]	ICAP United / Argus Coal Daily 6/14/13 (Index)	3
Trafigura AG	[redacted]	$3.35	[redacted]	ICAP United / Argus Coal Daily 8/9/13 (Index)	2, 7
Armstrong Coal Company	[redacted]	$3.62	[redacted]	ICAP United / Argus Coal Daily 8/3/12 (Index)	5
Patriot Coal Company	[redacted]	$3.50	[redacted]	Big Bend GEN 2013-01 (issued 10/5/12) (RFP)	1
Peabody Coal Company	[redacted]	$3.14	[redacted]	Big Bend GEN 2013-01 (issued 10/5/12) (RFP)	1, 6
Sunrise Coal	[redacted]	$3.14	[redacted]	Big Bend GEN 2013-01 (issued 10/5/12) (RFP)	1, 6
Sunrise Coal	[redacted]	$3.14	[redacted]	Big Bend GEN 2013-01 (issued 10/5/12) (RFP)	1,6
Patriot 2012SP2-09	[redacted]	$3.27	[redacted]	ICAP United, Inc - Coal 11/9/2012 (Index)	2
Glencore Ltd.	[redacted]	$5.55	[redacted]	Polk-LS-2012-01 (issued 7/28/11) (RFP)	1, 4
Valero Marketing	[redacted]	$3.45	[redacted]	Polk-PC-2012-01 (issued 8/11/11) (RFP)	1

Notes:
The contract $/MMBTU refers to the initial price of the contract at its inception. This price could be subject to escalation per the terms of the contract.
All prices are determined on a fully delivered basis. Index values have also been calculated on a delivered basis for comparison purposes.

1. The bid solicitation price is the average price submitted of all acceptable coal bids.
2. Pricing based on ICAP United Inc - Daily Coal price index.
3. Coal Pricing based on the average of three Indices. Argus 11,800 3.0lb SO_2, ICAP 11,500 4.5 LbSO_2 and Argus 11,500 Btu 5.0 Lb SO_2
4. While the Glencore $/MMBtu was [redacted], the [redacted] yielded the lowest overall cost.
5. 2013 Coal Pricing based on average of three Indices. Argus 11,500 5.0lb SO_2, ICAP 11,500 4.5 LbSO_2 and ICAP 11,800 Btu 4.50 Lb SO_2. Within this agreement are three Tampa Electric call options. Option #1, [redacted], Option #2 [redacted] and Option #3, [redacted].
6. Test burns, Spot contracts purchased from Long Term solicitation.
7. This offer was the only offer available.

- 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 purchased No. 2 oil for combustion turbines at Polk Station and for Big Bend Station startup. 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.

- No. 6 Oil

  Tampa Electric no longer purchases No. 6 oil for Phillips Station. Phillips Station was placed on long term standby in September 2009.

- Propane

  Tampa Electric purchases propane for Polk Unit No. 1. The purchase price is based upon the average of daily index prices published by Oil Price Information Service at Mont Belvieu, the primary propane hub for the southern United States. 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
2015

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: 140001-EI EXHIBIT: 49
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Brent C. 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 2015, 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 2015 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 $25.1 million and total fuel and purchased power costs decrease by $18.3 million due to lower prices. In the high case, natural gas expenditures increase by an estimated $48.3 million, and the total fuel and purchased power costs increase by $55.1 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 2015 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 2015 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Coal	59
Natural Gas	36
No. 2 Oil	0
No. 6 Oil	0
Purchased Power	5

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 2015 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its 2015 projection filing to be submitted August 22, 2014. Coal market pricing has retreated from record high levels in 2008. In 2014, coal prices have been relatively stable, and prices are expected to remain stable in 2015. Tampa Electric has secured a portion of its coal needs for 2015, 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 2015, 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 impact from price risk is 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 2014, 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 significant percentage of its projected natural gas usage in 2015.

   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 2014 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 2015, Tampa Electric has approximately [redacted] percent hedged with a currently estimated [redacted] of [redacted].

4. **Purchased Power:** Total forecasted purchased power for 2015 is 920 GWH. As of July 2014, Tampa Electric has physically hedged 227 GWH's of its 2015 expected purchased power needs through pre-scheduled purchased power agreements. The remaining GWH's of 2015 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.

Tampa Electric is responsible for natural gas fuel delivery on two purchase contracts for peaking power. Although this contract volume is not currently included in the company's hedging portfolio, Tampa Electric continually assesses whether it should be added.

In summary, Tampa Electric's planned operations in 2015 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 COMPANY
DOCKET NO. 140001-EI
HEDGING ACTIVITY REPORT
EXHIBIT NO. ___ (JBC-3), PAGE 1 OF 1
FILED: AUGUST 13, 2014

Tampa Electric
Natural Gas Hedging Activities
January 1, 2014 through July 31, 2014

		Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-14		Swaps	$1,067,285	[redacted]	3,388,832	[redacted]	[redacted]	[redacted]	$4.41
Feb-14		Swaps	$4,942,700		3,157,828				$5.56
Mar-14		Swaps	$2,232,670		4,603,963				$4.86
Apr-14		Swaps	$1,791,450		4,973,592				$4.58
May-14		Swaps	$2,668,620		5,530,263				$4.80
Jun-14		Swaps	$2,677,190		5,480,316				$4.62
Jul-14		Swaps	$1,903,555		5,467,276				$4.40
Total			$17,283,470		32,602,068				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 50
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Brent C. Caldwell JBC-3

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Duke Energy Florida, Inc.
Hedging Activities

Twelve Months Ended July 31, 2014

Docket No. 140001-EI
Audit Control No. 14-083-2-1
August 25, 2014

Simon O. Ojada
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 51
PARTY: STAFF
DESCRIPTION: Simon O. Ojada SOO-1

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Audit Findings
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Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated March 20, 2014. We applied these procedures to the schedules prepared by Duke Energy Florida, Inc. in support of its filing for hedging activities in Docket No. 140001-EI for the twelve months ended July 31, 2014.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

General

Definition

DEF or Utility refers to Duke Energy Florida, Inc.

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 twelve months ended July 31, 2014. 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 Numbers: 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 Results Report for the period August 1, 2013, to December 30, 2013, and its Hedging Information Report for the period January 1, 2014, to July 31, 2014, to its Hedging Summary by Commodity Reports for 2013 and 2014. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 21 natural gas and two No. 2 Oil hedging transactions from August 2013 through July 2014 as a sample. We reconciled the selected samples from the Hedging Results and Hedging Information Reports 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 twelve months ended July 31, 2014, 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 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 twelve months ending December 31, 2013 for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. 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, 2014

Docket No. 140001-EI
Audit Control No. 14-083-4-1
August 29, 2014

Iliana H. Piedra
Audit Manager

Jeffery A. Small
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 52
PARTY: STAFF
DESCRIPTION: Iliana H. Piedra IHP-1

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Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated March 20, 2014. We have applied these procedures to the schedules prepared by Florida Power & Light Company in support of its filing for hedging activities in Docket No. 140001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

FPL or Utility refers to Florida Power & Light Company.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, 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, 2014. 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 determined that the accounting treatment for hedging transactions and transactions 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 FPL 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 FPL's March 28, and August 13, 2014 filings in this docket for the period August 1, 2013, to July 31, 2014 to FPL's Derivative Settlement Report. We selected a sample of hedging transactions from various counterparties from August 2013 and April 2014 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. 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 FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2014, 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 FP L'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 our testing of transactions by agreeing the names of various employees from deal tickets and confirmations to FPL's procedures. We also determined the physical location of various personnel. We reviewed an internal audit relating to Sarbanes Oxley Compliance which included procedures to confirm the separation of duties related to FPL's hedging activities. 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, 2014

Docket No. 140001-EI
Audit Control No. 14-083-1-1
August 21, 2014

Debra M. Dobiac
Audit Manager

Lynn M. Deamer
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 53
PARTY: STAFF
DESCRIPTION: Debra M. Dobiac DD-1

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Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated March 20, 2014. We have applied these procedures to the schedules prepared by Gulf Power Company in support of its filing for hedging activities in Docket No. 140001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. 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, 2014. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. 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, 2013 to July 31, 2014. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with GPC's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objectives: The objective was to determine whether the quantities of natural gas, residual oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2014, 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 work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Audit Findings

None

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Tampa Electric Company
Hedging Activities

Twelve Months Ended July 31, 2014

Docket No. 140001-EI
Audit Control No. 14-083-2-2
August 19, 2014

Intesar Terkawi
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 54
PARTY: STAFF
DESCRIPTION: Intesar Terkawi IT-1

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Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated March 20, 2014. We applied these procedures to the schedules prepared by Tampa Electric Company in support of its filing for hedging activities in Docket No. 140001-EI for the twelve months ended July 31, 2014.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. 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 twelve months ended July 31, 2014. 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 verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that TECO implemented are in compliance with Commission Order Numbers PSC-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, 2013, to July 31, 2014. We selected all gas hedging transactions from October and November 2013 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 reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power 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 twelve months ended July 31, 2014, and compared them with the Utility's Risk Management Plan. There were variances for 4 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. All variances were a result of inaccurate forecasting.

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 internal and external auditor's work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically related to hedging activities. No exceptions were noted.

Audit Findings

None

55

FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 55
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-11) [Bates

Q.

For each Request for Proposal (RFP) for coal issued in 2013 by Florida Power & Light Company (FPL), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

A.

FPL is a co-owner of two coal fired power plants, the St. Johns River Power Park (SJRPP) located in Jacksonville, FL and Scherer #4 located near Juliette, GA.

SJRPP

No RFPs for coal were issued for SJRPP in 2013.

Scherer #4

The method of coal delivery to Plant Scherer is rail. The route of delivery is the BNSF Railway from coal mines in the Powder River Basin to Memphis, Tennessee and Norfolk Southern from Memphis, Tennessee to the Scherer site.

RFP's for spot coal were issued on March 12, June 6 and September 24. An RFP for annual coal was issued on April 13. See the attachment for a list of the bids received by RFP that includes the supplier, tonnage, quality and delivered price.

List of 2013 SCHERER Coal RFP'S

SPOT

Request for Proposal	Quarter	Supplier	Quantity Offered Tons per Month	Coal Quality Btu/lb	Coal Quality % Sulfur	Delivered Cost $/mmbtu
13-Mar						
6-Jun						
24-Sep						

ANNUAL

Request for Proposal	Year	Supplier	Quantity Offered Tons/Year	Coal Quality Btu/lb	Coal Quality % Sulfur	Delivered Cost $/mmbtu
13-Apr						

Request for Proposal	Year	Supplier	Quantity Offered Tons/Year	Coal Quality Btu/lb	Coal Quality % Sulfur	Delivered Cost $/mmbtu
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						
[redacted]						

Q.

Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

SJRPP

Not Applicable.

Scherer #4

Regarding the evaluation process, spot bids are ranked on the basis of delivered cost. Term bids are ranked based on Net Present Value. Purchases are made based on the bid ranking.

Below are the actions taken with respect to the bids identified in Interrogatory No. 1.

Spot RFP of March 13

FPL purchased 66,891 tons from [redacted] and 198,283 tons from [redacted].

Spot RFP of June 6

FPL purchased 321,000 tons from [redacted].

Spot RFP of September 24

No purchases.

Annual RFP of April 13

FPL purchased 500,000 tons and 572,700 tons from [redacted] for delivery in 2014 and 2015, respectively. FPL also purchased 200,070 tons and 927,203 tons from [redacted] for delivery in 2014 and 2015, respectively.

Q.

During 2013, did FPL experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

A.

SJRPP

SJRPP did not pay any train detention charges in 2013.

SJRPP booked $10,357.67 (100%) for ship demurrage in September of 2013. That amount was an estimate for fiscal year end accrual purposes.

The workforce at Coal Marketing Company's El Cerrejon mine in Colombia was on strike from February 7, 2013 through March 11, 2013. As a result SJRPP lost 2 vessels via a force majeure declaration. The 2013 deliveries of El Cerrejon coal were 1,893,004 tons (100%) compared to the contracted quantity of 2 million tons (100%).

Scherer #4

As detailed below, FPL incurred $129,482.68 of train "Detention at Destination" charges in 2013 for exceeding allowances provided for in the transportation contract related to train crews and locomotives. Of that amount, $87,125.83 was paid in January of 2014.

$ 2,378.13 (1Q crew release charges)
$ 7,803.04 (1Q locomotive charges)
$ 9,020.03 (2Q locomotive charges)
$ 5,448.93 (2Q crew release charges)
$ 5,465.27 (3Q crew release charges)
$12,241.46 (3Q locomotive charges)
$ 5,134.28 (4Q crew release charges)
$81,991.55 (4Q locomotive charges)

Q.

For each RFP for natural gas issued in 2013 by FPL, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

A.

FPL did not issue any RFPs for natural gas purchases during 2013. FPL contacts multiple suppliers and/or brokers to discuss pricing, terms, and volumes when making procurement decisions. This information is used by FPL to determine the appropriate supply portfolio.

Q.

Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

N/A. Please see FPL's response to Staff's First Set of Interrogatories, Interrogatory No. 4.

Q.

In 2013, did FPL participate in any capacity discussions or bid for any firm pipeline capacity during "open season"? Please explain your response and identify the pipeline companies.

A.

Yes, in the normal course of business, FPL participated in capacity discussions with pipeline companies during 2013. FPL entered into the following transactions to secure pipeline capacity.

a. In December 2012, FPL issued a Request for Proposals (RFP) for FPL's gas transportation capacity requirements in 2017 and 2020. After extensive analysis and discussions with all of the bidders, FPL selected the Sabal Trail Transmission, LLC and Florida Southeast Connection, LLC projects as the winning parties in the RFP. In late 2013, these gas transportation contracts were approved by the Florida Public Service Commission to be considered for fuel cost recovery.

b. In March 2013, FPL increased its capacity on the Gulf South pipeline by adding an incremental 100,000 MMBtu/day of firm transportation capability that begins on April 1, 2015 and extends for 10 years.

Q.

In 2013, did FPL participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

A.

Yes, in the normal course of business, FPL participated in capacity discussions with a number of storage companies in 2013.

a. In February of 2013, FPL entered into a new gas storage agreement with Bay Gas Storage. This new agreement was effective April 1, 2013 and includes a total of 2.5 Bcf of storage capacity for a term of one year. [redacted]

b. [redacted]

Q.

For each RFP for light oil issued in 2013 by FPL, list the bids received.

A.

FPL did not issue any RFPs for light oil purchases during 2013. FPL contacts multiple suppliers and/or brokers to discuss volumes, pricing, and terms when making procurement decisions. This information is used by FPL to determine the appropriate supply portfolio.

Q.

Please describe the action taken for each bid identified in response to Interrogatory No. 8. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

N/A. Please see FPL's response to Staff's First Set of Interrogatories, Interrogatory No. 8.

Q.

For each RFP for purchased power issued in 2013 by FPL, list the bids received.

A.

FPL did not issue any RFPs for purchased power during 2013. FPL routinely contacts multiple independent power producers, marketers, and other utilities to discuss volumes, pricing, and terms when making procurement decisions about longer term power purchases. Likewise, FPL contacts multiple suppliers and/or brokers to discuss volumes, pricing, and terms when making procurement decisions for shorter term power purchases. This information is then used by FPL to determine the appropriate supply portfolio.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 18 day of March, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 1 through 11 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-11) in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18 day of March, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:
May 30, 2017

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

Q.

Please describe the action taken for each bid identified in response to Interrogatory No. 10. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

N/A. Please see FPL's response to Staff's First Set of Interrogatories, Interrogatory No. 10.

56

FPL's Responses to Staff's Second Set of Interrogatories (No. 55)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 56
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Second Set of Interrogatories (No. 55) [Bates

Q.

Regarding the incentive mechanism, what is the status of outsourcing the asset optimization functions?

A.

For clarification, FPL is interpreting the terminology "outsourcing the asset optimization functions" in this interrogatory to be specifically related to the release of gas transportation capacity or gas storage capacity under an Asset Management Agreement ("AMA"). FPL's use of the term "outsource" in testimony and discovery in Docket No. 120015-EI was specific to AMA transactions where FPL could release a portion of gas transportation capacity or gas storage capacity to lock in value for FPL's customers on assets that were not projected to be needed over the period in which the agreements were signed. FPL does not intend to "outsource" any asset optimization function outside of AMA transactions. Combined, the [redacted] AMA's that have been executed by FPL represent nearly [redacted] of value. However, it is important to understand these agreements represent a very minor part of the asset optimization functions, which are handled primarily by FPL's Energy Marketing and Trading ("EMT") business unit.

57

FPL's Responses to Staff's Fifth Set of Interrogatories (No. 154 (CONFIDENTIAL), and Nos. 155-164)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 57
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Fifth Set of Interrogatories (No. 154

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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 hedging transactions, incorporating the transaction date, fixed price, transaction period, and NYMEX price is included as Attachment I to this response. The forward prices represent the Henry Hub Natural Gas financial swap prices published by NYMEX.

AUGUST 1, 2013 - JULY 31, 2014 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						0.1%
						-0.5%
						0.3%
						0.6%
						0.5%
						-0.5%
						0.4%
						-0.3%
						-0.5%
						1.1%
						-1.3%
						0.2%
						-0.4%
						0.7%
						-0.6%
						-1.2%
						0.1%
						-0.2%
						0.4%
						1.2%
						-1.4%
						0.7%
						0.6%
						0.6%
						0.2%
						0.3%
						0.5%
						1.4%
						1.9%
						0.9%
						-0.1%
						-2.1%
						-1.2%
						-1.0%
						0.3%
						0.1%
						-0.4%
						-0.6%
						0.2%
						0.5%
						2.3%
						0.5%
						-0.2%
						-0.6%
						0.0%
						-0.5%
						0.0%
						0.5%
						0.0%
						-1.3%
						-0.1%
						-0.2%
						-0.7%
						0.3%
						-0.6%
						-0.6%
						-1.6%
						-0.4%
						0.4%
						-0.2%
						-0.9%
						-0.3%
						-0.8%
						0.1%
						-0.3%
						-0.5%
						0.5%
						1.0%
						0.0%
						2.0%
						0.9%
						0.6%

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						0.1%
						0.4%
						0.1%
						1.1%
						1.0%
						-1.5%
						-1.0%
						1.1%
						0.2%
						0.4%
						-1.8%
						-0.1%
						0.5%
						0.0%
						0.2%
						-0.1%
						0.1%
						-0.6%
						0.1%
						-0.1%
						0.5%
						0.4%
						-0.6%
						0.6%
						-0.7%
						0.0%
						0.0%
						0.4%
						-0.8%
						0.3%
						-0.8%
						2.6%
						0.7%
						-0.2%
						-0.5%
						0.0%
						1.4%
						0.4%
						-0.4%
						1.3%
						-0.1%
						0.6%
						-0.6%
						0.3%
						-3.7%
						-1.6%
						-0.3%
						1.8%
						0.6%
						-1.2%
						-0.6%
						1.5%
						-0.1%
						-0.2%
						0.1%
						0.8%
						0.4%
						1.6%
						-1.3%
						0.0%
						-0.1%
						-0.5%
						-0.4%
						2.5%
						0.2%
						0.4%
						1.1%
						0.3%
						0.0%
						0.0%
						-0.1%
						-1.0%
						-0.7%
						-0.3%
						0.0%

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-0.2%
						0.9%
						0.5%
						0.0%
						0.4%
						-0.1%
						1.0%
						0.3%
						1.4%
						0.4%
						0.6%
						0.4%
						2.0%
						2.2%
						0.2%
						1.9%
						0.2%
						0.3%
						0.8%
						-0.7%
						0.7%
						0.6%
						0.4%
						-0.1%
						0.4%
						0.0%
						1.2%
						0.0%
						2.0%
						1.1%
						0.4%
						-2.5%
						-2.8%
						0.4%
						0.3%
						0.0%
						-0.5%
						-0.1%
						-0.5%
						0.2%
						0.3%
						-0.2%
						0.3%
						1.1%
						1.1%
						0.8%
						0.5%
						-1.1%
						0.0%
						-0.4%
						0.0%
						0.6%
						1.3%
						-0.2%
						-0.1%
						-0.3%
						-1.0%
						0.0%
						0.0%
						-0.3%
						0.1%
						-1.4%
						-0.1%
						-0.2%
						0.1%
						-0.1%
						-0.2%
						0.4%
						0.3%
						0.1%
						0.0%
						0.2%
						-0.2%
						-0.4%
						0.2%

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						0.2%
						0.3%
						0.0%
						0.6%
						-0.4%
						0.6%
						0.1%
						0.0%
						-0.9%
						0.3%
						0.5%
						0.4%
						0.4%
						0.5%
						-0.1%
						0.4%
						-0.3%
						-0.3%
						0.2%
						1.3%
						-0.2%
						0.7%
						0.2%
						0.7%
						-0.3%
						-0.2%
						-0.1%
						0.9%
						1.3%
						0.2%
						0.5%
						0.2%
						-1.0%
						-0.3%
						0.5%
						-0.1%
						0.5%
						-0.7%
						0.0%
						-0.1%
						0.0%
						-0.2%
						0.3%
						0.1%
						1.4%
						0.2%
						0.1%
						0.3%
						-1.2%
						-0.5%
						-0.2%
						0.1%
						0.5%
						-1.8%
						-0.6%
						0.0%
						0.4%
						-0.9%
						1.5%
						-0.5%
						0.5%
						0.0%
						0.1%
						-0.9%
						-0.2%
						-0.8%
						-2.4%
						-1.1%
						-0.2%
						0.6%
						1.6%
						0.2%
						-0.2%
						0.7%
						0.3%

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						0.0%
						2.0%
						-0.1%
						-0.3%
						0.0%
						0.5%
						0.4%
						0.0%
						-0.1%
						0.1%
						0.0%
						-0.7%
						0.0%
						-0.5%
						-0.8%
						-0.1%
						-0.2%
						-0.2%
						-1.0%
						0.1%
						-0.8%
						0.1%
						-0.2%
						-0.3%
						-0.2%
						0.1%
						-0.3%
						0.5%
						1.6%
						0.8%
						1.8%
						0.3%
						-0.3%
						-0.4%
						-0.2%
						0.8%
						0.0%
						0.9%
						0.3%
						0.3%
						-0.7%
						1.7%
						0.1%
						0.3%
						0.4%
						0.0%
						0.2%
						0.3%
						0.9%
						0.1%
						1.0%
						0.5%
						0.0%
						-0.9%
						-0.4%
						-1.5%
						-0.7%
						-0.5%
						-0.9%
						1.5%
						2.0%
						0.7%
						0.5%
						0.2%
						-0.4%
						-0.8%
						-0.3%
						-0.4%
						0.3%
						-0.3%
						0.0%
						-0.8%
						-0.4%
						0.1%
						0.4%

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price	
[redacted]						0.1%	
						1.0%	
						0.1%	
						0.9%	
						-0.8%	
						0.1%	
						-0.4%	
						-0.5%	
						-0.8%	
						-1.0%	
						-1.1%	
						-0.1%	
						-0.1%	
						0.0%	
						1.3%	
						1.1%	
						0.1%	
						0.0%	
						-1.6%	
						-1.3%	
						-1.3%	
						-0.5%	
						-1.0%	
						-0.7%	
						-0.3%	
						-0.1%	
						0.3%	
						1.0%	
						1.2%	
						0.6%	
						0.2%	
						-0.4%	
						-0.2%	
						-1.2%	
						-0.5%	
						-0.2%	
						0.2%	
						-0.5%	
						-0.2%	
						0.3%	
						0.0%	
						-0.6%	
						-0.2%	
						1.2%	*
						1.2%	*
						1.0%	*
						1.0%	*
						0.2%	*
						0.2%	*
						0.7%	*
						0.7%	*
						0.4%	*
						0.4%	*
						-0.5%	*
						-0.5%	*
						-1.8%	**
						-1.8%	**
						-1.0%	**
						-1.0%	**

(*) Note: These deals were originally executed as 12-month strip transactions. The October-December component was transferred to an affiliate of the 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.
(**) Note: These deals were originally executed as 7-month (April-October) strip transactions. The October component was transferred to an affiliate of the 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 154 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 hedge transactions for the period from August 1, 2013 through July 31, 2014 were less than 5 percent of the swap fixed prices. The calculations are included as part of FPL's response to Staff's Interrogatory No. 154.

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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 2013 or 2014.

Q.

For interrogatory 156 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 2013 or 2014.

Q.

Please state the realized hedging savings and costs by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2013, and ending July 31, 2014.

A.

The realized hedging gains and losses by fuel type and by type of hedging instrument for the period from August 1, 2013 to December 31, 2013 are included in the August 2013 Through December 2013 Hedging Activity True-Up Report, filed in Docket No. 140001-EI on March 28, 2014. The realized hedging gains and losses by fuel type and by type of hedging instrument for the period from January 1, 2014 through July 31, 2014 are included in the Fuel Hedging Activity Report, filed in Docket No. 140001-EI on August 13, 2014.

Q.

For the twelve months beginning August 1, 2013 and ending July 31, 2014, for each month that hedged volumes of natural gas were outside the percentage range for volumes to be hedged stated in FPL's risk management plan or otherwise stated in internal procedures governing FPL's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

A.

All hedged volumes of natural gas, for the twelve months beginning August 1, 2013 and ending July 31, 2014, were within approved percentage ranges as stated in FPL's Risk Management Plan(s) and internal procedures governing FPL's hedging activities.

Q.

Please provide a comparison of FPL's Risk Management Plans for 2014 and 2015. Please describe any changes between these respective plans.

A.

There are no significant differences between the 2015 and 2014 Risk Management Plans. Minor changes were made to incorporate routine updates to the Trading and Risk Management Procedures and Energy Trading and Risk Management Policy. Changes were included to clarify Risk Management policies and procedures that specifically apply to the Energy Marketing and Trading Division. Additional language was added to specify that production from natural gas reserve transactions, if approved by the Commission, are to be included as hedged volumes.

All hedging parameters in the 2015 Risk Management Plan (hedge percentages, execution window, hedge tenure) for natural gas are consistent with those outlined in the 2014 Risk Management Plan. The 2015 Risk Management Plan includes an updated overview of the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Q.

For open hedging transactions since August 1, 2013, has FPL experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

A.

FPL has not experienced any counterparty defaults related to open hedging transactions since August 1, 2013.

Q.

For all currently open hedging transactions, does FPL have any concern regarding default by a counter-party for any specific transaction? If yes, please identify the counter-party and explain.

A.

FPL does not have any specific counterparty credit concerns related to current open hedging transactions.

Q.

Since January 1, 2013, has FPL stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If yes, please identify the counter-party and explain.

A.

FPL has not stopped engaging in hedging transactions with any of its hedging counterparties due to credit risk concerns since January 1, 2013.

Q.

Has FPL incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If yes, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

A.

No. Any savings or costs associated with FPL's hedging program are included in the total fuel expense, which is recovered through FPL's fuel clause in the period realized. Any difference between the amounts realized and the amounts forecasted are adjusted in the over or under fuel recoveries. No specific tax effect is provided for any realized hedging cost.

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FPL's Responses to Staff's Sixth Set of Interrogatories (Nos. 165-166)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 58
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Sixth Set of Interrogatories,Nos. 165,166

Q.

Please refer to the March 3, 2014 testimony of FPL witness Yupp and to page 3, lines 18 through 19. Please describe the Asset Management Agreement and include references to any schedules. Also, state the dollar impact, actual or estimated, of this agreement for 2013, 2014, and 2015.

A.

The Asset Management Agreement (AMA) referenced in witness Yupp's testimony was executed on [redacted], with a term from [redacted]. 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. [redacted]. 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 in this instance to structure an 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.

The AMA Gains for 2013 are listed, by month, in column 7, on page 3, in Exhibit GJY-1 (Asset Optimization Detail Actual for the Period of: January 2013 through December 31, 2013), which was included in the Levelized Fuel Cost Recovery and Capacity Cost Recovery Final True-Up, January 2013 through December 2013, filed on March 3, 2014. The AMA Gains for 2014 were [redacted]. The monthly AMA Gains for 2014 will be included on a similar schedule when the Levelized Fuel Cost Recovery and Capacity Cost Recovery Final True-Up, January 2014 through December 2014, is filed in March 2015.

Q.

For purposes of this interrogatory, please refer to the testimony of Gerard J. Yupp, filed August 22, 2015. On Page 23, Lines 1-4 the witness addresses the incremental variable power plant operations and maintenance cost. Please answer the following:

a. Discuss how the incremental variable power plant operations and maintenance cost of $1.51 per MWh is calculated.

b. The testimony states that $1.51 per MWh is calculated based on projection data for 2013. Is there a "reset provision" for this calculation to base this cost on more current data? Please discuss.

A.

a. The incremental variable power plant operations and maintenance cost of $1.51 per MWh is for non-fuel O&M expenses and costs for capital replacement parts that vary with power plant output, as prescribed in Paragraph (12)(b)(ii) and Footnote 3 of the settlement agreement that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI (the "2012 Rate Case Settlement"). This rate is for the Steam and Other Production units in the FPL fossil fleet, because those are the types of units whose output is typically increased to make wholesale sales. The calculation includes three cost components.

(1) Overhaul expenses;
(2) Specific variable operating and maintenance expenses
(Ash disposal, Chemicals and Demineralized Water);
(3) Annual capital replacement part expenses

The 2013 test year MFR figures from the components above were accumulated and divided by the forecasted 2013 fossil fleet generation projections (excluding the FPL Solar plants which are recovered through ECRC) to determine $/MWh.

b. The 2012 Rate Case Settlement does not include a "reset provision" for the per-MWh rate to be used in calculating incremental variable power plant O&M cost. Rather, Paragraph 12(b)(ii) of the 2012 Rate Case Settlement expressly provides that the per-MWh rate will be "the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs." This per-MWh rate is then applied to each year's actual wholesale sales in excess of the 514,000 MWh threshold to determine that year's incremental variable power plant O&M cost that may be recovered through the Fuel Clause. Thus, the current rate of $1.51 per MWh will remain applicable until the settlement term ends on 12/31/2016.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 2nd day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 165 through 166 from **STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 165-166)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of October, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

59

DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 59
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-11) [Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No. 140001-EI Filed: March 21, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-11)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Set of Interrogatories to DEF (Nos. 1-11), as follows:

INTERROGATORIES

1. For each Request for Proposal (RFP) for coal issued in 2013 by Duke Energy Florida (Duke), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

Answer:

Please see Attachment A which is a list of bids received in response to the RFP Duke issued on July 26, 2013. The bid list includes the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery for each bid.

Please Note: Attachment A bearing Bates Numbers DEF-14FL-000088 through DEF-14FL-000095 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated March 21, 2014.

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

The action taken for each bid identified is contained in the response to Interrogatory No. 1 (Attachment A). The evaluations took into consideration factors including, but not limited to, the following:

(1) conformity to the technical and commercial aspects of the specifications (e.g. coal specifications, delivery schedules, warranties, etc.);
(2) coal quality and quantity assurances (or guarantees) by the bidder;
(3) unit prices and conditions of pricing;
(4) any exceptions to the specifications and resulting penalties;
(5) perceived or demonstrated supplier reliability and/or capability;
(6) supplier operations and/or shipping capabilities;
(7) previous performance; and
(8) any other considerations applicable under the circumstances.

DEF produced an evaluated delivered cost per MMbtu for each coal and selected the appropriate coals on the basis of this complete evaluation.

3. During 2013, did Duke experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

Answer:

During 2013, DEF replaced two existing cranes with two new cranes. These cranes are used to discharge Gulf barges. The installation of the new cranes began late 3rd quarter and the outage period extended through 4th quarter which caused constraints. DEF did experience demurrage charges for coal deliveries. Those demurrage charges were a result of river, Gulf barge, terminal and/or train loading or unloading delays. The general causes for the loading and/or unloading delays include, but are not limited to, weather impacts and operational considerations. Demurrage charges are not assigned nor categorized by event, rather attributable to general delays, so the specific demurrage charges for each event type cannot be provided. For demurrage charges that DEF incurred for 2013, please see Attachment D.

Please Note: Attachment D bearing Bates Number DEF-14FL-000096 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated March 21, 2014.

4. For each RFP for natural gas issued in 2013 by Duke, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

Answer:

There were no natural gas RFP's issued in 2013.

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

There were no natural gas RFP's issued in 2013.

6. In 2013, did Duke participate in any capacity discussions or bid for any firm pipeline capacity during "open season"? Please explain your response and identify the pipeline companies.

Answer:

REDACTED

DEF engages in ongoing discussions with suppliers and pipelines to stay abreast of developments. DEF [redacted] during 2013. DEF [redacted]. In summary, this agreement supports DEF's on-going strategy to access onshore natural gas supply to meet its existing natural gas generation needs.

7. In 2013, did Duke participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

Answer:

DEF engages in ongoing discussions with various gas suppliers, pipelines and existing storage providers to stay abreast of developments and potential gas storage opportunities. During 2013, DEF participated in discussions with existing storage contract providers and potential in state storage developers to discuss potential developments. DEF did not bid for any new gas storage in 2013.

8. For each RFP for light oil issued in 2013 by Duke, list the bids received.

Answer:

DEF issued one RFP for light oil in October 2013 for 2014 requirements. Please see "Attachment B" bearing Bates Numbers DEF-14FL-000097 through DEF-14FL-000106. Please see "Attachment C" bearing Bates Numbers DEF-14FL-000107 through DEF-14FL-000109 for a summary of the list of bids received and the response summary.

Please Note: Attachment C bearing Bates Numbers DEF-14FL-000107 through DEF-14FL-000109 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated March 21, 2014.

9. Please describe the action taken for each bid identified in response to Interrogatory No. 8. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

The bids were analyzed by calculating and comparing the estimated total average delivered cost per gallon by company to the respective facilities by using the applicable light oil published index prices and pricing parameters provided by each bidder. As future prices are not known, actual prices for the period October 2012 through September 2013 for the respective publication index prices were used to calculate estimated comparable annual average costs per gallon to each location for evaluation purposes. The company with the lowest estimated average cost per gallon for each location was recommended as the primary supplier. In addition, consistent with previous RFP's, DEF selected a backup supplier for each facility to provide additional supply access and reliability of fuel oil supply. Based on the analysis, DEF entered into agreements with the recommended fuel suppliers as outlined in "Attachment C".

10. For each RFP for purchased power issued in 2013 by Duke, list the bids received.

Answer:

On October 8, 2013, DEF issued an RFP for long-term supply resources beginning in year 2018. This RFP was issued to solicit competitive proposal alternatives to DEF's Next Planned Generating Unit, or the self-build Citrus Combined Cycle Unit with an in-service date of 2018. A total of 7 Bids were received, including the DEF Self Build Citrus Combined Cycle, on December 9, 2013. DEF is currently evaluating the proposals and does not expect the cost associated with this RFP to impact this Docket.

11. Please describe the action taken for each bid identified in response to Interrogatory No. 10. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

The October 8, 2013 RFP is still under review for long-term power resources and the evaluation processes is not expected to be completed until later in 2014. DEF does not expect the cost associated with the RFP to impact this Docket.

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Before me, the undersigned authority, personally appeared **JOSEPH McCALLISTER**, who

( ) is personally known to me, or

(XX) produced NC Driver's License as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 4 through 9 of Staff's First Set of Interrogatories to Duke Energy Florida, Inc. in Docket No. 140001-EI are true and correct to the best of his knowledge, information and belief.

Joseph McCallister

Joseph McCallister
Director of Natural Gas Oil & Emissions

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Rita G Kale
Notary Public, Rita G Kale
State of North Carolina

My commission Expires: June 17, 2017

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Before me, the undersigned authority, personally appeared **BRETT PHIPPS**, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 1 through 3 of Staff's First Set of Interrogatories to Duke Energy Florida, Inc. in Docket No. 140001-EI are true and correct to the best of his knowledge, information and belief.

Brett Phipps

BRETT J PHIPPS
Director of Fuel Procurement

Donna J Sears
Notary Public
State of North Carolina

My commission Expires: 1/16/2019

Donna J. Sears
Notary Public
Wake County
North Carolina
My Commission Expires Jan. 16, 2019

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DEF's Responses to Staff's Second Set of Interrogatories (Nos. 12, 13, 14 (CONFIDENTIAL), 15-17, 18 (CONFIDENTIAL), 19 (CONFIDENTIAL), and 20-27)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 60
PARTY: STAFF
DESCRIPTION: DEF's Responses to Staff's Second Set of Interrogatories (Nos. 12, 13, 14

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No. 140001-EI Filed: September 18, 2014

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 12-27)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Second Set of Interrogatories to DEF (Nos. 12-27), as follows:

INTERROGATORIES

12. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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:
Please see Attachments bearing bates numbers DEF-14FL-000110 through DEF-14FL-000115 and DEF-14FL-000121 through DEF-14FL-000123 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated September 18, 2014.

13. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, associated with swap contracts for fuel oil, please provide the following information:

(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. Please provide your responses in a schedule format.

Answer:
Please see Attachments bearing bates numbers DEF-14FL-000119 through DEF-14FL-000120 and DEF-14FL-000126 through DEF-14FL-000127. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated September 18, 2014.

14. For interrogatories 12 and 13 above, please explain any difference 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:

The trading prices represented in responses 12 and 13 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 were the data that was 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 and 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 12 and 13, DEF has outlined on the Attachment A for Question 14 illustrations of this for natural gas trades executed for 2013 and 2014. These are further described below and outlined in Attachments bearing bates numbers DEF-14FL-000128 through DEF-14FL-000129. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated September 18, 2014.

As outlined in Example #1 on the Attachment A for Question 14, DEF executed a natural gas financial swap for the November 2013 through March 2013 time period on July 6, 2012 for [redacted] per MMBtu. During the course of the trading day on July 6, 2012, the market price for the November 2013 through March 2014 strip time period traded from a low of approximately $3.9054 per MMBtu to a high of approximately $4.0210 per MMBtu, a range of approximately $0.1156 per MMBtu, and closed on that day at $3.9096 per MMBtu. At the time DEF executed this trade, the market price for this time period was [redacted] per MMBtu and as illustrated above was within the daily trading range.

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.

As this example illustrates, market prices for natural gas and fuel oil change within trading days and can experience large 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.

15. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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:
Please see Attachments bearing bates numbers DEF-14FL-000116 through DEF-14FL-000118 and DEF-14FL-000124 through DEF-14FL-000125. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated September 18, 2014.

16. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, associated with options for fuel oil 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:
Duke Energy Florida did not have any fuel oil options for August 2013 through July 2014.

17. For interrogatories 15 and 16 above, please explain any difference 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:
The option premium prices represented in responses 15 are the actual prices that 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 responses 15.

18. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2013, and ending July 31, 2014.

Answer:
REDACTED

Duke Energy Florida
For August 2013 through July 2014

Hedging Instrument	Fuel Type	Total Savings/(Cost) of Hedge
OTC Financial Instruments	Natural Gas	[redacted]
OTC Financial Instruments	Natural Gas - Storage	
OTC Financial Instruments	Light Oil	
OTC Financial Instruments	Light Oil - River Barge - Fuel Surcharge Hedge	
OTC Financial Instruments	Light Oil - Rail - Fuel Surcharge Hedge	
Total		

19. For the twelve months beginning August 1, 2013, and ending July 31, 2014, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in DEF's risk management plan or otherwise stated in internal procedures governing DEF's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

REDACTED

Answer:
The hedging targets ranges established in DEF's 2014 Risk Management Plan for calendar year 2014 was a range of [redacted] to [redacted] of forecasted natural gas burns with a targeted minimum hedge percentage of [redacted] of forecasted burn. In addition, DEF targeted to hedge at least [redacted] of forecasted light oil burns. Lastly, DEF targeted to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposure in the coal rail and river barge transportation agreements. DEF's hedging targets are based on annual calendar year forecasted burns and exposures. DEF monitors its actual and forecasted burns for calendar and rolling 12-month periods hedge percentages.

Although the audit period and the annual calendar periods noted in DEF's 2014 Risk Management Plan are different, for the period August 1, 2013 through July 31, 2014, DEF's actual hedge percentages for natural gas, light oil, and coal rail and river surcharge exposures were approximately [redacted], [redacted], [redacted] and [redacted], respectively. As such, these were within the hedging ranges and/or minimum hedge percentages outlined in DEF's 2014 Risk Management Plan. As outlined in the Plan, actual hedge percentages for any monthly periods, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

20. Please provide a comparison of DEF's Risk Management Plans for 2014 and 2015.

Please describe any changes between the respective plans.

Answer:
The overall substance and purpose of the Risk Management Plan (Plan) has not changed between the 2014 Plan and the 2015 Plan. The 2015 Risk Management 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 of Docket No. 011605-EI and further clarified in Order No. PSC-08-0667-PAA-EI of Docket No. 080001-EI. Outlined below are the major changes between the Duke Energy Florida (DEF) 2014 Plan and the 2015 Plan.

- On page 10 of the 2015 Plan, paragraph 3 – The Regulated Utilities Risk Limit was formally known as the Franchised Electric Risk Limits in the 2014 Plan.

- On page 13 of the 2015 Plan, paragraph 1 – The Transaction and Risk Committee (TRC) management member's titles changed to reflect current corporate organization structure.

- On page 17 of the 2015 Plan, paragraph 4 – DEF is replacing its fuel procurement software applications; CXL is replacing Aligne, GasOps is replacing GMS and Comtrac is replacing Fuelworx.

The overall substance of the key processes, oversight activities, and purpose of risk documents and objectives of the 2015 Risk Management Plan are the same 2014 Risk Management Plan.

21. Regarding hedging activities, how does DEF assess and evaluate counter-party credit risk?

Answer:
Credit Risk Management evaluates counterparties using a consistent analytic approach. The credit ratings are based on both external ratings and the evaluation of key counterparty attributes identified as leading indicators for financial performance and established, industry standard, and financial and credit metrics (e.g. leverage ratios, Funds from Operations, Cash Flow from Operations, Debt Service and Interest Coverage, Revenue trends, Profit Margins, Net Worth, Outstanding debt analysis and metric trend analysis, Bank Failure Ratio, Nonperforming Assets to Total Assets Ratio, etc.). The credit rating objectives promote an objective, fair, and consistent methodology to review counterparty candidates and establish and promote consistent risk standards. Evaluations are performed on an established frequency based on counterparty's credit rating. Credit Risk Management uses news and credit rating alerts to monitor counterparties for any material changes or issues. The on-going monitoring of markets, industries, news wires, and peer groups generate information which would prompt an interim review if warranted.

22. For open hedging transactions since August 1, 2013, has DEF experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

Answer:
DEF has not experienced any defaults.

23. For all currently open hedging transactions, does DEF have any concern regarding default by a counter-party for any specific transaction? If yes, please identify the counter-party and explain.

Answer:
DEF does not have any concerns regarding any counter-party defaults for specific transactions.

24. Since January 1, 2013, has DEF stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If yes, please identify the counter-party and explain.

Answer:
In January 2014, the credit group requested that no further transactions be conducted with Citigroup Energy until some of the open transactions settled because the potential exposure on the then-existing open hedge transactions were at a preset internal reporting limit. In March 2014, once previous transactions settled and the exposure was reduced, the credit group allowed transactions with Citigroup Energy to be resumed.

25. Please refer to the testimony of witness James McClay dated March 28, 2014 and to the attached Exhibit JM-1T. Regarding hedging costs for natural gas for the months of August 2013 through December 2013, please explain the incurrence of hedging costs for each month given that spot natural gas prices were generally flat during this period.

Answer:
DEF utilizes a phased hedging program where hedge transaction are executed for forward time periods consistent with its plan over time with the objective of reducing price risk and providing greater cost certainty for DEF's customers. All the hedging transactions for the months outlined above were executed at the then prevailing market price for these months at the time the hedging transactions were executed. Over time, natural gas prices declined and actual monthly settlement prices were lower than the prices that were previously hedged for these months. This resulted in aggregate net hedging costs for these months even though spot prices were generally flat during these months.

26. Please refer to the testimony of witness James McClay dated March 28, 2014 and to the attached Exhibit JM-1T. For financial swaps for natural gas during the period August 2013 through December 2013, it appears that smaller volumes hedged incurred greater hedging costs. Please explain.

Answer:
For the period of August 2013 through December 2013, some hedging transactions were executed when natural gas prices were higher. DEF executes hedging transactions over time and executes transactions at the prevailing market price that exists at the time of the hedge. As a result of natural gas price declines over time, some transactions were hedged at a higher prices and incurred greater hedging costs when compared to others transactions.

27. Has DEF incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If yes, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

Answer:
No. DEF has not incurred any federal and/or state tax expenses (credits) on realized hedging gains (losses) associated with fuel expense over the past three years.

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Before me, the undersigned authority, personally appeared **JAMES MCCLAY**, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 12 through 27 of Staff's Second Set of Interrogatories to Duke Energy Florida, Inc. in Docket No. 140001-EI are true and correct to the best of his knowledge, information and belief.

James McClay
Signature

James McClay
Print name

Manager Gas Trading
Title

9/12/2014
Date

Katie Jamison
Notary Public
State of North Carolina

My commission Expires: June 14, 2016

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FPUC's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 61
PARTY: STAFF
DESCRIPTION: FPUC's Responses to Staff's First Set of Interrogatories (Nos. 1-2) [Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 140001-EI DATED: August 28, 2014

RESPONSES TO COMMISSION STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1 - 2)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Responses to the First Set of Interrogatories (Nos. 1-2) served on the Company on August 8, 2014, by the Staff of the Florida Public Service Commission. The individual responses follow this cover sheet.

Respectfully submitted,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706
Attorneys for Florida Public Utilities Company

Response to Interrogatory 1(a)

INTERROGATORY RESPONSES

1. For purposes of this interrogatory and sub-parts, please refer to Schedule A from Exhibit CDY-1 ("Northwest Division True-up Exhibit"), and also to Page 2, Lines 6-10 of the Direct Testimony of Curtis D. Young, filed on July 25, 2014.

   a. Line 10 of the Northwest Division True-up Exhibit reflects that the Final Fuel and Purchased Power recovery calculation for the period January through December 2013 is an under-recovery of $1,777,389. This schedule was filed on March 3, 2014. Is this the correct final recovery amount for this period? If applicable, please identify all revised inputs or calculations that have changed the recovery amount since this schedule was filed.

   Company Response:

   Yes, the remaining true-up for the period January through December 2013 is an under-recovery of $1,777,389. There are no changes to this recovery amount since the aforementioned schedule was filed.

   (Curtis D. Young)

Response to Interrogatory 1(b)

b. Page 2, Line 9 of the Direct Testimony of Curtis D. Young, filed on July 25, 2014, states that the Northwest Division's final true-up balance for the period January through December 2013 is an under-recovery of $1,806,713. Is this the correct final recovery amount for this period? Please explain your response, and show the inputs and calculations to support this amount.

Company Response:

No, this is no longer the amount of the final remaining recovery for the period January through December 2013. The $1,806,713 was erroneously reported in the testimony of Curtis D. Young. The correct amount is $1,777,389 as reported in Line 10 of Schedule A from Exhibit CDY-1 of the Northwest Division True-up Exhibit, filed on March 3, 2014.

(Curtis D. Young)

Response to Interrogatory 2(a)

2. For purposes of this interrogatory and sub-parts, please refer to Schedule B from Exhibit CDY-1 ("Northeast Division True-up Exhibit"), and also to Page 2, Lines 6-10 of the Direct Testimony of Curtis D. Young, filed on July 25, 2014.

   a. Line 10 of the Northeast Division True-up Exhibit reflects that the Final Fuel and Purchased Power recovery calculation for the period January through December 2013 is an over-recovery of $1,255,621. This schedule was filed on March 3, 2014. Is this the correct final recovery amount for this period? If applicable, please identify all revised inputs or calculations that have changed the recovery amount since this schedule was filed.

   Company Response:

   Yes, the remaining true-up for the period January through December 2013 is an over-recovery of $1,255,621. There are no changes to this recovery amount since the aforementioned schedule was filed.

(Curtis D. Young)

Response to Interrogatory 2(b)

b. Page 2, Line 10 of the Direct Testimony of Curtis D. Young, filed on July 25, 2014, states that the Northeast Division's final true-up balance for the period January through December 2013 is an over-recovery of $1,213,227. Is this the correct final recovery amount for this period? Please explain your response, and show the inputs and calculations to support this amount.

Company Response:

No, this is no longer the amount of the final remaining recovery for the period January through December 2013. The $1,213,227 was erroneously reported in the testimony of Curtis D. Young. The correct amount is $1,255,621 as reported in Line 10 of Schedule B from Exhibit CDY-1 of the Northeast Division True-up Exhibit, filed on March 3, 2014.

(Curtis D. Young)

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 27th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis Young, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 1 & 2 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 1-2) in Docket No(s). 140001-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 27th day of August, 2014.

Dina Bellechase
Notary Public
State of Florida, at Large

My Commission Expires:
December 13, 2015

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FPUC's Responses to Staff's Second Set of Interrogatories (Nos. 3, 4, 5, and Amended 5)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 62
PARTY: STAFF
DESCRIPTION: FPUC's Responses to Staff's Second Set of Interrogatories (Nos. 3, 4, 5,

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 140001-EI DATED: September 24, 2014

RESPONSES TO COMMISSION STAFF'S SECOND SET OF INTERROGATORIES (NOS. 3 - 5)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Responses to the Second Set of Interrogatories (Nos. 3-5) served on the Company on September 3, 2014, by the Staff of the Florida Public Service Commission. The individual responses follow this cover sheet.

Respectfully submitted,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706
Attorneys for Florida Public Utilities Company

Response to Interrogatory 3

INTERROGATORY RESPONSES

3. Please discuss and quantify any cost savings FPUC might experience as a result of a consolidated fuel factor.

Company Response:

The most significant benefits from the consolidation of the fuel adjustment factor relates to the proper allocation of cost to customers and the ability to mitigate wholesale power rate fluctuations that may occur. There have been methods in place within the fuel filings that worked to assist in properly allocating the cost to the appropriate division. With consolidation, this issue will no longer be required to ensure appropriate cost allocation to the customers. It has also been well documented that cost changes have resulted in large swings in fuel costs to the customers in the two divisions, which would have been mitigated if consolidated fuel factors had been in place.

Cost savings will also occur on a regulatory basis by reducing the number of filings being prepared and submitted.

Respondent: Mark Cutshaw

Response to Interrogatory 4

4. **Please provide a comparison of the projected payments for energy (in cents per kilowatt-hour) and for capacity (in $ per kilowatt) in FPUC's purchased power contract with JEA and with Gulf Power Company for 2015 through the last year of the contract.**

Company Response:

Below is shown the rate information from both Gulf Power Company and JEA. There are unknown quantities related to both contracts as the contracts allow for determination of cost based on cost of service studies. Also, both Gulf Power Company and JEA energy charges include the fuel, base and environmental charges within the charges shown below.

JEA	Energy Charge (¢/kwh)	Capacity Charge ($/kw)
2015	5.522¢/kwh	$14.31/kw
2016	TBD	TBD
2017	TBD	TBD
GULF	Energy Charge (¢/kwh)	Capacity Charge ($/kw)
2015	5.442¢/kwh	$10.55/kw
2016	TBD	$11.15/kw
2017	TBD	$11.70/kw
2018	TBD	$12.25/kw
2019	TBD	$12.80/kw

Respondent: Mark Cutshaw

Response to Interrogatory 5(a)

5. **Please provide all E Schedules under the following scenarios:**

   a. **Consolidated fuel factors and the total under-recovery (as opposed to one-third as proposed) included in the consolidated 2015 cost recovery calculation.**

Company Response:

The comparative factors between those proposed in the Company's consolidated 2015 cost recovery calculation and those computed based on total recovery of the Company's 2014 under-recovery are as follows:

	Proposed Rates	With Total Under-Recovery
RS	$0.10405	$0.10718
GS	$0.10037	$0.10350
GSD	$0.09520	$0.09833
GSLD	$0.09154	$0.09467
LS	$0.07751	$0.08064

Residential Step Rates:

	Proposed Rates	With Total Under-Recovery
RS <= 1,000kWh/mo.	$0.09977	$0.10290
RS > 1,000kWh/mo.	$0.11227	$0.11540

TOU / Interruptible Rates:

	Proposed Rates		With Total Under-Recovery	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18377	$0.06077	$0.18690	$0.06390
GS	$0.14037	$0.05037	$0.14350	$0.05350
GSD	$0.13520	$0.06270	$0.13833	$0.06583
GSLD	$0.15154	$0.06154	$0.15467	$0.06467
Interruptible	$0.07654	$0.09154	$0.07967	$0.09467

The computation of these amounts can be found on the attached file 140001 FPUC ROG 2 No. 5a.

Respondent: Curtis Young

Response to Interrogatory 5(b)

b. Consolidated fuel factors and one-third of the total under-recovery added as a separate c/kwh surcharge for the two divisions (i.e., the under-recovery is not consolidated, but recovered in 2015 separately from each division's ratepayers).

Company Response:

The comparative factors between the Company's two divisions computed based on consolidated fuel factors with one-third of the Company's 2014 under-recovery added as a separate surcharge are as follows:

	Northwest Florida	Northeast Florida
RS	$0.10526	$0.10279
GS	$0.10158	$0.09911
GSD	$0.09641	$0.09394
GSLD	$0.09275	$0.09028
LS	$0.07842	$0.07595

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.09971	$0.09958
RS > 1,000kWh/mo.	$0.11221	$0.11208

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18371	$0.06071	n/a	n/a
GS	$0.14158	$0.05158	n/a	n/a
GSD	$0.13641	$0.06391	n/a	n/a
GSLD	$0.15275	$0.06275	n/a	n/a
Interruptible	$0.07775	$0.09275	n/a	n/a

The calculation of these amounts can be found on the attached schedule 140001 FPUC ROG 2 No. 5b.

Respondent: Curtis Young

Response to Interrogatory 5(c)

c. Consolidated fuel factors and the total under-recovery added as a separate c/kwh surcharge for the two divisions.

Company Response:

The comparative factors between the Company's two divisions computed based on consolidated fuel factors with the Company's total 2014 under-recovery added as a separate surcharge are as follows:

	Northwest Florida	Northeast Florida
RS	$0.11081	$0.10341
GS	$0.10713	$0.09973
GSD	$0.10196	$0.09456
GSLD	$0.09830	$0.09090
LS	$0.08397	$0.07657

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.10526	$0.10020
RS > 1,000kWh/mo.	$0.11776	$0.11270

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18926	$0.06626	n/a	n/a
GS	$0.14713	$0.05713	n/a	n/a
GSD	$0.14196	$0.06946	n/a	n/a
GSLD	$0.15830	$0.06830	n/a	n/a
Interruptible	$0.08330	$0.09830	n/a	n/a

The computation of these amounts can be found on the attached file 140001 FPUC ROG 2 No. 5c.

Respondent: Curtis Young

Response to Interrogatory 5(d)

d. Separate fuel factors (with transmission costs allocated consistent with the methodology approved by Order No. PSC-13-0665-FOF-EI) and the total under-recovery included separately in the fuel factor calculations for the two divisions.

Company Response:

The comparative factors between the Company's two divisions computed based on separate fuel factors with the Company's total 2014 under-recovery are as follows:

	Northwest Florida	Northeast Florida
RS	$0.11111	$0.10326
GS	$0.10714	$0.09980
GSD	$0.10163	$0.09503
GSLD	$0.09770	$0.09160
LS	$0.08257	$0.07834

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.10555	$0.10005
RS > 1,000kWh/mo.	$0.11805	$0.11255

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18955	$0.06655	n/a	n/a
GS	$0.14714	$0.05714	n/a	n/a
GSD	$0.14163	$0.06913	n/a	n/a
GSLD	$0.15770	$0.06770	n/a	n/a
Interruptible	$0.08270	$0.09770	n/a	n/a

The computations for the above amounts can be found on the attached files 140001 FPUC ROG 2 No. 5d Marianna and 140001 FPUC ROG 2 No. 5d Fernandina.

(Curtis D. Young)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Electronic Mail to the following parties of record this 24th day of September, 2014:

Martha Barrera Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 Mbarrera@PSC.STATE.FL.US	James D. Beasley/J. Jeffry Wahlen/Ashley Daniels Ausley Law Firm Post Office Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com adaniels@ausley.com
Jeffry Stone/Russell Badders/Steven Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591-2950 jas@beggslane.com	James W. Brew/F. Alvin Taylor Brickfield Law Firm Eighth Floor, West Tower 1025 Thomas Jefferson Street, NW Washington, DC 20007 jbrew@bbrslaw.com
John T. Butler Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420 John.Butler@fpl.com	Kenneth Hoffman Florida Power & Light Company 215 South Monroe Street, Suite 810 Tallahassee, FL 32301 Ken.Hoffman@fpl.com
Ms. Paula K. Brown Tampa Electric Company Regulatory Affairs P.O. Box 111 Tampa, FL 33601-0111 Regdept@tecoenergy.com	Florida Industrial Users Power Group Jon C. Moyle, Jr. Moyle Law Firm 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com
Cheryl Martin Florida Public Utilities Company 911 South 8th Street Fernandina Beach, FL 32034 Cheryl_Martin@fpuc.com	Florida Retail Federation Robert Scheffel Wright/John T. LaVia Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com

Robert L. McGee, Jr. Gulf Power Company One Energy Place Pensacola, FL 32520 rlmcgee@southernco.com	J.R. Kelly/P. Christensen/C. Rehwinkel/ Office of Public Counsel c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400 Christensen.patty@leg.state.fl.us
Matthew Bernier/Paul Lewis, Jr. Duke Energy 106 East College Avenue, Suite 800 Tallahassee, FL 32301 Paul.lewisjr@duke-energy.com Matthew.Bernier@duke-energy.com	John T. Burnett/Dianne M. Triplett Duke Energy 299 First Avenue North St. Petersburg, FL 33701 John.burnett@duke-energy.com Dianne.Triplett@duke-energy.com
	Randy B. Miller White Springs Agricultural Chemicals, Inc. Post Office Box 300 White Springs, FL 32096 Rmiller@pcsphosphate.com

By: _____

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

Docket No. 140001- EI

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 24th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis Young, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 5(a) – (d) from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 3-5) in Docket No(s). 140001-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 24th day of September, 2014.

Notary Public
State of Florida, at Large

BONNIE L. ERDEK
MY COMMISSION # EE 089032
EXPIRES: May 1, 2015
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 01, 2015

Docket No. 140001- EI

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF NASSAU)

I hereby certify that on this 24th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared P. Mark Cutshaw, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 3 and 4 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 3-5) in Docket No(s). 140001-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 24th day of September, 2014.

Linda J. Gamble
Notary Public
State of Florida, at Large

My Commission Expires:
Jan 30, 2015

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	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)	32,655,875		657,651		4.96553
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)	31,497,027		657,651		4.78932
10a	Demand Costs of Purchased Power	26,518,254	*			
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,978,773	*			
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163		26,400		5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	65,713,065		684,051		9.60646
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	65,713,065		684,051		9.60646
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)	65,713,065		684,051		9.60646
21	Net Unbilled Sales	0	*	0		0.00000
22	Company Use	65,900	*	686		0.01025
23	T & D Losses	3,872,460	*	40,311		0.60220
24	SYSTEM MWH SALES	65,713,065		643,054		10.21890
25	Wholesale MWH Sales					
26	Jurisdictional MWH Sales	65,713,065		643,054		10.21890
26a	Jurisdictional Loss Multiplier	1.00000		1.00000		
27	Jurisdictional MWH Sales Adjusted for Line Losses	65,713,065		643,054		10.21890
27a	GSLD1 MWH Sales			23,741		
27b	Other Classes MWH Sales			619,313		
27c	GSLD1 CP KW			558,000	*	
28	Projected Unbilled Revenues	(500,000)		619,313		-0.08073
29	GPIF **					
30	TRUE-UP (OVER) UNDER RECOVERY **	2,907,565		619,313		0.46948
31	TOTAL JURISDICTIONAL FUEL COST	68,120,630		619,313		10.99939
31a	Demand Purchased Power Costs (Line 10a)	26,518,254	*			
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	39,194,811	*			
31c	True up Over/Under Recovery (Line 29)	2,907,565	*			
31d	Unbilled Revenues	(500,000)				

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	26,518,254		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	23,198,173	619,313	3.74579
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	39,194,811		
35	Total KWH Purchased (Line 12)		684,051	
36	Average Cost per KWH Purchased			5.72981
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.90170
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,832	23,741	5.89205
39	Balance to Other Classes	37,795,979	619,313	6.10289
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,832	23,741	5.89205
40e	Total Non-demand Costs Including True-up	1,398,832	23,741	5.89205
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89629
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	60,994,152	619,313	9.84868
41b	Less: Total Demand Cost Recovery	23,198,173 ***		
41c	Total Other Costs to be Recovered	37,795,979	619,313	6.10289
41d	Unbilled Revenue	(500,000)	619,313	-0.08073
41e	Other Classes' Portion of True-up (Line 30c)	2,907,565	619,313	0.46948
41f	Total Demand & Non-demand Costs Including True-up	40,203,544	619,313	6.49164
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	40,232,490		6.496

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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	304,265,841	57.313%	60,603.3	1.089	1.030	65,997.0	313,393,816	55.85%	49.13%
45	GS	59,699,265	63.216%	10,780.5	1.089	1.030	11,740.0	61,490,243	9.93%	9.64%
46	GSD	160,601,476	73.904%	24,807.2	1.089	1.030	27,015.0	165,419,521	22.86%	25.93%
47	GSLD	87,197,838	84.021%	11,847.1	1.089	1.030	12,901.5	89,813,773	10.92%	14.08%
48	LS	7,548,623	178.492%	482.8	1.089	1.030	525.8	7,775,082	0.44%	1.22%
49	TOTAL	619,313,043		108,520.9			118,179.3	637,892,435	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	51.55%	3.78%	55.33%	$12,835,549	0.04219	0.04222	0.06496	0.10718
51	GS	9.17%	0.74%	9.91%	2,298,939	0.03851	0.03854	0.06496	0.10350
52	GSD	21.10%	1.99%	23.09%	5,356,458	0.03335	0.03337	0.06496	0.09833
53	GSLD	10.08%	1.08%	11.16%	2,588,916	0.02969	0.02971	0.06496	0.09467
54	LS	0.41%	0.09%	0.50%	115,991	0.01537	0.01538	0.06496	0.08034
55	TOTAL	92.31%	7.68%	99.99%	$23,198,173				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	304,265,841	$0.10718	$32,611,213
57	RS	<= 1,000kWh/mo.	200,167,898	$0.10290	$20,597,957
58	RS	> 1,000 kWh/mo.	104,097,943	$0.11540	$12,013,256
59	RS	Total Sales	304,265,841		$32,611,213

(2) From Gulf Power 2009 Load Research results.

TOU Rates

		(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peek
	Rate Schedule				
60	RS	0.0840	(0.0390)	$0.18690	$0.06390
61	GS	0.0400	(0.0500)	$0.14350	$0.05350
62	GSD	0.0400	(0.0325)	$0.13833	$0.06583
63	GSLD	0.0600	(0.0300)	$0.15467	$0.06467
64	Interruptible	(0.0150)	-	$0.07967	$0.09467

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	2,907,565
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	2,907,565
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		619,313,043
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.46948

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
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		2,845,312	2,543,306	2,382,618	2,215,999	2,360,557	2,861,980	3,372,457	3,323,552	3,276,256	2,815,571	2,270,645	2,387,622	32,655,875	3
3a	DEMAND & NON FUEL COST OF PUR POWER		2,632,048	2,602,158	2,580,529	2,564,518	2,581,118	2,650,182	2,718,951	2,714,099	2,701,216	2,638,640	2,561,505	2,552,063	31,497,027	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		5,607,821	5,244,754	5,093,608	4,914,805	5,075,963	5,646,450	6,225,696	6,171,939	6,111,760	5,588,499	4,961,624	5,070,146	65,713,065	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,937,442	1,934,464	1,931,118	1,932,428	1,932,583	1,934,082	1,933,893	1,932,984	1,933,123	1,932,376	1,931,914	1,931,771	23,198,173	5a
5b	TOTAL OTHER COST TO BE RECOVERED		3,670,379	3,310,290	3,162,490	2,982,377	3,143,380	3,712,368	4,291,803	4,238,955	4,178,637	3,656,123	3,029,710	3,138,375	42,514,892	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		3,273,529	2,909,700	2,755,455	2,562,258	2,735,256	3,320,768	3,902,538	3,842,244	3,794,654	3,277,526	2,659,416	2,762,635	37,795,979	6a
6b	SYSTEM KWH SOLD (MWH)		55,618	49,880	46,740	43,531	46,338	56,293	66,425	65,504	64,443	55,308	44,438	48,536	643,054	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		53,577	47,739	44,537	41,119	44,122	54,341	64,503	63,455	62,613	53,579	42,859	46,869	619,313	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.10995	6.09502	6.18689	6.23132	6.1993	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	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)		6.10995	6.09502	6.18689	6.23132	6.19930	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)		(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	10
11	GPIF (CENTS/KWH)															11
12	TRUE-UP (CENTS/KWH)	2,907,565	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	0.46948	12
13	TOTAL		6.49870	6.48377	6.57564	6.62007	6.58805	6.49973	6.43892	6.44382	6.44924	6.50593	6.59378	6.28313	6.49164	13
14	REVENUE TAX FACTOR	0.00072	0.00468	0.00467	0.00473	0.00477	0.00474	0.00468	0.00464	0.00464	0.00464	0.00468	0.00475	0.00452	0.00467	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		6.50338	6.48844	6.58037	6.62484	6.59279	6.50441	6.44356	6.44846	6.45388	6.51061	6.59853	6.28765	6.49631	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.503	6.488	6.58	6.625	6.593	6.504	6.444	6.448	6.454	6.511	6.599	6.288	6.496	16

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2015	JEA/GULF	MS	57,078,315			57,078,315	4.984926	9.596219	2,845,312
FEBRUARY 2015	JEA/GULF	MS	51,168,680			51,168,680	4.970435	10.055886	2,543,306
MARCH 2015	JEA/GULF	MS	47,949,117			47,949,117	4.969055	10.350862	2,382,618
APRIL 2015	JEA/GULF	MS	44,641,813			44,641,813	4.963954	10.708608	2,215,999
MAY 2015	JEA/GULF	MS	47,538,143			47,538,143	4.965606	10.395179	2,360,557
JUNE 2015	JEA/GULF	MS	57,784,307			57,784,307	4.952867	9.539202	2,861,980
JULY 2015	JEA/GULF	MS	68,218,775			68,218,775	4.943591	8.929225	3,372,457
AUGUST 2015	JEA/GULF	MS	67,269,693			67,269,693	4.940638	8.975291	3,323,552
SEPTEMBER 2015	JEA/GULF	MS	66,177,020			66,177,020	4.950746	9.032549	3,276,256
OCTOBER 2015	JEA/GULF	MS	56,767,969			56,767,969	4.959788	9.607902	2,815,571
NOVEMBER 2015	JEA/GULF	MS	45,571,217			45,571,217	4.982630	10.603513	2,270,645
DECEMBER 2015	JEA/GULF	MS	47,485,772			47,485,772	5.028079	10.402453	2,387,622
TOTAL			657,650,823	0	0	657,650,823	4.965534	9.754858	32,655,875

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	10.29	10.29	10.29	10.29	10.29	10.29	10.29
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	102.90	102.90	102.90	102.90	102.90	102.90	102.90
GROSS RECEIPTS TAX	3.48	3.48	3.48	3.48	3.48	3.48	3.48
TOTAL REVENUES *** $	139.03	139.03	139.03	139.03	139.03	139.03	139.03

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	10.29	10.29	10.29	10.29	10.29	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	102.90	102.90	102.90	102.90	102.90	1,234.80
GROSS RECEIPTS TAX	3.48	3.48	3.48	3.48	3.48	41.76
TOTAL REVENUES *** $	139.03	139.03	139.03	139.03	139.03	1,668.36

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

FPUC ROG 2 No. 5a

FLORIDA PUBLIC UTILITIES COMPANY SCHEDULE E1
FUEL AND PURCHASED POWER PAGE 1 OF 2
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
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)	18,129,824		324,485	5.58726
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 & Transformation Cost of Purch Power (E2)	12,880,871		324,485	3.96964
10a	Demand Costs of Purchased Power	12,370,323	*		
10b	Transformation Energy & Customer Costs of Purchased Power	510,548	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,010,695		324,485	9.55690
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,010,695		324,485	9.55690
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)	31,010,695		324,485	9.55690
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,841	*	239	0.00725
23	T & D Losses	880,477	*	9,213	0.27949
24	SYSTEM MWH SALES	31,010,695		315,033	9.84363
25	Less Total Demand Cost Recovery	12,370,323	***		
26	Jurisdictional MWH Sales	18,640,372		315,033	5.91696
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	18,640,372		315,033	5.91696
28	Projected Unbilled Revenues	(500,000)		315,033	(0.15871)
29	TRUE-UP **	2,624,811		315,033	0.83319
30	TOTAL JURISDICTIONAL FUEL COST	20,765,183		315,033	6.59143
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.59618
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	20,780,134			6.596

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	i)/Total Col. (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.	2 CP Demar Percentage	Energy Percentage
34	RS	138,567,298	57.313%	27,599.6	1.089	1.030	30,056.0	142,724,317	51.08%	43.98%
35	GS	29,068,201	63.216%	5,249.1	1.089	1.030	5,716.3	29,940,247	9.71%	9.23%
36	GSD	83,570,738	73.904%	12,908.7	1.089	1.030	14,057.8	86,077,860	23.88%	26.53%
37	GSLD	58,534,854	84.021%	7,952.8	1.089	1.030	8,660.6	60,290,900	14.71%	18.58%
38	OL, OL1	4,073,972	178.492%	260.6	1.089	1.030	283.8	4,196,191	0.48%	1.29%
39	SL1, SL2 & SL3	1,218,459	178.492%	77.9	1.089	1.030	84.8	1,255,013	0.14%	0.39%
40	TOTAL	315,033,522		54,048.7			58,859.1	324,484,528	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072 Demand Cost Recovery Adj for Taxes	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery		Other Charges	Levelized Adjustment
41	RS	47.15%	3.39%	50.54%	$6,251,961	0.04512	0.04515	0.06596	$0.11111
42	GS	8.96%	0.71%	9.67%	1,196,210	0.04115	0.04118	0.06596	$0.10714
43	GSD	22.04%	2.04%	24.08%	2,978,774	0.03564	0.03567	0.06596	$0.10163
44	GSLD	13.58%	1.43%	15.01%	1,856,785	0.03172	0.03174	0.06596	$0.09770
45	OL, OL1	0.44%	0.10%	0.54%	66,800	0.01640	0.01641	0.06596	$0.08237
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%	19,793	0.01624	0.01625	0.06596	$0.08221
47	TOTAL	92.30%	7.70%	100.00%	$12,370,323				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	138,567,298	$0.11111	$15,396,212
49	RS	<= 1,000kWh/mo.	77,033,226	$0.10556	$8,131,557
50	RS	> 1,000 kWh/mo.	61,534,072	$0.11806	$7,264,656
51	RS	Total Sales	138,567,298		$15,396,212

TOU Rates

		(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
	Rate Schedule				
52	RS	0.0840	(0.0390)	$0.18956	$0.06656
53	GS	0.0400	(0.0500)	$0.14714	$0.05714
54	GSD	0.0400	(0.0325)	$0.14163	$0.06913
55	GSLD	0.0600	(0.0300)	$0.15770	$0.06770
56	Interruptible	(0.0150)	-	$0.08270	$0.09770

(2) From Gulf Power Co. 2009 Load Research data results.

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014; (Estimated)	$	2,624,811
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	2,624,811
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission.		315,033,522
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015.		0.83318

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

LINE NO.			(a) 2015 JANUARY	(b) 2015 FEBRUARY	(c) 2015 MARCH	(d) 2015 APRIL	(e) 2015 MAY	(f) 2015 JUNE	(g) 2015 JULY	(h) 2015 AUGUST	(i) 2015 SEPTEMBER	(j) 2015 OCTOBER	(k) 2015 NOVEMBER	(l) 2015 DECEMBER	(m) 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		1,623,903	1,422,010	1,329,528	1,227,454	1,310,667	1,559,651	1,812,472	1,778,217	1,779,784	1,550,107	1,291,755	1,444,278	18,129,824	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		1,075,737	1,073,967	1,072,132	1,072,691	1,072,867	1,073,928	1,074,120	1,073,611	1,073,684	1,073,035	1,072,499	1,072,600	12,880,871	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,699,640	2,495,977	2,401,658	2,300,145	2,383,534	2,633,579	2,886,592	2,851,828	2,853,468	2,623,142	2,364,254	2,516,878	31,010,695	5
6	LESS: TOTAL DEMAND COST RECOVERY		1,033,062	1,031,523	1,029,794	1,030,471	1,030,551	1,031,326	1,031,226	1,030,758	1,030,830	1,030,444	1,030,205	1,030,131	12,370,323	6
7	TOTAL OTHER COST TO BE RECOVERED		1,666,578	1,464,454	1,371,864	1,269,674	1,352,983	1,602,253	1,855,364	1,821,070	1,822,638	1,592,698	1,334,049	1,486,747	18,640,372	7
7a	SYSTEM KWH SOLD (MWH)		28,218	24,710	23,103	21,329	22,775	27,101	31,494	30,899	30,926	26,935	22,446	25,097	315,033	7a
7b	COST PER KWH SOLD (CENTS/KWH)		5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.924	5.91696	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.92400	5.91696	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)		(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	10
11	TRUE-UP (CENTS/KWH)		0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	0.27773	11
12	TOTAL		6.02510	6.04558	6.05705	6.07163	6.05967	6.03117	6.01019	6.01264	6.01257	6.03214	6.06239	6.04302	6.03598	12
13	REVENUE TAX FACTOR	0.00072	0.00434	0.00435	0.00436	0.00437	0.00436	0.00434	0.00433	0.00433	0.00433	0.00434	0.00436	0.00435	0.00435	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.02944	6.04993	6.06141	6.07620	6.06403	6.03551	6.01452	6.01697	6.01690	6.03848	6.06675	6.04737	6.04033	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.029	6.050	6.061	6.076	6.064	6.036	6.015	6.017	6.017	6.038	6.067	6.047	6.040	15

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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 2015	GULF POWER COMPANY	RE	29,064,342			29,064,342	5.587269	9.287463	1,623,903
FEBRUARY 2015	GULF POWER COMPANY	RE	25,450,887			25,450,887	5.587271	9.805855	1,422,010
MARCH 2015	GULF POWER COMPANY	RE	23,795,628			23,795,628	5.587271	10.091593	1,329,526
APRIL 2015	GULF POWER COMPANY	RE	21,968,768			21,968,768	5.587268	10.468703	1,227,454
MAY 2015	GULF POWER COMPANY	RE	23,458,093			23,458,093	5.587269	10.159538	1,310,667
JUNE 2015	GULF POWER COMPANY	RE	27,914,377			27,914,377	5.587267	9.433415	1,559,651
JULY 2015	GULF POWER COMPANY	RE	32,439,311			32,439,311	5.587271	8.897513	1,812,472
AUGUST 2015	GULF POWER COMPANY	RE	31,826,220			31,826,220	5.587271	8.959682	1,778,217
SEPTEMBER 2015	GULF POWER COMPANY	RE	31,854,273			31,854,273	5.587269	8.956940	1,779,784
OCTOBER 2015	GULF POWER COMPANY	RE	27,743,559			27,743,559	5.587266	9.453877	1,550,107
NOVEMBER 2015	GULF POWER COMPANY	RE	23,119,617			23,119,617	5.587266	10.224884	1,291,755
DECEMBER 2015	GULF POWER COMPANY	RE	25,849,452			25,849,452	5.587265	9.735518	1,444,278
TOTAL			324,484,528	0	0	324,484,528	5.587269	9.555801	18,129,824

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	10.00	10.00
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	100.03	100.03
GROSS RECEIPTS TAX	3.40	3.40	3.40	3.40	3.40	3.40	3.40
TOTAL REVENUES *** $	136.08	136.08	136.08	136.08	136.08	136.08	136.08

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	1,200.36
GROSS RECEIPTS TAX	3.40	3.40	3.40	3.40	3.40	40.80
TOTAL REVENUES *** $	136.08	136.08	136.08	136.08	136.08	1,632.96

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	14,526,051	333,166	4.36000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Non Fuel Cost of Purch Power (E2)	18,616,156	333,166	5.58765
10a	Demand Costs of Purchased Power	14,147,931 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,468,225 *		
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163	26,400	5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	34,702,370	359,566	9.65118
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	34,702,370	359,566	9.65118
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)	34,702,370	359,566	9.65118
21	Net Unbilled Sales	97 *	1	0.00003
22	Company Use	43,141 *	447	0.01315
23	T & D Losses	3,001,227 *	31,097	0.91495
24	SYSTEM MWH SALES	34,702,370	328,021	10.57931
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	34,702,370	328,021	10.57931
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	34,702,370	328,021	10.57931
27a	GSLD1 MWH Sales		23,741	
27b	Other Classes MWH Sales		304,280	
27c	GSLD1 CP KW		558,000 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	282,754	304,280	0.09293
30	TOTAL JURISDICTIONAL FUEL COST	34,985,124	304,280	11.49767
30a	Demand Purchased Power Costs (Line 10a)	14,147,931 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	20,554,439 *		
30c	True up Over/Under Recovery (Line 29)	282,754 *		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	14,147,931		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	10,827,850	304,280	3.55852
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	20,554,439		
35	Total KWH Purchased (Line 12)		359,566	
36	Average Cost per KWH Purchased			5.71646
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.89230
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,891	23,741	5.89230
39	Balance to Other Classes	19,155,548	304,280	6.29537
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,891	23,741	5.89230
40e	Total Non-demand Costs Including True-up	1,398,891	23,741	5.89230
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89654
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	29,983,398	304,280	9.85388
41b	Less: Total Demand Cost Recovery	10,827,850 ***		
41c	Total Other Costs to be Recovered	19,155,548	304,280	6.29537
41d	Other Classes' Portion of True-up (Line 30c)	282,754	304,280	0.09293
41e	Total Demand & Non-demand Costs Including True-up	19,438,302	304,280	6.38829
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	19,452,298		6.393

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

NORTHEAST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	)/Total Col. (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.	2 CP Demar Percentage	Energy Percentage
44	RS	165,698,543	57.313%	33,003.6	1.089	1.030	35,940.9	170,669,499	60.60%	54.45%
45	GS	30,631,064	63.216%	5,531.3	1.089	1.030	6,023.6	31,549,996	10.15%	10.07%
46	GSD	77,030,738	73.904%	11,896.5	1.089	1.030	12,957.5	79,341,660	21.84%	25.32%
47	GSLD	28,662,984	84.021%	3,894.3	1.089	1.030	4,240.9	29,522,874	7.15%	9.42%
48	OL	1,380,239	178.492%	88.3	1.089	1.030	96.2	1,421,646	0.16%	0.45%
49	SL	875,953	178.492%	56.0	1.089	1.030	61.0	902,232	0.10%	0.29%
	TOTAL	304,279,521		54,472.0			59,320.1	313,407,907	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11) Demand	(13) Tot. Col. 13 * (9)	(14) (13)/(1)	(15) (14) * 1.00072 Demand Cost	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Allocation Percentage	Demand Dollars	Demand Cost Recovery	Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	55.95%	4.19%	60.14%	$6,511,869	0.03930	0.03933	0.06393	0.10326
51	GS	9.37%	0.77%	10.14%	1,097,944	0.03584	0.03587	0.06393	0.09980
52	GSD	20.16%	1.95%	22.11%	2,394,038	0.03108	0.03110	0.06393	0.09503
53	GSLD	6.60%	0.72%	7.32%	792,599	0.02765	0.02767	0.06393	0.09160
54	OL	0.15%	0.03%	0.18%	19,490	0.01412	0.01413	0.06393	0.07806
55	SL	0.09%	0.02%	0.11%	11,911	0.01360	0.01361	0.06393	0.07754
	TOTAL	92.32%	7.68%	100.00%	$10,827,850				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	165,698,543	$0.10326	$17,110,032
57	RS	<= 1,000kWh/mo.	123,134,672	$0.10005	$12,319,508
58	RS	> 1,000 kWh/mo.	42,563,871	$0.11255	$4,790,524
59	RS	Total Sales	165,698,543		$17,110,032

(2) From Gulf Power Co. 2009 Load Research results.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	282,754
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		304,279,521
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.09293

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,221,409	1,121,296	1,053,092	988,545	1,049,890	1,302,329	1,559,985	1,545,335	1,496,472	1,265,464	978,890	943,344	14,526,051	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,556,311	1,528,191	1,508,397	1,491,827	1,508,251	1,576,254	1,644,831	1,640,488	1,627,532	1,565,605	1,489,006	1,479,463	18,616,156	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,908,181	2,748,777	2,691,950	2,614,660	2,692,429	3,012,871	3,339,104	3,320,111	3,258,292	2,965,357	2,597,370	2,553,268	34,702,370	5
5a	LESS: TOTAL DEMAND COST RECOVERY		904,380	902,941	901,324	901,957	902,032	902,756	902,665	902,226	902,293	901,932	901,709	901,640	10,827,850	5a
5b	TOTAL OTHER COST TO BE RECOVERED		2,003,801	1,845,836	1,790,626	1,712,703	1,790,397	2,110,115	2,436,439	2,417,885	2,355,999	2,063,425	1,695,661	1,651,628	23,874,520	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		1,606,951	1,445,246	1,383,591	1,292,584	1,382,273	1,718,515	2,047,174	2,021,174	1,972,016	1,684,828	1,325,367	1,275,888	19,155,607	6a
6b	SYSTEM KWH SOLD (MWH)		27,400	25,171	23,638	22,202	23,563	29,192	34,931	34,605	33,516	28,372	21,991	23,440	328,021	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		25,359	23,030	21,435	19,790	21,347	27,240	33,009	32,556	31,686	26,643	20,412	21,773	304,280	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.33681	6.27549	6.45482	6.5315	6.47525	6.30879	6.20187	6.2083	6.22362	6.32372	6.49308	5.85996	6.29539	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)		6.33681	6.27549	6.45482	6.53150	6.47525	6.30879	6.20187	6.20830	6.22362	6.32372	6.49308	5.85996	6.29539	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	282,754	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	11
12	TOTAL		6.42974	6.36842	6.54775	6.62443	6.56818	6.40172	6.29480	6.30123	6.31655	6.41665	6.58601	5.95289	6.38832	12
13	REVENUE TAX FACTOR	0.00072	0.00463	0.00459	0.00471	0.00477	0.00473	0.00461	0.00453	0.00454	0.00455	0.00462	0.00474	0.00429	0.00460	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.43437	6.37301	6.55246	6.62920	6.57291	6.40633	6.29933	6.30577	6.32110	6.42127	6.59075	5.95718	6.39292	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.434	6.373	6.552	6.629	6.573	6.406	6.299	6.306	6.321	6.421	6.591	5.957	6.393	15

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR TERRUPTIB	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	28,013,973			28,013,973	4.359999	9.915480	1,221,409
FEBRUARY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	25,717,793			25,717,793	4.360001	10.302155	1,121,296
MARCH 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,153,490			24,153,490	4.359999	10.605047	1,053,092
APRIL 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,673,045			22,673,045	4.360001	10.939739	988,545
MAY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,080,050			24,080,050	4.359999	10.623487	1,049,890
JUNE 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,869,930			29,869,930	4.360000	9.637060	1,302,329
JULY 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,779,464			35,779,464	4.360001	8.957138	1,559,985
AUGUST 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,443,472			35,443,472	4.359999	8.988462	1,545,335
SEPTEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,322,747			34,322,747	4.360001	9.101847	1,496,472
OCTOBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,024,410			29,024,410	4.359999	9.754096	1,265,464
NOVEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,451,600			22,451,600	4.360001	10.992072	978,890
DECEMBER 2015	JACKSONVILLE ELECTRIC AUTHORITY	MS	21,636,320			21,636,320	4.360002	11.197870	943,344
TOTAL			333,166,295	0	0	333,166,295	4.360000	9.947647	14,526,051

SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR TERRUPTIB	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	9.95	9.95
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	99.48	99.48
GROSS RECEIPTS TAX	3.39	3.39	3.39	3.39	3.39	3.39	3.39
TOTAL REVENUES *** $	135.52	135.52	135.52	135.52	135.52	135.52	135.52

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	1,193.76
GROSS RECEIPTS TAX	3.39	3.39	3.39	3.39	3.39	40.68
TOTAL REVENUES *** $	135.52	135.52	135.52	135.52	135.52	1,626.24

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	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)	32,655,875	657,651	4.96553
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)	31,497,027	657,651	4.78932
10a	Demand Costs of Purchased Power	26,518,254 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,978,773 *		
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163	26,400	5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	65,713,065	684,051	9.60646
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	65,713,065	684,051	9.60646
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)	65,713,065	684,051	9.60646
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	65,900 *	686	0.01025
23	T & D Losses	3,872,460 *	40,311	0.60220
24	SYSTEM MWH SALES	65,713,065	643,054	10.21890
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	65,713,065	643,054	10.21890
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	65,713,065	643,054	10.21890
27a	GSLD1 MWH Sales		23,741	
27b	Other Classes MWH Sales		619,313	
27c	GSLD1 CP KW		558,000 *	
28	Projected Unbilled Revenues	(500,000)	619,313	-0.08073
29	GPIF **			
30	TRUE-UP (OVER) UNDER RECOVERY **		619,313	0.00000
31	TOTAL JURISDICTIONAL FUEL COST	65,213,065	619,313	10.52990
31a	Demand Purchased Power Costs (Line 10a)	26,518,254 *		
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	39,194,811 *		
31c	True up Over/Under Recovery (Line 29)	0 *		
31d	Unbilled Revenues	(500,000)		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	26,518,254		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	23,198,173	619,313	3.74579
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	39,194,811		
35	Total KWH Purchased (Line 12)		684,051	
36	Average Cost per KWH Purchased			5.72981
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.90170
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,832	23,741	5.89205
39	Balance to Other Classes	37,795,979	619,313	6.10289
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,832	23,741	5.89205
40e	Total Non-demand Costs Including True-up	1,398,832	23,741	5.89205
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89629
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	60,994,152	619,313	9.84868
41b	Less: Total Demand Cost Recovery	23,198,173 ***		
41c	Total Other Costs to be Recovered	37,795,979	619,313	6.10289
41d	Unbilled Revenue	(500,000)	619,313	-0.08073
41e	Other Classes' Portion of True-up (Line 30c)	0	619,313	0.00000
41f	Total Demand & Non-demand Costs Including True-up	37,295,979	619,313	6.02215
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	37,322,832		6.026

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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	304,265,841	57.313%	60,603.3	1.089	1.030	65,997.0	313,393,816	55.85%	49.13%
45	GS	59,699,265	63.216%	10,780.5	1.089	1.030	11,740.0	61,490,243	9.93%	9.64%
46	GSD	160,601,476	73.904%	24,807.2	1.089	1.030	27,015.0	165,419,521	22.86%	25.93%
47	GSLD	87,197,838	84.021%	11,847.1	1.089	1.030	12,901.5	89,813,773	10.92%	14.08%
48	LS	7,548,623	178.492%	482.8	1.089	1.030	525.8	7,775,082	0.44%	1.22%
	TOTAL	619,313,043		108,520.9			118,179.3	637,892,435	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	Marianna Surcharge	Marianna With Surcharge	Fernandina Surcharge	Fernandina With Surcharge
50	RS	51.55%	3.78%	55.33%	$12,835,549	0.04219	0.04222	0.06026	0.10248	0.00278	0.10526	0.00031	0.10279
51	GS	9.17%	0.74%	9.91%	2,298,939	0.03851	0.03854	0.06026	0.09880	0.00278	0.10158	0.00031	0.09911
52	GSD	21.10%	1.99%	23.09%	5,356,458	0.03335	0.03337	0.06026	0.09363	0.00278	0.09641	0.00031	0.09394
53	GSLD	10.08%	1.08%	11.16%	2,588,916	0.02969	0.02971	0.06026	0.08997	0.00278	0.09275	0.00031	0.09028
54	LS	0.41%	0.09%	0.50%	115,991	0.01537	0.01538	0.06026	0.07564	0.00278	0.07842	0.00031	0.07595
	TOTAL	92.31%	7.68%	99.99%	$23,196,173								

Step Rate Allocation for Residential Customers

		(18)		Marianna (19)	(20)	(21) (19) * (20)		Fernandina (19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation		Annual kWh	Levelized Adj.	Revenues		Annual kWh	Levelized Adj.	Revenues
56	RS	Sales		138,567,298	$0.10526	$14,585,220		165,698,543	$0.10279	$17,032,120
57	RS	<= 1,000kWh/mo.		77,033,226	$0.09971	$7,680,704		123,134,672	$0.09958	$12,261,610
58	RS	> 1,000 kWh/mo.		61,534,072	$0.11221	$6,904,516		42,563,871	$0.11208	$4,770,510
59	RS	Total Sales		138,567,298		$14,585,220		165,698,543		$17,032,120

(2) From Gulf Power 2009 Load Research results.

TOU Rates

		(22)	Marianna (23)	(24)	(25)
	Rate Schedule	On Peak Rate Differential	Off Peak Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
60	RS	0.0840	(0.0390)	$0.18371	$0.06071
61	GS	0.0400	(0.0500)	$0.14158	$0.05158
62	GSD	0.0400	(0.0325)	$0.13641	$0.06391
63	GSLD	0.0600	(0.0300)	$0.15275	$0.06275
64	Interruptible	(0.0150)	-	$0.07775	$0.09275

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	2,907,565
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	969,188
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		619,313,043
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.15649

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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		2,845,312	2,543,306	2,382,618	2,215,999	2,360,557	2,861,980	3,372,457	3,323,552	3,276,256	2,815,571	2,270,645	2,387,622	32,655,875	3
3a	DEMAND & NON FUEL COST OF PUR POWER		2,632,048	2,602,158	2,580,529	2,564,518	2,581,118	2,650,182	2,718,951	2,714,099	2,701,216	2,638,640	2,561,505	2,552,063	31,497,027	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		5,607,821	5,244,754	5,093,608	4,914,805	5,075,963	5,646,450	6,225,696	6,171,939	6,111,760	5,588,499	4,961,624	5,070,146	65,713,065	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,937,442	1,934,464	1,931,118	1,932,428	1,932,583	1,934,082	1,933,893	1,932,984	1,933,123	1,932,376	1,931,914	1,931,771	23,198,173	5a
5b	TOTAL OTHER COST TO BE RECOVERED		3,670,379	3,310,290	3,162,490	2,982,377	3,143,380	3,712,368	4,291,803	4,238,955	4,178,637	3,656,123	3,029,710	3,138,375	42,514,892	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		3,273,529	2,909,700	2,755,455	2,562,258	2,735,256	3,320,768	3,902,538	3,842,244	3,794,654	3,277,526	2,659,416	2,762,635	37,795,979	6a
6b	SYSTEM KWH SOLD (MWH)		55,618	49,880	46,740	43,531	46,338	56,293	66,425	65,504	64,443	55,308	44,438	48,536	643,054	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		53,577	47,739	44,537	41,119	44,122	54,341	64,503	63,455	62,613	53,579	42,859	46,869	619,313	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.10995	6.09502	6.18689	6.23132	6.1993	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	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)		6.10995	6.09502	6.18689	6.23132	6.19930	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)		(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	10
11	GPIF (CENTS/KWH)															11
12	TRUE-UP (CENTS/KWH)	-	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	12
13	TOTAL		6.02922	6.01429	6.10616	6.15059	6.11857	6.03025	5.96944	5.97434	5.97976	6.03645	6.12430	5.81365	6.02216	13
14	REVENUE TAX FACTOR	0.00072	0.00434	0.00433	0.00440	0.00443	0.00441	0.00434	0.00430	0.00430	0.00431	0.00435	0.00441	0.00419	0.00434	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		6.03356	6.01862	6.11056	6.15502	6.12298	6.03459	5.97374	5.97864	5.98407	6.04080	6.12871	5.81784	6.02650	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.034	6.019	6.111	6.155	6.123	6.035	5.974	5.979	5.984	6.041	6.129	5.818	6.027	16

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	JEA/GULF	MS	57,078,315			57,078,315	4.984926	9.596219	2,845,312
FEBRUARY 2015	JEA/GULF	MS	51,168,680			51,168,680	4.970435	10.055886	2,543,306
MARCH 2015	JEA/GULF	MS	47,949,117			47,949,117	4.969055	10.350862	2,382,618
APRIL 2015	JEA/GULF	MS	44,641,813			44,641,813	4.963954	10.708608	2,215,999
MAY 2015	JEA/GULF	MS	47,538,143			47,538,143	4.965606	10.395179	2,360,557
JUNE 2015	JEA/GULF	MS	57,784,307			57,784,307	4.952867	9.539202	2,861,980
JULY 2015	JEA/GULF	MS	68,218,775			68,218,775	4.943591	8.929225	3,372,457
AUGUST 2015	JEA/GULF	MS	67,269,693			67,269,693	4.940638	8.975291	3,323,552
SEPTEMBER 2015	JEA/GULF	MS	66,177,020			66,177,020	4.950746	9.032549	3,276,256
OCTOBER 2015	JEA/GULF	MS	56,767,969			56,767,969	4.959788	9.607902	2,815,571
NOVEMBER 2015	JEA/GULF	MS	45,571,217			45,571,217	4.982630	10.603513	2,270,645
DECEMBER 2015	JEA/GULF	MS	47,485,772			47,485,772	5.028079	10.402453	2,387,622
TOTAL			657,650,823	0	0	657,650,823	4.965534	9.754858	32,655,875

SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	9.97	9.97	9.97	9.97	9.97	9.97	9.97
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.71	99.71	99.71	99.71	99.71	99.71	99.71
GROSS RECEIPTS TAX	3.39	3.39	3.39	3.39	3.39	3.39	3.39
TOTAL REVENUES *** $	135.75	135.75	135.75	135.75	135.75	135.75	135.75

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	9.97	9.97	9.97	9.97	9.97	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.71	99.71	99.71	99.71	99.71	1,196.52
GROSS RECEIPTS TAX	3.39	3.39	3.39	3.39	3.39	40.68
TOTAL REVENUES *** $	135.75	135.75	135.75	135.75	135.75	1,629.00

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014; (Estimated)	$	2,624,811
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	874,937
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission.		315,033,522
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015.		0.27773

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	94,251
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		304,279,521
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.03098

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	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)	32,655,875		657,651		4.96553
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)	31,497,027		657,651		4.78932
10a	Demand Costs of Purchased Power	26,518,254	*			
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,978,773	*			
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163		26,400		5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	65,713,065		684,051		9.60646
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	65,713,065		684,051		9.60646
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)	65,713,065		684,051		9.60646
21	Net Unbilled Sales	0	*	0		0.00000
22	Company Use	65,900	*	686		0.01025
23	T & D Losses	3,872,460	*	40,311		0.60220
24	SYSTEM MWH SALES	65,713,065		643,054		10.21890
25	Wholesale MWH Sales					
26	Jurisdictional MWH Sales	65,713,065		643,054		10.21890
26a	Jurisdictional Loss Multiplier	1.00000		1.00000		
27	Jurisdictional MWH Sales Adjusted for Line Losses	65,713,065		643,054		10.21890
27a	GSLD1 MWH Sales			23,741		
27b	Other Classes MWH Sales			619,313		
27c	GSLD1 CP KW			558,000	*	
28	Projected Unbilled Revenues	(500,000)		619,313		-0.08073
29	GPIF **					
30	TRUE-UP (OVER) UNDER RECOVERY **			619,313		0.00000
31	TOTAL JURISDICTIONAL FUEL COST	65,213,065		619,313		10.52990
31a	Demand Purchased Power Costs (Line 10a)	26,518,254	*			
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	39,194,811	*			
31c	True up Over/Under Recovery (Line 29)	0	*			
31d	Unbilled Revenues	(500,000)				

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	26,518,254		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	23,198,173	619,313	3.74579
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	39,194,811		
35	Total KWH Purchased (Line 12)		684,051	
36	Average Cost per KWH Purchased			5.72981
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.90170
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,832	23,741	5.89205
39	Balance to Other Classes	37,795,979	619,313	6.10289
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,832	23,741	5.89205
40e	Total Non-demand Costs Including True-up	1,398,832	23,741	5.89205
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89629
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	60,994,152	619,313	9.84868
41b	Less: Total Demand Cost Recovery	23,198,173 ***		
41c	Total Other Costs to be Recovered	37,795,979	619,313	6.10289
41d	Unbilled Revenue	(500,000)	619,313	-0.08073
41e	Other Classes' Portion of True-up (Line 30c)	0	619,313	0.00000
41f	Total Demand & Non-demand Costs Including True-up	37,295,979	619,313	6.02215
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	37,322,832		6.026

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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	304,265,841	57.313%	60,603.3	1.089	1.030	65,997.0	313,393,816	55.85%	49.13%
45	GS	59,699,265	63.216%	10,780.5	1.089	1.030	11,740.0	61,490,243	9.93%	9.64%
46	GSD	160,601,476	73.904%	24,807.2	1.089	1.030	27,015.0	165,419,521	22.86%	25.93%
47	GSLD	87,197,838	84.021%	11,847.1	1.089	1.030	12,901.5	89,813,773	10.92%	14.08%
48	LS	7,548,623	178.492%	482.8	1.089	1.030	525.8	7,775,082	0.44%	1.22%
49	TOTAL	619,313,043		108,520.9			118,179.3	637,892,435	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11) Demand Allocation	(13) Tot. Col. 13 * (9)	(14) (13)/(1)	(15) (14) * 1.00072 Demand Cost Recovery	(16)	(17) (15) + (16)				
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Percentage	Demand Dollars	Demand Cost Recovery	Adj for Taxes	Other Charges	Levelized Adjustment	Surcharge Marianna	Marianna With Surcharge	Surcharge Fernandina	Fernandina With Surchage
50	RS	51.55%	3.78%	55.33%	$12,835,549	0.04219	0.04222	0.06026	0.10248	0.00833	0.11081	0.00093	0.10341
51	GS	9.17%	0.74%	9.91%	2,298,939	0.03851	0.03854	0.06026	0.09880	0.00833	0.10713	0.00093	0.09973
52	GSD	21.10%	1.99%	23.09%	5,358,458	0.03335	0.03337	0.06026	0.09383	0.00833	0.10196	0.00093	0.09456
53	GSLD	10.08%	1.08%	11.16%	2,588,916	0.02969	0.02971	0.06026	0.08997	0.00833	0.09830	0.00093	0.09090
54	LS	0.41%	0.09%	0.50%	115,991	0.01537	0.01538	0.06026	0.07564	0.00833	0.08397	0.00093	0.07657
55	TOTAL	92.31%	7.68%	99.99%	$23,198,173								

Step Rate Allocation for Residential Customers

		(18)	(19)	Marianna (20)	(21) (19) * (20)		Fernandina (19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues		Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	138,567,298	$0.11081	$15,354,892		165,698,543	$0.10341	$17,134,770
57	RS	<= 1,000kWh/mo.	77,033,226	$0.10526	$8,108,585		123,134,672	$0.10020	$12,337,892
58	RS	> 1,000 kWh/mo.	61,534,072	$0.11776	$7,246,307		42,563,871	$0.11270	$4,796,878
59	RS	Total Sales	138,567,298		$15,354,892		165,698,543		$17,134,770

(2) From Gulf Power 2009 Load Research results.

TOU Rates

		Marianna (22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
	Rate Schedule				
60	RS	0.0640	(0.0390)	$0.18926	$0.06626
61	GS	0.0400	(0.0500)	$0.14713	$0.05713
62	GSD	0.0400	(0.0325)	$0.14196	$0.06946
63	GSLD	0.0600	(0.0300)	$0.15830	$0.06830
64	Interruptible	(0.0150)	-	$0.08330	$0.09830

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	2,907,565
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	2,907,565
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		619,313,043
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.46948

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
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		2,845,312	2,543,306	2,382,618	2,215,999	2,360,557	2,861,980	3,372,457	3,323,552	3,276,256	2,815,571	2,270,645	2,387,622	32,655,875	3
3a	DEMAND & NON FUEL COST OF PUR POWER		2,632,048	2,602,158	2,580,529	2,564,518	2,581,118	2,650,182	2,718,951	2,714,099	2,701,216	2,638,640	2,561,505	2,552,063	31,497,027	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		5,607,821	5,244,754	5,093,608	4,914,805	5,075,963	5,646,450	6,225,696	6,171,939	6,111,760	5,588,499	4,961,624	5,070,146	65,713,065	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,937,442	1,934,464	1,931,118	1,932,428	1,932,583	1,934,082	1,933,893	1,932,984	1,933,123	1,932,376	1,931,914	1,931,771	23,198,173	5a
5b	TOTAL OTHER COST TO BE RECOVERED		3,670,379	3,310,290	3,162,490	2,982,377	3,143,380	3,712,368	4,291,803	4,238,955	4,178,637	3,656,123	3,029,710	3,138,375	42,514,892	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		3,273,529	2,909,700	2,755,455	2,562,258	2,735,256	3,320,768	3,902,538	3,842,244	3,794,654	3,277,526	2,659,416	2,762,635	37,795,979	6a
6b	SYSTEM KWH SOLD (MWH)		55,618	49,880	46,740	43,531	46,338	56,293	66,425	65,504	64,443	55,308	44,438	48,536	643,054	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		53,577	47,739	44,537	41,119	44,122	54,341	64,503	63,455	62,613	53,579	42,859	46,869	619,313	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.10995	6.09502	6.18689	6.23132	6.1993	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	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)		6.10995	6.09502	6.18689	6.23132	6.19930	6.11098	6.05017	6.05507	6.06049	6.11718	6.20503	5.89438	6.10289	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)		(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	(0.0807)	10
11	GPIF (CENTS/KWH)															11
12	TRUE-UP (CENTS/KWH)	-	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	12
13	TOTAL		6.02922	6.01429	6.10616	6.15059	6.11857	6.03025	5.96944	5.97434	5.97976	6.03645	6.12430	5.81365	6.02216	13
14	REVENUE TAX FACTOR	0.00072	0.00434	0.00433	0.00440	0.00443	0.00441	0.00434	0.00430	0.00430	0.00431	0.00435	0.00441	0.00419	0.00434	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		6.03356	6.01862	6.11056	6.15502	6.12298	6.03459	5.97374	5.97864	5.98407	6.04080	6.12871	5.81784	6.02650	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.034	6.019	6.111	6.155	6.123	6.035	5.974	5.979	5.984	6.041	6.129	5.818	6.027	16

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2015	JEA/GULF	MS	57,078,315			57,078,315	4.984926	9.596219	2,845,312
FEBRUARY 2015	JEA/GULF	MS	51,168,680			51,168,680	4.970435	10.055886	2,543,306
MARCH 2015	JEA/GULF	MS	47,949,117			47,949,117	4.969055	10.350862	2,382,618
APRIL 2015	JEA/GULF	MS	44,641,813			44,641,813	4.963954	10.708608	2,215,999
MAY 2015	JEA/GULF	MS	47,538,143			47,538,143	4.965606	10.395179	2,360,557
JUNE 2015	JEA/GULF	MS	57,784,307			57,784,307	4.952867	9.539202	2,861,980
JULY 2015	JEA/GULF	MS	68,218,775			68,218,775	4.943591	8.929225	3,372,457
AUGUST 2015	JEA/GULF	MS	67,269,693			67,269,693	4.940638	8.975291	3,323,552
SEPTEMBER 2015	JEA/GULF	MS	66,177,020			66,177,020	4.950746	9.032549	3,276,256
OCTOBER 2015	JEA/GULF	MS	56,767,969			56,767,969	4.959788	9.607902	2,815,571
NOVEMBER 2015	JEA/GULF	MS	45,571,217			45,571,217	4.982630	10.603513	2,270,645
DECEMBER 2015	JEA/GULF	MS	47,485,772			47,485,772	5.028079	10.402453	2,387,622
TOTAL			657,650,823	0	0	657,650,823	4.965534	9.754858	32,655,875

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2015	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	10.53	10.53	10.53	10.53	10.53	10.53	10.53
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	105.26	105.26	105.26	105.26	105.26	105.26	105.26
GROSS RECEIPTS TAX	3.54	3.54	3.54	3.54	3.54	3.54	3.54
TOTAL REVENUES *** $	141.45	141.45	141.45	141.45	141.45	141.45	141.45

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	10.53	10.53	10.53	10.53	10.53	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	105.26	105.26	105.26	105.26	105.26	1,263.12
GROSS RECEIPTS TAX	3.54	3.54	3.54	3.54	3.54	42.48
TOTAL REVENUES *** $	141.45	141.45	141.45	141.45	141.45	1,697.40

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014; (Estimated)	$	2,624,811
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	2,624,811
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission.		315,033,522
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015.		0.83318

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015	$	282,754
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		304,279,521
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.09293

FPUC ROG 2 No. 5d - Marianna

FLORIDA PUBLIC UTILITIES COMPANY SCHEDULE E1
FUEL AND PURCHASED POWER PAGE 1 OF 2
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
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)	18,129,824		324,485	5.58726
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 & Transformation Cost of Purch Power (E2)	12,880,871		324,485	3.96964
10a	Demand Costs of Purchased Power	12,370,323	*		
10b	Transformation Energy & Customer Costs of Purchased Power	510,548	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,010,695		324,485	9.55690
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,010,695		324,485	9.55690
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)	31,010,695		324,485	9.55690
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,841	*	239	0.00725
23	T & D Losses	880,477	*	9,213	0.27949
24	SYSTEM MWH SALES	31,010,695		315,033	9.84363
25	Less Total Demand Cost Recovery	12,370,323	***		
26	Jurisdictional MWH Sales	18,640,372		315,033	5.91696
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	18,640,372		315,033	5.91696
28	Projected Unbilled Revenues	(500,000)		315,033	(0.15871)
29	TRUE-UP **	2,624,811		315,033	0.83319
30	TOTAL JURISDICTIONAL FUEL COST	20,765,183		315,033	6.59143
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.59618
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	20,780,134			6.596

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

NORTHWEST FLORIDA DIVISION

		(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
34	RS	138,567,298	57.313%	27,599.6	1.089	1.030	30,056.0	142,724,317	51.07%	43.98%
35	GS	29,068,201	63.216%	5,249.1	1.089	1.030	5,716.3	29,940,247	9.71%	9.23%
36	GSD	83,570,738	73.904%	12,908.7	1.089	1.030	14,057.6	86,077,860	23.88%	26.53%
37	GSLD	58,534,854	84.021%	7,952.8	1.089	1.030	8,660.6	60,290,900	14.71%	18.58%
38	LS	5,292,431	178.492%	338.5	1.089	1.030	368.6	5,451,204	0.63%	1.68%
39	TOTAL	315,033,522		54,048.7			58,859.1	324,484,528	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
40	RS	47.14%	3.39%	50.53%	$6,250,725	0.04511	0.04514	0.06596	$0.11110
41	GS	8.96%	0.71%	9.67%	1,196,210	0.04115	0.04118	0.06596	$0.10714
42	GSD	22.04%	2.04%	24.08%	2,978,774	0.03564	0.03567	0.06596	$0.10163
43	GSLD	13.58%	1.43%	15.01%	1,856,785	0.03172	0.03174	0.06596	$0.09770
44	LS	0.58%	0.13%	0.71%	87,829	0.01660	0.01661	0.06596	$0.08257
45	TOTAL	92.30%	7.70%	100.00%	$12,370,323				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
46	RS	Sales	138,567,298	$0.11110	$15,394,827
47	RS	<= 1,000kWh/mo.	77,033,226	$0.10555	$8,130,786
48	RS	> 1,000 kWh/mo.	61,534,072	$0.11805	$7,264,041
49	RS	Total Sales	138,567,298		$15,394,827

TOU Rates

		(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
	Rate Schedule				
50	RS	0.0840	(0.0390)	$0.18955	$0.06655
51	GS	0.0400	(0.0500)	$0.14714	$0.05714
52	GSD	0.0400	(0.0325)	$0.14163	$0.06913
53	GSLD	0.0600	(0.0300)	$0.15770	$0.06770
54	Interruptibl	(0.0150)	-	$0.08270	$0.09770

55 (2) From Gulf Power Co. 2009 Load Research data results.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014; (Estimated)	$	2,624,811
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	874,937
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission.		315,033,522
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015.		0.83318

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

LINE NO.		(a) 2015 JANUARY	(b) 2015 FEBRUARY	(c) 2015 MARCH	(d) 2015 APRIL	(e) 2015 MAY	(f) 2015 JUNE	(g) 2015 JULY	(h) 2015 AUGUST	(i) 2015 SEPTEMBER	(j) 2015 OCTOBER	(k) 2015 NOVEMBER	(l) 2015 DECEMBER	(m) 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	1,623,903	1,422,010	1,329,526	1,227,454	1,310,667	1,559,651	1,812,472	1,778,217	1,779,784	1,550,107	1,291,755	1,444,278	18,129,824	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,075,737	1,073,967	1,072,132	1,072,691	1,072,867	1,073,928	1,074,120	1,073,611	1,073,684	1,073,035	1,072,499	1,072,600	12,880,871	3a
3b	QUALIFYING FACILITIES													0	3b
4	ENERGY COST OF ECONOMY PURCHASES													0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	2,699,640	2,495,977	2,401,658	2,300,145	2,383,534	2,633,579	2,886,592	2,851,828	2,853,468	2,623,142	2,364,254	2,516,878	31,010,695	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,033,062	1,031,523	1,029,794	1,030,471	1,030,551	1,031,326	1,031,228	1,030,758	1,030,830	1,030,444	1,030,205	1,030,131	12,370,323	6
7	TOTAL OTHER COST TO BE RECOVERED	1,666,578	1,464,454	1,371,864	1,269,674	1,352,983	1,602,253	1,855,364	1,821,070	1,822,638	1,592,698	1,334,049	1,486,747	18,640,372	7
7a	SYSTEM KWH SOLD (MWH)	28,218	24,710	23,103	21,329	22,775	27,101	31,494	30,899	30,926	26,935	22,446	25,097	315,033	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.924	5.91696	7b
8	JURISDICTIONAL LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)	5.90608	5.92656	5.93803	5.95281	5.94065	5.91215	5.89117	5.89362	5.89355	5.91312	5.94337	5.92400	5.91696	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	(0.15871)	10
11	TRUE-UP (CENTS/KWH)	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	0.83318	11
12	TOTAL	6.58055	6.60103	6.61250	6.62728	6.61512	6.58662	6.56564	6.56809	6.56802	6.58759	6.61784	6.59847	6.59143	12
13	REVENUE TAX FACTOR 0.00072	0.00474	0.00475	0.00476	0.00477	0.00476	0.00474	0.00473	0.00473	0.00473	0.00474	0.00476	0.00475	0.00475	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	6.58529	6.60578	6.61726	6.63205	6.61988	6.59136	6.57037	6.57282	6.57275	6.59233	6.62260	6.60322	6.59618	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	6.585	6.606	6.617	6.632	6.620	6.591	6.570	6.573	6.573	6.592	6.623	6.603	6.596	15

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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	2015	GULF POWER COMPANY	RE	29,064,342			29,064,342	5.587269	9.287463	1,623,903
FEBRUARY	2015	GULF POWER COMPANY	RE	25,450,887			25,450,887	5.587271	9.805855	1,422,010
MARCH	2015	GULF POWER COMPANY	RE	23,795,628			23,795,628	5.587271	10.091593	1,329,526
APRIL	2015	GULF POWER COMPANY	RE	21,968,768			21,968,768	5.587268	10.468703	1,227,454
MAY	2015	GULF POWER COMPANY	RE	23,458,093			23,458,093	5.587269	10.159538	1,310,667
JUNE	2015	GULF POWER COMPANY	RE	27,914,377			27,914,377	5.587267	9.433415	1,559,651
JULY	2015	GULF POWER COMPANY	RE	32,439,311			32,439,311	5.587271	8.897513	1,812,472
AUGUST	2015	GULF POWER COMPANY	RE	31,826,220			31,826,220	5.587271	8.959682	1,778,217
SEPTEMBER	2015	GULF POWER COMPANY	RE	31,854,273			31,854,273	5.587269	8.956940	1,779,784
OCTOBER	2015	GULF POWER COMPANY	RE	27,743,559			27,743,559	5.587266	9.453877	1,550,107
NOVEMBER	2015	GULF POWER COMPANY	RE	23,119,617			23,119,617	5.587266	10.224884	1,291,755
DECEMBER	2015	GULF POWER COMPANY	RE	25,849,452			25,849,452	5.587265	9.735518	1,444,278
TOTAL				324,484,528	0	0	324,484,528	5.587269	9.555801	18,129,824

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	10.55	10.55	10.55	10.55	10.55	10.55	10.55
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	105.55	105.55	105.55	105.55	105.55	105.55	105.55
GROSS RECEIPTS TAX	3.54	3.54	3.54	3.54	3.54	3.54	3.54
TOTAL REVENUES *** $	141.74	141.74	141.74	141.74	141.74	141.74	141.74

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	10.55	10.55	10.55	10.55	10.55	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	105.55	105.55	105.55	105.55	105.55	1,266.60
GROSS RECEIPTS TAX	3.54	3.54	3.54	3.54	3.54	42.48
TOTAL REVENUES *** $	141.74	141.74	141.74	141.74	141.74	1,700.88

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)				
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	14,526,051		333,166	4.36000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Non Fuel Cost of Purch Power (E2)	18,616,156		333,166	5.58765
10a	Demand Costs of Purchased Power	14,147,931	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,468,225	*		
11	Energy Payments to Qualifying Facilities (E8a)	1,560,163		26,400	5.90971
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	34,702,370		359,566	9.65118
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	34,702,370		359,566	9.65118
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)	34,702,370		359,566	9.65118
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	43,141	*	447	0.01315
23	T & D Losses	3,001,324	*	31,098	0.91498
24	SYSTEM MWH SALES	34,702,370		328,021	10.57931
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	34,702,370		328,021	10.57931
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	34,702,370		328,021	10.57931
27a	GSLD1 MWH Sales			23,741	
27b	Other Classes MWH Sales			304,280	
27c	GSLD1 CP KW			558,000	*
28	GPIF **				
29	TRUE-UP (OVER) UNDER RECOVERY **	282,754		304,280	0.09293
30	TOTAL JURISDICTIONAL FUEL COST	34,985,124		304,280	11.49767
30a	Demand Purchased Power Costs (Line 10a)	14,147,931	*		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	20,554,439	*		
30c	True up Over/Under Recovery (Line 29)	282,754	*		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	14,147,931		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	3,320,081	558,000 (KW)	$5.95 /KW
33	Balance to Other Classes	10,827,850	304,280	3.55852
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	20,554,439		
35	Total KWH Purchased (Line 12)		359,566	
36	Average Cost per KWH Purchased			5.71646
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.89230
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,398,891	23,741	5.89230
39	Balance to Other Classes	19,155,548	304,280	6.29537
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,320,081	558,000 (KW)	$5.95 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.95 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,398,891	23,741	5.89230
40e	Total Non-demand Costs Including True-up	1,398,891	23,741	5.89230
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.89654
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	29,983,398	304,280	9.85388
41b	Less: Total Demand Cost Recovery	10,827,850 ***		
41c	Total Other Costs to be Recovered	19,155,548	304,280	6.29537
41d	Other Classes' Portion of True-up (Line 30c)	282,754	304,280	0.09293
41e	Total Demand & Non-demand Costs Including True-up	19,438,302	304,280	6.38829
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	19,452,298		6.393

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

NORTHEAST FLORIDA DIVISION

		(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	165,698,543	57.313%	33,003.6	1.089	1.030	35,940.9	170,669,499	60.60%	54.45%
45	GS	30,631,064	63.216%	5,531.3	1.089	1.030	6,023.6	31,549,996	10.15%	10.07%
46	GSD	77,030,738	73.904%	11,898.5	1.089	1.030	12,957.5	79,341,660	21.84%	25.32%
47	GSLD	28,662,984	84.021%	3,894.3	1.089	1.030	4,240.9	29,522,874	7.15%	9.42%
48	LS	2,256,192	178.492%	144.3	1.089	1.030	157.1	2,323,878	0.26%	0.74%
49	TOTAL	304,279,521		54,472.0			59,320.0	313,407,907	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	55.95%	4.19%	60.14%	$6,511,869	0.03930	0.03933	0.06393	0.10326
51	GS	9.37%	0.77%	10.14%	1,097,944	0.03584	0.03587	0.06393	0.09980
52	GSD	20.16%	1.95%	22.11%	2,394,038	0.03108	0.03110	0.06393	0.09503
53	GSLD	6.60%	0.72%	7.32%	792,599	0.02765	0.02767	0.06393	0.09160
54	LS	0.24%	0.06%	0.30%	32,484	0.01440	0.01441	0.06393	0.07834
55	TOTAL	92.32%	7.69%	100.01%	$10,827,850				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	165,698,543	$0.10326	$17,110,032
57	RS	<= 1,000kWh/mo.	123,134,672	$0.10005	$12,319,508
58	RS	> 1,000 kWh/mo.	42,563,871	$0.11255	$4,790,524
59	RS	Total Sales	165,698,543		$17,110,032

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2014 - DECEMBER 2014
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2014 - December 2014. (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 2014.)(Estimated)	$	282,754
Portion of 2014 Under-recovery to be collected for the period January 2015 - December 2015 (at one-third of 2014 True-up)	$	94,251
Estimated kilowatt hour sales for the months of January 2015 - December 2015 as per estimate filed with the Commission. (Excludes GSLD1 customers)		304,279,521
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2015 - December 2015		0.09293

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,221,409	1,121,296	1,053,092	988,545	1,049,890	1,302,329	1,559,985	1,545,335	1,496,472	1,265,464	978,890	943,344	14,526,051	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,556,311	1,528,191	1,508,397	1,491,827	1,508,251	1,576,254	1,644,831	1,640,488	1,627,532	1,565,605	1,489,006	1,479,463	18,616,156	3a
3b	QUALIFYING FACILITIES		130,461	99,290	130,461	134,288	134,288	134,288	134,288	134,288	134,288	134,288	129,474	130,461	1,560,163	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,908,181	2,748,777	2,691,950	2,614,660	2,692,429	3,012,871	3,339,104	3,320,111	3,258,292	2,965,357	2,597,370	2,553,268	34,702,370	5
5a	LESS: TOTAL DEMAND COST RECOVERY		904,380	902,941	901,324	901,957	902,032	902,756	902,665	902,226	902,293	901,932	901,709	901,640	10,827,850	5a
5b	TOTAL OTHER COST TO BE RECOVERED		2,003,801	1,845,836	1,790,626	1,712,703	1,790,397	2,110,115	2,436,439	2,417,885	2,355,999	2,063,425	1,695,661	1,651,628	23,874,520	5b
6	APPORTIONMENT TO GSLD1 CLASS		396,851	400,590	407,036	420,119	408,125	391,600	389,265	396,711	383,984	378,598	370,295	375,740	4,718,913	6
6a	BALANCE TO OTHER CLASSES		1,606,951	1,445,246	1,383,591	1,292,584	1,382,273	1,718,515	2,047,174	2,021,174	1,972,016	1,684,828	1,325,367	1,275,888	19,155,607	6a
6b	SYSTEM KWH SOLD (MWH)		27,400	25,171	23,638	22,202	23,563	29,192	34,931	34,605	33,516	28,372	21,991	23,440	328,021	6b
7	GSLD1 MWH SOLD		2,041	2,141	2,203	2,412	2,216	1,952	1,922	2,049	1,830	1,729	1,579	1,667	23,741	7
7a	BALANCE MWH SOLD OTHER CLASSES		25,359	23,030	21,435	19,790	21,347	27,240	33,009	32,556	31,686	26,643	20,412	21,773	304,280	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.33681	6.27549	6.45482	6.5315	6.47525	6.30879	6.20187	6.2083	6.22362	6.32372	6.49308	5.85996	6.29539	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)		6.33681	6.27549	6.45482	6.53150	6.47525	6.30879	6.20187	6.20830	6.22362	6.32372	6.49308	5.85996	6.29539	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	282,754	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	0.09293	11
12	TOTAL		6.42974	6.36842	6.54775	6.62443	6.56818	6.40172	6.29480	6.30123	6.31655	6.41665	6.58601	5.95289	6.38832	12
13	REVENUE TAX FACTOR	0.00072	0.00463	0.00459	0.00471	0.00477	0.00473	0.00461	0.00453	0.00454	0.00455	0.00462	0.00474	0.00429	0.00460	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.43437	6.37301	6.55246	6.62920	6.57291	6.40633	6.29933	6.30577	6.32110	6.42127	6.59075	5.95718	6.39292	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.434	6.373	6.552	6.629	6.573	6.406	6.299	6.306	6.321	6.421	6.591	5.957	6.393	15

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	28,013,973			28,013,973	4.359999	9.915480	1,221,409
FEBRUARY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	25,717,793			25,717,793	4.360001	10.302155	1,121,296
MARCH 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,153,490			24,153,490	4.359999	10.605047	1,053,092
APRIL 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,673,045			22,673,045	4.360001	10.939739	988,545
MAY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,080,050			24,080,050	4.359999	10.623487	1,049,890
JUNE 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,869,930			29,869,930	4.360000	9.637060	1,302,329
JULY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,779,464			35,779,464	4.360001	8.957138	1,559,985
AUGUST 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,443,472			35,443,472	4.359999	8.988462	1,545,335
SEPTEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,322,747			34,322,747	4.360001	9.101847	1,496,472
OCTOBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,024,410			29,024,410	4.359999	9.754096	1,265,464
NOVEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,451,600			22,451,600	4.360001	10.992072	978,890
DECEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	21,636,320			21,636,320	4.360002	11.197870	943,344
TOTAL			333,166,295	0	0	333,166,295	4.360000	9.947647	14,526,051

SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

(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 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
FEBRUARY 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	4.513182	4.513182	99,290
MARCH 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
APRIL 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
MAY 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JUNE 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
JULY 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
AUGUST 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
SEPTEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
OCTOBER 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	6.104000	6.104000	134,288
NOVEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.885182	5.885182	129,474
DECEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,200,000			2,200,000	5.930045	5.930045	130,461
TOTAL			26,400,000	0	0	26,400,000	5.909708	5.909708	1,560,163

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

NORTHEAST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	32.65	32.65
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	10.00	10.00
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.05	100.05	100.05	100.05	100.05	100.05	100.05
GROSS RECEIPTS TAX	3.40	3.40	3.40	3.40	3.40	3.40	3.40
TOTAL REVENUES *** $	136.10	136.10	136.10	136.10	136.10	136.10	136.10

	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	PERIOD TOTAL
BASE RATE REVENUES ** $	32.65	32.65	32.65	32.65	32.65	391.80
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.05	100.05	100.05	100.05	100.05	1,200.60
GROSS RECEIPTS TAX	3.40	3.40	3.40	3.40	3.40	40.80
TOTAL REVENUES *** $	136.10	136.10	136.10	136.10	136.10	1,633.20

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.070
	32.65

*** EXCLUDES FRANCHISE TAXES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 140001-EI DATED: October 7, 2014

AMENDED RESPONSE TO COMMISSION STAFF'S SECOND SET OF INTERROGATORIES (NO. 5)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Amended Response to the Second Set of Interrogatories (No. 5) served on the Company on September 3, 2014, by the Staff of the Florida Public Service Commission. The amendment is necessary to address an error in the narrative for the response to Interrogatory 5(a), as well as to provide revised schedules responsive to Interrogatories 5(a-d) reflecting the approval of new base rates for the Company. The individual responses follow this cover sheet.

Respectfully submitted,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706
Attorneys for Florida Public Utilities Company

Response to Interrogatory 5(a)

5. **Please provide all E Schedules under the following scenarios:**

   a. **Consolidated fuel factors and the total under-recovery (as opposed to one-third as proposed) included in the consolidated 2015 cost recovery calculation.**

Company Response:

The comparative factors between those proposed in the Company's consolidated 2015 cost recovery calculation and those computed based on total recovery of the Company's 2014 under-recovery are as follows:

	Proposed Rates	With Total Under-Recovery
RS	$0.10405	$0.10718
GS	$0.10037	$0.10350
GSD	$0.09520	$0.09833
GSLD	$0.09154	$0.09467
LS	$0.07751	**$0.08034**(corrected)

Residential Step Rates:

	Proposed Rates	With Total Under-Recovery
RS <= 1,000kWh/mo.	$0.09977	$0.10290
RS > 1,000kWh/mo.	$0.11227	$0.11540

TOU / Interruptible Rates:

	Proposed Rates		With Total Under-Recovery	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18377	$0.06077	$0.18690	$0.06390
GS	$0.14037	$0.05037	$0.14350	$0.05350
GSD	$0.13520	$0.06270	$0.13833	$0.06583
GSLD	$0.15154	$0.06154	$0.15467	$0.06467
Interruptible	$0.07654	$0.09154	$0.07967	$0.09467

The computation of these amounts can be found on the attached file 140001 FPUC ROG 2 No. 5a (revised).

Respondent: Curtis Young

Response to Interrogatory 5(b)

b. Consolidated fuel factors and one-third of the total under-recovery added as a separate c/kwh surcharge for the two divisions (i.e., the under-recovery is not consolidated, but recovered in 2015 separately from each division's ratepayers).

Company Response:

The comparative factors between the Company's two divisions computed based on consolidated fuel factors with one-third of the Company's 2014 under-recovery added as a separate surcharge are as follows:

	Northwest Florida	Northeast Florida
RS	$0.10526	$0.10279
GS	$0.10158	$0.09911
GSD	$0.09641	$0.09394
GSLD	$0.09275	$0.09028
LS	$0.07842	$0.07595

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.09971	$0.09958
RS > 1,000kWh/mo.	$0.11221	$0.11208

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18371	$0.06071	n/a	n/a
GS	$0.14158	$0.05158	n/a	n/a
GSD	$0.13641	$0.06391	n/a	n/a
GSLD	$0.15275	$0.06275	n/a	n/a
Interruptible	$0.07775	$0.09275	n/a	n/a

The calculation of these amounts can be found on the attached schedule 140001 FPUC ROG 2 No. 5b(revised).

Respondent: Curtis Young

Response to Interrogatory 5(c)

c. Consolidated fuel factors and the total under-recovery added as a separate c/kwh surcharge for the two divisions.

Company Response:

The comparative factors between the Company's two divisions computed based on consolidated fuel factors with the Company's total 2014 under-recovery added as a separate surcharge are as follows:

	Northwest Florida	Northeast Florida
RS	$0.11081	$0.10341
GS	$0.10713	$0.09973
GSD	$0.10196	$0.09456
GSLD	$0.09830	$0.09090
LS	$0.08397	$0.07657

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.10526	$0.10020
RS > 1,000kWh/mo.	$0.11776	$0.11270

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18926	$0.06626	n/a	n/a
GS	$0.14713	$0.05713	n/a	n/a
GSD	$0.14196	$0.06946	n/a	n/a
GSLD	$0.15830	$0.06830	n/a	n/a
Interruptible	$0.08330	$0.09830	n/a	n/a

The computation of these amounts can be found on the attached file 140001 FPUC ROG 2 No. 5c(revised).

Respondent: Curtis Young

Response to Interrogatory 5(d)

d. Separate fuel factors (with transmission costs allocated consistent with the methodology approved by Order No. PSC-13-0665-FOF-EI) and the total under-recovery included separately in the fuel factor calculations for the two divisions.

Company Response:

The comparative factors between the Company's two divisions computed based on separate fuel factors with the Company's total 2014 under-recovery are as follows:

	Northwest Florida	Northeast Florida
RS	$0.11111	$0.10326
GS	$0.10714	$0.09980
GSD	$0.10163	$0.09503
GSLD	$0.09770	$0.09160
LS	$0.08257	$0.07834

Residential Step Rates:	Northwest Florida	Northeast Florida
RS <= 1,000kWh/mo.	$0.10555	$0.10005
RS > 1,000kWh/mo.	$0.11805	$0.11255

TOU / Interruptible Rates:

	Northwest Florida		Northeast Florida	
	On-Peak	Off-Peak	On-Peak	Off-Peak
RS	$0.18955	$0.06655	n/a	n/a
GS	$0.14714	$0.05714	n/a	n/a
GSD	$0.14163	$0.06913	n/a	n/a
GSLD	$0.15770	$0.06770	n/a	n/a
Interruptible	$0.08270	$0.09770	n/a	n/a

The computations for the above amounts can be found on the attached files 140001 FPUC ROG 2 No. 5d Marianna(revised) and 140001 FPUC ROG 2 No. 5d Fernandina(revised).

(Curtis D. Young)

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.29	10.29	10.29	10.29	10.29	10.29	10.29
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	102.90	102.90	102.90	102.90	102.90	102.90	102.90
GROSS RECEIPTS TAX	3.53	3.53	3.53	3.53	3.53	3.53	3.53
TOTAL REVENUES *** $	141.10	141.10	141.10	141.10	141.10	141.10	141.10

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.29	10.29	10.29	10.29	10.29	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	102.90	102.90	102.90	102.90	102.90	1,234.80
GROSS RECEIPTS TAX	3.53	3.53	3.53	3.53	3.53	42.36
TOTAL REVENUES *** $	141.10	141.10	141.10	141.10	141.10	1,693.20

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	10.00	10.00
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	100.03	100.03
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	3.45	3.45
TOTAL REVENUES *** $	138.15	138.15	138.15	138.15	138.15	138.15	138.15

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.03	100.03	100.03	100.03	100.03	1,200.36
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	41.40
TOTAL REVENUES *** $	138.15	138.15	138.15	138.15	138.15	1,657.80

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	9.95	9.95
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	99.48	99.48
GROSS RECEIPTS TAX	3.44	3.44	3.44	3.44	3.44	3.44	3.44
TOTAL REVENUES *** $	137.59	137.59	137.59	137.59	137.59	137.59	137.59

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	9.95	9.95	9.95	9.95	9.95	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.48	99.48	99.48	99.48	99.48	1,193.76
GROSS RECEIPTS TAX	3.44	3.44	3.44	3.44	3.44	41.28
TOTAL REVENUES *** $	137.59	137.59	137.59	137.59	137.59	1,651.08

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	9.97	9.97	9.97	9.97	9.97	9.97	9.97
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	99.71	99.71	99.71	99.71	99.71	99.71	99.71
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	3.45	3.45
TOTAL REVENUES *** $	137.83	137.83	137.83	137.83	137.83	137.83	137.83

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	9.97	9.97	9.97	9.97	9.97	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	99.71	99.71	99.71	99.71	99.71	1,196.52
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	41.40
TOTAL REVENUES *** $	137.83	137.83	137.83	137.83	137.83	1,653.96

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.53	10.53	10.53	10.53	10.53	10.53	10.53
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	105.26	105.26	105.26	105.26	105.26	105.26	105.26
GROSS RECEIPTS TAX	3.59	3.59	3.59	3.59	3.59	3.59	3.59
TOTAL REVENUES *** $	143.52	143.52	143.52	143.52	143.52	143.52	143.52

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.53	10.53	10.53	10.53	10.53	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	105.26	105.26	105.26	105.26	105.26	1,263.12
GROSS RECEIPTS TAX	3.59	3.59	3.59	3.59	3.59	43.08
TOTAL REVENUES *** $	143.52	143.52	143.52	143.52	143.52	1,722.24

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2015 - DECEMBER 2015

	JANUARY 2015	FEBRUARY 2015	MARCH 2015	APRIL 2015	MAY 2015	JUNE 2015	JULY 2015
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.55	10.55	10.55	10.55	10.55	10.55	10.55
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	105.55	105.55	105.55	105.55	105.55	105.55	105.55
GROSS RECEIPTS TAX	3.60	3.60	3.60	3.60	3.60	3.60	3.60
TOTAL REVENUES *** $	143.82	143.82	143.82	143.82	143.82	143.82	143.82

	AUGUST 2015	SEPTEMBER 2015	OCTOBER 2015	NOVEMBER 2015	DECEMBER 2015	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.55	10.55	10.55	10.55	10.55	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	105.55	105.55	105.55	105.55	105.55	1,266.60
GROSS RECEIPTS TAX	3.60	3.60	3.60	3.60	3.60	43.20
TOTAL REVENUES *** $	143.82	143.82	143.82	143.82	143.82	1,725.84

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	34.67	34.67
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	10.00	10.00
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.05	100.05	100.05	100.05	100.05	100.05	100.05
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	3.45	3.45
TOTAL REVENUES *** $	138.17	138.17	138.17	138.17	138.17	138.17	138.17

	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	PERIOD TOTAL
BASE RATE REVENUES ** $	34.67	34.67	34.67	34.67	34.67	416.04
FUEL RECOVERY FACTOR CENTS/KWH	10.00	10.00	10.00	10.00	10.00	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.05	100.05	100.05	100.05	100.05	1,200.60
GROSS RECEIPTS TAX	3.45	3.45	3.45	3.45	3.45	41.40
TOTAL REVENUES *** $	138.17	138.17	138.17	138.17	138.17	1,658.04

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.070
	34.67

*** EXCLUDES FRANCHISE TAXES

Docket No. 140001- EI

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 7th day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis Young, who is personally known to me, and he/she acknowledged before me that he/she provided the revised answers to interrogatory number(s) 5(a) – (d) from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 3-5) in Docket No(s). 140001-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 7th day of October, 2014.

Dina Bellechases
Notary Public
State of Florida, at Large

My Commission Expires:
December 13, 2015

63

FPUC's Responses to Staff's Fourth Set of Interrogatories (Nos. 15-20)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 63
PARTY: STAFF
DESCRIPTION: FPUC's Responses to Staff's 4th Set of Interrogatories (Nos. 15-20) [Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 140001-EI DATED: September 29, 2014

RESPONSES TO COMMISSION STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 15 - 20)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Responses to the Fourth Set of Interrogatories (Nos. 15-20) served on the Company on September 11, 2014, by the Staff of the Florida Public Service Commission. The individual responses follow this cover sheet.

Respectfully submitted,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706
Attorneys for Florida Public Utilities Company

INTERROGATORY RESPONSES

15. What is FPUC's definition of "price shock" as used on page 6, line of the August 22, 2014 (revised September 5, 2014) testimony of FPUC witnesses Young and Cutshaw?

Company Response:

"Price shock" is a descriptive term that occurs when customers receive bills that are significantly more than amounts previously paid or expected. There is no set amount as each customer has differing levels of tolerance for paying increased electric bills.

Respondent: Mark Cutshaw

Response to Interrogatory 16

16. What is FPUC's definition of "rate shock" as used on page 15, line 17, of the August 22, 2014 testimony (revised September 5, 2014) of FPUC witnesses Young and Cutshaw?

Company Response:

"Rate shock" is a descriptive term that occurs when customers receive bills that are significantly more than amounts previously paid or expected. There is no set amount as each customer has differing levels of tolerance for paying increased electric bills.

Respondent: Mark Cutshaw

Response to Interrogatory 17

17. Please refer to page 15, lines 15 through 19 of the panel testimony of FPUC witnesses Young and Cutshaw filed on August 22, 2014 (revised September 5, 2014). What is the specific "rate shock" that FPUC is trying to mitigate?

Company Response:

Residential customers using 1000 kilowatt-hours in Northeast Florida received fuel adjustments that increased the total bill in the amount of 32.9% in January 2007, 15.6% in October 2007, 3.1% in January 2008 and 15.2% in July 2008 with future increases at 6.2% or less. After receiving a reduction of 1.6% in January 2007, residential customers using 1000 kilowatt-hours in Northwest Florida received fuel adjustments that increased the total bill in the amount of 13.5% in October 2007, 28.6% in January 2008, 11.1% in July 2008, 10.7% in January 2009, 13.8% in January 2010 with the next two adjustments being decreases. Many customers viewed these dramatic swings as rate shock and have repeatedly expressed this to FPU and the Commission. FPU is proposing to work to equalize the annual increases in a manner that avoids dramatic swings in cost that impact our customers' budgets. During 2016, the completion of a generating facility (Eight Flags Energy, LLC) on Amelia Island is anticipated to provide an overall price decrease to FPU customers. With a decrease in fuel adjustments possible in the near term, mitigation of any significant fuel increase would provide benefits to customers and avoid unnecessary rate shock that may occur in the near term.

Respondent: Mark Cutshaw

Response to Interrogatory 18

18. Please identify the Commission orders that FPUC relied upon to support the use of a fuel cost deferral over 3 years or more to offset or mitigate a base rate increase.

Company Response:

The Company is not specifically aware of any case in which the Commission addressed deferral of fuel cost recovery in order to mitigate a base rate or other non-fuel increase. However, by Order No. PSC-08-0495-PCO-EI, issued in Docket No. 080001-EI, the Commission did allow Progress Energy n/k/a Duke to defer collection of 50% of a projected under-recovery, because it would provide the "ratepayers with the least degree of immediate rate shock. . ." and a "better opportunity to adjust their budgets for the eventual expected increases. . . ." Order at p. 13. In that same Order, the Commission stated that ". . .stable annual fuel factors are important for customers because stable factors give customer more certainty in planning their expenditures for electricity." Order at p. 11[1]. In this instance, the Company believes that its overall fuel costs will experience a decrease in the near future. Thus, deferral of a portion of the under-recovery will lessen, to some degree, the impact of the Company's base rate increases, while also providing stable fuel factors and accurate price signals to customers. Furthermore, the Company expects that its fuel factors will remain stable, or decrease, in the near term due to active projects with alternative providers; thus, deferral should not result in more severe impacts to FPUC customers in later years.

Respondent: Mark Cutshaw

[1] Citing, Order No. PSC-98-0691-FOF-PU, issued in Docket No. 980269-PU, on May 19, 1998.

Response to Interrogatory 19

19. Please identify the Commission orders relied upon by FPUC to allow deferral of a portion of a fuel cost under recovery to offset a non-fuel increase in the utility's rates?

Company Response:

The Company is not specifically aware of any case in which the Commission addressed deferral of fuel cost recovery in order to mitigate a base rate or other non-fuel increase. However, by Order No. PSC-08-0495-PCO-EI, issued in Docket No. 080001-EI, the Commission did allow Progress Energy n/k/a Duke to defer collection of 50% of a projected under-recovery, because it would provide the "ratepayers with the least degree of immediate rate shock. . ." and a "better opportunity to adjust their budgets for the eventual expected increases. . . ." Order at p. 13. In that same Order, the Commission stated that ". . .stable annual fuel factors are important for customers because stable factors give customer more certainty in planning their expenditures for electricity." Order at p. 11[2]. In this instance, the Company believes that its overall fuel costs will experience a decrease in the near future. Thus, deferral of a portion of the under-recovery will lessen, to some degree, the impact of the Company's base rate increases, while also providing stable fuel factors and accurate price signals to customers. Furthermore, the Company expects that its fuel factors will remain stable, or decrease, in the near term due to active projects with alternative providers; thus, deferral should not result in more severe impacts to FPUC customers in later years.

Respondent: Mark Cutshaw

[2] Citing, Order No. PSC-98-0691-FOF-PU, issued in Docket No. 980269-PU, on May 19, 1998.

Response to Interrogatory 20

20. Please refer to page 15, lines 19 through 20, of the August 22, 2014 (revised September 5, 2014) testimony of FPUC witnesses Young and Cutshaw. How certain is FPUC regarding the expectation of "a fuel cost reduction from a generation project beginning in 2016"?

Company Response:

Progress is continuing towards the completion of a generation project that should be in place during 2016. Assuming that all approvals are granted, including the PPA that will be submitted for Commission approval, significant cost will begin being incurred in early 2015 in order to obtain equipment that will be in place by 2016. Current information indicates that cost for energy from the project will be less than the wholesale power cost with approximately one half of the total energy needs being provided from the project. FPU is committed to the success of this project and is certain that customers will benefit from the generation project.

Respondent: Mark Cutshaw

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Nassau)

I hereby certify that on this 25th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared P. Mark Cutshaw, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 15 – 20 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 15-20) in Docket No(s). 140001-EI, and that the responses are true and correct based on his/her personal knowledge. P. Mark Cutshaw

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of Sept., 2014.

Bonnie L. Erdek
Notary Public
State of Florida, at Large

BONNIE L. ERDEK
MY COMMISSION # EE 089032
EXPIRES: May 1, 2015
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 01, 2015

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Gulf's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 64
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's First Set of Interrogatories (Nos. 1-11) [Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 140001-EI Date Filed: March 24, 2014

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-11)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's First Set of Interrogatories (Nos. 1-11) on the following pages.

Respectfully submitted by electronic mail the 24th day of March, 2014.

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

1. For each Request for Proposal (RFP) for coal issued in 2013 by Gulf Power Company (Gulf), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

ANSWER:

Gulf did not issue any RFP's for coal in 2013.

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

N/A

3. During 2013, did Gulf experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

ANSWER:

Gulf did not experience any detention charges or have any transportation constraints for coal deliveries in 2013.

Gulf did incur minor demurrage charges of $28,600 under the terms of its barge transportation agreement with Crounse Corporation in 2013. These charges are incurred when barges remain in Gulf's possession for longer than the allotted time specified in the agreement. Barge demurrage typically occurs due to weather delays that slow the movement of barges from point to point or due to operational issues at the generating plant such as unplanned maintenance on barge unloaders.

4. For each RFP for natural gas issued in 2013 by Gulf, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

ANSWER:

Southern Company Services (SCS), as agent for Alabama Power Company, Georgia Power Company, Mississippi Power Company, Gulf Power Company, and Southern Power Company solicits bids for firm, baseload natural gas supply to assist in serving the fuel requirements of its affiliates.
In order to qualify for consideration, all bids must contain 1) delivery point(s), 2) volume, 3) term, and 4) pricing.

The bids received from the Fall 2013 RFP are listed below:

Supplier: BG

Volume and Pipeline: Annual Supply 10,000 per day Holly Field into Gulf South
1 Price: Gas Daily CGML [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Annual Supply 10,000 per day Holly Field into Gulf South
2 Price: Gas Daily CGML [redacted] (Term: 6/14 – 5/15) Call Option

Supplier: BP

Volume and Pipeline: Annual Supply 25,000 per day FGT Z3 Pool into FGT
3 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Annual Supply 25,000 per day FGT Z3 Pool into Destin
4 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Summer Supply 25,000 per day FGT Z3 Pool into FGT
5 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 9/14)

Volume and Pipeline: Summer Supply 25,000 per day FGT Z3 Pool into Destin
6 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 9/14)

Supplier: EXXON

Volume and Pipeline: Annual Supply 15,000 per day Mobile Bay into FGT

1 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into FGT

2 Price: Inside FERC FGT Z3 [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Winter Supply 15,000 per day Mobile Bay into FGT

3 Price: Gas Daily FGT Z3 [redacted] (Term: 11/14 – 5/15)

Supplier: Iberdrola Energy

Volume and Pipeline: Annual Supply 20,000 per day FGT Z3 Pool into FGT

4 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

Supplier: QEP

Volume and Pipeline: Annual Supply 5,000 per day GSPL/FGT Airport into Mobile Bay

5 Price: Inside FERC FGT Z3 [redacted] (Term: 6/14 – 5/15)

Supplier: Tenaska

Volume and Pipeline: Summer Supply 25,000 per day All Delivery Points into Destin

6 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 9/14)

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

After reviewing the gas supply needs, each bid was evaluated based on price, location, volume, term, transportation rights (firm or interruptible) and the flexibility of supply.

The lowest cost bidders that met the necessary volume and term were selected as shown below:

Supplier: BG
Volume and Pipeline: Annual Supply 10,000 per day Holly Field into Gulf South
1 Price: Gas Daily CGML [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Annual Supply 10,000 per day Holly Field into Gulf South
2 Price: Gas Daily CGML [redacted] (Term: 6/14 – 5/15) Call Option

Supplier: BP
Volume and Pipeline: Summer Supply 25,000 per day FGT Z3 Pool into Destin
3 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 9/14)

Supplier: EXXON
Volume and Pipeline: Annual Supply 15,000 per day Mobile Bay into FGT
4 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into FGT
5 Price: Inside FERC FGT Z3 [redacted] (Term: 6/14 – 5/15)

Supplier: Iberdrola Energy
Volume and Pipeline: Annual Supply 20,000 per day FGT Z3 Pool into FGT
6 Price: Gas Daily FGT Z3 [redacted] (Term: 6/14 – 5/15)

6. In 2013, did Gulf participate in any capacity discussions or bid for any firm pipeline capacity during "open season"? Please explain your response and identify the pipeline companies.

ANSWER:

Southern Company Services (SCS), as agent for Gulf Power, participated in an open season solicitation on Transco Pipeline for additional firm transportation to Florida Gas Transmission to supply gas to Plant Smith. Firm transportation capacity of 75,000 MMBTU/day was contracted on Transco Pipeline to support the gas supply needs of Plant Smith starting on April 1, 2015.

7. In 2013, did Gulf participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

ANSWER:

No.

8. For each RFP for light oil issued in 2013 by Gulf, list the bids received.

ANSWER:

A solicitation (RFP) was issued on 12-16-2013, soliciting bids from all known suppliers capable of providing fuel oil to Gulf Power's Plants Crist, Scholz and Smith as well as for oil to facilities under Purchase Power Agreements (PPA); the Baconton Power facility in Baconton, GA and the Central AL facility located in Billingsly, AL. The solicitation requested bids for the fuel oil requirements for one year; the period 3-1-2014 through 2-28-2015 with one exception. The PPA agreement with the Baconton plant expires on 6-1-2014; therefore, so would the corresponding fuel oil purchase agreement. In response to the solicitation, sent to 28 potential suppliers, bids were received by the required date of 1-15-2014 from 7 potential suppliers.

The offers received are in cents per gallon to be added to the daily OPIS index for dyed ultra-low sulfur diesel.

2014/2015 Gulf Power Fuel Oil Bid Results

	Supplier	Baconton	Crist	Scholz	Smith	Central Al
2	Boswell	NB	[redacted]			
3	Indigo	[redacted]				
4	Brad Lanier	[redacted]	NB	NB	NB	NB
5	Hightower	[redacted]				
6	TAC	[redacted]				
7	PS Energy	[redacted]				
8	Mansfield	[redacted]				

After the winter event of January 6th-7th and subsequent burning of a larger than normal amount of CT fuel oil throughout the Southern Company, SCS Fuel Services decided to re-bid the Central AL facility in an attempt to develop a select group of suppliers and origin terminals to fulfill any future needs that arise during periods of high demand, if warranted. An additional bid was received from Petroleum Traders in response to this bid request.

	Origin	Montgomery	Birmingham
2	Petroleum Traders	[redacted]	
3	Mansfield	[redacted]	
4	Boswell	[redacted]	
5	PS Energy	[redacted]	
6	Indigo Energy	[redacted]	

9. Please describe the action taken for each bid identified in response to Interrogatory No. 8. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

Original bids were opened on 1-15-2014, recorded and reviewed to insure there were no exceptions taken by the suppliers to Gulf's Term and Conditions and that all bids were signed appropriately by a supplier representative. SCS Fuel Services recommended to Gulf Power that for Plants Baconton(PPA), Crist, Scholz and Smith, the low bidder, Boswell Oil Company be issued purchase order agreements for the upcoming annual period. However for Baconton, with just 4 months remaining on the PPA agreement, a purchase agreement through only the end of May was recommended.
The recommendation to delay supplier selection(s) for the Central AL PPA facility until the re-bid for the Central AL oil supply agreement was received was agreed to by Gulf Power. Once re-bids for the Central, AL facility were received and reviewed on February 17, 2014, SCS Fuel Services recommended that Petroleum Traders using Montgomery, AL as the origin terminal be selected as the primary supplier and that Petroleum Traders pulling oil out of Birmingham and Indigo Energy out of Montgomery be chosen as alternate suppliers if the need should arise. Gulf Power agreed with this recommendation.

The fuel oil purchase orders listed below were issued for the 3-1-2014 through 2-28-2015 annual period:

Plant	Supplier	PO Number
Crist	Boswell Oil Co.	GO1401
Smith	Boswell Oil Co.	GO1402
Scholz	Boswell Oil Co.	GO1403
Baconton PPA	Boswell Oil Co.	GO1404
Central AL PPA	Petroleum Traders	GO1405 (Montgomery)
Central AL PPA	Petroleum Traders	GO1406 (Birmingham)
Central AL PPA	Indigo Energy	GO1407

10. For each RFP for purchased power issued in 2013 by Gulf, list the bids received.

ANSWER:

No RFP's for purchased power were issued in 2013.

11. Please describe the action taken for each bid identified in response to Interrogatory No. 10. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

N/A

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 140001-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 21st day of March, 2014.

Melissa A. Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

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Gulf's Responses to Staff's Second Set of Interrogatories (Nos. 12 (CONFIDENTIAL), 13, 14 (CONFIDENTIAL), and 15-25)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 65
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's Second Set of Interrogatories (Nos. 12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)

Docket No. 140001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 12-25)

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. 12-25) on the following pages.

Respectfully submitted by electronic mail this 18th day of September, 2014.

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

12. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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:

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
1	7/13/2009	[redacted]	1/1/2013	12/31/2013	6.935	[redacted]
2	8/31/2009		1/1/2013	12/31/2013	6.896	
3	9/3/2009		1/1/2013	12/31/2013	6.747	
4	9/16/2010		1/1/2013	12/31/2013	5.496	
5	1/5/2011		1/1/2013	12/31/2013	5.236	
6	2/23/2011		1/1/2013	12/31/2013	5.126	
7	3/7/2011		1/1/2014	12/31/2014	5.478	
8	4/5/2011		1/1/2013	12/31/2013	5.369	
9	4/18/2011		1/1/2013	12/31/2013	5.281	
10	5/5/2011		1/1/2013	12/31/2013	5.287	
11	5/5/2011		1/1/2014	12/31/2014	5.605	
12	5/9/2011		1/1/2013	12/31/2013	5.217	
13	5/26/2011		1/1/2013	12/31/2013	5.266	
14	6/3/2011		1/1/2014	12/31/2014	5.572	
15	6/3/2011		1/1/2013	12/31/2013	5.333	
16	6/9/2011		1/1/2014	12/31/2014	5.490	
17	6/16/2011		1/1/2014	12/31/2014	5.476	
18	6/23/2011		1/1/2014	12/31/2014	5.341	
19	6/23/2011		1/1/2014	12/31/2014	5.341	
20	7/6/2011		1/1/2014	12/31/2014	5.349	
21	7/6/2011		1/1/2013	12/31/2013	5.087	

	(A) Transaction Date	(B) Fixed Price	(C) Period Begin Date	(D) Period End Date	(E) Average NYMEX Price at Market Close ($/MMBTU)	(F) % Difference
22	7/7/2011	[redacted]	1/1/2013	12/31/2013	5.064	[redacted]
23	7/7/2011		1/1/2014	12/31/2014	5.356	
24	7/28/2011		1/1/2013	12/31/2013	5.102	
25	7/29/2011		1/1/2013	12/31/2013	5.047	
26	7/29/2011		1/1/2014	12/31/2014	5.344	
27	8/3/2011		1/1/2013	12/31/2013	5.053	
28	8/4/2011		1/1/2013	12/31/2013	4.959	
29	8/4/2011		1/1/2014	12/31/2014	5.269	
30	8/29/2011		1/1/2013	12/31/2013	4.901	
31	9/9/2011		1/1/2014	12/31/2014	5.235	
32	9/9/2011		1/1/2013	12/31/2013	4.930	
33	9/15/2011		1/1/2013	12/31/2013	4.927	
34	9/23/2011		1/1/2014	12/31/2014	5.102	
35	9/29/2011		1/1/2013	12/31/2013	4.821	
36	10/3/2011		1/1/2013	12/31/2013	4.785	
37	10/7/2011		1/1/2013	12/31/2013	4.682	
38	10/7/2011		1/1/2014	12/31/2014	4.981	
39	10/18/2011		1/1/2013	12/31/2013	4.615	
40	11/7/2011		1/1/2013	12/31/2013	4.507	
41	11/7/2011		1/1/2014	12/31/2014	4.878	
42	11/9/2011		1/1/2014	12/31/2014	4.812	
43	11/9/2011		1/1/2013	12/31/2013	4.446	
44	11/11/2011		1/1/2013	12/31/2013	4.382	
45	11/14/2011		1/1/2013	12/31/2013	4.345	
46	11/14/2011		1/1/2014	12/31/2014	4.703	
47	11/18/2011		5/1/2013	12/31/2013	4.316	
48	11/22/2011		5/1/2013	12/31/2013	4.364	
49	11/23/2011		5/1/2013	12/31/2013	4.387	
50	11/23/2011		1/1/2014	12/31/2014	4.675	
51	12/5/2011		1/1/2013	12/31/2013	4.351	
52	12/6/2011		1/1/2014	12/31/2014	4.706	
53	12/8/2011		1/1/2014	12/31/2014	4.633	
54	12/9/2011		1/1/2013	12/28/2013	4.150	
55	12/9/2011		1/1/2014	12/31/2014	4.520	
56	12/14/2011		1/1/2014	12/31/2014	4.399	

	(A) Transaction Date	(B) Fixed Price	(C) Period Begin Date	(D) Period End Date	(E) Average NYMEX Price at Market Close ($/MMBTU)	(F) % Difference
57	12/14/2011	[redacted]	5/1/2013	12/31/2013	4.061	[redacted]
58	12/28/2011		1/1/2013	12/31/2013	4.023	
59	1/5/2012		5/1/2013	12/31/2013	3.960	
60	1/5/2012		1/1/2014	12/31/2014	4.338	
61	1/11/2012		6/1/2013	8/31/2013	3.747	
62	1/13/2012		1/1/2014	12/31/2014	4.170	
63	1/17/2012		5/1/2013	12/31/2013	3.606	
64	1/19/2012		1/1/2013	12/31/2013	3.400	
65	1/19/2012		1/1/2014	12/31/2014	3.865	
66	1/26/2012		1/1/2013	12/31/2013	3.652	
67	1/26/2012		1/1/2014	12/31/2014	4.005	
68	1/30/2012		1/1/2013	12/31/2013	3.675	
69	1/30/2012		1/1/2014	12/31/2014	4.033	
70	1/31/2012		1/1/2014	12/31/2014	3.946	
71	1/31/2012		1/1/2013	12/31/2013	3.560	
72	2/7/2012		1/1/2014	12/31/2014	4.065	
73	2/9/2012		1/1/2013	12/31/2013	3.688	
74	2/27/2012		1/1/2013	12/31/2013	3.685	
75	2/28/2012		1/1/2013	12/31/2013	3.590	
76	2/28/2012		1/1/2014	12/31/2014	4.006	
77	3/5/2012		6/1/2013	12/31/2013	3.579	
78	3/7/2012		1/1/2013	12/31/2013	3.411	
79	3/7/2012		1/1/2014	12/31/2014	3.834	
80	3/13/2012		1/1/2013	12/31/2013	3.507	
81	3/13/2012		1/1/2014	12/31/2014	3.932	
82	3/29/2012		1/1/2013	12/31/2013	3.428	
83	4/11/2012		1/1/2013	12/31/2013	3.393	
84	4/17/2012		1/1/2013	12/31/2013	3.305	
85	4/17/2012		1/1/2014	12/31/2014	3.765	
86	4/19/2012		1/1/2014	12/31/2014	3.719	
87	4/19/2012		1/1/2013	12/31/2013	3.240	
88	4/23/2012		1/1/2014	12/31/2014	3.702	
89	5/10/2012		1/1/2014	12/31/2014	4.000	
90	5/10/2012		6/1/2013	12/31/2013	3.717	
91	5/21/2012		1/1/2014	12/31/2014	3.922	

	(A) Transaction Date	(B) Fixed Price	(C) Period Begin Date	(D) Period End Date	(E) Average NYMEX Price at Market Close ($/MMBTU)	(F) % Difference
92	5/21/2012	[redacted]	6/1/2013	9/30/2013	3.557	[redacted]
93	5/23/2012		6/1/2013	12/31/2013	3.664	
94	5/25/2012		6/1/2013	9/30/2013	3.504	
95	5/29/2012		1/1/2014	12/31/2014	3.858	
96	5/30/2012		5/1/2013	12/31/2013	3.436	
97	6/7/2012		1/1/2014	12/31/2014	3.788	
98	6/7/2012		1/1/2013	12/31/2013	3.371	
99	6/13/2012		1/1/2013	12/31/2013	3.296	
100	6/15/2012		1/1/2014	12/31/2014	3.815	
101	6/28/2012		1/1/2013	12/31/2013	3.525	
102	6/28/2012		1/1/2014	12/31/2014	3.903	
103	7/6/2012		1/1/2013	12/31/2013	3.531	
104	7/6/2012		1/1/2014	12/31/2014	3.906	
105	7/12/2012		6/1/2013	12/31/2013	3.700	
106	8/1/2012		6/1/2013	12/31/2013	3.790	
107	8/1/2012		1/1/2014	12/31/2014	4.086	
108	8/2/2012		6/1/2013	12/31/2013	3.614	
109	8/2/2012		1/1/2014	12/31/2014	3.931	
110	8/10/2012		1/1/2014	12/31/2014	3.976	
111	8/10/2012		5/1/2013	12/31/2013	3.628	
112	8/13/2012		5/1/2013	12/31/2013	3.586	
113	8/13/2012		1/1/2014	12/31/2014	3.933	
114	8/16/2012		5/1/2013	12/31/2013	3.548	
115	8/16/2012		1/1/2014	12/31/2014	3.898	
116	8/23/2012		6/1/2013	12/31/2013	3.613	
117	8/23/2012		1/1/2014	12/31/2014	3.927	
118	8/27/2012		6/1/2013	12/31/2013	3.495	
119	8/27/2012		1/1/2014	12/31/2014	3.819	
120	9/5/2012		1/1/2013	12/31/2013	3.461	
121	9/5/2012		1/1/2014	12/31/2014	3.868	
122	9/7/2012		1/1/2013	12/31/2013	3.376	
123	9/7/2012		1/1/2014	12/31/2014	3.805	
124	9/18/2012		1/1/2013	12/31/2013	3.545	
125	10/22/2012		1/1/2014	12/31/2014	4.222	
126	10/24/2012		1/1/2014	12/31/2014	4.229	

	(A) Transaction Date	(B) Fixed Price	(C) Period Begin Date	(D) Period End Date	(E) Average NYMEX Price at Market Close ($/MMBTU)	(F) % Difference
127	11/1/2012	[redacted]	1/1/2014	12/31/2014	4.226	[redacted]
128	11/2/2012		4/1/2013	10/31/2013	3.745	
129	11/2/2012		1/1/2014	12/31/2014	4.123	
130	11/9/2012		4/1/2013	10/31/2013	3.713	
131	11/9/2012		1/1/2014	12/31/2014	4.094	
132	11/26/2012		5/1/2014	9/30/2014	4.153	
133	11/29/2012		1/1/2014	12/31/2014	4.117	
134	11/30/2012		4/1/2013	10/31/2013	3.672	
135	11/30/2012		1/1/2014	12/31/2014	4.070	
136	12/4/2012		7/1/2013	9/30/2013	3.697	
137	12/10/2012		5/1/2014	11/30/2014	3.993	
138	12/11/2012		6/1/2013	12/31/2013	3.684	
139	12/12/2012		5/1/2014	11/30/2014	3.937	
140	1/2/2013		6/1/2013	12/31/2013	3.564	
141	1/2/2013		5/1/2014	11/30/2014	3.949	
142	1/9/2013		6/1/2013	12/31/2013	3.467	
143	1/9/2013		5/1/2014	11/30/2014	3.888	
144	1/29/2013		1/1/2014	12/31/2014	3.989	
145	2/14/2013		10/1/2013	12/ 31/2013	3.642	
146	2/14/2013		1/1/2014	12/31/2014	3.954	
147	3/12/2013		6/1/2014	9/30/2014	4.080	
148	3/21/2013		4/1/2014	10/31/2014	4.107	
149	5/16/2013		2/1/2014	12/31/2014	4.181	
150	5/16/2013		6/1/2013	10/31/2013	3.988	
151	5/22/2013		6/1/2014	9/30/2014	4.274	
152	5/22/2013		6/1/2013	9/30/2013	4.230	
153	5/28/2013		6/1/2014	12/31/2014	4.330	
154	5/30/2013		6/1/2014	12/31/2014	4.230	
155	5/31/2013		11/1/2013	12/31/2013	4.161	
156	6/6/2013		7/1/2013	12/31/2013	3.898	
157	6/6/2013		1/1/2014	12/31/2014	4.099	
158	6/14/2013		1/1/2014	12/31/2014	4.028	
159	6/21/2013		1/1/2014	3/31/2014	4.096	
160	6/24/2013		8/1/2013	12/31/2013	3.830	
161	6/27/2013		11/1/2013	3/31/2014	3.850	

	(A) Transaction Date	(B) Fixed Price	(C) Period Begin Date	(D) Period End Date	(E) Average NYMEX Price at Market Close ($/MMBTU)	(F) % Difference
162	6/27/2013	[redacted]	1/1/2014	12/31/2014	3.931	[redacted]
163	7/11/2013		1/1/2014	12/31/2014	3.958	
164	7/26/2013		11/1/2013	12/31/2013	3.747	
165	7/26/2013		2/1/2014	2/28/2014	3.916	
166	7/26/2013		7/1/2014	8/31/2014	3.917	
167	7/29/2013		1/1/2014	12/31/2014	3.873	
168	8/5/2013		4/1/2014	12/31/2014	3.783	
169	8/7/2013		11/1/2013	12/31/2013	3.485	
170	8/7/2013		1/1/2014	12/31/2014	3.699	
171	9/10/2013		1/1/2014	3/31/2014	3.897	
172	9/24/2013		1/1/2014	3/31/2014	3.824	
173	10/21/2013		1/1/2014	3/31/2014	3.881	
174	10/22/2013		1/1/2014	3/31/2014	3.797	
175	10/28/2013		1/1/2014	3/31/2014	3.740	
176	11/4/2013		1/1/2014	12/31/2014	3.606	

13. For interrogatory 12 above, please explain any difference 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.

14. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, associated with options for natural gas prices, please provide the following information:

(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:

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Date Deal Was Entered	Strike $/MMBtu	Option Prem.	Portfolio	Put Call	Direction	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)
1	9/24/2013	[redacted]	$0.00	Collar	Call	Buy	5/1/2014	10/31/2014	3.830
2	9/24/2013		$0.00	Collar	Put	Sell	5/1/2014	10/31/2014	3.830
3	10/3/2013		$0.00	Collar	Call	Buy	2/1/2014	4/30/2014	3.749
4	10/3/2013		$0.00	Collar	Put	Sell	2/1/2014	4/30/2014	3.749
5	10/22/2013		$0.00	Collar	Call	Buy	6/1/2014	6/30/2014	3.801
6	10/22/2013		$0.00	Collar	Put	Sell	6/1/2014	6/30/2014	3.801
7	10/28/2013		$0.00	Collar	Call	Buy	5/1/2014	11/30/2014	3.802
8	10/28/2013		$0.00	Collar	Put	Sell	5/1/2014	11/30/2014	3.802
9	10/31/2013		$0.00	Collar	Call	Buy	2/1/2014	1/31/2015	3.761
10	10/31/2013		$0.00	Collar	Put	Sell	2/1/2014	1/31/2015	3.761
11	11/4/2013		$0.00	Collar	Call	Buy	2/1/2014	1/31/2015	3.639
12	11/4/2013		$0.00	Collar	Put	Sell	2/1/2014	1/31/2015	3.639
13	6/26/2014		$0.00	Collar	Call	Buy	8/1/2014	10/31/2014	4.426
14	6/26/2014		$0.00	Collar	Put	Sell	8/1/2014	10/31/2014	4.426
15	6/27/2014		$0.00	Collar	Call	Buy	8/1/2014	10/31/2014	4.394
16	6/27/2014		$0.00	Collar	Put	Sell	8/1/2014	10/31/2014	4.394
17	7/7/2014		$0.00	Collar	Call	Buy	8/1/2014	10/31/2014	4.222
18	7/7/2014		$0.00	Collar	Put	Sell	8/1/2014	10/31/2014	4.222

15. For interrogatory 14 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:

In all of the collar transactions, the future price is within the bounds of the collar strike price.

16. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2013, and ending July 31, 2014.

ANSWER:

Month	Fuel Type	Swaps	Options	Total
Aug-13	Natural Gas	$ 2,385,644	$ -	$ 2,385,644
Sep-13	Natural Gas	$ 1,541,155	$ -	$ 1,541,155
Oct-13	Natural Gas	$ 1,306,667	$ -	$ 1,306,667
Nov-13	Natural Gas	$ 1,348,136	$ -	$ 1,348,136
Dec-13	Natural Gas	$ (406,630)	$ -	$ (406,630)
Jan-14	Natural Gas	$ (1,351,800)	$ (60,320)	$ (1,412,120)
Feb-14	Natural Gas	$ (3,137,135)	$ (129,450)	$ (3,266,585)
Mar-14	Natural Gas	$ (1,133,385)	$ (49,290)	$ (1,182,675)
Apr-14	Natural Gas	$ (676,100)	$ (39,450)	$ (715,550)
May-14	Natural Gas	$ (961,675)	$ (144,190)	$ (1,105,865)
Jun-14	Natural Gas	$ (710,500)	$ (66,060)	$ (776,560)
Jul-14	Natural Gas	$ 567,224	$ 190,650	$ 757,874

17. For the twelve months beginning August 1, 2013, and ending July 31, 2014, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in Gulf's risk management plan or otherwise stated in internal procedures governing Gulf's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

ANSWER:

Gulf does not establish monthly targets, but rather has a target range for hedge volumes as a percentage of its annual gas burn for its gas fired generation units. Actual gas burn for the period was 60,725,731 MMBTU and the hedged amount for the period was 35,290,000 MMBTU. The hedged amount is equivalent to 58% of the actual burn for the period. This is within the target hedge range established in Gulf's Risk Management Plan.

18. Please provide a comparison of Gulf's Risk Management Plans for 2014 and 2015. Please describe any changes between these respective plans.

ANSWER:

There were no changes made to Gulf's Risk Management Plan between 2014 and 2015.

19. Regarding hedging activities, how does Gulf assess and evaluate counter-party credit risk?

ANSWER:

Gulf only enters into material agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. In addition, the Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

20. For open hedging transactions since August 1, 2013, has Gulf experienced any defaults by a counter-party? If so, please identify the counter-party and explain.

ANSWER:

No.

21. For all currently open hedging transactions, does Gulf have any concern regarding default by a counter-party for any specific transaction? If so, please identify the counter-party and explain.

ANSWER:

No.

22. Since January 1, 2013, has Gulf stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If so, please identify the counter-party and explain.

ANSWER:

No.

23. Has Gulf incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

ANSWER:

No.

24. Regarding natural gas prices, does Gulf use its firm gas storage for physically hedging the price of natural gas? Please explain.

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.

25. How does Gulf price/charge natural gas withdrawn from storage?

ANSWER:

Natural gas withdrawn from storage is expensed at the weighted average cost of gas in Plant Smith or Plant Central Alabama's inventory account.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 140001-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 17th day of September, 2014.

Melissa A. Darnes

Notary Public, State of Florida at Large

MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

66

Gulf's Responses to Staff's Third Set of Interrogatories (No. 26)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 66
PARTY: STAFF
DESCRIPTION: Gulf's Responses to Staff's Third Set of Interrogatories (No. 26) [Bates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 140001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S THIRD SET OF INTERROGATORIES (NO. 26)

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. 26) on the following pages.

Respectfully submitted by electronic mail this 24th day of September, 2014.

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

26. For the purpose of this interrogatory, please refer to Exhibit HRB-2, exhibit attached to the direct testimony of H. R. Ball, filed on July 25, 2014. Please provide a copy of the Amended and Restated Purchase Agreement between Gulf and Bay County, Florida in type and strike format, highlighting changes to the agreement from the previous version; or alternately, provide a listing of all material changes to the previous agreement including pricing, dates of commencement and termination, interconnection requirements, and other such data.

ANSWER:

Gulf does not have a type and strike comparison of the Amended and Restated Purchase Agreement between Gulf and Bay County, Florida and the agreement previously in place between Gulf and Bay County. The new agreement has various non-material changes which include the correction of a few spelling and punctuation errors, as well as instances where the parties redrafted a sentence for clarity. There are three substantive/material changes in the new agreement. The three changes address a new commencement date, the term of the agreement and price for energy delivered pursuant to the agreement. The previous agreement had a commencement date of July 23, 2008 and a term of six years. The new agreement has a commencement date of July 23, 2014 and has a term of three years. The previous agreement had a fixed rate of 72.50 $/MWh for the first four years of the term and $75.00 $/MWh for the remaining two years of the term. The new agreement has a fixed rate of 34.56 $/MWh for its entire term.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 140001-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 23rd day of September, 2014.

Melissa A. Darnes
Notary Public, State of Florida at Large

MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

67

TECO's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 67
PARTY: STAFF
DESCRIPTION: TECO's Responses to Staff's First Set of Interrogatories (Nos. 1-11) [Bates

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 140001-EI FILED: March 24, 2013

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-11)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 1-11) propounded and served on February 21, 2014 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 1-11)

Number	Witness	Subject	Bates Stamped Page
1	Caldwell	For each Request for Proposal (RFP) for coal issued in 2013 by Tampa Electric Company (TECO), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.	1
2	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.	5
3	Caldwell	During 2013, did TECO experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.	6
4	Caldwell	For each RFP for natural gas issued in 2013 by TECO, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.	7
5	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.	12
6	Caldwell	In 2013, did TECO participate in any capacity discussions or bid for any firm pipeline capacity during "open season"? Please explain your response and identify the pipeline companies.	13
7	Caldwell	In 2013, did TECO participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.	14
8	Caldwell	For each RFP for light oil issued in 2013 by TECO, list the bids received.	15
9	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 8. Include in your response an explanation of the evaluation process and how successful proposals were selected.	16

10	Smith	For each RFP for purchased power issued in 2013 by TECO, list the bids received.	17
11	Smith	Please describe the action taken for each bid identified in response to Interrogatory No. 10. Include in your response an explanation of the evaluation process and how successful proposals were selected.	18

Brent Caldwell
Director, Bulk Fuel & Power

Benjamin Smith
Manager, Wholesale Products & Fuel Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1
PAGE 1 OF 4
FILED: MARCH 24, 2014

1. For each Request for Proposal (RFP) for coal issued in 2013 by Tampa Electric Company (TECO), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

A. Tampa Electric issued three RFPs for solid fuel during 2013. The bids are described in the following tables.

Big Bend Gen 2014-01

		Coal Quality					Delivered Price [1]			
Supplier	Tons Bid	Btu/lb	Ash (Lbs)	Sulfur (Lbs)	Moisture (%)	Chlorine (%)	$/Ton	$/MMBtu	Delivery Method	Delivery Route
[redacted]									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									Railcar	PAL / CSX Rail
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery

		Coal Quality					Delivered Price [1]			
Supplier	Tons Bid	Btu/lb	Ash (Lbs)	Sulfur (Lbs)	Moisture (%)	Chlorine (%)	$/Ton	$/MMBtu	Delivery Method	Delivery Route
[redacted]									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery
									Railcar	CSX Rail
									Railcar	CSX Rail
									Railcar	INRD/CSX Rail
									Railcar	CSX Rail
									Railcar	CSX Rail
									Railcar	CSX Rail
									Railcar	CSX Rail

1 The delivered costs per MMBtu in the above table are based on the average pricing for 2014-2015.

Tampa Electric evaluated the bids listed above on a total delivered cost per MMBtu basis and identified a short list of qualifying bidders. Tampa Electric then asked those qualifying bidders to submit a best and final offer with the opportunity to include additional years. The offers that the company received in response to its request for best and final pricing are shown in the following table.

REDACTED

Big Bend Gen 2014-01
Best and Final Offers

		Coal Quality					Delivered Price [1]				
Supplier	Tons Bid	Btu/lb	Ash (Lbs)	Sulfur (Lbs)	Moisture (%)	Chlorine (%)	$/Ton	$/MMBtu	Delivery Method	Delivery Route	Awarded [2]
[redacted]									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	Yes [redacted]
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
									FAS Tampa	Delivered Tampa	
									Railcar	CSX Rail	
									Railcar	CSX Rail	Yes [redacted]
									Railcar	CSX Rail	Yes [redacted]
									Railcar	CSX Rail	

1 The delivered costs per MMBtu in the above table are based on the average pricing for a three-year term.
2 Prior to contracting for a long-term fuel purchase, Tampa Electric would need to conduct a test burn of the offered coal. Tampa Electric has not tested the coal offered from [redacted], but intends to do so in 2014 or 2015 so that the bidder may be a potential long term supplier in the future.

REDACTED

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Polk PC 2013-01

Supplier	Tonnage Bid	Sulfur % (max dry)	$ /Ton Delivered	$ / MMBtu Delivered	Delivery Method	Delivery Route	Awarded
					River Barge/ Ocean Vessel	Mississippi River / Gulf Delivery	
					Ocean Vessel	Delaware Tampa	
					River Barge/ Ocean Vessel	Mississippi River / Gulf Delivery	
					River Barge/ Ocean Vessel	Black Warrior River/ Gulf Delivery	
					Ocean Vessel	Gulf Delivery	
					Ocean Vessel	Gulf Delivery	Yes

Polk LS 2013-01

		Coal Quality					Delivered Price				
Supplier	Tonnage Bid	Btu/lb	Ash (Lbs)	Sulfur (Lbs)	Moisture (%)	Chlorine (%)	$/Ton	Cents per MMBtu	Delivery Method	Delivery Route	Awarded
									Ocean Vessel	Gulf Delivery	
									River Barge/ Ocean Vessel	Mississippi River / Gulf Delivery	
									Railcar/ River Barge/ Ocean Vessel	Mississippi River / Gulf Delivery	
									Railcar/Ocean Vessel	Rail/Gulf Delivery	
									Ocean Vessel	Ocean Delivery	Yes

REDACTED

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. All bids were evaluated on a total delivered cost per MMBtu basis. To identify a short list of qualifying bidders, Tampa Electric also evaluated bids based on projected commodity and transportation costs, quality, proposed terms and conditions, blending impacts, supplier reliability and supplier financial strength. Qualifying bids accounting for operational impacts, containing acceptable quality, terms and conditions and supplier reliability as specified in the RFP were considered. Once qualifying bids were identified, Tampa Electric selected the quality-adjusted lowest priced alternative on a utilized, portfolio basis.

As a result of the Big Bend Gen 2014-01 solicitation identified in the company's response to Interrogatory No. 1, Tampa Electric selected three vendors for coal supply. The vendors are identified in the response to Interrogatory No. 1. Also see the company's response to Interrogatory No. 1 for additional details regarding the Big Bend Gen 2014-01 evaluation process. Tampa Electric agreed to purchase the following annual amounts:

Year	Projected Tons
2014	[redacted]
2015	
2016	
2017	
2018	

As a result of the Polk LS 2013-01 and the Polk PC 2013-01 solicitations identified in the company's response to Interrogatory No. 1, Tampa Electric selected a vendor for petroleum coke and a vendor for low sulfur coal. Those vendors are identified in Tampa Electric's response to Interrogatory No. 1. From those vendors, Tampa Electric agreed to purchase the following annual amounts:

Year	Fuel Type	Projected Tons
2013	Petroleum Coke	[redacted]
2013	Low Sulfur Coal	
2014	Petroleum Coke	
2014	Low Sulfur Coal	

3. During 2013, did TECO experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

A. Yes. During 2013, Tampa Electric experienced trucking detention and vessel unloading demurrage charges for coal deliveries. Detention and demurrage are common charges associated with transportation of bulk commodities. These charges reflect the natural operational and timing-sensitive nature of loading, unloading and transferring bulk commodities. Detention and demurrage charges are part of the overall negotiation; sometimes the detention and demurrage may be embedded in a higher rate and sometimes the charges are stated separately.

Tampa Electric's contracts contain provisions that provide for detention and demurrage charges in the event that contractual guarantees for either loading or unloading of coal are not met. Demurrage and detention charges are payable to the owner of transportation equipment if there is an inability to load or discharge within the time agreed upon within the contract. During 2013, Tampa Electric incurred demurrage for vessel unloading at the stations and detention for truck loading at the station. No unusual or identifiable events caused transportation constraints during 2013.

REDACTED

4. For each RFP for natural gas issued in 2013 by TECO, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

A. Tampa Electric issued one RFP for natural gas supply during 2013. The bids are described in the following table.

Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Pipeline	Awarded
[redacted]						
						Yes
						Yes

REDACTED

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Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Pipeline	Awarded
[redacted]						
						Yes
						Yes

REDACTED

Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Pipeline	Awarded
[redacted]						
						Yes
						Yes
						Yes
						Yes

REDACTED

Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Pipeline	Awarded
[redacted]						
						Yes
						Yes
						Yes

REDACTED

Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Pipeline	Awarded
[redacted]						Yes
						Yes

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. Tampa Electric issued one RFP for natural gas supply in 2013. The RFP was issued in September 2013, and Tampa Electric sent the RFP to approximately 95 qualified suppliers. In response to the RFP, Tampa Electric received approximately 113 gas supply package options from 22 respondents. Each gas supply option was evaluated based on price, pipeline, receipt point, supply type, firmness, time frame, and special conditions. Special conditions included the following items:

- pipeline optionality, or the ability to move supply from one pipeline to another at Tampa Electric's option;
- volume flexibility, the ability to adjust the daily baseload gas volume at the beginning of each month; and
- pricing conversion, an indexed gas price that can be converted to a fixed price at Tampa Electric's request.

Tampa Electric grouped the packages by time frame (*e.g.*, winter packages), gas supply type (*e.g.*, baseload, swing, or peaking), and pipeline. For each group, the packages were ranked by price. Special provisions and strategic considerations related to price and supplier risk were considered. The company selected the lowest cost supply packages while accounting for needed reliability, optionality and flexibility. Finally, Tampa Electric contacted the selected suppliers to execute a deal confirmation. If an agreement could not be reached, the next best vendor was contacted.

As a result of the September 2013 RFP, eight vendors were awarded a total of 105,000 to 118,000 MMBtu per day depending on the season. The selected packages included baseload supply with various time frames and delivery on different pipelines.

6. In 2013, did TECO participate in any capacity discussions or bid for any firm pipeline capacity during "open season"? Please explain your response and identify the pipeline companies.

A. Tampa Electric participated in discussions about pipeline capacity with several entities during 2013. Tampa Electric provided non-binding responses to Sabal Trail and Florida Southeastern Connection. Tampa Electric discussed pipeline capacity availability with Kinder Morgan, Florida Gas Transmission, Gulfstream and Sabal Trail. In September 2013, Peoples Gas System ("PGS") as a division of Tampa Electric also issued a solicitation for long-term, firm primary delivery pipeline capacity for both PGS and Tampa Electric and is in discussions to finalize an addition of pipeline capacity for each company's portfolio.

7. In 2013, did TECO participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

A. Tampa Electric did participate in an RFP for storage capacity in October 2013; however, no agreement has been reached at this time. The respondents to this RFP included PAA Natural Gas Storage ("PNG"), Shell and Virginia Power Energy Marketing ("VPEM").

8. For each RFP for light oil issued in 2013 by TECO, list the bids received.

A. Tampa Electric issued an RFP for light oil in 2013 and received one bid response. The responding supplier was RKA Petroleum Companies ("RKA"). Light oil represents less than one percent of Tampa Electric's generation.

9. Please describe the action taken for each bid identified in response to Interrogatory No. 8. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. Tampa Electric received only one bid to its RFP for light oil. The responding supplier was RKA. RKA has been a reliable, cost-effective supplier in the past. Tampa Electric evaluated the bid based on projected commodity and transportation costs and supplier reliability and awarded the contract to RKA.

10. For each RFP for purchased power issued in 2013 by TECO, list the bids received.

A. Tampa Electric did not issue an RFP in 2013 for purchased power, so no bids were received.

11. Please describe the action taken for each bid identified in response to Interrogatory No. 10. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. As previously stated in Tampa Electric's response to Interrogatory No. 10, the company did not issue an RFP in 2013 for purchased power. Thus, there were no bids to review or evaluate.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1-11) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 20th day of March, 2014.

Penelope Rusk

Sworn to and subscribed before me this 20th day of March, 2014.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

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TECO's Responses to Staff's Second Set of Interrogatories (Nos. 12 (CONFIDENTIAL), 13, 14, 15 (CONFIDENTIAL), 16 (CONFIDENTIAL), and 17-23)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 68
PARTY: STAFF
DESCRIPTION: TECO's Responses to Staff's Second Set of Interrogatories (Nos. 12

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 140001-EI FILED: September 18, 2014

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 12-23)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 12-23) propounded and served on August 29, 2014 by the Florida Public Service Commission Staff.

REDACTED

12. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2013, and ending July 31, 2014, 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 following table.

Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
23-Aug-11	[redacted]	201308	$ 4.886
24-Aug-11		201308	$ 4.828
9-Nov-12		201308	$ 3.754
17-Feb-12		201308	$ 3.831
23-Feb-12		201308	$ 3.854
7-Aug-12		201308	$ 3.644
9-Aug-12		201308	$ 3.676
6-Sep-12		201308	$ 3.454
11-Sep-12		201308	$ 3.605
13-Sep-12		201308	$ 3.656
16-Oct-12		201308	$ 3.949
6-Nov-12		201308	$ 3.847
29-Nov-12		201308	$ 3.783
3-Jan-13		201308	$ 3.454
10-May-13		201308	$ 3.983
28-Nov-11		201311	$ 4.675
28-Nov-11		201311	$ 4.675
4-May-12		201311	$ 3.678
7-Nov-12		201311	$ 3.966

REDACTED

TAMPA ELECTRIC COMPANY
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Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
7-Nov-12	[redacted]	201311	$ 3.966
29-Nov-12		201311	$ 3.930
3-Jan-13		201311	$ 3.628
4-Jan-13		201311	$ 3.700
4-Jan-13		201311	$ 3.700
5-Aug-13		201311	$ 3.454
23-Aug-13		201311	$ 3.643
27-Dec-11		201312	$ 4.400
26-Aug-13		201312	$ 3.835
26-Aug-13		201312	$ 3.835
28-Dec-11		201312	$ 4.372
25-Jun-12		201312	$ 3.906
29-Nov-12		201312	$ 4.123
13-Dec-12		201312	$ 3.924
3-Jan-13		201312	$ 3.838
4-Jan-13		201312	$ 3.904
14-Jan-13		201312	$ 3.945
20-Jun-13		201312	$ 4.129
23-Aug-13		201312	$ 3.814
23-Aug-13		201312	$ 3.814
23-Sep-13		201312	$ 3.847
14-Aug-13		201401	$ 3.761
25-Jan-12		201401	$ 4.172
26-Jan-12		201401	$ 4.076
22-Feb-12		201401	$ 4.288
13-Jul-12		201401	$ 4.123
23-Jan-13		201401	$ 4.203
23-Jan-13		201401	$ 4.203
11-Apr-13		201401	$ 4.541
12-Apr-13		201401	$ 4.644
1-Jul-13		201401	$ 3.910
1-Jul-13		201401	$ 3.910
12-Jul-13		201401	$ 3.980
13-Aug-13		201401	$ 3.715
13-Aug-13		201401	$ 3.715

REDACTED

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Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
16-Aug-13	[redacted]	201401	$ 3.788
16-Aug-13		201401	$ 3.788
19-Aug-13		201401	$ 3.876
14-Aug-13		201402	$ 3.761
23-Feb-12		201402	$ 4.278
23-Feb-12		201402	$ 4.278
7-Aug-12		201402	$ 4.083
23-Jan-13		201402	$ 4.198
8-Feb-13		201402	$ 4.021
8-Feb-13		201402	$ 4.021
10-May-13		201402	$ 4.321
24-May-13		201402	$ 4.572
3-Jul-13		201402	$ 4.012
3-Jul-13		201402	$ 4.012
13-Aug-13		201402	$ 3.718
13-Aug-13		201402	$ 3.718
13-Aug-13		201402	$ 3.718
16-Aug-13		201402	$ 3.787
16-Aug-13		201402	$ 3.787
20-Aug-13		201402	$ 3.870
24-Jun-13		201403	$ 4.053
14-Aug-13		201403	$ 3.725
26-Dec-13		201403	$ 4.441
23-Mar-12		201403	$ 3.957
7-Sep-12		201403	$ 3.789
23-Jan-13		201403	$ 4.142
19-Mar-13		201403	$ 4.286
20-Mar-13		201403	$ 4.281
11-Jun-13		201403	$ 4.043
11-Jun-13		201403	$ 4.043
20-Jun-13		201403	$ 4.151
3-Jul-13		201403	$ 3.976
3-Jul-13		201403	$ 3.976
16-Aug-13		201403	$ 3.756
20-Aug-13		201403	$ 3.839

140001 Hearing Exhibits - 0239

REDACTED

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Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
25-Oct-12	[redacted]	201404	$ 4.130
14-Aug-13		201404	$ 3.677
23-Apr-12		201404	$ 3.558
23-Apr-12		201404	$ 3.558
24-Apr-12		201404	$ 3.585
11-Apr-13		201404	$ 4.049
12-Apr-13		201404	$ 4.076
1-Jul-13		201404	$ 3.799
1-Jul-13		201404	$ 3.799
13-Aug-13		201404	$ 3.639
13-Aug-13		201404	$ 3.639
16-Aug-13		201404	$ 3.701
20-Aug-13		201404	$ 3.783
27-Jan-14		201404	$ 4.286
4-May-12		201405	$ 3.779
14-Aug-13		201405	$ 3.699
14-Aug-13		201405	$ 3.699
7-Nov-12		201405	$ 4.011
7-Nov-12		201405	$ 4.011
10-May-13		201405	$ 4.048
3-Jul-13		201405	$ 3.910
12-Jul-13		201405	$ 3.896
13-Aug-13		201405	$ 3.664
16-Aug-13		201405	$ 3.723
16-Aug-13		201405	$ 3.723
16-Aug-13		201405	$ 3.723
20-Aug-13		201405	$ 3.805
5-Feb-14		201405	$ 4.485
25-Mar-14		201406	$ 4.443
27-Jun-12		201406	$ 3.811
24-Jun-13		201406	$ 3.984
14-Aug-13		201406	$ 3.731
14-Aug-13		201406	$ 3.731
25-Jun-12		201406	$ 3.769
13-Dec-12		201406	$ 3.885

REDACTED

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Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
11-Jun-13	[redacted]	201406	$ 3.949
11-Jun-13		201406	$ 3.949
20-Jun-13		201406	$ 4.043
3-Jul-13		201406	$ 3.946
12-Jul-13		201406	$ 3.928
13-Aug-13		201406	$ 3.696
13-Aug-13		201406	$ 3.696
16-Aug-13		201406	$ 3.754
16-Aug-13		201406	$ 3.754
16-Aug-13		201406	$ 3.754
16-Aug-13		201406	$ 3.754
19-Aug-13		201406	$ 3.834
25-Jul-12		201407	$ 3.981
10-Apr-14		201407	$ 4.709
14-Aug-13		201407	$ 3.764
26-Jul-12		201407	$ 4.024
23-Jan-13		201407	$ 4.104
1-Jul-13		201407	$ 3.891
3-Jul-13		201407	$ 3.982
12-Jul-13		201407	$ 3.963
13-Aug-13		201407	$ 3.728
13-Aug-13		201407	$ 3.728
13-Aug-13		201407	$ 3.728
13-Aug-13		201407	$ 3.728
13-Aug-13		201407	$ 3.728
13-Aug-13		201407	$ 3.728
16-Aug-13		201407	$ 3.786
16-Aug-13		201407	$ 3.786
16-Aug-13		201407	$ 3.786
16-Aug-13		201407	$ 3.786
19-Aug-13		201407	$ 3.866
27-Sep-11		201309	$ 4.849
27-Sep-11		201309	$ 4.849
9-Nov-12		201309	$ 3.756
17-Feb-12		201309	$ 3.831

REDACTED

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Transaction Date	Fixed Price	Month of Swap	NYMEX Forward Price
(a)	(b)	(c)	(d)
12-Mar-12	[redacted]	201309	$ 3.468
28-Mar-12		201309	$ 3.538
6-Sep-12		201309	$ 3.457
7-Sep-12		201309	$ 3.404
11-Sep-12		201309	$ 3.608
13-Sep-12		201309	$ 3.659
16-Oct-12		201309	$ 3.950
6-Nov-12		201309	$ 3.849
29-Nov-12		201309	$ 3.786
3-Jan-13		201309	$ 3.469
10-Jun-13		201309	$ 3.825
11-Jun-13		201309	$ 3.746
20-Jun-13		201309	$ 3.897
23-Aug-13		201309	$ 3.485
23-Aug-13		201309	$ 3.485
9-Nov-12		201310	$ 3.790
28-Oct-11		201310	$ 4.681
22-Feb-12		201310	$ 3.888
17-Apr-12		201310	$ 3.367
16-Oct-12		201310	$ 3.985
16-Oct-12		201310	$ 3.985
6-Nov-12		201310	$ 3.885
4-Jan-13		201310	$ 3.586
4-Jan-13		201310	$ 3.586
3-Jan-13		201310	$ 3.507
1-Jul-13		201310	$ 3.587
23-Aug-13		201310	$ 3.521
23-Aug-13		201310	$ 3.521

13. For interrogatory 12 above, please explain any difference 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. Regarding Tampa Electric's hedging transactions that settled between August 1, 2013 and July 31, 2014, the company did not engage in any transactions where the swap fixed price and the corresponding forward price for the month being hedged differed by more than five percent.

14. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2013, and ending July 31, 2014.

A. The requested information is provided in the following table.

For the Month Ending	Realized Hedging Gain/(Loss) ($)	Fuel Type	Hedging Instrument
08/31/2013	(1,208,040)	Natural Gas	Swap
09/30/2013	(710,690)	Natural Gas	Swap
10/31/2013	(871,990)	Natural Gas	Swap
11/30/2013	(756,725)	Natural Gas	Swap
12/31/2013	(288,670)	Natural Gas	Swap
01/31/2014	1,067,285	Natural Gas	Swap
02/28/2014	4,942,700	Natural Gas	Swap
03/31/2014	2,232,670	Natural Gas	Swap
04/30/2014	1,791,450	Natural Gas	Swap
05/31/2014	2,668,620	Natural Gas	Swap
06/30/2014	2,677,190	Natural Gas	Swap
07/31/2014	1,903,555	Natural Gas	Swap

REDACTED

TAMPA ELECTRIC COMPANY
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15. For the twelve months beginning August 1, 2013, and ending July 31, 2014, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in Tampa Electric's risk management plan or otherwise stated in internal procedures governing Tampa Electric's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

A. The requested information is provided in the following table.

Month-Year	Target Minimum	Target Maximum	% of Actual Consumption Hedged	Above Maximum? Below Minimum?	Explanation
13-Aug	60%	80%	[redacted]	No	
13-Sep	60%	80%		No	
13-Oct	60%	80%		No	
13-Nov	60%	80%		No	
13-Dec	60%	80%		No	
14-Jan	60%	80%		No	
14-Feb	60%	80%		Yes	Gas-fired generation lower than projected due to higher than projected coal-fired generation.
14-Mar	60%	80%		Yes	Gas-fired generation higher than projected due to lower than projected coal-fired generation.
14-Apr	60%	80%		Yes	Gas-fired generation higher than projected due to lower than projected coal-fired generation.
14-May	60%	80%		Yes	Gas-fired generation higher than projected due to higher retail sales than projected.
14-Jun	60%	80%		No	
14-Jul	60%	80%		No	
12-Month	**60%**	**80%**	**65%**	**No**	**12-month cumulative hedge percentage is within the desired hedge range.**

16. Please provide a comparison of Tampa Electric's Risk Management Plans for 2014 and 2015. Please describe any changes between these respective plans.

A. The changes to Tampa Electric's Risk Management Plan for 2015 compared to 2014 are changes to reflect the time period covered and the actual data associated with the different time period, or minor edits for clarity.

The requested comparison is attached.

TAMPA ELECTRIC COMPANY
FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES
RISK MANAGEMENT PLAN
~~2014~~
2015

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.

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II. Oversight & Reporting of Fuel Procurement Activities

The company provides fuel and wholesale energy procurement activities with independent and unavoidable oversight.

A. The TECO Energy Board of Directors established an Energy Risk Management Policy ("Risk Policy"). This policy governs all energy commodities transacting activities at each of TECO Energy's operating units. The scope of this policy includes:

- Roles and responsibilities of various persons and functions with respect to risk management
- Authorized transacting activity
- Risk limits
- Valuation and data management
- Credit risk management
- Reporting
- Compliance and enforcement

B. The Risk Policy established the Risk Advisory Committee ("RAC"). The responsibilities of the RAC include the following activities:

- Reviewing the Risk Management Policy periodically and recommending changes and enhancements for approval by the Board of Directors ("Board").
- Reviewing corporate risk limits for recommendation to the Board.
- Establishing the quantitative limits for operating companies within Board approved corporate risk limits. The RAC may, at its discretion, delegate approval of sub-limits to operating company management.
- Approving parameters for counterparty credit limits and the allocation of limits among the operating companies.
- Establishing guidelines for risk management and measurement.
- Overseeing and reviewing the risk management process and infrastructure.
- Reviewing and approving transacting strategies proposed by the operating companies.
- Understanding and approving methodologies used for valuation and risk measurement.
- Reviewing and approving corporate and operating company risk limits.

- Establishing credit underwriting standards, and monitoring credit risk-taking activities and related exposures.
- Reviewing risk reports, including portfolio risk summaries and profitability and performance summaries.
- Enacting, maintaining, and enforcing limit violation and trader misconduct policies.
- Taking appropriate courses of action when the risk position of a transacting group has exceeded or is approaching the established limits.
- Reviewing and approving new risk management products.
- Presenting periodic reports to the Board or its committees.

C. TECO Energy established a corporate risk management function ("middle office"), which is overseen by the 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 ~~insure~~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 ~~2014~~2015, 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 ~~2014~~2015 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 $~~40.0~~25.1 million and total fuel and purchased power costs decrease by $~~68.5~~18.3 million due to lower prices. In the high case, natural gas expenditures increase by an estimated $~~75.2~~48.3 million, and the total fuel and purchased power costs increase by $~~52.6~~55.1 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 ~~2014~~2015 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

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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 ~~2014~~2015 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Coal	59
Natural Gas	~~37~~36
No. 2 Oil	0
No. 6 Oil	0
Purchased Power	45

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 ~~2014~~2015 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its ~~2014~~2015 projection filing to be

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submitted August ~~30, 2013~~22, 2014. Coal market pricing has retreated from record high levels in 2008. In ~~2013~~2014, coal prices have been relatively stable, and prices are expected to remain stable in ~~2014~~2015. Tampa Electric has secured a portion of its coal needs for ~~2014~~2015, 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 ~~2014~~2015, 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 ~~price~~cost impact from price risk is 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 ~~2013~~2014, 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 significant percentage of its projected natural gas usage in ~~2014~~2015.

   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 ~~2013~~2014 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 ~~2014~~2015, Tampa Electric has approximately [redacted] percent hedged with a currently estimated [redacted] of [redacted].

4. **Purchased Power:** Total forecasted purchased power for ~~2014~~2015 is ~~713~~920 GWH. As of July ~~2013~~2014, Tampa Electric has physically hedged ~~328~~227 GWH's of its ~~2014~~2015 expected purchased power needs through pre-scheduled purchased power agreements. The remaining GWH's of ~~2014~~2015 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.

Tampa Electric is responsible for natural gas fuel delivery on two purchase contracts for peaking power. Although this contract volume is not currently included in the company's hedging portfolio, Tampa Electric continually assesses whether it should be added.

In summary, Tampa Electric's planned operations in ~~2014~~2015 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.

17. Regarding hedging activities, how does Tampa Electric assess and evaluate counter-party credit risk?

A. Pursuant to Tampa Electric's Risk Management Plan, most recently filed on July 25, 2014, the company's contract administration and credit department negotiates acceptable credit terms with each counterparty when establishing a contract to enter into swap positions, monitors and verifies transactions entered into under each contract, establishes the credit limits and acceptable credit exposure standards, and monitors and evaluates exposure to each counterparty in relation to established credit limits and negotiated thresholds.

18. For open hedging transactions since August 1, 2013, has Tampa Electric 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 related to its open hedging transactions since August 1, 2013.

19. For all currently open hedging transactions, does Tampa Electric have any concern regarding default by a counter-party for any specific transaction? If yes, please identify the counter-party and explain.

A. No. Tampa Electric currently does not have any heightened concerns regarding default by any counterparty for any specific transaction. Tampa Electric mitigates credit risk associated with hedging by establishing and monitoring thresholds that are aligned with each counterparty's credit risk profile.

20. Since January 1, 2013, has Tampa Electric stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If yes, please identify the counter-party and explain.

A. No. Since January 1, 2013, Tampa Electric has not stopped engaging in hedging transactions with any counterparty due to credit risk concerns.

21. Has Tampa Electric incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If yes, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

A. Tampa Electric's fuel expenses, including hedging gains or losses, are treated on a cash basis as the expense is incurred, for tax purposes. Recovery of fuel expenses, including hedging gains or losses, occurs through the fuel and purchased power cost recovery clause ("fuel clause"). The expenses or credits are recovered in the same manner that other fuel expense is treated.

When Tampa Electric realizes a gain due to hedging, Tampa Electric incurs a tax expense for the same calendar year based on the realized gain. Alternatively, when Tampa Electric realizes a loss due to hedging, Tampa Electric incurs a tax benefit (deduction) for the same calendar year based on the realized loss.

The annual gains or losses, determining tax rate and requested amount of tax expense or credit are shown in the table below.

Period	Gains/(Losses)	Tax Rate	Tax Expense/(Credit)
2011	($33,889,480)	38.575	($13,072,867)
2012	($61,518,120)	38.575	($23,730,615)
2013	($3,256,370)	38.575	($1,256,145)

Upon realization of a hedging gain or loss, Tampa Electric is able to include the amount for recovery or refund to ratepayers through the fuel clause. The recovery or refund amount is spread over the period for which the fuel clause factor is set.

22. Regarding natural gas prices, does Tampa Electric use its firm gas storage for physically hedging the price of natural gas? Please explain.

A. No. Tampa Electric does not use its firm gas storage to hedge the price of its physical gas supply. Tampa Electric uses its firm gas storage for operational needs including changing load demands, pipeline and supply constraints, and pipeline imbalance management.

23. How does Tampa Electric price/charge natural gas withdrawn from storage?

A. The method used by Tampa Electric to price/charge natural gas withdrawn from storage is to value the volumes withdrawn at the index price published in *Gas Daily* for Florida Gas Transmission ("FGT") Zone 3 for the date of the withdrawal.

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. 12-23) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 16th day of September, 2014.

Penelope Rusk

Sworn to and subscribed before me this 16th day of September, 2014.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission EE052251
Expires 03/01/2015

My Commission expires _____

EXHIBIT NO. 69

DOCKET NO: 140001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: RRSSA Excerpt

(Hearing Exh. 98 from Dkt. No. 130001-EI)

DOCUMENTS:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 69
PARTY: OPC.
DESCRIPTION: Foster/RRSSA Exerpt

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

EXHIBIT NO. 78

DOCKET NO: 130001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: RRSSA Excerpt

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 130009-EI
In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.	Docket No. 100437-EI
In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 130001-EI
In re: Environmental cost recovery clause	Docket No. 130007-EI
In re: Petition of Progress Energy Florida, Inc. to approve establishment of a regulatory asset and associated three-year amortization schedule for costs associated with PEF's previously approved thermal discharge compliance project.	Docket No. 130091-EI
In re: Petition of Duke Energy Florida, Inc. for limited proceeding to approve Revised and Restated Stipulation and Settlement Agreement, including certain Rate Adjustments.	Docket No. _____

REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, Inc. ("DEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), (collectively referenced as the "Parties"), previously resolved certain issues in a Stipulation and Settlement Agreement (the "2012 Settlement Agreement"), dated January 20, 2012, that was approved by the Florida

EXHPAGE-000001

charged to the CR3 Decommissioning Trust Fund will not be added to the total CR3 Regulatory Asset value.

j. DEF shall exclude the following amounts related to CR3 from all surveillance reports: (1) revenues associated with the recovery of the CR3 Regulatory Asset base rate increase along with expenses (including, but not limited to, amortization); (2) rate base items (including, but not limited to, all amounts that have been deferred to or recorded in regulatory assets and liabilities); and (3) cost of capital accounts with specific adjustments for items including, but not limited to, deferred income taxes, with all other CR3-related items removed from capital structure on a pro-rata basis.

Fuel Adjustment Clause:

6. Refunds through the Fuel Adjustment Clause. Pursuant to the terms of this Revised and Restated Settlement Agreement, DEF agrees to the following:

a. Pursuant to the 2012 Settlement Agreement, DEF is refunding through the Fuel Adjustment Clause ("Fuel Clause") 50% of $258 million in 2013, and refunding the remaining 50% through the Fuel Clause in 2014. In addition, $30 million will be refunded through the Fuel Clause solely to customers on Rate Schedules RS-1, RSL-1, RSL-2, GS-1, and GS-2 (and their time-of-use counterpart schedules, to the extent applicable) based on an allocation of 94% of such refund amounts to the Residential Service rate schedules and 6% to the General Service, Non-Demand rate schedules, at an annual rate of $10 million per year in years 2014, 2015, and 2016.

b. DEF shall: (1) refund $40 million towards replacement fuel and purchased power costs in 2015; and (2) refund $60 million towards replacement fuel

and purchased power costs in 2016.

c. Except for the aforementioned refunds, DEF shall be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the absence of CR3 for any reason for the period beginning October 1, 2009. DEF's right to recover its prudently incurred fuel and purchased power costs does not affect the rights of customers to receive reimbursement from NEIL proceeds for such costs as otherwise provided in this Revised and Restated Settlement Agreement. Thus, for the period beginning October 1, 2009, the unavailability of CR3 for any reason shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties waive their rights to challenge DEF's recovery of such costs, except that Intervenor Parties reserve the right to raise issues regarding the prudence and reasonableness of DEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the unavailability of CR3 for any reason.

7. Pursuant to the terms of this Revised and Restated Settlement Agreement, the Parties further agree to the following:

a. DEF shall be allowed to increase retail fuel rates as follows:

(i) 2014 - $1.00/mWh
(ii) 2015 - $1.00/mWh
(iii) 2016 - $1.50/mWh

These increases shall be added to the fuel factor at secondary metering consistent with the normal fuel projection process. All other fuel factors will be developed using the adjusted fuel factor at secondary metering in a manner consistent with the normal derivation of fuel factors. An example of this is shown in Exhibit 12 to this Revised and Restated Settlement Agreement for illustrative purposes using the

projected fuel costs and sales from Docket No. 120001-EI (actual costs and sales will be different when rates are set for 2014-2016). These rate increases are not cumulative but apply only for the years shown. For example, retail fuel rates will increase by $1.00/mWh in 2014, increase by an additional $.50/mWh in 2016 and decrease by $1.50/mWh in 2017. Revenues collected from these retail fuel rates will be calculated by multiplying the relevant $/mWh increase above times the jurisdictional mWh sales as reported in line 26 of Schedule A-1. These revenues will be removed from the fuel revenues for purposes of calculating the fuel true-up over/under recovery. As a result of the accelerated recovery of the carrying charge associated with the CR3 Regulatory Asset, DEF will not defer for recovery the carrying charge on the portion of the CR3 Regulatory Asset supported by these revenues. An example of this calculation is provided on Exhibit 11 to this Revised and Restated Settlement Agreement.

b. If DEF determines that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3, DEF shall be allowed to petition to collect those additional funds through a surcharge in base rates. This surcharge will be the lesser of the Commission approved annual contribution amount or $8 million. The $8 million limitation shall expire with the last billing cycle for December 2018. After the last billing cycle for December 2018, DEF shall be authorized to recover the actual Commission approved annual contribution to the Nuclear Decommissioning Trust through a base rate surcharge, and that surcharge shall expire following the conclusion of DEF's next base rate case. If the Commission approves an annual contribution to the Nuclear Decommissioning Trust in excess of $8 million prior to the last billing cycle for December 2018, this incremental amount of the

annual contribution in excess of what has been authorized for recovery in the base rate surcharge shall be deferred with carrying costs based on the Commission approved allowance for funds used during construction ("AFUDC"), and recovered (including carrying costs) through the CCR Clause over a 4 year period beginning with the first billing cycle for January 2019, unless otherwise agreed to by the Parties. The Intervenor Parties reserve their rights to challenge the prudence of any additional CR3 decommissioning costs in appropriate proceedings before the Commission. The Parties expressly agree that any proceeding to recover costs associated with decommissioning CR3 under this paragraph 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 level of cost of removal reserve.

c. DEF shall credit the retail allocation of the NEIL settlement amount of $530 million (system), approximately $489 million (retail), through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

d. DEF shall collect from customers the approximately $328 million (system), $326 million (retail) previously credited in the Fuel Adjustment Clause beginning with the first billing cycle for January 2014. Thus, the approximate net effect of paragraphs 7c and 7d above is that DEF will credit the NEIL CR3 settlement amount of $163 million (retail) through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

e. Effective with the first billing cycle for January 2014, DEF shall change billing of the Retail CCR Clause for demand rate classes to be on a kilo-watt

("kW") basis rather than the current kilo-watt-hour ("kWh") method. This requires a modification to Exhibit 5 to this Revised and Restated Settlement Agreement (which was also an exhibit to the 2012 Settlement Agreement), and that modification to Exhibit 5 is presented in Exhibit 9 to this Revised and Restated Settlement Agreement.

Crystal River 1 & 2 ("CRS") Retirement:

8. If DEF retires Crystal River coal units 1 & 2 ("Crystal River South" or "CRS"), as a compliance measure to meet Mercury and Air Toxics Standards ("MATS"), the Best Available Retrofit Technology ("BART"), and/or the National Ambient Air Quality Standards ("NAAQS"), DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Parties, any remaining CRS net book value existing at December 31, 2020 through the CCR Clause.

CR3 Extended Power Uprate project ("EPU" or "Uprate"):

9. a. DEF shall recover all CR3 EPU revenue requirements through the Nuclear Cost Recovery Clause ("NCRC") consistent with the provisions of Section 366.93(6), Florida Statutes ("F.S."), and Commission Rule 25-6.0423(6), F.A.C. with a seven (7) year amortization recovery period established as 2013-2019. Intervenor Parties fully and forever waive, release, discharge, and otherwise extinguish any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the prudence of DEF's CR3 EPU investment and activities, except that the Intervenor Parties do not waive their rights to participate in the NCRC or

Example of Recovery of CR3 Regulatory Asset Carrying Cost

Line		2014	2015	2016
1	Fuel Rate Increase ($/mWh)	$1.00	$1.00	$1.50
2	Multiply by Retail mWhs	x	x	x
3	Equals Total Revenue Recovered in Rates	$x	$x	$x
4	Less Income Tax Expense	-$x	-$x	-$x
5	Equals Avoided Increase in CR3 Regulatory Asset	$x	$x	$x

Note: The effects of the calculation on line 5 of this exhibit are incorporated in the final calculation of line 17 of exhibit 10.

EXHIBIT NO. 70

DOCKET NO: 140001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: DEF Summary of NEIL Reimbursement

(Hearing Exh. 99 from Dkt. No. 130001-EI)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 70
PARTY: OPC
DESCRIPTION: Foster/DEF Summary NEIL Reimbursement

EXHIBIT NO. 99

DOCKET NO: 130001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: DEF Summary of NEIL Reimbursement

DOCUMENTS:

PROFFERED BY: **OFFICE OF PUBLIC COUNSEL**

DUKE ENERGY FLORIDA
SUMMARY OF NEIL REIMBURSEMENT

TOTAL
$'s in millions

Year	NEIL Replacement Power Reimbursement	NEIL Replacement Capacity Reimbursement	NEIL Repair Reimbursement	NEIL Final Settlement	Total
2009	$ -	$ -	$ -	$ -	$ -
2010	$ 108	$ 4	$ 64	$ -	$ 176
2011	$ 39	$ -	$ 72	$ -	$ 111
2012	$ 11	$ -	$ 7	$ -	$ 18
2013	$ -	$ -	$ -	$ 530	$ 530
Total	$ 158	$ 4	$ 143	$ 530	$ 835

RETAIL
$'s in millions

Year	NEIL Replacement Power Reimbursement[1]	NEIL Replacement Capacity Reimbursement[2]	NEIL Repair Reimbursement[3]	NEIL Final Settlement[4]	Total
2009	$ -	$ -	$ -	$ -	$ -
2010	$ 100	$ 3	$ 54	$ -	$ 157
2011	$ 38	$ -	$ 61	$ -	$ 99
2012	$ 10	$ -	$ 6	$ -	$ 16
2013	$ -	$ -	$ -	$ 490	$ 490
Total	$ 148	$ 3	$ 121	$ 490	$ 762

[1] The retail portion of NEIL Replacement Power Reimbursement was passed through the Fuel Clause in the years shown.

[2] The retail portion of NEIL Replacement Capacity Reimbursement was passed through the Capacity Clause

[3] The retail portion of NEIL Repair Reimbursement was applied to CWIP

[4] The retail portion of the Final NEIL Settlement was passed through the Fuel Clause

EXHIBIT NO. 71

DOCKET NO: 140001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: Fuel Cost Recovery Schedules

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 71
PARTY: OPC
DESCRIPTION: Foster/Fuel Recovery Schedules

Docket 140001-EI
Exhibit No. ____(TGF-3)
Part 2

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

JANUARY THROUGH DECEMBER 2015

PART 2 - 2015 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 RRSSA – Summary of RRSSA Adjustments

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. 140001-EI
Schedule E1
Exhibit TGF-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2015

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)		1,450,550,393	35,719,602	4.06094
2.	Spent Nuclear Fuel Disposal Cost		0	0 *	0.00000
3.	Coal Car Investment		0	0	0.00000
4.	Adjustment to Fuel Cost		(40,353,675)	0	0.00000
5.	TOTAL COST OF GENERATED POWER		1,410,196,718	35,719,602	3.94796
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		101,841,738	2,017,470	5.04799
7.	Energy Cost of Economy Purchases (E9)		16,351,874	356,500	4.58678
8.	Payments to Qualifying Facilities (E8)		145,142,688	3,087,667	4.70072
9.	TOTAL COST OF PURCHASED POWER		263,336,300	5,461,637	4.82156
10.	TOTAL AVAILABLE MWH			41,181,239	
11.	Fuel Cost of Economy Sales	(E6)	(4,199,152)	(126,300)	3.32474
11a.	Gain on Economy Sales	(E6)	(923,813)	(126,300) *	0.73144
12.	Fuel Cost of Stratified Sales	(E6)	(21,800,391)	(550,476)	3.96028
13.	TOTAL FUEL COST AND GAINS ON POWER SALES		(26,923,356)	(676,776)	3.97818
14.	Net Inadvertent Interchange				
15.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,646,609,662	40,504,463	4.06525
16.	Net Unbilled		3,781,869 *	(93,029)	0.00995
17.	Company Use		5,853,987 *	(144,000)	0.01540
18.	T & D Losses		91,160,151 *	(2,242,422)	0.23974
19.	Adjusted System Sales		1,646,609,662	38,025,012	4.33033
20.	Wholesale Sales (Excluding Supplemental Sales)		(10,295,965)	(239,422)	4.30035
21.	Jurisdictional Sales		1,636,313,676	37,785,590	4.33052
22.	Jurisdictional Sales Adjusted for Line Losses x	1.00148	1,638,735,421	37,785,590	4.33693
23.	Prior Period True-Up (Sch E1-A)		73,672,203	37,785,590	0.19497
24.	Total Jurisdictional Fuel Cost		1,712,407,624	37,785,590	4.53191
25.	Revenue Tax Factor		1,232,933		1.00072
26.	Fuel Cost Adjusted for Taxes		1,713,640,557	37,785,590	4.53517
27.	GPIF **		2,231,853	37,785,590	0.00591
28.	Fuel Factor Adjusted for taxes including GPIF		1,715,872,410	37,785,590	4.54108
29.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				4.541

* 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 2015

1. Actual Over/(Under) Recovery January - December 2013. (Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '13)	$	(5,961,090)
2. Projected (Over)/Under Recovery January - December 2013 . (Refunded)/Collected January - December 2013 . (Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '13)	$	33,195,183
3. Estimated Over/(Under) Recovery January - December 2014 (Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '14)	$	(100,906,296)
4. Total Over/(Under) Recovery to be Included in the January - December 2014 Projected Period (Lines 1 through 3)	$	(73,672,203)
5. Jurisdictional mWh Sales (Projected Period)	mWh	37,785,590
6. True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.195

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 129,009,047	$ 113,289,817	$ 117,898,602	$ 123,707,993	$ 148,849,928	$ 150,044,426	$ 782,797,813
	2	Fuel Cost of Power Sold	(8,399,700)	(4,874,897)	(4,172,032)	(4,008,945)	(2,404,449)	(3,611,616)	(27,469,439)
	3	Fuel Cost of Purchased Power	6,995,460	6,888,472	4,137,281	9,618,764	15,941,968	14,635,873	58,215,817
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	9,767,721	8,788,027	10,717,751	5,483,300	9,437,328	11,822,064	56,036,188
	4	Energy Cost of Economy Purchases	1,128,552	1,964,275	902,144	1,910,882	2,797,492	2,205,474	10,926,619
	5	Adjustments to Fuel Cost	(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(12,913,643)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
B	1	Jurisdictional MWH Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	17,013,292
	2	Non-Jurisdictional MWH Sales	22,565	44,021	16,238	32,556	33,247	28,733	177,361
	3	TOTAL SALES (Lines B1 + B2)	2,645,518	2,960,084	2,583,858	2,594,512	2,990,919	3,415,762	17,190,653
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	98.97%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	112,142,525	125,857,590	109,339,746	109,372,789	128,046,715	147,816,093	732,575,469
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	1b	RRSSA Fuel Adjustment	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(17,013,282)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	118,064,769	131,488,725	115,317,323	115,356,040	133,634,241	152,974,262	786,835,361
	4	Fuel & Net Power Transactions (Line A6)	138,504,493	126,060,088	129,506,146	136,697,603	174,604,893	162,219,933	867,593,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	137,533,195	124,365,581	128,880,719	135,188,866	172,922,325	161,095,355	859,985,842
	6	Over/(Under) Recovery (Line C3 - Line C5)	(19,468,426)	7,121,144	(13,563,396)	(19,832,826)	(39,288,084)	(8,121,092)	(93,152,480)
	7	Interest Provision	(716)	(1,063)	(1,108)	(1,862)	(3,570)	(4,021)	(12,439)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,469,142)	7,120,081	(13,564,504)	(19,834,688)	(39,291,654)	(8,125,113)	(93,164,920)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(3,194,825)	(428,560)	2,337,705	5,103,970	7,870,235	10,636,500	10,636,500
	12	Regulatory Accounting Adjustment	-	-	(588,930)	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($22,663,967)	(12,777,621)	($24,154,739)	($41,233,113)	($77,758,502)	($83,117,350)	($83,117,350)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 152,197,049	$ 153,089,439	$ 143,724,962	$ 125,026,239	$ 105,582,127	$ 113,198,782	$ 1,575,629,231
	2	Fuel Cost of Power Sold	(3,454,453)	(3,933,202)	(2,604,929)	(2,273,796)	(1,720,555)	(984,793)	(42,641,167)
	3	Fuel Cost of Purchased Power	13,422,539	14,076,449	12,104,080	11,244,071	5,443,096	5,926,210	120,432,262
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	12,830,242	12,768,252	12,331,692	12,332,063	11,820,155	13,174,893	131,093,485
	4	Energy Cost of Economy Purchases	1,387,310	1,538,315	3,090,433	2,406,094	813,273	1,003,572	21,165,616
	5	Adjustments to Fuel Cost	(19,486)	(19,498)	(19,508)	(19,502)	(19,488)	(19,481)	(13,030,585)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
B	1	Jurisdictional MWH Sales	3,578,550	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665
	2	Non-Jurisdictional MWH Sales	24,537	27,901	29,414	26,399	20,273	15,121	321,006
	3	TOTAL SALES (Lines B1 + B2)	3,603,087	3,780,718	3,746,740	3,460,117	2,941,281	2,764,075	37,486,671
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.32%	99.26%	99.21%	99.24%	99.31%	99.45%	99.14%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	158,609,389	164,276,459	162,714,963	150,237,348	127,680,111	120,110,401	1,614,204,140
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	1b	RRSSA Fuel Adjustment	(3,578,550)	(3,752,817)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,165,665)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,268)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	161,576,036	169,068,839	167,542,835	155,348,827	133,304,301	125,906,647	1,679,580,845
	4	Fuel & Net Power Transactions (Line A6)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	175,423,175	176,466,894	167,343,481	147,805,348	121,067,595	131,787,280	1,779,859,814
	6	Over/(Under) Recovery (Line C3 - Line C5)	(13,847,139)	(7,398,056)	199,354	7,543,480	12,238,705	(5,880,633)	(100,278,769)
	7	Interest Provision	(4,430)	(4,823)	(4,865)	(4,533)	(3,901)	(3,604)	(38,598)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(13,851,569)	(7,402,879)	194,489	7,538,946	12,232,804	(5,884,237)	(100,317,366)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	13,402,765	16,169,030	18,935,295	21,701,560	24,467,825	27,234,094	27,234,093
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(588,930)
	13	TOTAL TRUE-UP BALANCE	($94,202,854)	($98,639,287)	($95,578,514)	($85,573,302)	($70,574,233)	($73,672,202)	($73,672,203)

Docket: 140001-EI
Witness: Foster
Exhibit: TGF-3, Part 2
Schedule: RRSSA

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

System:	Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
1 RRSSA Refund ($40 million)	(3,347,151)	(3,352,208)	(3,345,133)	(3,343,789)	(3,346,142)	(3,345,805)	(3,350,183)	(3,353,897)	(3,354,573)	(3,353,559)	(3,351,533)	(3,346,478)	(40,190,452)		6.b.
2 Other Adjustments to Fuel Cost	(13,594)	(13,614)	(13,585)	(13,580)	(13,589)	(13,588)	(13,606)	(13,621)	(13,624)	(13,620)	(13,611)	(13,591)	(163,223)		
3 Total 2015 Adjustments to Fuel Cost (Lines 1 + 2)	(3,360,745)	(3,365,822)	(3,358,718)	(3,357,369)	(3,359,731)	(3,359,394)	(3,363,789)	(3,367,518)	(3,368,197)	(3,367,179)	(3,365,144)	(3,360,069)	(40,353,675)	E1, line 4	
4 Jurisdictional % of Total Sales	99.44%	99.29%	99.50%	99.54%	99.47%	99.48%	99.35%	99.24%	99.22%	99.25%	99.31%	99.46%			
5 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			

Retail:	Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
6 RRSSA Refund ($40 million)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(3,333,333)	(40,000,000)		6.b.
7 Other Adjustments to Fuel Cost	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(13,517)	(162,209)		
8 Total 2015 Adjustments to Fuel Cost (Lines 6 + 7)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(3,346,851)	(40,162,209)		
9 Retail mWh Sales	3,053,112	2,711,825	2,630,687	2,655,086	2,850,830	3,443,184	3,787,779	3,680,235	3,748,879	3,503,048	2,952,686	2,768,240	37,785,590	E1-D, line 5	
10 RRSSA Fuel Adjustment ($/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		E1-D, line 9	7.a. / 7.a(ii)
11 Total RRSSA Fuel Adjustment to Revenue (Line 9 * 10)	(3,053,112)	(2,711,825)	(2,630,687)	(2,655,086)	(2,850,830)	(3,443,184)	(3,787,779)	(3,680,235)	(3,748,879)	(3,503,048)	(2,952,686)	(2,768,240)	(37,785,590)		

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2015

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	2,231,853
	B. True-Up (Over) / Under Recovery	$	73,672,203
2.	JURISDICTIONAL mWh SALES	mWh	37,785,590
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.006
	B. True-Up Factor	Cents/kWh	0.195

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2015

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$ 1,638,735,421	
1a.	Prior Period True-up (E1, Line 23)	$ 73,672,203	
2.	Regulatory Assessment Fee (E1, Line 25)	$ 1,232,933	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$ 2,231,853	
4.	Total amount to be Recovered	$ 1,715,872,410	
5.	Jurisdictional Sales (January - December 2015)	37,785,590	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)	4.541	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)	37,738,631	mWh
	LEVELIZED FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):		
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)	4.547	Cents/kWh
9.	Fuel Factor Adjustment pursuant to 2013 Revised and Restated Stipulation and Settlement Agreement	0.100	Cents/kWh
10.	Adjusted Fuel Factor at Secondary Metering (Line 8 + Line 9)	4.647	Cents/kWh
11.	Fuel Factor at Primary Metering	4.601	Cents/kWh
12.	Fuel Factor at Transmission Metering	4.554	Cents/kWh
	LEVELIZED FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):		
13.	2013 Settlement Agreement Refund (per Order No. PSC-13-0598-FOF-EI)*	$ (9,400,000)	
14.	Interest Amortization on Settlement Agreement Refund*	$ (15,408)	
15.	Applicable Jurisdictional Sales at Secondary Metering**	18,390,957	mWh
16.	Fuel Factor at Secondary Metering Rate Adjustment (Line 13 + Line 14 / Line 15 / 10)	(0.049)	Cents/kWh
17.	Fuel Factor at Secondary Metering (Line 10 + Line 16)	4.598	Cents/kWh
	LEVELIZED FUEL FACTORS (only GS-1, GST-1 & GS-2):		
18.	2013 Settlement Agreement Refund (per Order No. PSC-13-0596-FOF-EI)*	$ (600,000)	
19.	Interest Amortization on Settlement Agreement Refund*	$ (983)	
20.	Applicable Jurisdictional Sales at Secondary Metering**	1,420,031	mWh
21.	Fuel Factor at Secondary Metering Rate Adjustment (Line 18 + Line 19 / Line 20 / 10)	(0.042)	Cents/kWh
22.	Fuel Factor at Secondary Metering (Line10 + Line 21)	4.605	Cents/kWh
23.	Fuel Factor at Primary Metering	4.559	Cents/kWh
24.	Fuel Factor at Transmission Metering	4.513	Cents/kWh
	TIERED FUEL FACTORS:		
25.	Fuel Factor - First Tier (0-1000 kWh)	4.323	Cents/kWh
26.	Fuel Factor - Second Tier (Over 1000 kWh)	5.323	Cents/kWh

* The 2013 Settlement Agreement refunds and associated interest included on lines 13-14 and 18-19 are included in paragraph 6 of the 2013 RRSSA

** Applicable Jurisdictional Sales at Secondary Metering utilized in the calculation of the 2013 Settlement Agreement Refund Fuel Factor Adjustment (lines 15 & 20) are a subset of the Effective Jurisdictional Sales reported above on line 7.

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	33,430,835	33,430,835
Distribution Primary	4,013,650	3,973,513
Transmission	341,105	334,283
Total	37,785,590	37,738,631

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2015

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	Time of Use: On-Peak Multiplier 1.346	Time of Use: Off-Peak Multiplier 0.837
	FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):					
1.	Distribution Secondary	–	–	4.647	6.255	3.890
2.	Distribution Primary	–	–	4.601	6.193	3.851
3.	Transmission	–	–	4.554	6.130	3.812
4.	Lighting Service	–	–	4.332	–	–
	Line 4 calculated at secondary rate of 4.647 * (18.7% * On-Peak Multiplier 1.346 + 81.3% * Off-Peak Multiplier 0.837).					
	FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):					
5.	Distribution Secondary	4.323	5.323	4.598	6.189	3.849
	FUEL FACTORS (only GS-1, GST-1 & GS-2):					
6.	Distribution Secondary	–		4.605	6.198	3.854
7.	Distribution Primary	–	–	4.559	6.136	3.816
8.	Transmission	–	–	4.513	6.074	3.777

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-15	848,405	36,773,208	4.334	2,296,121	74,786,984	3.257	3,144,526	111,560,192	3.548
Feb-15	738,227	34,512,286	4.675	2,064,839	71,390,078	3.457	2,803,066	105,902,364	3.778
Mar-15	770,030	32,571,134	4.230	2,153,340	76,932,716	3.573	2,923,370	109,503,849	3.746
Apr-15	1,077,068	63,994,355	5.942	1,968,264	63,780,311	3.240	3,045,332	127,774,666	4.196
May-15	1,243,861	72,794,852	5.852	2,406,613	82,359,441	3.422	3,650,474	155,154,093	4.250
Jun-15	1,405,702	81,752,678	5.816	2,521,153	84,546,503	3.353	3,926,855	166,299,181	4.235
Jul-15	1,471,948	96,339,873	6.545	2,627,310	90,223,588	3.434	4,099,258	186,563,560	4.551
Aug-15	1,364,647	82,629,098	6.055	2,797,685	102,503,512	3.664	4,162,332	185,132,609	4.448
Sep-15	1,426,454	86,673,853	6.076	2,483,906	84,276,951	3.393	3,910,360	170,950,805	4.372
Oct-15	1,213,054	67,123,022	5.533	2,249,444	74,078,928	3.293	3,462,498	141,201,950	4.078
Nov-15	725,131	29,467,100	4.064	2,103,699	75,115,038	3.571	2,826,830	104,582,138	3.697
Dec-15	881,722	37,629,270	4.268	2,216,298	70,667,815	3.189	3,098,020	108,297,085	3.496
TOTAL	13,166,249	722,260,328	5.488	27,888,872	950,661,965	3.409	41,054,921	1,672,922,293	4.075

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1.346	0.837	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2013
Estimated for the Period of : January through December 2015

		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		344,867	(1,518)	343,349		0.9851266	348,533		
Distribution Primary		3,960,209	(17,395)	3,942,814		0.9751266	4,043,387		
Distribution Secondary		32,310,913	(142,218)	32,168,695		0.9360703	34,365,683		
Total Retail		36,615,989	(161,131)	36,454,858	97.21%	0.9405860	38,757,602	97.36%	1.00148
						5.94%			
Wholesale									
Generation Level		626,100	(22,884)	603,216		1.0000000	603,216		
Transmission		419,322	(2,872)	416,450		0.9851266	422,737		
Distribution Primary		26,079	(1,158)	24,921		0.9751266	25,557		
Distribution Secondary		-	-	-			-		
Total Wholesale		1,071,500	(26,914)	1,044,586	2.79%	0.9934159	1,051,510	2.64%	0.94822
						0.66%			
Subtotal Class		37,687,489	(188,045)	37,499,444	100.00%	0.9419814	39,809,112	100.00%	1.00000
						5.80%			
Non-Class									
SEPA	Transmission	30,736	-	30,736		0.9851266	31,200		
Homestead - Base	Generation	124,539	665	125,204		1.0000000	125,204		
SECI - Base	Generation	89,061	(3,692)	85,369		1.0000000	85,369		
Homestead - Intermediate	Generation	8,459	45	8,504		1.0000000	8,504		
Reedy Creek - Base	Generation	9,965	53	10,018		1.0000000	10,018		
Reedy Creek - Intermediate	Generation	99,225	530	99,755		1.0000000	99,755		
NSB - Peaking	Generation	9,446	50	9,496		1.0000000	9,496		
Tallahassee - Base	Transmission	8,482	45	8,527		0.9851266	8,656		
Gainesville - Base	Generation	37,083	198	37,281		1.0000000	37,281		
Interchange	Generation	426,503	-	426,503		1.0000000	426,503		
Company Use	Secondary	161,653	-	161,653		0.9360703	172,693		
Total Non-Class		1,005,153	(2,106)	1,003,047			1,014,680		
Total System		38,692,642	(190,151)	38,502,491		0.943139	40,823,791		

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2015

			Estimated Jan-15	Estimated Feb-15	Estimated Mar-15	Estimated Apr-15	Estimated May-15	Estimated Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	TOTAL
1	Fuel Cost of System Net Generation		$113,245,954	$100,531,367	$104,243,014	$113,277,405	$132,785,987	$138,880,328	$142,696,460	$144,773,035	$135,530,016	$120,355,860	$97,148,895	$108,082,070	$1,450,550,393
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(3,360,745)	(3,365,822)	(3,358,718)	(3,357,369)	(3,359,731)	(3,359,394)	(3,363,789)	(3,367,518)	(3,368,197)	(3,367,179)	(3,365,144)	(3,360,069)	(40,353,675)
2	Fuel Cost of Power Sold		(1,038,840)	(665,089)	(194,320)	(147,722)	(886,743)	(26,948)	(483,815)	(468,841)	(3,240)	(4,618)	(142,180)	(136,796)	(4,199,152)
2a	Gains on Power Sales		(228,545)	(146,320)	(42,750)	(32,498)	(195,084)	(5,928)	(106,439)	(103,146)	(712)	(1,016)	(31,280)	(30,095)	(923,813)
2b	Fuel Cost of Stratified Sales		(1,215,937)	(1,250,429)	(1,303,070)	(1,572,220)	(1,689,334)	(2,067,518)	(2,357,532)	(2,464,570)	(2,753,161)	(2,297,359)	(1,740,143)	(1,089,118)	(21,800,391)
3	Fuel Cost of Purchased Power (Excl Economy)		4,313,976	6,121,894	5,286,038	4,619,223	9,120,856	12,039,049	14,241,003	14,514,843	11,272,680	10,334,527	6,241,234	3,736,315	101,841,738
3a	Energy Payments to Qualifying Facilities		13,203,009	11,868,505	12,002,597	10,786,174	12,528,047	12,071,387	12,448,464	12,410,731	11,971,496	11,891,761	11,295,954	12,643,543	145,142,668
4	Energy Cost of Economy Purchases		541,062	427,832	1,175,780	1,389,895	1,794,295	2,086,429	1,379,450	1,487,857	2,579,449	1,905,474	939,971	644,380	16,351,874
5	Total System Fuel & Net Power Transactions		$125,459,934	$113,541,938	$117,808,571	$124,962,888	$150,099,293	$157,517,414	$164,453,801	$166,782,391	$156,228,333	$138,817,551	$110,347,317	$120,490,230	$1,646,609,662
6	Jurisdictional mWh Sold		3,053,112	2,711,625	2,630,887	2,855,086	2,850,830	3,443,184	3,787,779	3,680,235	3,748,879	3,503,048	2,952,685	2,768,240	37,785,590
7	Jurisdictional % of Total Sales		99.44%	99.29%	99.50%	99.54%	99.47%	99.48%	99.35%	99.24%	99.22%	99.25%	99.31%	99.46%	99.37%
8	Jurisdictional Fuel & Net Power Transactions		124,757,358	112,735,790	117,219,528	124,388,059	149,303,767	156,797,804	163,384,852	165,514,845	155,009,752	137,776,419	109,585,920	119,839,583	1,636,313,676
9	Jurisdictional Loss Multiplier		1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
10	Jurisdictional Fuel & Net Power Transactions		124,941,899	112,902,639	117,393,013	124,572,153	149,524,738	157,029,865	163,626,661	165,759,807	155,239,186	137,980,328	109,748,108	120,016,945	1,638,735,422
11	Adjustnd System Sales	mWh	3,070,268	2,731,256	2,643,916	2,867,455	2,866,060	3,461,116	3,812,375	3,706,258	3,778,362	3,529,488	2,973,079	2,783,380	38,025,012
12	System Cost per kWh Sold	c/kWh	4.0863	4.1571	4.4559	4.6847	5.2371	4.5539	4.3137	4.4976	4.1348	3.9331	3.7115	4.3289	4.3303
13	Jurisdictional Loss Multiplier	x	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
14	Jurisdictional Cost per kWh Sold	c/kWh	4.0923	4.1633	4.4624	4.6918	5.2450	4.5606	4.3199	4.5041	4.1409	3.9369	3.7168	4.3355	4.3369
15	Prior Period True-Up	+	0.2011	0.2264	0.2334	0.2312	0.2154	0.1783	0.1621	0.1668	0.1538	0.1753	0.2078	0.2218	0.1950
16	Total Jurisdictional Fuel Expense	c/kWh	4.2934	4.3897	4.6958	4.9231	5.4603	4.7389	4.4819	4.6709	4.3047	4.1141	3.9248	4.5573	4.5319
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	4.2965	4.3929	4.6992	4.9266	5.4642	4.7423	4.4852	4.6742	4.3078	4.1171	3.9278	4.5606	4.5352
19	GPIF	+	0.0051	0.0069	0.0071	0.0070	0.0065	0.0054	0.0049	0.0051	0.0050	0.0053	0.0063	0.0067	0.0059
20	Total Recovery Factor (rounded .001)	c/kWh	4.303	4.400	4.706	4.934	5.471	4.748	4.490	4.679	4.313	4.122	3.934	4.567	4.541

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2015

			Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
3	COAL		37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
4	GAS		74,987,317	65,153,020	65,740,975	76,341,745	95,207,574	98,625,108	476,055,739
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	113,245,954	100,531,367	104,243,014	113,277,405	132,785,987	136,880,328	700,964,055
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		565	513	74	21	16	129	1,318
10	COAL		1,028,298	957,458	1,050,974	982,603	993,270	1,014,726	6,027,329
11	GAS		1,778,960	1,483,660	1,502,028	1,735,327	2,229,801	2,359,104	11,088,880
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,807,823	2,441,631	2,553,076	2,717,951	3,223,087	3,373,959	17,117,527
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	3,381	2,924	1,590	1,173	2,011	2,121	13,200
17	COAL	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
18	GAS	MCF	13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
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		18,593	16,843	9,209	6,605	11,688	12,305	76,243
23	COAL		10,584,690	9,838,950	10,815,632	10,375,406	10,491,562	10,694,891	62,801,131
24	GAS		13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	23,993,389	21,093,278	22,190,470	23,823,783	27,943,217	28,932,472	147,976,609
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.02%	0.02%	0.00%	0.00%	0.00%	0.00%	0.01%
30	COAL		36.62%	39.21%	41.17%	36.15%	30.82%	30.08%	35.21%
31	GAS		63.36%	60.77%	58.83%	63.85%	69.18%	69.92%	64.78%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
37	COAL	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
38	GAS	$/MCF	5.60	5.80	5.78	5.68	5.46	5.41	5.59
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		22.00	22.07	22.45	23.20	22.32	22.21	22.26
43	COAL		3.57	3.56	3.54	3.55	3.56	3.55	3.55
44	GAS		5.60	5.80	5.78	5.68	5.46	5.41	5.59
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	4.72	4.77	4.70	4.76	4.75	4.73	4.74
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		34,678	33,027	124,446	324,048	729,250	95,388	58,060
50	COAL		10,293	10,276	10,291	10,559	10,563	10,540	10,419
51	GAS		7,526	7,574	7,567	7,746	7,821	7,726	7,674
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,545	8,639	8,692	8,765	8,670	8,575	8,645
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		76.27	72.88	279.34	751.91	1627.44	211.88	129.22
57	COAL		3.68	3.66	3.64	3.74	3.76	3.74	3.70
58	GAS		4.22	4.39	4.38	4.40	4.27	4.18	4.29
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	C/KWH	4.03	4.12	4.08	4.17	4.12	4.06	4.10

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2015

			Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
3	COAL		39,499,890	42,256,051	36,768,990	36,526,293	24,380,598	35,316,613	437,953,621
4	GAS		102,595,281	101,961,226	99,496,778	83,650,884	72,212,697	72,412,214	1,008,384,819
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	142,696,460	144,773,035	136,530,018	120,355,860	97,148,895	108,082,070	1,450,550,393
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		426	1,038	273	17	0	53	3,125
10	COAL		1,059,392	1,133,741	993,536	991,078	658,041	994,936	11,858,055
11	GAS		2,471,106	2,451,475	2,357,042	1,963,298	1,788,654	1,737,967	23,858,422
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,530,924	3,586,254	3,350,851	2,954,393	2,446,695	2,732,958	35,719,602
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	4,801	4,431	2,054	1,367	4,508	2,818	33,179
17	COAL	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
18	GAS	MCF	19,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,938,293
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		27,819	25,668	11,900	7,926	26,132	16,334	192,302
23	COAL		11,141,102	11,922,450	10,481,332	10,456,304	6,842,379	10,242,473	123,887,171
24	GAS		19,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,938,293
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	30,304,564	30,954,557	28,819,270	25,575,052	20,180,624	23,207,090	307,017,766
	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%	0.03%	0.01%	0.00%	0.00%	0.00%	0.01%
30	COAL		30.00%	31.61%	29.65%	33.55%	26.90%	36.41%	33.20%
31	GAS		69.99%	68.36%	70.34%	66.45%	73.11%	63.59%	66.79%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
37	COAL	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
38	GAS	$/MCF	5.36	5.36	5.43	5.54	5.42	5.59	5.51
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		21.61	21.65	22.21	22.54	21.26	21.63	21.90
43	COAL		3.55	3.54	3.51	3.49	3.56	3.45	3.54
44	GAS		5.36	5.37	5.43	5.54	5.43	5.59	5.51
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	4.71	4.68	4.74	4.71	4.81	4.66	4.73
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		65,303	24,728	43,590	466,235	0	308,189	61,537
50	COAL		10,517	10,516	10,550	10,550	10,398	10,295	10,448
51	GAS		7,744	7,753	7,775	7,697	7,443	7,450	7,668
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,583	8,631	8,601	8,657	8,248	8,492	8,595
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		141.15	53.54	96.79	1051.08	0.00	666.50	134.78
57	COAL		3.73	3.73	3.70	3.69	3.71	3.55	3.69
58	GAS		4.15	4.16	4.22	4.26	4.04	4.17	4.23
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	C/KWH	4.04	4.04	4.07	4.07	3.97	3.95	4.06

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-15

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAL 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 CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	376	4,950	1.8	89.72	47.0	10,588	COAL	2,130 TONS	24.61	52,411	374,480	7.57
3 CRYSTAL RIVER	2	500	120,074	32.3	95.46	33.8	11,028	COAL	53,822 TONS	24.60	1,324,210	5,984,111	4.98
4 CRYSTAL RIVER	4	732	437,485	80.3	77.02	85.3	10,250	COAL	194,267 TONS	23.08	4,483,998	15,333,967	3.51
5 CRYSTAL RIVER	5	712	465,809	87.9	96.03	91.5	10,142	COAL	204,668 TONS	23.08	4,724,071	16,135,138	3.46
6 ANCLOTE	1	517	0	0.0	91.64	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	521	0	0.0	99.01	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	98.71	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	92.90	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	73	0	0.0	96.13	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	517	26,506	6.9	91.64	34.6	10,824	GAS	288,914 MCF	1.00	288,914	2,015,529	7.60
12 ANCLOTE	2	521	90,375	23.3	99.01	23.3	10,847	GAS	980,299 MCF	1.00	980,299	5,099,012	5.64
13 AVON PARK	1-2	69	91	0.2	82.42	44.0	15,440	GAS	1,405 MCF	1.00	1,405	7,405	8.14
14 BARTOW	1-4	228	497	0.3	92.74	24.7	13,280	GAS	6,600 MCF	1.00	6,600	36,296	7.30
15 BARTOW CC	1	1279	690,976	72.6	85.81	76.1	7,160	GAS	4,947,316 MCF	1.00	4,947,316	27,987,679	4.05
16 DEBARY	1-10	785	2,355	0.4	96.74	12.0	12,536	GAS	29,522 MCF	1.00	29,522	168,284	7.06
17 HIGGINS	1-4	129	264	0.3	92.66	22.7	16,451	GAS	4,343 MCF	1.00	4,343	23,562	8.93
18 HINES CC	1-4	2,204	874,407	53.3	83.25	21.6	7,102	GAS	6,210,030 MCF	1.00	6,210,030	34,450,302	3.94
19 INT CITY	1-14	1,186	7,638	0.9	88.39	8.0	12,447	GAS	95,067 MCF	1.00	95,067	547,231	7.16
20 SUWANNEE	1	67	633	1.3	97.10	944.8	12,404	GAS	7,852 MCF	1.00	7,852	168,979	26.69
21 SUWANNEE	2	66	290	0.6	99.35	31.4	15,845	GAS	4,595 MCF	1.00	4,595	144,425	49.80
22 SUWANNEE	3	67	24,629	49.4	99.03	51.4	12,102	GAS	298,065 MCF	1.00	298,065	1,458,995	5.92
23 TIGER BAY CC	1	225	25,624	15.3	86.39	99.9	7,422	GAS	190,186 MCF	1.00	190,186	1,012,605	3.95
24 UNIV OF FLA. CC	1	47	34,875	99.2	97.10	102.2	9,428	GAS	326,912 MCF	1.00	326,912	1,869,013	5.39
25 AVON PARK	1-2	69	0	0.0	82.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	228	9	0.3	92.74	0.0	14,000	LIGHT OIL	22 BBLS	5.73	126	3,197	35.52
27 BAYBORO	1-4	231	6	0.0	96.13	0.0	13,167	LIGHT OIL	14 BBLS	5.64	79	1,853	30.88
28 DEBARY	1-10	785	189	0.4	96.74	162.0	13,048	LIGHT OIL	425 BBLS	5.80	2,466	60,172	31.84
29 HIGGINS	1-4	129	0	0.0	92.66	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	1,186	293	0.9	88.39	111.5	13,642	LIGHT OIL	689 BBLS	5.80	3,997	86,141	30.08
32 RIO PINAR	1	16	0	0.0	98.71	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	200	68	0.0	98.49	1.7	12,882	LIGHT OIL	151 BBLS	5.80	876	20,860	30.68
34 TURNER	1-4	198	0	0.0	72.34	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,000 BBLS	5.79	12,048	258,025	0.00
36 TOTAL			2,807,823								23,993,389	113,245,154	4.03

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	378	0	0.0	94.29	0.0	0	COAL	0 TONS	0.00	0	143,306	0.00
3	CRYSTAL RIVER	2	500	115,192	34.3	90.38	37.6	10,896	COAL	51,013 TONS	24.60	1,255,090	5,802,088	4.86
4	CRYSTAL RIVER	4	732	417,409	84.9	95.71	87.7	10,244	COAL	185,464 TONS	23.05	4,275,777	14,575,878	3.49
5	CRYSTAL RIVER	5	712	424,857	88.8	95.39	92.8	10,140	COAL	186,865 TONS	23.05	4,308,083	14,683,212	3.46
6	ANCLOTE	1	517	0	0.0	94.89	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	98.91	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.14	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.78	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.79	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	22,287	6.4	94.89	52.6	10,275	GAS	228,988 MCF	1.00	228,988	1,973,938	8.41
12	ANCLOTE	2	521	91,842	26.2	98.91	26.2	10,676	GAS	980,525 MCF	1.00	980,525	5,218,277	5.68
13	AVON PARK	1-2	69	63	0.1	77.50	45.7	15,381	GAS	969 MCF	1.00	969	5,314	8.43
14	BARTOW	1-4	228	380	0.3	92.86	24.3	13,205	GAS	5,018 MCF	1.00	5,018	28,363	7.46
15	BARTOW CC	1	1279	422,229	49.1	96.43	50.9	7,334	GAS	3,096,700 MCF	1.00	3,096,700	18,267,920	4.33
16	DEBARY	1-10	785	1,722	0.4	97.04	12.7	12,454	GAS	21,445 MCF	1.00	21,445	126,844	7.37
17	HIGGINS	1-4	129	192	0.2	91.79	24.8	16,188	GAS	3,108 MCF	1.00	3,108	18,478	9.62
18	HINES CC	1-4	2,204	861,264	56.2	95.89	23.2	7,062	GAS	8,082,310 MCF	1.00	8,082,310	34,723,781	4.03
19	INT CITY	1-14	1,186	5,564	0.7	88.39	8.2	12,387	GAS	68,920 MCF	1.00	68,920	422,076	7.59
20	SUWANNEE	1	67	469	1.0	95.71	0.0	12,264	GAS	5,752 MCF	1.00	5,752	163,510	34.86
21	SUWANNEE	2	66	251	0.5	99.29	31.7	15,590	GAS	3,913 MCF	1.00	3,913	147,425	58.74
22	SUWANNEE	3	67	22,353	49.6	99.29	51.3	12,064	GAS	269,664 MCF	1.00	269,664	1,337,357	5.98
23	TIGER BAY CC	1	225	23,825	15.8	89.64	101.8	7,377	GAS	175,767 MCF	1.00	175,767	1,079,233	4.53
24	UNIV OF FLA. CC	1	47	31,219	98.8	96.79	102.2	9,427	GAS	294,306 MCF	1.00	294,306	1,740,506	5.58
25	AVON PARK	1-2	69	0	0.0	77.50	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	8	0.3	92.86	0.0	13,500	LIGHT OIL	19 BBLS	5.68	108	2,795	34.94
27	BAYBORO	1-4	231	6	0.0	94.82	0.0	13,167	LIGHT OIL	14 BBLS	5.64	79	1,847	30.78
28	DEBARY	1-10	785	165	0.4	97.04	21.0	12,345	LIGHT OIL	351 BBLS	5.80	2,037	50,867	30.83
29	HIGGINS	1-4	129	0	0.0	91.79	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	284	0.7	88.39	82.2	13,183	LIGHT OIL	647 BBLS	5.79	3,744	83,090	29.26
32	RIO PINAR	1	16	0	0.0	98.57	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	200	50	0.0	98.10	1.6	13,120	LIGHT OIL	113 BBLS	5.81	656	16,026	32.05
34	TURNER	1-4	199	0	0.0	72.68	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP			0	-	0.00	0.0	0	LIGHT OIL	1,760 BBLS	5.80	10,319	218,525	0.00
36	TOTAL			2,441,631								21,093,278	100,531,367	4.12

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-15

(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 CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	376	2,514	0.9	52.72	51.4	10,493	COAL	1,072 TONS	24.61	26,380	256,410	10.20
3 CRYSTAL RIVER	2	500	137,494	37.0	94.24	38.5	10,889	COAL	60,856 TONS	24.60	1,497,226	5,562,609	4.77
4 CRYSTAL RIVER	4	732	432,150	79.4	92.57	85.1	10,260	COAL	192,497 TONS	23.03	4,433,605	15,036,210	3.48
5 CRYSTAL RIVER	5	712	478,816	90.4	98.60	91.2	10,146	COAL	210,923 TONS	23.03	4,858,221	16,440,101	3.43
6 ANCLOTE	1	517	0	0.0	94.38	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	521	0	0.0	94.48	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	33.55	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	92.73	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	73	0	0.0	95.19	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	517	1,283	0.3	94.38	49.6	10,469	GAS	13,432 MCF	1.00	13,432	865,117	67.43
12 ANCLOTE	2	521	110,263	28.4	94.48	29.6	10,548	GAS	1,162,999 MCF	1.00	1,162,999	5,963,447	5.41
13 AVON PARK	1-2	69	7	0.0	79.35	0.0	15,429	GAS	108 MCF	1.00	108	537	7.67
14 BARTOW	1-4	228	176	0.1	93.47	25.7	13,227	GAS	2,328 MCF	1.00	2,328	12,779	7.26
15 BARTOW CC	1	1279	377,082	39.6	62.58	41.8	7,441	GAS	2,806,054 MCF	1.00	2,806,054	16,517,888	4.38
16 DEBARY	1-10	785	624	0.1	96.42	11.4	12,447	GAS	7,767 MCF	1.00	7,767	45,391	7.27
17 HIGGINS	1-4	129	71	0.1	90.73	27.5	16,183	GAS	1,149 MCF	1.00	1,149	5,248	7.39
18 HINES CC	1-4	2,204	928,004	56.6	79.11	22.9	7,051	GAS	6,543,362 MCF	1.00	6,543,362	37,502,013	4.04
19 INT CITY	1-14	1,186	6,385	0.7	94.17	7.4	12,380	GAS	79,044 MCF	1.00	79,044	439,875	6.89
20 SUWANNEE	1	67	2,044	4.1	96.13	34.3	14,312	GAS	29,254 MCF	1.00	29,254	277,154	13.56
21 SUWANNEE	2	66	1,606	3.3	99.88	29.0	14,865	GAS	23,873 MCF	1.00	23,873	248,426	15.47
22 SUWANNEE	3	67	21,048	42.2	99.03	50.9	12,077	GAS	254,201 MCF	1.00	254,201	1,274,233	6.05
23 TIGER BAY CC	1	225	30,395	18.2	88.71	100.8	7,400	GAS	224,923 MCF	1.00	224,923	1,308,539	4.31
24 UNIV OF FLA. CC	1	47	23,040	65.9	100.00	102.1	9,424	GAS	217,135 MCF	1.00	217,135	1,280,328	5.56
25 AVON PARK	1-2	69	0	0.0	79.35	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	228	0	0.0	93.47	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	231	3	0.0	95.16	0.0	18,667	LIGHT OIL	10 BBLS	5.60	56	1,339	44.63
28 DEBARY	1-10	785	0	0.0	96.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29 HIGGINS	1-4	129	0	0.0	90.73	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	1,186	51	0.7	94.17	542.7	14,255	LIGHT OIL	126 BBLS	5.77	727	19,309	37.86
32 RIO PINAR	1	16	0	0.0	98.39	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	200	20	0.0	98.28	0.8	14,900	LIGHT OIL	51 BBLS	5.84	298	6,439	32.20
34 TURNER	1-4	199	0	0.0	72.82	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35 OTHER & START UP		-	0		0.00	0.0	0	LIGHT OIL	1,403 BBLS	5.79	8,128	171,419	0.00
36 TOTAL			2,553,076								22,190,470	104,243,014	4.08

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-15

(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 (¢/KWH)
1 CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	376	8,723	3.2	88.51	59.5	10,542	COAL	3,738 TONS	24.60	91,961	533,303	6.11
3 CRYSTAL RIVER	2	500	138,581	38.5	97.70	38.9	11,051	COAL	62,242 TONS	24.60	1,531,274	8,837,269	4.79
4 CRYSTAL RIVER	4	732	429,741	81.5	98.44	82.3	10,445	COAL	195,013 TONS	23.02	4,488,661	15,174,956	3.53
5 CRYSTAL RIVER	5	712	405,578	79.1	96.70	81.6	10,512	COAL	185,229 TONS	23.02	4,263,490	14,432,221	3.56
6 ANCLOTE	1	517	0	0.0	64.99	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	521	0	0.0	95.31	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	97.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	31.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	73	0	0.0	81.54	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	517	70,619	19.0	64.99	54.2	10,437	GAS	737,056 MCF	1.00	737,056	4,609,589	6.53
12 ANCLOTE	2	521	143,123	38.2	95.31	39.5	10,627	GAS	1 520,923 MCF	1.00	1,520,923	8,162,074	5.70
13 AVON PARK	1-2	69	0	0.0	79.00	0.0	0	GAS	0 MCF	0.00	0	0	0.00
14 BARTOW	1-4	228	0	0.0	92.00	0.0	0	GAS	0 MCF	0.00	0	866	0.00
15 BARTOW CC	1	1279	346,146	37.6	46.33	39.7	7,679	GAS	2,658,155 MCF	1.00	2,658,155	15,218,183	4.40
16 DEBARY	1-10	785	137	0.0	95.63	8.7	13,102	GAS	1,795 MCF	1.00	1,795	9,278	6.77
17 HIGGINS	1-4	129	8	0.0	89.75	0.0	17,125	GAS	137 MCF	1.00	137	677	8.46
18 HINES CC	1-4	2,204	1,018,489	64.1	70.54	22.7	7,005	GAS	7,120,092 MCF	1.00	7,120,092	40,418,979	3.98
19 INT CITY	1-14	1,186	5,855	0.7	94.46	6.3	12,977	GAS	75,983 MCF	1.00	75,983	438,676	7.50
20 SUWANNEE	1	67	7,534	15.6	95.33	26.5	14,794	GAS	111,461 MCF	1.00	111,461	630,727	8.37
21 SUWANNEE	2	66	7,612	16.0	99.33	29.0	14,870	GAS	113,194 MCF	1.00	113,194	637,363	8.37
22 SUWANNEE	3	67	9,804	20.3	99.00	51.2	12,376	GAS	121,334 MCF	1.00	121,334	674,910	6.88
23 TIGER BAY CC	1	225	97,587	60.2	88.33	101.8	7,117	GAS	694,564 MCF	1.00	694,564	3,888,664	3.98
24 UNIV OF FLA. CC	1	47	30,413	89.9	64.44	102.1	9,433	GAS	286,878 MCF	1.00	286,878	1,851,559	5.43
25 AVON PARK	1-2	69	3	0.0	79.00	0.0	19,667	LIGHT OIL	10 BBLS	5.90	59	1,308	43.60
26 BARTOW	1-4	228	0	0.0	92.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	231	0	0.0	95.25	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28 DEBARY	1-10	785	0	0.0	95.63	0.0	0	LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29 HIGGINS	1-4	129	0	0.0	89.75	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	1,186	3	0.7	94.46	0.0	16,000	LIGHT OIL	8 BBLS	6.00	48	4,458	148.60
32 RIO PINAR	1	16	0	0.0	98.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	200	15	0.0	97.89	3.8	15,667	LIGHT OIL	40 BBLS	5.88	235	6,894	45.96
34 TURNER	1-4	199	0	0.0	72.17	0.0	0	LIGHT OIL	0 BBLS	0.00	0	852	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,115 BBLS	5.80	6,483	136,918	*0.00*
36 TOTAL			2,717,951								23,823,783	113,277,405	4.17

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: May-15

	(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	CRYS RIV NUC	3	0	0	0.0	0.00	0.0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	19,749	7.1	92.77	56.0	10,593	COAL	8,503 TONS	24.60	209,195	1,021,121	5.17
3	CRYSTAL RIVER	2	484	158,333	43.1	94.92	43.9	10,933	COAL	70,360 TONS	24.60	1,730,864	7,406,780	4.68
4	CRYSTAL RIVER	4	722	418,739	78.0	94.58	81.9	10,454	COAL	190,279 TONS	23.01	4,377,450	14,780,037	3.53
5	CRYSTAL RIVER	5	700	396,449	76.1	93.76	80.8	10,528	COAL	181,432 TONS	23.01	4,173,933	14,110,084	3.56
6	ANCLOTE	1	501	0	0.0	62.10	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	96.43	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	97.10	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	96.13	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	39.35	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	144,485	38.8	62.10	50.9	10,481	GAS	1,511,488 MCF	1.00	1,511,488	8,285,473	5.73
12	ANCLOTE	2	510	167,694	44.2	96.43	45.4	10,482	GAS	1,757,822 MCF	1.00	1,757,822	9,367,372	5.59
13	AVON PARK	1-2	49	59	0.2	78.87	20.1	23,780	GAS	1,403 MCF	1.00	1,403	6,220	10.54
14	BARTOW	1-4	177	146	0.1	92.74	28.1	13,952	GAS	2,037 MCF	1.00	2,037	9,823	6.73
15	BARTOW CC	1	1159	662,747	76.9	48.39	79.4	7,330	GAS	4,858,129 MCF	1.00	4,858,129	26,290,293	3.97
16	DEBARY	1-10	645	2,042	0.4	96.48	9.9	13,359	GAS	27,279 MCF	1.00	27,279	134,126	6.57
17	HIGGINS	1-4	113	96	0.1	91.53	10.6	22,313	GAS	2,142 MCF	1.00	2,142	9,520	9.92
18	HINES CC	1-4	1,912	1,074,738	75.6	72.66	23.2	7,148	GAS	7,382,239 MCF	1.00	7,682,239	42,321,060	3.94
19	INT CITY	1-14	987	19,960	2.7	93.96	7.1	13,016	GAS	259,797 MCF	1.00	259,797	1,369,304	6.86
20	SUWANNEE	1	52	187	0.5	94.52	0.0	13,198	GAS	2,468 MCF	1.00	2,468	127,378	68.12
21	SUWANNEE	2	50	518	1.4	99.68	38.4	15,266	GAS	7,908 MCF	1.00	7,908	149,609	28.88
22	SUWANNEE	3	51	24,048	63.4	98.71	67.3	12,315	GAS	296,158 MCF	1.00	296,158	1,416,703	5.89
23	TIGER BAY CC	1	204	101,221	66.7	87.74	99.8	7,218	GAS	730,585 MCF	1.00	730,585	4,054,263	4.01
24	UNIV OF FLA. CC	1	46	31,860	93.1	85.48	97.8	9,433	GAS	300,532 MCF	1.00	300,532	1,666,130	5.23
25	AVON PARK	1-2	49	0	0.0	78.87	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	177	3	0.1	92.74	0.0	21,667	LIGHT OIL	11 BBLS	5.91	65	1,850	61.67
27	BAYBORO	1-4	174	0	0.0	95.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	4	0.4	96.48	0.0	18,000	LIGHT OIL	12 BBLS	6.00	72	9,019	225.48
29	HIGGINS	1-4	113	0	0.0	91.53	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	6	2.7	93.96	0.0	16,000	LIGHT OIL	16 BBLS	6.00	96	5,464	91.07
32	RIO PINAR	1	12	0	0.0	97.74	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	3	0.0	97.63	0.2	16,333	LIGHT OIL	8 BBLS	6.13	49	2,855	95.17
34	TURNER	1-4	149	0	0.0	73.23	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP			0	-	0.00	0.0	0	LIGHT OIL	1,964 BBLS	5.80	11,388	240,370	0.00
36	TOTAL			3,223,087								27,943,217	132,785,987	4.12

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0.0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	33,029	12.2	94.33	55.0	10,602	COAL	14,234 TONS	24.60	350,163	1,599,669	4.84
3	CRYSTAL RIVER	2	494	156,233	43.9	96.68	45.1	10,907	COAL	69,268 TONS	24.60	1,704,081	7,230,751	4.63
4	CRYSTAL RIVER	4	722	419,603	80.7	95.96	83.3	10,438	COAL	190,425 TONS	23.00	4,379,088	14,788,962	3.52
5	CRYSTAL RIVER	5	700	405,861	80.5	96.55	83.1	10,500	COAL	185,314 TONS	23.00	4,261,559	14,382,513	3.54
6	ANCLOTE	1	501	0	0.0	95.19	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	94.32	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	95.33	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	99.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	128,401	35.6	95.19	52.1	10,387	GAS	1,333,755 MCF	1.00	1,333,755	7,333,109	5.71
12	ANCLOTE	2	510	158,715	43.2	94.32	45.5	10,489	GAS	1,664,776 MCF	1.00	1,664,776	8,783,643	5.53
13	AVON PARK	1-2	49	78	0.2	77.17	33.1	19,692	GAS	1,536 MCF	1.00	1,536	7,075	9.07
14	BARTOW	1-4	177	478	0.4	92.25	19.3	15,151	GAS	7,242 MCF	1.00	7,242	35,139	7.35
15	BARTOW CC	1	1159	689,312	82.6	92.67	84.6	7,302	GAS	5,033,078 MCF	1.00	5,033,078	26,967,457	3.91
16	DEBARY	1-10	645	2,522	0.6	96.87	10.1	13,384	GAS	33,754 MCF	1.00	33,754	174,569	6.92
17	HIGGINS	1-4	113	402	0.5	90.75	12.3	20,366	GAS	8,195 MCF	1.00	8,195	37,741	9.39
18	HINES CC	1-4	1,912	1,209,729	87.9	83.85	23.5	7,123	GAS	8,617,096 MCF	1.00	8,617,096	46,994,294	3.88
19	INT CITY	1-14	987	16,865	2.4	95.10	7.3	12,963	GAS	218,873 MCF	1.00	218,873	1,171,534	6.94
20	SUWANNEE	1	52	608	1.6	94.00	233.8	13,931	GAS	8,470 MCF	1.00	8,470	154,508	25.41
21	SUWANNEE	2	50	892	2.5	99.33	38.8	15,124	GAS	13,491 MCF	1.00	13,491	172,462	19.33
22	SUWANNEE	3	51	24,781	67.5	99.33	67.7	12,311	GAS	305,070 MCF	1.00	305,070	1,453,648	5.87
23	TIGER BAY CC	1	204	94,441	64.3	90.33	100.0	7,196	GAS	679,579 MCF	1.00	679,579	3,693,869	3.91
24	UNIV OF FLA. CC	1	46	31,860	96.2	98.33	97.8	9,428	GAS	300,361 MCF	1.00	300,361	1,646,060	5.17
25	AVON PARK	1-2	49	3	0.2	77.17	0.0	19,667	LIGHT OIL	10 BBLS	5.90	59	1,301	43.37
26	BARTOW	1-4	177	0	0.0	92.25	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	174	0	0.0	96.08	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	95	0.6	96.87	202.9	15,000	LIGHT OIL	245 BBLS	5.82	1,425	37,685	39.67
29	HIGGINS	1-4	113	0	0.0	90.75	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	0	0.0	95.10	0.0	0	LIGHT OIL	0 BBLS	0.00	0	3,444	0.00
32	RIO PINAR	1	12	0	0.0	97.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	31	0.0	97.56	1.0	14,710	LIGHT OIL	78 BBLS	5.85	456	11,640	37.55
34	TURNER	1-4	149	0	0.0	72.92	0.0	0	LIGHT OIL	0 BBLS	0.00	0	852	0.00
35	OTHER & START UP			0	-	0.00	0.0	0	LIGHT OIL	1,788 BBLS	5.80	10,365	218,422	0.00
36	TOTAL			3,373,959								28,932,472	136,880,328	4.06

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-15

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	375	45,478	16.3	96.91	53.9	10,620	COAL	19,631 TONS	24.60	482,941	2,140,920	4.71
3 CRYSTAL RIVER	2	494	166,276	45.2	97.74	46.3	10,886	COAL	73,575 TONS	24.60	1,810,021	7,630,191	4.59
4 CRYSTAL RIVER	4	722	423,916	78.9	90.68	86.1	10,405	COAL	191,839 TONS	22.99	4,410,646	14,820,409	3.50
5 CRYSTAL RIVER	5	700	423,724	81.4	94.56	85.5	10,473	COAL	193,007 TONS	22.99	4,437,494	14,908,370	3.52
6 ANCLOTE	1	501	0	0.0	94.80	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	510	0	0.0	98.77	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	97.10	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	97.74	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	71	0	0.0	95.48	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	501	139,705	37.5	94.80	52.4	10,410	GAS	1,454,262 MCF	1.00	1,454,262	7,880,296	5.64
12 ANCLOTE	2	510	171,114	45.1	96.77	46.5	10,456	GAS	1,789,158 MCF	1.00	1,789,158	9,351,829	5.47
13 AVON PARK	1-2	49	58	0.2	81.61	32.1	19,034	GAS	1,104 MCF	1.00	1,104	5,245	9.04
14 BARTOW	1-4	177	506	0.4	92.82	21.1	14,828	GAS	7,503 MCF	1.00	7,503	36,388	7.19
15 BARTOW CC	1	1,159	716,056	83.0	97.10	85.8	7,300	GAS	5,226,924 MCF	1.00	5,226,924	27,775,043	3.88
16 DEBARY	1-10	645	3,427	0.8	96.68	10.5	13,373	GAS	45,828 MCF	1.00	45,828	240,392	7.01
17 HIGGINS	1-4	113	219	0.3	91.85	16.2	18,155	GAS	3,976 MCF	1.00	3,976	19,695	8.99
18 HINES CC	1-4	1,912	1,281,043	88.6	94.98	23.8	7,117	GAS	8,974,914 MCF	1.00	8,974,914	46,460,832	3.84
19 INT CITY	1-14	987	22,303	3.0	88.89	7.2	12,980	GAS	289,495 MCF	1.00	289,495	1,548,125	6.93
20 SUWANNEE	1	52	932	2.4	94.52	162.9	14,023	GAS	13,069 MCF	1.00	13,069	168,018	18.03
21 SUWANNEE	2	50	699	1.9	99.68	38.8	15,363	GAS	10,739 MCF	1.00	10,739	152,685	21.84
22 SUWANNEE	3	51	24,856	65.5	98.39	66.6	12,314	GAS	306,086 MCF	1.00	306,086	1,454,959	5.85
23 TIGER BAY CC	1	204	97,898	64.5	88.08	99.8	7,233	GAS	708,077 MCF	1.00	708,077	3,854,213	3.94
24 UNIV OF FLA. CC	1	46	32,292	94.4	86.45	97.8	9,430	GAS	304,509 MCF	1.00	304,509	1,649,551	5.11
25 AVON PARK	1-2	49	5	0.2	81.61	0.0	15,400	LIGHT OIL	13 BBLS	5.92	77	1,678	33.56
26 BARTOW	1-4	177	17	0.4	92.82	0.0	13,941	LIGHT OIL	41 BBLS	5.78	237	8,017	35.39
27 BAYBORO	1-4	174	54	0.0	95.97	15.5	14,611	LIGHT OIL	137 BBLS	5.76	789	17,269	31.98
28 DEBARY	1-10	645	215	0.8	96.68	112.9	14,158	LIGHT OIL	525 BBLS	5.80	3,044	71,897	33.44
29 HIGGINS	1-4	113	0	0.0	91.85	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	987	65	3.0	88.89	2266.3	13,954	LIGHT OIL	156 BBLS	5.81	907	22,478	34.58
32 RIO PINAR	1	12	0	0.0	96.06	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	153	54	0.0	97.53	1.3	14,056	LIGHT OIL	131 BBLS	5.79	759	18,158	33.63
34 TURNER	1-4	149	16	0.0	72.98	0.0	16,563	LIGHT OIL	46 BBLS	5.76	265	6,259	39.12
35 OTHER & START UP		-	0		0.00	0.0	0	LIGHT OIL	3,752 BBLS	5.79	21,741	457,474	0.00
36 TOTAL			5,530,924								30,304,584	142,656,460	4.04

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-15

(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 CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	375	91,113	32.7	91.71	51.9	10,855	COAL	39,461 TONS	24.60	970,781	4,138,960	4.54
3 CRYSTAL RIVER	2	494	157,850	42.9	92.65	45.1	10,910	COAL	70,005 TONS	24.60	1,722,164	7,231,625	4.58
4 CRYSTAL RIVER	4	722	445,219	82.9	94.99	86.5	10,400	COAL	201,426 TONS	22.99	4,630,309	15,493,534	3.48
5 CRYSTAL RIVER	5	700	439,559	84.4	97.63	88.0	10,463	COAL	200,072 TONS	22.99	4,599,196	15,391,812	3.50
6 ANCLOTE	1	501	0	0.0	90.18	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	510	0	0.0	95.54	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	98.06	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	98.06	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	71	0	0.0	99.03	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	501	163,239	43.8	90.18	46.3	10,473	GAS	1,709,639 MCF	1.00	1,709,639	8,986,322	5.51
12 ANCLOTE	2	510	137,129	36.1	95.54	48.1	10,500	GAS	1,439,807 MCF	1.00	1,439,807	7,799,601	5.69
13 AVON PARK	1-2	49	167	0.5	78.55	28.4	19,557	GAS	3,266 MCF	1.00	3,266	15,402	9.22
14 BARTOW	1-4	177	585	0.7	92.58	21.3	14,825	GAS	13,266 MCF	1.00	13,266	65,452	7.31
15 BARTOW CC	1	1,159	711,024	82.5	98.77	86.2	7,298	GAS	5,188,842 MCF	1.00	5,188,842	27,545,882	3.87
16 DEBARY	1-10	645	3,485	0.9	96.19	12.3	13,208	GAS	46,029 MCF	1.00	46,029	244,105	7.00
17 HIGGINS	1-4	113	847	0.8	91.37	15.9	18,162	GAS	11,751 MCF	1.00	11,751	57,363	6.87
18 HINES CC	1-4	1,912	1,249,935	87.9	94.99	23.6	7,126	GAS	8,907,342 MCF	1.00	8,907,342	48,105,635	3.85
19 INT CITY	1-14	987	23,896	3.3	88.02	7.3	12,952	GAS	309,506 MCF	1.00	309,506	1,667,839	7.06
20 SUWANNEE	1	62	792	2.0	92.90	126.9	13,855	GAS	10,973 MCF	1.00	10,973	167,308	21.12
21 SUWANNEE	2	50	712	1.9	99.35	39.5	15,277	GAS	10,877 MCF	1.00	10,877	158,590	22.27
22 SUWANNEE	3	51	25,875	68.2	98.88	68.8	12,309	GAS	318,497 MCF	1.00	318,497	1,519,237	5.87
23 TIGER BAY CC	1	204	100,739	66.4	98.77	100.0	7,208	GAS	726,082 MCF	1.00	726,082	3,929,190	3.90
24 UNIV OF FLA. CC	1	46	32,940	96.2	98.39	97.8	9,428	GAS	310,560 MCF	1.00	310,560	1,679,300	5.10
25 AVON PARK	1-2	49	0	0.0	78.55	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	177	9	0.7	92.58	0.0	13,222	LIGHT OIL	21 BBLS	5.67	119	3,018	33.53
27 BAYBORO	1-4	174	0	0.0	96.13	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28 DEBARY	1-10	645	724	0.9	96.19	36.3	13,518	LIGHT OIL	1,685 BBLS	5.79	9,787	214,448	29.62
29 HIGGINS	1-4	113	0	0.0	91.37	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	987	177	3.3	88.02	487.8	14,192	LIGHT OIL	434 BBLS	5.79	2,512	56,127	31.71
32 RIO PINAR	1	12	0	0.0	98.06	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	153	128	0.1	97.31	3.1	13,438	LIGHT OIL	297 BBLS	5.79	1,720	38,855	30.36
34 TURNER	1-4	149	0	0.0	72.98	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35 OTHER & START UP		-	0	-	0.0	0.0	0	LIGHT OIL	1,990 BBLS	5.79	11,530	242,470	0.00
36 TOTAL			3,588,254								3,954,557	144,773,035	4.03

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-15

	(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	CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	14,772	5.5	96.00	54.7	10,804	COAL	6,368 TONS	24.60	156,647	788,291	5.32
3	CRYSTAL RIVER	2	494	156,358	44.0	94.70	45.8	10,894	COAL	69,243 TONS	24.60	1,703,423	7,135,303	4.56
4	CRYSTAL RIVER	4	722	417,571	80.3	96.52	82.9	10,449	COAL	189,834 TONS	22.98	4,363,298	14,595,405	3.50
5	CRYSTAL RIVER	5	700	404,835	80.3	97.45	81.9	10,518	COAL	185,252 TONS	22.98	4,257,964	14,251,991	3.52
6	ANCLOTE	1	501	0	0.0	98.32	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	97.53	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	98.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	97.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	174,098	48.3	96.32	49.2	10,399	GAS	1,810,442 MCF	1.00	1,810,442	9,554,843	5.49
12	ANCLOTE	2	510	152,237	41.5	97.53	46.8	10,453	GAS	1,591,297 MCF	1.00	1,591,297	8,591,701	5.64
13	AVON PARK	1-2	49	37	0.1	79.50	25.2	19,811	GAS	733 MCF	1.00	733	3,499	9.46
14	BARTOW	1-4	177	341	0.3	93.75	19.3	15,413	GAS	5,256 MCF	1.00	5,256	24,904	7.30
15	BARTOW CC	1	1,159	677,261	81.2	98.67	84.0	7,321	GAS	4,957,912 MCF	1.00	4,957,912	26,704,919	3.94
16	DEBARY	1-10	645	1,391	0.4	96.07	11.5	13,487	GAS	18,761 MCF	1.00	18,761	92,238	6.63
17	HIGGINS	1-4	113	209	0.3	91.42	12.3	19,967	GAS	4,173 MCF	1.00	4,173	19,343	9.26
18	HINES CC	1-4	1,912	1,173,790	85.3	94.80	23.0	7,152	GAS	8,395,161 MCF	1.00	8,395,161	46,159,968	3.93
19	INT CITY	1-14	987	15,761	2.2	88.76	7.2	13,047	GAS	205,636 MCF	1.00	205,636	1,025,486	6.51
20	SUWANNEE	1	52	181	0.5	96.00	87.0	14,210	GAS	2,572 MCF	1.00	2,572	125,495	69.33
21	SUWANNEE	2	50	222	0.6	99.33	40.4	15,221	GAS	3,379 MCF	1.00	3,379	127,293	57.34
22	SUWANNEE	3	51	24,352	66.3	98.67	68.4	12,343	GAS	300,587 MCF	1.00	300,587	1,434,710	5.89
23	TIGER BAY CC	1	204	118,460	80.7	92.67	99.8	7,207	GAS	853,877 MCF	1.00	853,877	4,660,313	3.93
24	UNIV OF FLA. CC	1	46	18,564	56.4	96.11	97.9	9,433	GAS	176,252 MCF	1.00	176,252	972,066	5.20
25	AVON PARK	1-2	49	0	0.0	79.50	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26	BARTOW	1-4	177	0	0.0	93.75	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	174	0	0.0	95.33	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28	DEBARY	1-10	645	247	0.4	96.07	36.3	14,462	LIGHT OIL	617 BBLS	5.79	3,572	83,004	33.60
29	HIGGINS	1-4	113	0	0.0	91.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	12	2.2	88.76	0.0	14,417	LIGHT OIL	30 BBLS	5.77	173	7,071	58.93
32	RIO PINAR	1	12	0	0.0	96.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33	SUWANNEE	1-3	153	14	0.0	98.00	0.5	13,571	LIGHT OIL	32 BBLS	5.94	190	5,867	42.05
34	TURNER	1-4	149	0	0.0	72.17	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,375 BBLS	5.79	7,965	187,455	0.00
36	TOTAL			3,350,851								28,819,270	136,530,018	4.07

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-15

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	375	8,968	3.2	94.52	53.1	10,630	COAL	3,875 TONS	24.80	95,332	534,478	5.96
3 CRYSTAL RIVER	2	484	148,636	40.4	94.53	42.5	10,966	COAL	68,259 TONS	24.80	1,630,012	6,831,663	4.60
4 CRYSTAL RIVER	4	722	433,344	80.7	96.67	83.1	10,442	COAL	196,878 TONS	22.98	4,524,765	15,098,565	3.48
5 CRYSTAL RIVER	5	700	400,130	76.8	96.65	81.9	10,512	COAL	183,017 TONS	22.98	4,206,186	14,061,587	3.51
6 ANCLOTE	1	501	0	0.0	98.71	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	510	0	0.0	94.90	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.84	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	71	0	0.0	96.45	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	501	159,483	42.8	98.71	43.6	10,540	GAS	1,680,911 MCF	1.00	1,680,911	8,448,237	5.30
12 ANCLOTE	2	510	2,449	0.6	94.90	43.7	10,752	GAS	26,331 MCF	1.00	26,331	966,081	40.26
13 AVON PARK	1-2	49	0	0.0	83.55	0.0	0	GAS	0 MCF	0.00	0	58	0.00
14 BARTOW	1-4	177	169	0.1	93.79	15.9	15,834	GAS	2,676 MCF	1.00	2,676	13,293	7.87
15 BARTOW CC	1	1,159	705,613	81.8	98.71	82.9	7,308	GAS	5,156,650 MCF	1.00	5,156,650	28,200,059	4.00
16 DEBARY	1-10	645	2,166	0.5	95.97	8.8	13,821	GAS	29,937 MCF	1.00	29,937	145,423	6.71
17 HIGGINS	1-4	113	229	0.3	92.74	11.9	20,607	GAS	4,719 MCF	1.00	4,719	21,336	9.32
18 HINES CC	1-4	1,912	959,357	67.4	95.38	20.5	7,259	GAS	6,964,306 MCF	1.00	6,964,306	38,969,256	4.06
19 INT CITY	1-14	987	14,223	1.9	82.63	7.1	13,090	GAS	186,178 MCF	1.00	186,178	966,171	6.95
20 SUWANNEE	1	52	78	0.2	94.19	0.0	13,244	GAS	1,033 MCF	1.00	1,033	117,262	150.34
21 SUWANNEE	2	50	461	1.2	96.39	38.4	15,295	GAS	7,051 MCF	1.00	7,051	143,051	31.03
22 SUWANNEE	3	51	24,387	64.3	98.71	66.6	12,311	GAS	300,238 MCF	1.00	300,238	1,466,115	6.01
23 TIGER BAY CC	1	204	63,795	42.0	92.17	99.9	7,201	GAS	459,402 MCF	1.00	459,402	2,498,199	3.92
24 UNIV OF FLA. CC	1	46	30,888	90.3	93.14	97.9	9,434	GAS	291,390 MCF	1.00	291,390	1,834,341	5.29
25 AVON PARK	1-2	49	0	0.0	83.55	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	177	0	0.0	93.79	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	174	0	0.0	96.05	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28 DEBARY	1-10	645	4	0.5	95.97	0.0	22,500	LIGHT OIL	16 BBLS	5.63	90	9,375	234.38
29 HIGGINS	1-4	113	0	0.0	92.74	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	987	3	1.9	82.63	0.0	15,667	LIGHT OIL	8 BBLS	5.86	47	4,420	147.33
32 RIO PINAR	1	12	0	0.0	96.77	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	153	10	0.0	97.10	1.3	15,200	LIGHT OIL	26 BBLS	5.85	152	5,038	50.38
34 TURNER	1-4	149	0	0.0	72.90	0.0	0	LIGHT OIL	0 BBLS	0.00	0	662	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,317 BBLS	5.80	7,637	159,017	0.00
36 TOTAL			2,954,393								25,575,052	120,355,860	4.07

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-15

(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 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2 CRYSTAL RIVER	1	378	7,533	2.8	92.04	27.8	11,167	COAL	3,419 TONS	24.60	84,121	488,403	6.48
3 CRYSTAL RIVER	2	500	106,094	29.5	94.44	34.7	11,021	COAL	47,531 TONS	24.60	1,169,285	4,940,159	4.66
4 CRYSTAL RIVER	4	732	404,287	76.7	93.16	81.6	10,288	COAL	181,172 TONS	22.98	4,163,316	13,936,442	3.45
5 CRYSTAL RIVER	5	712	140,127	27.3	93.55	87.1	10,174	COAL	62,039 TONS	22.98	1,425,657	5,015,594	3.58
6 ANCLOTE	1	517	0	0.0	92.64	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	521	0	0.0	0.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	99.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.33	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	73	0	0.0	96.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	517	119,123	32.0	92.64	39.1	10,406	GAS	1,239,604 MCF	1.00	1,239,604	5,951,903	5.00
12 ANCLOTE	2	521	0	0.0	0.00	0.0	0	GAS	0 MCF	0.00	0	647,638	0.00
13 AVON PARK	1-2	69	0	0.0	81.33	0.0	0	GAS	0 MCF	0.00	0	58	0.00
14 BARTOW	1-4	228	22	0.0	93.42	0.0	13,273	GAS	292 MCF	1.00	292	2,116	9.62
15 BARTOW CC	1	1,279	762,361	82.8	98.00	84.4	7,113	GAS	5,422,781 MCF	1.00	5,422,781	29,194,661	3.83
16 DEBARY	1-10	785	301	0.1	96.27	116.0	12,379	GAS	3,726 MCF	1.00	3,726	16,752	5.57
17 HIGGINS	1-4	129	4	0.0	92.00	0.0	14,250	GAS	57 MCF	1.00	57	244	6.10
18 HINES CC	1-4	2,204	844,343	53.2	81.38	31.3	7,082	GAS	5,979,269 MCF	1.00	5,979,269	32,766,281	3.88
19 INT CITY	1-14	1,186	5,063	0.6	93.79	32.0	12,385	GAS	62,705 MCF	1.00	62,705	325,683	6.43
20 SUWANNEE	1	67	54	0.1	95.00	0.0	12,074	GAS	652 MCF	1.00	652	117,038	216.74
21 SUWANNEE	2	66	46	0.1	99.00	34.8	14,543	GAS	669 MCF	1.00	669	117,422	255.27
22 SUWANNEE	3	67	23,563	48.8	100.00	50.5	12,059	GAS	284,149 MCF	1.00	284,149	1,329,560	5.64
23 TIGER BAY CC	1	225	0	0.0	78.67	0.0	0	GAS	0 MCF	0.00	0	0	0.00
24 UNIV OF FLA. CC	1	47	33,754	99.7	91.00	100.0	9,427	GAS	318,189 MCF	1.00	318,189	1,743,341	5.16
25 AVON PARK	1-2	69	0	0.0	81.33	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	228	0	0.0	93.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	231	0	0.0	95.33	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28 DEBARY	1-10	785	0	0.0	96.27	0.0	0	LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29 HIGGINS	1-4	129	0	0.0	92.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	1,186	0	0.0	93.79	0.0	0	LIGHT OIL	0 BBLS	0.00	0	3,444	0.00
32 RIO PINAR	1	18	0	0.0	97.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	200	0	0.0	98.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
34 TURNER	1-4	199	0	0.0	73.08	0.0	0	LIGHT OIL	0 BBLS	0.00	0	852	0.00
35 OTHER & START UP		0	0	-	0.00	0.0	0	LIGHT OIL	4,506 BBLS	5.80	26,132	543,833	0.00
36 TOTAL			2,446,895								20,160,624	97,148,895	3.97

Docket No. 140001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-15

(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 CRYS RIV NUC	3	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	[illegible]	0	0.00
2 CRYSTAL RIVER	1	376	52,965	18.9	96.21	33.7	10,911	COAL	23,492 TONS	24.60	577,923	2,513,519	4.75
3 CRYSTAL RIVER	2	500	51,389	13.8	90.55	32.9	11,050	COAL	23,083 TONS	24.60	567,857	2,472,236	4.81
4 CRYSTAL RIVER	4	732	448,098	82.3	97.10	83.9	10,271	COAL	200,285 TONS	22.98	4,602,345	15,341,082	3.42
5 CRYSTAL RIVER	5	712	442,486	83.5	28.10	89.9	10,167	COAL	195,585 TONS	22.98	4,494,348	14,989,776	3.39
6 ANCLOTE	1	517	0	0.0	94.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7 ANCLOTE	2	521	0	0.0	54.46	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8 SUWANNEE	1	30	0	0.0	99.03	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9 SUWANNEE	2	30	0	0.0	97.42	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10 SUWANNEE	3	73	0	0.0	100.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11 ANCLOTE	1	517	95,008	24.7	94.67	25.3	10,726	GAS	1,019,102 MCF	1.00	1,019,102	5,092,190	5.36
12 ANCLOTE	2	521	3,359	0.9	54.46	35.8	11,351	GAS	38,128 MCF	1.00	38,128	785,714	23.39
13 AVON PARK	1-2	69	7	0.0	78.39	0.0	15,429	GAS	108 MCF	1.00	108	668	9.54
14 BARTOW	1-4	228	66	0.0	92.02	28.9	13,212	GAS	872 MCF	1.00	872	5,269	8.01
15 BARTOW CC	1	1279	725,162	76.2	94.52	80.7	7,148	GAS	5,183,180 MCF	1.00	5,183,180	28,770,773	3.97
16 DEBARY	1-10	785	991	0.2	96.42	11.5	12,508	GAS	12,393 MCF	1.00	12,393	85,627	8.62
17 HIGGINS	1-4	129	30	0.0	90.89	0.0	15,833	GAS	475 MCF	1.00	475	2,357	7.86
18 HINES CC	1-4	2,204	842,230	51.4	79.45	21.1	7,078	GAS	5,961,714 MCF	1.00	5,961,714	33,550,701	3.98
19 INT CITY	1-14	1,186	3,161	0.4	93.46	7.5	12,467	GAS	39,408 MCF	1.00	39,408	227,909	7.21
20 SUWANNEE	1	67	134	0.3	94.19	0.0	12,291	GAS	1,647 MCF	1.00	1,647	135,725	101.29
21 SUWANNEE	2	66	24	0.0	99.35	36.4	15,750	GAS	378 MCF	1.00	378	127,476	531.15
22 SUWANNEE	3	67	25,046	50.2	97.42	50.2	12,081	GAS	302,688 MCF	1.00	302,688	1,454,089	5.81
23 TIGER BAY CC	1	225	7,958	4.8	0.00	98.3	7,643	GAS	60,831 MCF	1.00	60,831	342,403	4.30
24 UNIV OF FLA. CC	1	47	34,790	99.5	97.42	102.1	9,427	GAS	327,959 MCF	1.00	327,959	1,851,281	5.32
25 AVON PARK	1-2	69	0	0.0	78.39	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
26 BARTOW	1-4	228	0	0.0	92.02	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27 BAYBORO	1-4	231	0	0.0	93.95	0.0	0	LIGHT OIL	0 BBLS	0.00	0	120	0.00
28 DEBARY	1-10	785	0	0.0	96.42	0.0	0	LIGHT OIL	0 BBLS	0.00	0	7,490	0.00
29 HIGGINS	1-4	129	0	0.0	90.89	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31 INT CITY	1-14	1,186	38	0.4	93.46	0.0	14,316	LIGHT OIL	93 BBLS	5.85	544	14,722	38.74
32 RIO PINAR	1	16	0	0.0	96.39	0.0	0	LIGHT OIL	0 BBLS	0.00	0	61	0.00
33 SUWANNEE	1-3	200	15	0.0	96.99	1.5	14,533	LIGHT OIL	38 BBLS	5.74	218	6,440	42.93
34 TURNER	1-4	199	0	0.0	72.66	0.0	0	LIGHT OIL	0 BBLS	0.00	0	652	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,687 BBLS	5.85	15,572	323,756	0.00
36 TOTAL		3,733,858								23,207,090	108,082,070		3.95

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2015

			Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	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	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	3,381	2,924	1,590	1,173	2,011	2,121	13,200
15	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
16	AMOUNT	$	430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
17	BURNED:								
18	UNITS	BBL	3,381	2,924	1,590	1,173	2,011	2,121	13,200
19	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	129.03
20	AMOUNT	$	430,941	373,863	206,709	157,901	260,391	273,325	1,703,130
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	127.46	127.86	130.01	134.61	129.48	128.87	
24	AMOUNT	$	135,449,787	135,875,394	138,155,497	143,051,620	137,600,349	136,944,458	
	COAL								
25	PURCHASES:								
26	UNITS	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
27	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
28	AMOUNT	$	37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
29	BURNED:								
30	UNITS	TON	454,887	423,342	465,348	446,222	450,574	459,241	2,699,614
31	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	82.68
32	AMOUNT	$	37,827,696	35,004,484	38,295,330	36,777,759	37,318,022	37,981,895	223,205,186
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	83.16	82.69	82.29	82.42	82.82	82.71	
36	AMOUNT	$	79,371,200	78,920,410	78,546,167	78,666,715	79,051,361	78,939,212	
	GAS								
37	BURNED:								
38	UNITS	MCF	13,389,106	11,237,385	11,365,629	13,441,572	17,439,987	18,225,276	85,098,955
39	UNIT COST	$/MCF	5.60	5.80	5.78	5.66	5.46	5.41	5.59
40	AMOUNT	$	74,987,317	65,153,020	65,740,975	76,341,745	95,207,574	98,625,108	476,055,739
	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 2015

	HEAVY OIL		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	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	4,601	4,431	2,054	1,387	4,508	2,818	33,179
15	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
16	AMOUNT	$	601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
17	BURNED:								
18	UNITS	BBL	4,601	4,431	2,054	1,387	4,508	2,818	33,179
19	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	126.95
20	AMOUNT	$	601,289	555,758	264,250	178,683	555,600	353,243	4,211,953
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	125.24	125.43	128.65	130.71	123.25	125.35	
24	AMOUNT	$	133,093,596	133,287,642	136,716,299	138,905,861	130,973,746	133,210,491	
	COAL								
25	PURCHASES:								
26	UNITS	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
27	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
28	AMOUNT	$	39,499,890	42,256,051	36,766,990	36,526,293	24,380,598	35,316,613	437,953,621
29	BURNED:								
30	UNITS	TON	478,052	510,964	450,697	450,029	294,161	442,445	5,325,962
31	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	82.23
32	AMOUNT	$	39,499,890	42,256,051	36,766,990	36,526,293	24,380,598	35,316,613	437,953,621
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	82.63	82.70	81.58	81.16	82.88	79.82	
36	AMOUNT	$	78,863,810	78,932,436	77,867,070	77,467,915	79,107,197	76,186,269	
	GAS								
37	BURNED:								
38	UNITS	MCF	18,135,643	19,006,439	18,326,038	15,110,822	13,312,113	12,948,283	182,936,293
39	UNIT COST	$/MCF	5.36	5.36	5.43	5.54	5.42	5.59	5.51
40	AMOUNT	$	102,595,281	101,961,226	99,496,778	83,650,884	72,212,897	72,412,214	1,008,384,819
	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 2015

(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-15	ECONSALE	--	31,940		31,940	3.252	3.968	1,038,840	1,267,385	228,545
	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	--	26,478		26,478	4.592	4.592	1,215,937	1,215,937	0
	TOTAL		58,418		58,418	3.860	4.251	2,254,777	2,483,322	228,545
Feb-15	ECONSALE	--	19,240		19,240	3.457	4.217	665,089	811,409	146,320
	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	--	25,437		25,437	4.916	4.916	1,250,429	1,250,429	0
	TOTAL		44,677		44,677	4.287	4.615	1,915,518	2,061,838	146,320
Mar-15	ECONSALE	--	5,535		5,535	3.511	4.283	194,320	237,070	42,750
	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	--	27,434		27,434	4.750	4.750	1,303,070	1,303,070	0
	TOTAL		32,969		32,969	4.542	4.671	1,497,390	1,540,140	42,750
Apr-15	ECONSALE	--	5,700		5,700	2.592	3.162	147,722	180,220	32,498
	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	--	38,178		38,178	4.118	4.118	1,572,220	1,572,220	0
	TOTAL		43,878		43,878	3.920	3.994	1,719,942	1,752,440	32,498
May-15	ECONSALE	--	32,645		32,645	2.716	3.314	886,743	1,081,827	195,084
	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	--	44,189		44,189	3.823	3.823	1,689,334	1,689,334	0
	TOTAL		76,834		76,834	3.353	3.607	2,576,077	2,771,161	195,084
Jun-15	ECONSALE	--	555		555	4.855	5.924	26,948	32,876	5,928
	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	--	54,378		54,378	3.802	3.802	2,067,519	2,067,519	0
	TOTAL		54,933		54,933	3.813	3.824	2,094,467	2,100,395	5,928

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-15	ECONSALE	–	12,335		12,335	3.922	4.785	483,815	590,254	106,439
	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	–	62,859		62,859	3.751	3.751	2,357,532	2,357,532	0
	TOTAL		75,194		75,194	3.779	3.920	2,841,347	2,947,786	106,439
Aug-15	ECONSALE	–	8,250		8,250	5.683	6.933	468,841	571,987	103,146
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	64,864		64,864	3.800	3.800	2,464,570	2,464,570	0
	TOTAL		73,114		73,114	4.012	4.153	2,933,411	3,036,557	103,146
Sep-15	ECONSALE	–	70		70	4.629	5.646	3,240	3,952	712
	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	–	72,881		72,881	3.778	3.778	2,753,161	2,753,161	0
	TOTAL		72,951		72,951	3.778	3.779	2,756,401	2,757,113	712
Oct-15	ECONSALE	–	165		165	2.799	3.415	4,618	5,634	1,016
	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	–	59,672		59,672	3.850	3.850	2,297,359	2,297,359	0
	TOTAL		59,837		59,837	3.847	3.849	2,301,977	2,302,993	1,016
Nov-15	ECONSALE	–	5,485		5,485	2.592	3.162	142,180	173,460	31,280
	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	–	45,899		45,899	3.791	3.791	1,740,143	1,740,143	0
	TOTAL		51,384		51,384	3.663	3.724	1,882,323	1,913,603	31,280
Dec-15	ECONSALE	–	4,380		4,380	3.123	3.810	136,796	166,891	30,095
	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	–	28,207		28,207	3.861	3.861	1,089,118	1,089,118	0
	TOTAL		32,587		32,587	3.762	3.854	1,225,914	1,256,009	30,095
Jan-15	ECONSALE	–	126,300		126,300	3.325	4.056	4,199,152	5,122,965	923,813
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-15	EXCESS GAIN	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	550,476		550,476	3.960	3.960	21,800,391	21,800,391	0
	TOTAL		676,776		676,776	3.842	3.978	25,999,543	26,923,356	923,813

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(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-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	7,017			7,017	8.068	8.068	566,155
	SOCO Franklin	--	31,997			31,997	5.549	5.549	1,775,494
	SOCO Scherer	--	33,548			33,548	3.629	3.629	1,217,298
	Vandolah (NSG)	--	9,340			9,340	8.084	8.084	755,029
	TOTAL		81,902	0	0	81,902	5.267	5.267	4,313,976
Feb-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	14,454			14,454	6.809	6.809	984,151
	SOCO Franklin	--	55,529			55,529	4.787	4.787	2,658,337
	SOCO Scherer	--	34,302			34,302	3.629	3.629	1,244,977
	Vandolah (NSG)	--	18,440			18,440	6.694	6.694	1,234,429
	TOTAL		122,725	0	0	122,725	4.988	4.988	6,121,894
Mar-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	9,527			9,527	6.644	6.644	632,976
	SOCO Franklin	--	63,298			63,298	4.662	4.662	2,951,119
	SOCO Scherer	--	22,208			22,208	3.642	3.642	808,840
	Vandolah (NSG)	--	12,414			12,414	7.194	7.194	893,103
	TOTAL		107,447	0	0	107,447	4.920	4.920	5,286,038
Apr-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	18,389			18,389	6.775	6.775	1,245,876
	SOCO Franklin	--	23,096			23,096	5.695	5.695	1,315,340
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	30,930			30,930	6.654	6.654	2,058,007
	TOTAL		72,415	0	0	72,415	6.379	6.379	4,619,223
May-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	42,443			42,443	6.658	6.658	2,825,975
	SOCO Franklin	--	39,312			39,312	4.822	4.822	1,895,608
	SOCO Scherer	--	15,068			15,068	3.649	3.649	549,817
	Vandolah (NSG)	--	60,165			60,165	6.398	6.398	3,849,456
	TOTAL		156,988	0	0	156,988	5.810	5.810	9,120,856
Jun-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	40,089			40,089	6.639	6.639	2,661,520
	SOCO Franklin	--	124,781			124,781	4.009	4.009	5,002,423
	SOCO Scherer	--	37,161			37,161	3.626	3.626	1,347,551
	Vandolah (NSG)	--	45,539			45,539	6.648	6.648	3,027,555
	TOTAL		247,570	0	0	247,570	4.863	4.863	12,039,049
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	131,919			131,919	6.759	6.759	8,916,653
Jun-15	SOCO Franklin	--	338,013			338,013	4.615	4.615	15,598,321
	SOCO Scherer	--	142,287			142,287	3.632	3.632	5,166,483
	Vandolah (NSG)	--	176,828			176,828	6.683	6.683	11,817,579
	TOTAL		789,047	0	0	789,047	5.260	5.260	41,501,036

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(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-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	48,644			48,644	6.678	6.678	3,248,370
	SOCO Franklin	--	140,177			140,177	3.983	3.983	5,583,673
	SOCO Scherer	--	38,113			38,113	3.634	3.634	1,384,838
	Vandolah (NSG)	--	61,531			61,531	6.540	6.540	4,024,122
	TOTAL		288,465	0	0	288,465	4.937	4.937	14,241,003
Aug-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	51,889			51,889	6.789	6.789	3,522,884
	SOCO Franklin	--	132,711			132,711	4.014	4.014	5,327,505
	SOCO Scherer	--	37,122			37,122	3.634	3.634	1,349,001
	Vandolah (NSG)	--	65,877			65,877	6.551	6.551	4,315,453
	TOTAL		287,599	0	0	287,599	5.047	5.047	14,514,843
Sep-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	26,769			26,769	6.593	6.593	1,764,943
	SOCO Franklin	--	133,209			133,209	3.999	3.999	5,327,548
	SOCO Scherer	--	35,438			35,438	3.642	3.642	1,290,552
	Vandolah (NSG)	--	44,210			44,210	6.536	6.536	2,889,639
	TOTAL		239,626	0	0	239,626	4.704	4.704	11,272,680
Oct-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	30,951			30,951	6.787	6.787	2,100,620
	SOCO Franklin	--	97,459			97,459	4.176	4.176	4,069,677
	SOCO Scherer	--	37,042			37,042	3.631	3.631	1,344,882
	Vandolah (NSG)	--	42,834			42,834	6.582	6.582	2,819,448
	TOTAL		208,286	0	0	208,286	4.962	4.962	10,334,627
Nov-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	15,546			15,546	6.528	6.528	1,014,869
	SOCO Franklin	--	53,983			53,983	4.719	4.719	2,547,284
	SOCO Scherer	--	33,077			33,077	3.630	3.630	1,200,676
	Vandolah (NSG)	--	24,120			24,120	6.129	6.129	1,478,395
	TOTAL		126,726	0	0	126,726	4.925	4.925	6,241,284
Dec-15	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,495			2,495	8.131	8.131	202,871
	SOCO Franklin	--	38,199			38,199	5.349	5.349	2,043,219
	SOCO Scherer	--	33,777			33,777	3.637	3.637	1,228,442
	Vandolah (NSG)	--	3,250			3,250	8.055	8.055	261,783
	TOTAL		77,721	0	0	77,721	4.807	4.807	3,736,315
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	308,213			308,213	6.739	6.739	20,771,210
Dec-15	SOCO Franklin	--	933,751			933,751	4.337	4.337	40,497,235
	SOCO Scherer	--	356,856			356,856	3.634	3.634	12,966,874
	Vandolah (NSG)	--	418,650			418,650	6.594	6.594	27,606,419
			2,017,470	0	0	2,017,470	5.048	5.048	101,841,736
TOTAL									

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jan-15	QUAL. FACILITIES	COGEN	276,981			276,981	4.767	11.680	13,203,009
Feb-15	QUAL. FACILITIES	COGEN	250,157			250,157	4.752	12.407	11,888,505
Mar-15	QUAL. FACILITIES	COGEN	241,703			241,703	4.966	12.888	12,002,597
Apr-15	QUAL. FACILITIES	COGEN	230,930			230,930	4.671	12.962	10,786,174
May-15	QUAL. FACILITIES	COGEN	266,574			266,574	4.700	11.883	12,529,047
Jun-15	QUAL. FACILITIES	COGEN	257,962			257,962	4.680	12.102	12,071,397
Jul-15	QUAL. FACILITIES	COGEN	266,562			266,562	4.670	11.853	12,448,464
Aug-15	QUAL. FACILITIES	COGEN	266,582			266,582	4.656	11.838	12,410,731
Sep-15	QUAL. FACILITIES	COGEN	257,962			257,962	4.641	12.064	11,971,496
Oct-15	QUAL. FACILITIES	COGEN	255,185			255,185	4.660	12.164	11,891,761
Nov-15	QUAL. FACILITIES	COGEN	240,086			240,086	4.705	12.680	11,295,964
Dec-15	QUAL. FACILITIES	COGEN	276,983			276,983	4.565	11.478	12,643,543
TOTAL	QUAL. FACILITIES	COGEN	3,087,667			3,087,667	4.701	12.142	145,142,688

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(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-15	ECONPURCH	--	6,536	6.459	6.459	422,155	7.801	509,852	87,697
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		9,763	5.542	5.542	541,062	6.440	628,759	87,697
Feb-15	ECONPURCH		4,878	6.569	6.569	320,433	7.595	370,493	50,060
	SEPA	--	2,915	3.684	3.684	107,399	3.684	107,399	0
	TOTAL		7,793	5.490	5.490	427,832	6.132	477,892	50,060
Mar-15	ECONPURCH	--	23,454	4.506	4.506	1,056,873	5.881	1,379,416	322,543
	SEPA		3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		26,681	4.407	4.407	1,175,780	5.616	1,498,323	322,543
Apr-15	ECONPURCH	--	26,613	4.790	4.790	1,274,824	6.305	1,678,009	403,185
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		29,736	4.674	4.674	1,389,895	6.030	1,793,080	403,185
May-15	ECONPURCH		33,247	5.039	5.039	1,675,388	6.698	2,226,782	551,394
	SEPA	--	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		36,474	4.919	4.919	1,794,295	6.431	2,345,689	551,394
Jun-15	ECONPURCH	--	44,795	4.401	4.401	1,971,358	5.876	2,632,260	660,902
	SEPA	--	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		47,918	4.354	4.354	2,086,429	5.733	2,747,331	660,902
Jan-15 THRU Jun-15	ECONPURCH	--	139,523	4.817	4.817	6,721,031	6.30	8,796,812	2,075,781
	SEPA	--	18,842	3.685	3.685	694,262	3.68	694,262	0
	TOTAL		158,365	4.682	4.682	7,415,293	5.993	9,491,074	2,075,781

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(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-15	ECONPURCH	–	22,417	5.623	5.623	1,260,543	7.398	1,658,444	397,901
	SEPA	–	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		25,644	5.379	5.379	1,379,450	6.931	1,777,351	397,901
Aug-15	ECONPURCH	–	26,921	5.085	5.085	1,368,950	6.712	1,806,962	438,012
	SEPA	–	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		30,148	4.935	4.935	1,487,857	6.388	1,925,869	438,012
Sep-15	ECONPURCH	–	58,871	4.186	4.186	2,464,378	5.619	3,307,698	843,320
	SEPA	–	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		61,994	4.161	4.161	2,579,449	5.521	3,422,769	843,320
Oct-15	ECONPURCH	–	41,572	4.298	4.298	1,786,567	5.723	2,379,097	592,530
	SEPA	–	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		44,799	4.253	4.253	1,905,474	5.576	2,498,004	592,530
Nov-15	ECONPURCH	–	17,688	4.664	4.664	824,900	6.002	1,061,613	236,713
	SEPA	–	3,123	3.685	3.685	115,071	3.685	115,071	0
	TOTAL		20,811	4.517	4.517	939,971	5.654	1,176,684	236,713
Dec-15	ECONPURCH	–	11,512	4.565	4.565	525,473	5.658	651,398	125,925
	SEPA	–	3,227	3.685	3.685	118,907	3.685	118,907	0
	TOTAL		14,739	4.372	4.372	644,380	5.226	770,305	125,925
Jan-15 THRU Dec-15	ECONPURCH	–	318,504	4.694	4.694	14,951,842	6.173	19,662,024	4,710,182
	SEPA	–	37,996	3.685	3.685	1,400,032	3.685	1,400,032	0
	TOTAL		356,500	4.587	4.587	16,351,874	5.908	21,062,056	4,710,182

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January through December 2015

	Approved Jan 14 - Dec 14 ($/1000 KWH)	Requested Jan 15 - Dec 15 ($/1000 KWH)	Difference from Current $	Difference from Current %
Base Rate	$58.50	$58.50	$0.00	0.00%
Fuel Cost Recovery	40.77	43.23	2.46	6.04%
Capacity Cost Recovery (CCR)	10.82	10.74	(0.08)	-0.74%
Energy Conservation Cost Recovery (ECCR) [1]	4.02	2.54	(1.48)	-36.82%
Environmental Cost Recovery (ECRC)	2.43	1.38	(1.05)	-43.21%
Nuclear CR3 Uprate	2.17	2.00	(0.17)	-7.83%
Nuclear Levy	3.45	3.45	0.00	0.00%
Subtotal	122.16	121.84	(0.32)	-0.26%
Gross Receipts Tax	3.13	3.12	(0.01)	-0.32%
Total	$125.29	$124.96	($0.33)	-0.26%

[1] The 2015 ECCR Residential bill impact represents DEF's current estimate and is subject to change. DEF submits the 2015 ECCR Projection Filing in Docket 140002-EI on August 27, 2014.

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	14,061,818	4.598	$ 646,562,413	4.323	$ 607,920,005
Over 1,000 kWh	5,328,545	4.598	245,006,502	5.323	283,648,910
Total	19,390,364		$ 891,568,915		$ 891,568,915
Rate Differential by Tier - Cents per kWh				1.000	

Residential Sales:	
Total	19,390,957
Time of Use	593
Levelized	19,390,364

Duke Energy Florida
Generating System Comparative Data by Fuel Type

		2012 Actual	2013 Actual	2014 Actual / Estimated	2015 Projection	2013 vs. 2012	2014 vs. 2013	2015 vs. 2014
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		6,890,407	19,773,117	0	0	187.0%	-100.0%	0.0%
LIGHT OIL		18,829,066	16,141,228	13,743,980	4,211,953	-14.3%	-14.9%	-69.4%
COAL		407,895,600	439,925,452	534,985,801	437,953,621	7.9%	21.6%	-18.1%
GAS		1,054,896,646	1,013,506,189	1,026,899,450	1,008,384,819	-3.9%	1.3%	-1.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,488,511,720	1,489,345,986	1,575,629,231	1,450,550,393	0.1%	5.8%	-7.9%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		45,476	123,377	0	0	171.3%	-100.0%	0.0%
LIGHT OIL		72,093	35,150	42,939	3,125	-51.2%	22.2%	-92.7%
COAL		10,034,864	10,633,975	13,278,858	11,858,055	6.0%	24.9%	-10.7%
GAS		23,997,245	23,066,236	22,129,017	23,858,422	-3.9%	-4.1%	7.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	34,149,677	33,858,739	35,450,815	35,719,602	-0.9%	4.7%	0.8%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	89,248	250,994	0	0	181.2%	-100.0%	0.0%
LIGHT OIL	BBL	163,136	132,000	106,987	33,179	-19.1%	-18.9%	-69.0%
COAL	TON	4,543,203	4,792,094	5,832,852	5,325,982	5.5%	21.7%	-8.7%
GAS	MCF	187,422,970	177,503,510	172,872,912	182,938,293	-5.3%	-2.6%	5.8%
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		568,459	1,529,500	0	0	169.1%	-100.0%	0.0%
LIGHT OIL		925,480	764,007	613,779	192,302	-17.4%	-19.7%	-68.7%
COAL		106,599,484	111,597,504	136,345,462	123,887,171	4.7%	22.2%	-9.1%
GAS		189,832,950	180,039,861	174,398,564	182,938,293	-5.2%	-3.1%	4.9%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	297,926,373	293,930,892	311,358,805	307,017,766	-1.3%	5.9%	-1.4%
GENERATION MIX (% MWH)								
HEAVY OIL		0.13%	0.36%	0.00%	0.00%	150.4%	-109.9%	0.0%
LIGHT OIL		0.21%	0.10%	0.12%	0.01%	-47.4%	0.0%	-92.6%
COAL		29.38%	31.41%	37.46%	33.20%	6.8%	19.4%	-11.5%
GAS		70.27%	68.13%	62.42%	66.79%	-3.0%	-8.4%	7.0%
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	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT								
HEAVY OIL	$/BBL	77.21	78.78	0.00	0.00	2.0%	-100.0%	0.0%
LIGHT OIL	$/BBL	115.42	122.28	128.48	126.96	5.9%	5.1%	-1.2%
COAL	$/TON	89.78	91.80	91.72	82.23	2.3%	-0.1%	-10.3%
GAS	$/MCF	5.63	5.71	5.94	5.51	1.4%	4.0%	-7.2%
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		12.12	12.93	0.00	0.00	6.7%	-100.0%	0.0%
LIGHT OIL		20.35	21.13	22.39	21.90	3.8%	6.0%	-2.2%
COAL		3.83	3.94	3.92	3.54	3.0%	-0.5%	-9.9%
GAS		5.56	5.63	5.89	5.51	1.3%	4.8%	-6.4%
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	5.00	5.07	5.06	4.73	1.4%	-0.1%	-6.6%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		12,500	12,397	0	0	-0.8%	-100.0%	0.0%
LIGHT OIL		12,837	21,735	14,294	61,537	69.3%	-34.2%	330.5%
COAL		10,623	10,494	10,268	10,448	-1.2%	-2.2%	1.7%
GAS		7,911	7,805	7,881	7,668	-1.3%	1.0%	-2.7%
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	8,724	8,661	8,783	8,595	-0.5%	1.2%	-2.1%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		15.15	16.03	0.00	0.00	5.8%	-100.0%	0.0%
LIGHT OIL		26.12	45.92	32.01	134.78	75.8%	-30.3%	321.1%
COAL		4.06	4.14	4.03	3.69	1.8%	-2.8%	-8.3%
GAS		4.40	4.39	4.64	4.23	0.0%	5.6%	-8.9%
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	4.36	4.40	4.44	4.06	0.9%	1.0%	-8.6%

Docket 140001-EI
Exhibit No. ___(TGF-2)
Part 1

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2014

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-12-04:25-PAA-EU)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 129,009,047	$ 113,269,617	$ 117,696,602	$ 123,707,993	$ 148,849,928	$ 150,044,426	$ 782,797,613
	2	Fuel Cost of Power Sold	(8,399,700)	(4,874,697)	(4,172,032)	(4,006,945)	(2,404,448)	(3,611,616)	(27,469,439)
	3	Fuel Cost of Purchased Power	6,995,460	6,686,472	4,137,261	9,616,764	15,941,968	14,835,873	58,215,817
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	9,787,721	8,788,027	10,717,751	5,483,300	9,437,328	11,822,064	56,036,188
	4	Energy Cost of Economy Purchases	1,126,552	1,984,275	902,144	1,910,882	2,797,492	2,205,474	10,926,819
	5	Adjustments to Fuel Cost	(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(12,913,643)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	138,504,493	126,060,088	129,508,148	136,697,603	174,804,893	162,219,933	887,593,155
B	1	Jurisdictional MWH Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	17,013,292
	2	Non-Jurisdictional MWH Sales	22,565	44,021	16,236	32,556	33,247	28,733	177,361
	3	TOTAL SALES (Lines B1 + B2)	2,645,518	2,960,084	2,583,856	2,594,512	2,990,919	3,415,762	17,190,653
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	98.97%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	112,142,525	125,857,590	109,339,748	109,372,799	128,046,715	147,816,093	732,575,469
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	1b	RRSSA Fuel Adjustment	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(17,013,292)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	118,064,769	131,486,725	115,317,323	115,356,040	133,634,241	152,974,262	766,833,361
	4	Fuel & Net Power Transactions (Line A6)	138,504,493	126,060,088	129,508,148	136,697,603	174,804,893	162,219,933	887,593,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	137,533,195	124,365,581	128,860,719	135,188,666	172,922,325	161,095,355	859,965,842
	6	Over/(Under) Recovery (Line C3 - Line C5)	(19,468,426)	7,121,144	(13,563,398)	(19,832,626)	(39,288,084)	(8,121,092)	(93,152,480)
	7	Interest Provision	(716)	(1,063)	(1,108)	(1,962)	(3,570)	(4,021)	(12,439)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,469,142)	7,120,081	(13,564,504)	(19,834,588)	(39,291,654)	(8,125,113)	(93,164,920)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(3,194,825)	(428,560)	2,337,705	5,103,970	7,870,235	10,636,500	10,636,500
	12	Regulatory Accounting Adjustment	-	-	(588,830)	-	-	-	(588,830)
	13	TOTAL TRUE-UP BALANCE	($22,663,966)	(12,777,621)	($24,164,790)	($41,233,113)	($77,758,502)	($83,117,350)	($83,117,350)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 152,197,049	$ 163,089,436	$ 143,724,982	$ 125,026,239	$ 105,592,127	$ 113,199,782	$ 1,575,829,231
	2	Fuel Cost of Power Sold	(3,454,463)	(3,933,202)	(2,804,829)	(2,273,786)	(1,720,555)	(984,793)	(42,641,167)
	3	Fuel Cost of Purchased Power	13,422,539	14,076,449	12,104,080	11,244,071	5,443,096	5,926,210	120,432,282
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	12,830,242	12,768,252	12,331,662	12,332,063	11,620,155	13,174,893	131,093,485
	4	Energy Cost of Economy Purchases	1,367,310	1,538,315	3,090,433	2,406,094	813,273	1,003,572	21,165,816
	5	Adjustments to Fuel Cost	(19,486)	(19,498)	(19,508)	(19,502)	(19,488)	(19,481)	(13,030,585)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
B	1	Jurisdictional MWH Sales	3,578,550	3,752,617	3,717,326	3,433,718	2,921,008	2,748,954	37,185,665
	2	Non-Jurisdictional MWH Sales	24,537	27,901	29,414	26,399	20,273	15,121	321,006
	3	TOTAL SALES (Lines B1 + B2)	3,603,087	3,780,718	3,746,740	3,460,117	2,941,281	2,764,075	37,486,671
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.32%	99.28%	99.21%	99.24%	99.31%	99.45%	99.14%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	156,609,389	164,276,459	162,714,963	150,237,348	127,660,111	120,110,401	1,614,204,140
	1a	RRSSA Refund - $129M	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	1b	RRSSA Fuel Adjustment	(3,578,550)	(3,752,617)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,185,665)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,266)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	161,576,036	169,068,839	167,542,835	155,348,827	133,304,301	125,906,647	1,679,560,845
	4	Fuel & Net Power Transactions (Line A6)	176,363,202	177,519,755	168,426,750	148,717,170	121,728,608	132,300,204	1,792,648,843
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	175,423,175	176,466,894	167,343,481	147,805,348	121,067,595	131,767,260	1,779,859,614
	6	Over/(Under) Recovery (Line C3 - Line C5)	(13,847,139)	(7,398,056)	199,354	7,543,480	12,236,705	(5,860,633)	(100,278,769)
	7	Interest Provision	(4,430)	(4,823)	(4,865)	(4,533)	(3,901)	(3,604)	(36,596)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(13,851,569)	(7,402,879)	194,489	7,538,946	12,232,804	(5,864,237)	(100,317,366)
	9	Plus: Prior Period Balance	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)	(5,961,090)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	13,402,765	16,169,030	18,935,295	21,701,560	24,467,825	27,234,094	27,234,093
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(566,930)
	13	TOTAL TRUE-UP BALANCE	($94,202,854)	($98,839,267)	($95,678,514)	($95,573,302)	($70,574,233)	($73,672,202)	($73,672,203)

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2014

		DOLLARS				MWH				c/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %
1	Fuel Cost of System Net Generation (E3)	1,575,629,231	1,415,304,375	160,324,856	11%	35,450,615	34,832,378	618,237	2%	4.445	4.063	0.381	9%
2	Spent Nuclear Fuel Disposal Cost	0	0	-	0%	0	0	-	0%	0.000	0.000	0.000	0%
3	Coal Car Investment	0	0	-	0%			-		0.000	0.000	0.000	
4	Adjustment to Fuel Cost [1]	(13,030,585)	(128,673,569)	115,642,984	0%			-		0.000	0.000	0.000	
5	TOTAL COST OF GENERATED POWER	1,562,598,647	1,286,630,806	275,967,840	21%	35,450,615	34,832,378	618,237	2%	4.408	3.694	0.714	19%
6	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	120,432,282	193,909,321	(73,477,059)	-38%	2,184,819	3,301,834	(1,117,015)	-34%	5.512	5.873	-0.361	-6%
				-				-		0.000	0.000	0.000	
7	Energy Cost of Economy Purchases (E9)	21,165,616	13,558,753	7,606,863	56%	380,889	201,860	179,029	89%	5.557	6.717	-1.160	
8	Payments to Qualifying Facilities (E8)	131,093,485	137,578,568	(6,485,083)	-5%	2,828,107	3,019,852	(191,745)	-6%	4.635	4.556	0.080	2%
9	TOTAL COST OF PURCHASED POWER	272,691,383	345,046,642	(72,355,279)	-21%	5,393,815	6,523,546	(1,129,731)	-17%	5.056	5.289	-0.234	-4%
				-		40,844,430	41,355,924	(511,494)	-1%	0.000	0.000	0.000	
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)												
11	Fuel Cost of Economy Sales (E6)	(6,463,505)	(3,510,887)	(2,952,618)	84%	(138,922)	(91,711)	(47,211)	51%	4.653	3.828	0.824	22%
11a	Gain on Economy Sales (E6)	(5,887,982)	(667,252)	(5,220,730)	782%	(138,922)	(91,711)	(47,211)	51%	4.238	0.728	3.511	483%
11b	Gain on Economy Sales -20% (E6)	1,105,892	0	1,105,892	0%								
12	Fuel Cost of Stratified Sales (E6)	(31,396,371)	(37,314,237)	5,918,866	-16%	(748,283)	(975,861)	227,578	-23%	4.196	3.824	0.372	10%
13	TOTAL FUEL COST AND GAINS OF POWER SALES (LINES 11 + 11a + 12)	(42,641,167)	(41,492,376)	(1,148,791)	3%	(887,205)	(1,067,572)	180,367	-17%	4.806	3.887	0.920	24%
14	Net Inadvertent Interchange					105,789		105,789					
15	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 9 + 13 + 14)	1,792,648,843	1,590,185,072	202,463,771	13%	40,063,014	40,288,352	(225,338)	-1%	4.475	3.947	0.528	13%
16	Net Unbilled					(139,190)	(24,268)	(114,922)	474%	0.000	0.000	0.000	
17	Company Use					(153,585)	(144,000)	(9,585)	7%	0.000	0.000	0.000	
18	T & D Losses					(2,283,568)	(2,224,817)	(58,751)	3%	0.000	0.000	0.000	
19	SYSTEM MWH SALES	1,792,648,843	1,590,185,072	202,463,771	13%	37,486,671	37,895,267	(408,596)	-1%	4.782	4.196	0.586	14%
20	Wholesale MWH Sales	(15,422,270)	(9,546,966)	(5,875,304)	62%	(321,006)	(230,488)	(90,518)	39%	4.804	4.142	0.662	16%
21	Jurisdictional MWH Sales	1,777,226,573	1,580,638,106	196,588,466	12%	37,165,665	37,664,779	(499,114)	-1%	4.782	4.197	0.585	14%
21a	Jurisdictional Loss Multiplier	1.00148	1.0015	(0)	0%	1.00148	1.0015	(0)	0%				
22	Jurisdictional Sales Adjusted for Line Losses	1,779,859,614	1,583,009,063	196,850,552	12%	37,165,665	37,664,779	(499,114)	-1%	4.789	4.203	0.586	14%
23	TRUE-UP **	5,961,090	33,195,183	(27,234,094)	-82%	37,165,665	37,664,779	(499,114)	-1%	0.016	0.088	-0.072	-82%
24	TOTAL JURISDICTIONAL FUEL COST	1,785,820,703	1,616,204,246	169,616,457	10%	37,165,665	37,664,779	(499,114)	-1%	4.805	4.291	0.514	12%
25	Revenue Tax Factor	1,285,791	1,163,667	122,124	10%								
26	Fuel Factor Adjusted for Taxes	1,787,106,494	1,617,367,913	169,738,581	10%	37,165,665	37,664,779	(499,114)	-1%	4.808	4.294	0.514	12%
27	GPIF **	3,262,447	3,262,447	-	0%	37,165,665	37,664,779	(499,114)	-1%	0.009	0.009	0.000	1%
28	Fuel Factor Adjusted for Taxes Including GPIF	1,790,368,941	1,620,630,360	169,738,581	10%	37,165,665	37,664,779	(499,114)	-1%	4.817	4.303	0.514	12%
29	FUEL FACTOR ROUNDED TO NEAREST .001 c/KWH									4.817	4.303	0.514	12%

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional MWH Sales

[1] The $129 million retail refund required per RRSSA paragraph 6.a was treated as a reduction to fuel expense in the 2014 Original Projection. In the 2014 Estimated/Actual filing, the refund is treated as an adjustment to revenue, as shown on line C.1a of Schedule E1-B (Sheets 1&2). The difference in treatment is the primary cause of the difference amount on line 4 and 28 of the above schedule. In both filings, retail ratepayers are receiving a refund of $129 million.

Docket: 140001-EI
Exhibit: TGF-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 2014

Retail:	Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	12 Month Period	Schedule Reference	RRSSA Paragraph
1 Final NEIL Reimbursement [1]	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(13,695,754)	(164,349,049)		7.c. / 7.d.
2 RRSSA Refund (2nd 50% of $258 million)	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000	E1-B, line C1a	6.a.
3 RRSSA Refund ($10 million)	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000	E1-B, line C1c	6.a.
4 Total RRSSA Refunds (Lines 2 + 3)	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	11,583,333	139,000,000		
5 Retail mWh Sales	2,622,954	2,916,063	2,567,620	2,561,956	2,957,671	3,387,029	3,578,590	3,752,817	3,717,326	3,433,718	2,921,008	2,748,954	37,165,665	E1-B, line B1	
6 RRSSA Fuel Adjustment ($/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)
7 Total RRSSA Fuel Adjustment to Revenue (Line 5 * 6)	(2,622,954)	(2,916,063)	(2,567,620)	(2,561,956)	(2,957,671)	(3,387,029)	(3,578,590)	(3,752,817)	(3,717,326)	(3,433,718)	(2,921,008)	(2,748,954)	(37,165,665)	E1-B, line C1b	

Notes:
[1] - Final NEIL Reimbursement is included in the 2013 True-up provision, which applies to retail only

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2014

			Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	TOTAL
1	Fuel Cost of System Net Generation		$128,009,047	$113,269,617	$117,896,602	$123,707,993	$148,849,928	$150,044,428	$152,197,049	$153,088,439	$143,724,982	$125,028,239	$105,592,127	$113,199,782	$1,575,629,231
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(14,587)	(13,606)	24,401	(16,191)	(17,373)	(12,876,287)	(19,466)	(19,496)	(19,506)	(19,502)	(19,488)	(19,461)	(13,030,585)
2	Fuel Cost of Power Sold		(2,033,703)	(999,742)	(732,117)	(259,845)	(97,422)	(177,909)	(925,989)	(1,243,464)	0	(300)	(1,300)	(1,715)	(6,483,505)
2a	Gains on Power Sales		(3,871,141)	(207,731)	(259,066)	(25,456)	(5,217)	(25,766)	(157,457)	(218,650)	0	(54)	(229)	(302)	(4,782,290)
2b	Fuel Cost of Stratified Sales		(2,494,856)	(3,967,224)	(3,170,850)	(3,721,643)	(2,310,810)	(3,407,919)	(2,371,007)	(2,470,887)	(2,604,928)	(2,273,442)	(1,719,028)	(682,776)	(31,396,371)
3	Fuel Cost of Purchased Power (Exd Economy)		6,995,460	6,866,472	4,137,881	9,618,764	15,841,966	14,636,873	13,422,539	14,076,449	12,104,060	11,244,071	5,443,096	5,926,210	120,432,252
3a	Energy Payments to Qualifying Facilities		9,787,721	8,788,027	10,717,751	5,463,300	9,437,326	11,822,064	12,830,242	12,768,252	12,331,682	12,332,063	11,620,155	13,174,893	131,093,485
4	Energy Cost of Economy Purchases		1,126,552	1,984,275	902,144	1,910,882	2,797,492	2,205,474	1,387,310	1,838,315	3,090,433	2,408,094	813,273	1,003,572	21,166,816
5	Total System Fuel & Net Power Transactions		$136,504,493	$126,050,088	$129,506,146	$136,687,603	$174,604,883	$162,219,933	$176,383,202	$177,519,755	$166,426,750	$148,717,170	$121,728,608	$132,300,204	$1,792,648,643
6	Jurisdictional MWH Sold		2,622,954	2,916,053	2,567,620	2,581,956	2,957,671	3,367,029	3,576,550	3,752,617	3,717,326	3,433,718	2,921,008	2,748,954	37,165,865
7	Jurisdictional % of Total Sales		99.15%	98.51%	99.37%	98.75%	98.89%	99.16%	99.32%	99.26%	99.21%	99.24%	99.31%	99.45%	99.14%
8	Jurisdictional Fuel & Net Power Transactions		137,327,204	124,161,792	128,690,258	134,966,883	172,666,778	160,857,286	175,163,932	176,206,109	165,096,179	147,586,919	120,866,880	131,572,553	1,777,226,573
9	Jurisdictional Loss Multiplier		1.00150	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
10	Jurisdictional Fuel & Net Power Transactions		137,533,195	124,345,681	128,880,719	135,166,856	172,922,325	161,095,355	175,423,175	176,466,894	165,343,461	147,805,348	121,057,595	131,767,280	1,779,868,514
11	Adjusted System Sales	MWH	2,646,518	2,960,084	2,583,858	2,564,512	2,990,919	3,415,782	3,603,087	3,780,718	3,746,740	3,460,117	2,941,261	2,764,075	37,466,671
12	System Cost per MWH Sold	c/kwh	5.2354	4.2567	5.0122	5.2667	5.8379	4.7491	4.8948	4.6954	4.4853	4.2980	4.1386	4.7864	4.7821
13	Jurisdictional Loss Multiplier	x	1.0015	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148	1.00148
14	Jurisdictional Cost per MWH Sold	c/kwh	5.2434	4.2648	5.0196	5.2788	5.8466	4.7562	4.9021	4.7023	4.5017	4.3045	4.1447	4.7934	4.7890
15	Prior Period True-Up	÷	0.0189	0.0170	0.0194	0.0194	0.0166	0.0147	0.0139	0.0132	0.0134	0.0145	0.0170	0.0181	0.0160
16	Total Jurisdictional Fuel Expense	c/kwh	5.2624	4.2819	5.0388	5.2982	5.8634	4.7708	4.9160	4.7155	4.5151	4.3190	4.1617	4.8114	4.8050
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	5.2662	4.2850	5.0424	5.3000	5.8676	4.7743	4.9195	4.7189	4.5183	4.3221	4.1647	4.8148	4.8085
19	GPIF	÷	0.0104	0.0093	0.0106	0.0106	0.0092	0.0080	0.0076	0.0072	0.0073	0.0079	0.0093	0.0099	0.0088
20	Total Recovery Factor (rounded .001)	c/kwh	5.277	4.294	5.053	5.311	5.877	4.782	4.927	4.726	4.526	4.330	4.174	4.826	4.817

Duke Energy Florida
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January through December 2013

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional Kwh sales - difference	(767,385,169)
2	Non-Jurisdictional Kwh sales - difference	136,131,039
3	Total System Kwh sales - difference Schedule A2, pg 1 of 2, line B3	(631,254,130)
	System:	
4	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C4	$ 22,072,214
	Jurisdictional:	
5	Fuel Revenues - difference Schedule A2, page 2 of 2, line C3	$ 82,636,701
6	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C6 - C12 - C7	16,322,163
7	True Up amount for the period	66,314,538
8	True Up for the prior period Schedule A2, page 2 of 2, lines C9 + C10	(72,210,888)
9	Interest Provision Schedule A2, page 2 of 2, line C8	(64,940)
10	Actual True Up ending balance for the period January 2013 through December 2013 Schedule A2, page 2 of 2, line C13	(5,961,090)
11	Estimated True Up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2013, Docket No. 130001-EI.	(33,195,183)
12	Total True Up for the period January 2013 through December 2013	$ 27,234,093

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2013

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,978)	(2,328,177)	(2,554,581)	(3,037,856)	(5,011,053)	(4,283,713)	(20,261,357)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,788	8,068,615	11,342,391	10,281,586	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	19,749,624	16,442,524	16,096,280	16,205,598	16,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(3,726,853)	(980,950)	(1,208,363)	(1,893,142)	(497,107,752)	(1,180,522)	(505,897,583)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	123,947,956	117,806,426	133,320,665	141,650,431	(344,979,200)	184,125,923	355,872,202
B	1	Jurisdictional KWH Sales	2,608,843	2,578,190	2,542,534	2,678,410	3,007,039	3,332,388	16,747,412
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,465
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,898,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	RRSSA Refunds	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	64,500,000
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,456)
	2a	Incentive Provision	(124,831)	(124,831)	(124,831)	(124,831)	(124,831)	(124,831)	(749,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	91,801,634	90,634,172	89,410,047	94,647,634	107,915,157	120,813,711	595,222,557
	4	Fuel & Net Power Transactions (Line A6)	123,947,956	117,806,426	133,320,665	141,650,431	(344,979,200)	184,125,923	355,872,202
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	123,193,249	117,239,842	132,759,579	140,940,796	(343,976,484)	183,295,699	353,452,683
	6	Over/(Under) Recovery (Line 3 - Line 5)	(31,391,415)	(26,605,670)	(43,349,531)	(46,293,164)	451,891,641	(62,481,988)	241,769,874
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,089	(74,541)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,048)	(26,625,199)	(43,370,900)	(46,314,161)	451,886,538	(62,475,899)	241,695,332
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,818	36,341,726	48,455,637	60,569,547	72,683,456	72,683,456
	11	Subtotal Prior Period True-up	(205,463,690)	(193,349,781)	(181,235,872)	(168,121,962)	(157,008,053)	(144,894,144)	(144,894,144)
	12	Regulatory Accounting Adjustment	0	0	(229,070)	0	37,080	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	(251,[illegible])	([illegible]262,866,088)	([illegible]17,166,340)	$146,971,189	[illegible],609,198	[illegible]

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2013

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 140,787,849	$ 156,764,431	$ 144,016,453	$ 123,843,275	$ 105,810,373	$ 113,426,007	$ 1,489,345,986
	2	Fuel Cost of Power Sold	(5,791,581)	(4,126,083)	(4,498,837)	(4,754,695)	(3,820,361)	(2,661,402)	(45,914,318)
	3	Fuel Cost of Purchased Power	12,925,771	13,825,220	11,043,093	8,927,041	4,362,905	6,219,268	118,627,580
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	19,484,721	14,922,235	13,518,916	12,409,944	13,395,961	12,520,453	194,768,082
	4	Energy Cost of Economy Purchases	2,341,535	1,452,499	2,198,163	1,870,099	787,375	631,034	16,754,127
	5	Adjustments to Fuel Cost	(957,291)	(6,906,504)	(554,753)	(993,701)	(1,083,908)	926,244	(515,447,495)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	168,791,004	175,931,800	165,723,035	141,301,964	119,452,345	131,061,614	1,258,133,963
B	1	Jurisdictional KWH Sales	3,558,686	3,478,835	3,700,720	3,384,393	2,942,773	2,803,169	36,616,988
	2	Non-Jurisdictional KWH Sales	22,864	25,100	28,730	26,959	24,277	20,351	248,433
	3	TOTAL SALES (Lines B1 + B2)	3,581,550	3,503,935	3,729,450	3,411,352	2,967,050	2,823,520	36,865,421
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.36%	99.28%	99.23%	99.21%	99.18%	99.28%	99.32%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	131,542,415	128,793,108	137,289,690	124,618,095	106,490,443	102,320,188	1,335,207,737
	1a	RRSSA Refunds	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	10,750,000	129,000,000
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	130,053,875	127,304,568	135,801,150	123,129,554	105,001,902	100,831,648	1,317,345,253
	4	Fuel & Net Power Transactions (Line A6)	168,791,004	175,931,800	165,723,035	141,301,964	119,452,345	131,061,614	1,258,133,963
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	167,962,308	174,927,065	164,693,638	140,395,957	118,650,545	130,313,147	1,250,395,366
	6	Over/(Under) Recovery (Line 3 - Line 5)	(37,908,433)	(47,622,521)	(28,892,488)	(17,266,402)	(13,648,643)	(29,481,500)	66,949,886
	7	Interest Provision	4,186	2,853	1,346	638	631	147	(64,939)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(37,904,247)	(47,619,668)	(28,891,142)	(17,265,764)	(13,648,012)	(29,481,352)	66,884,947
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,365	96,911,275	109,025,184	121,139,093	133,253,003	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,234)	(120,666,325)	(108,552,416)	(96,438,506)	(84,324,597)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	(443,360)	(635,349)
	13	TOTAL TRUE-UP BALANCE	$70,818,861	$35,312,602	$18,535,670	$13,383,815	$11,649,712	($5,961,090)	(5,961,090)

Duke Energy Florida
Calculation of 2013 Estimated/Actual True-up
For the Period of January through December 2013 (Filed August 2, 2013)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,978)	(2,326,177)	(2,554,581)	(3,037,867)	(5,011,053)	(4,283,713)	(20,261,358)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,766	8,066,815	11,342,391	10,281,566	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	19,749,624	18,442,524	18,066,280	16,205,598	18,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(14,542,710)	(11,782,902)	(12,003,796)	(12,497,267)	(507,869,089)	(11,979,214)	(570,694,978)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,132,100	107,004,475	122,525,232	130,846,304	(355,780,537)	173,327,232	291,074,805
B	1	Jurisdictional KWH Sales	2,606,843	2,578,190	2,542,535	2,678,410	3,007,039	3,332,396	16,747,413
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,466
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,668,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,454)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(747,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	81,051,835	79,884,173	78,660,048	83,897,634	97,165,158	110,063,712	530,722,559
	4	Fuel & Net Power Transactions (Line A6)	113,132,100	107,004,475	122,525,232	130,846,304	(355,780,537)	173,327,232	291,074,805
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	112,443,249	106,469,842	122,009,578	130,190,797	(354,726,484)	172,545,699	288,932,682
	6	Over/(Under) Recovery (Line 3 - Line 5)	(31,391,414)	(26,585,669)	(43,349,531)	(46,293,163)	451,891,642	(62,481,988)	241,789,874
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,086	(74,541)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,047)	(26,625,199)	(43,370,900)	(46,314,160)	451,886,539	(62,475,899)	241,695,332
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,818	36,341,727	48,455,636	60,569,545	72,683,454	72,683,454
	11	Subtotal Prior Period True-up	(205,463,691)	(193,349,782)	(181,235,873)	(169,121,964)	(157,008,055)	(144,894,146)	(144,894,146)
	12	Regulatory Accounting Adjustment	0	0	(229,070)	0	37,080	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	($251,380,027)	($282,866,088)	($317,068,339)	$146,971,190	$96,609,196	96,609,196

Duke Energy Florida
Calculation of 2013 Estimated/Actual True-up
For the Period of January through December 2013 (Filed August 2, 2013)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 145,250,812	$ 150,607,717	$ 136,985,940	$ 114,538,238	$ 107,076,208	$ 108,923,607	$ 1,468,079,120
	2	Fuel Cost of Power Sold	(5,569,460)	(5,527,090)	(5,386,128)	(4,989,913)	(3,255,666)	(2,375,280)	(47,344,905)
	3	Fuel Cost of Purchased Power	23,957,592	25,094,990	21,710,075	18,555,272	9,564,987	6,499,016	166,696,213
	3a	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0
	3b	Energy Payments to Qualified Facilities	18,004,359	13,089,077	12,644,871	11,903,930	12,867,264	15,760,883	192,576,244
	4	Energy Cost of Economy Purchases	1,756,060	1,775,447	1,778,869	1,742,573	915,791	706,536	16,166,496
	5	Adjustments to Fuel Cost	(10,817,565)	(10,821,916)	(10,826,271)	(10,826,450)	(10,827,360)	(10,816,477)	(635,633,018)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
B	1	Jurisdictional KWH Sales	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,683,127
	2	Non-Jurisdictional KWH Sales	18,864	21,241	22,861	20,547	17,439	14,034	215,839
	3	TOTAL SALES (Lines B1 + B2)	3,602,269	3,770,211	3,774,900	3,298,134	2,858,604	2,746,382	36,898,966
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.48%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	132,431,293	138,550,051	138,670,863	121,129,229	105,000,455	100,978,923	1,340,914,612
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,913)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	120,192,753	126,311,511	126,432,323	108,890,689	92,761,915	88,740,380	1,194,052,129
	4	Fuel & Net Power Transactions (Line A6)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
	6	Over/(Under) Recovery (Line 3 - Line 5)	(51,749,146)	(47,190,956)	(29,765,347)	(21,434,318)	(22,823,112)	(29,529,673)	39,277,324
	7	Interest Provision	3,842	1,974	656	(18)	(519)	(1,222)	(69,829)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(51,745,304)	(47,188,981)	(29,764,691)	(21,434,336)	(22,823,632)	(29,530,895)	39,207,494
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,383	96,911,272	109,025,181	121,139,090	133,252,999	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,217)	(120,666,328)	(108,552,419)	(96,438,510)	(84,324,601)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	(191,990)
	13	TOTAL TRUE-UP BALANCE	$56,977,803	$21,902,730	$4,251,948	($5,068,478)	($15,778,201)	($33,195,184)	(33,195,183)

Duke Energy Florida
Fuel and Net Power Cost Variance Analysis
January through December 2013

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	2,216,309	(1,558,362)	2,755,764	3,413,711
2	Light Oil	18,957,474	(21,625,917)	(1,306,955)	(3,975,398)
3	Coal	22,277,893	3,117,476	29,567,156	54,962,525
4	Gas	(20,755,302)	22,720,535	71,375,628	73,340,861
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	22,696,374	2,653,732	102,391,593	127,741,699
8	Firm Purchases	(71,978,016)	0	(7,151,352)	(79,129,368)
9	Economy Purchases	9,836,545	0	(4,179,174)	5,657,371
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	23,475,347	0	9,344,448	32,819,795
12	Total Purchases	(38,666,124)	0	(1,986,078)	(40,652,202)
13	Economy Sales	0	0	0	0
14	Other Power Sales	760,020	0	97,312	857,332
15	Supplemental Sales	(875,163)	0	(6,542,399)	(7,417,562)
16	Total Sales	(115,143)	0	(6,445,087)	(6,560,230)
17	Nuclear Fuel Disposal Cost	0	0	0	0
18	Nuclear Decom & Decon	0	0	0	0
	Other Jurisdictional Adjustments:				
19a	Final NEIL Adjustment	0	0	(164,713,428)	(164,713,428)
19b	Sch A2 Page 1 of 2 Line 6b, excl NEIL	0	0	106,256,374	106,256,374
20	Total Fuel and Net Power Cost Variance	(16,084,893)	2,653,732	35,503,374	22,072,213

Docket: 140001-EI
Witness: Foster
Exhibit: TGF-1T (Sheet 7 of 7)

Duke Energy Florida
Summary of Revised and Restated Settlement Agreement (RRSSA) Adjustments
For the Period of January through December 2013

System:	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	12 Month Period	Schedule Reference	RRSSA Paragraph
1 Final NEIL Reimbursement	-	-	-	-	(492,313,428)	-	-	-	-	-	-	-	(492,313,428)		7.c. / 7.d.
2 Other Adjustments to Fuel Cost	(3,726,853)	(980,950)	(1,208,363)	(1,693,142)	(4,794,324)	(1,180,622)	(957,281)	(6,906,504)	(564,763)	(983,701)	(1,063,908)	926,244	(23,134,067)		
3 Total 2013 Adjustments to Fuel Cost (Lines 1 + 2)	(3,726,853)	(980,950)	(1,208,363)	(1,693,142)	(497,107,752)	(1,180,622)	(957,281)	(6,906,504)	(564,763)	(983,701)	(1,063,908)	926,244	(515,447,495)	E1-B, line A5	
4 Jurisdictional % of Total Sales	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.36%	99.28%	99.23%	99.21%	99.18%	99.28%			

Retail:	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Actual Jul-13	Actual Aug-13	Actual Sep-13	Actual Oct-13	Actual Nov-13	Actual Dec-13	12 Month Period	Schedule Reference	RRSSA Paragraph
5 Final NEIL Reimbursement (Line 1 * 4)	-	-	-	-	(490,147,249)	-	-	-	-	-	-	-	(490,147,249)		7.c. / 7.d.
6 Other Adjustments to Fuel Cost (Line 2 * 4)	(3,699,647)	(974,770)	(1,201,475)	(1,682,136)	(4,773,229)	(1,173,439)	(951,164)	(6,856,777)	(550,481)	(985,851)	(1,055,184)	919,575	(22,984,600)		
7 Total 2013 Adjustments to Fuel Cost (Lines 5 +6)	(3,699,647)	(974,770)	(1,201,475)	(1,682,136)	(494,920,478)	(1,173,439)	(951,164)	(6,856,777)	(550,481)	(985,851)	(1,055,184)	919,575	(513,131,829)		
8 RRSSA Refund (1st 50% of $258 million)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(129,000,000)	E1-B, line C1a	6.a.
9 Total 2013 RRSSA Adjustments & Refunds (Lines 5 + 8)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(500,897,249)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(10,750,000)	(619,147,249)		

Duke Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2013

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 46	$ 518,070,756	$ 527,802,715	$ (9,731,959)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 42	539,122,320	$ 527,802,715	$ 11,319,605
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 49	(30,138)	0	(30,138)
4	Sub Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 50	$ (21,081,701)	$	$ (21,081,701)
5	Prior Period True-up - January through December 2013- Over/(Under) Recovery Sheet 2 of 3, Line 51	(20,253,873)	(10,485,623)	(9,768,250)
6	Prior Period True-up - January through December 2013 - (Refunded)/Collected Sheet 2 of 3, Line 52	10,485,623	10,485,623	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2013 Sheet 2 of 3, Line 55	$ (30,849,951)	$	$ (30,849,951)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2013 Docket No. 130001-EI. (Sheet 3 of 3, Line 54)	(24,360,251)		
9	Total Over/(Under) Recovery for the period January through December 2013 (Line 7 - Line 8)	$ (6,489,700)		

EXHIBIT NO. ___72_____

DOCKET NO: **140001-EI**

WITNESS: **Foster**

PARTY: **Duke Energy Florida**

DESCRIPTION: **Late-filed Exhibit providing carrying costs for CR3 Regulatory Asset**

DOCUMENTS: 2014 AFUDC on CR3 Regulatory Asset and Updated Exhibit 10

PROFFERED BY: **Duke Energy Florida.**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 72
PARTY: Duke Energy
DESCRIPTION: Foster/Late-filed, updated EXH 10

Fuel Docket #140001
Late Filed Exhibit

CR3 Regulatory Asset AFUDC and Early Recovery
2014 (Actual Jan-Sep, Estimated Oct-Dec)
($ million)

AFUDC on CR3 Regulatory Asset	$74.6
Fuel Revenue ($1.00/mwh)	$38.5
Less Income Tax (38.575%)	($14.8)
Early Recovery Applied to CR3 Regulatory Asset	$23.6

DUKE ENERGY FLORIDA **Schedule 6**
Earnings Surveillance Report
CR3 Regulatory Asset Value
September 2014
(In Millions)

Line No.	Pre or Post Retirement Component Classification	*category*	Subject to Cap	Dry Cask Storage	Total Regulatory Asset
1					
2	Electric Plant In Service	a	856		856
3	Less Accumulated Depreciation	b	435		435
4	Net plant balance	fallout	420		420
5	Write-Down	b	(295)		(295)
6	Construction Work In Progress (CWIP)				
7	Steam Generator Replacement (SGR) Project	a	360		360
8	Delam Repair Project	b	167		167
9	License Amendment Request (LAR)	b	20		20
10	Dry Cask Storage	d		28	28
11	Fukushima	d	3		3
12	Building Stabilization Project	c	22		22
13	Other - CWIP	d	50		50
14	Nuclear Fuel Inventories	a	256		256
15	Nuclear Materials and Supplies Inventories	a	52		52
16	Deferred expenses	e	101		101
17	Cumulative AFUDC (6.00%)	fallout	108	5	113
18	Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)	b	108		108
19	Total CR3 Regulatory Asset	fallout	1,372	33	1,405

category

a The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs except that the Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value after February 5, 2013 and to sell or otherwise salvage assets after February 5, 2013 that would otherwise be included in the CR3 Regulatory Asset.

b The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs.

c The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover costs incurred by the Company before February 5, 2013. The Intervenor Parties retain the right to challenge the prudence of any costs incurred after and applicable to the period after February 5, 2013 that are submitted for recovery by the Company.

d The Intervenor Parties retain the right to challenge the prudence of any costs submitted for recovery by the Company.

e The Intervenor Parties retain the right to verify that the Company has complied with paragraph 5b of the Revised and Restated Settlement Agreement.

Note Reference Docket No. 130208-EI, Order No. PSC-13-0598-FOF-EI, Settlement Exhibit 10.