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September 1, 2016

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 160001-EI

Dear Ms. Stauffer:

Attached for filing in the above docket on behalf of Tampa Electric Company are the original of each of the following:

1. Petition of Tampa Electric Company.

2. Prepared Direct Testimony and Exhibit (PAR-3) of Penelope A. Rusk.

3. Prepared Direct Testimony and Exhibit (BSB-2) of Brian S. Buckley.

4. Prepared Direct Testimony of J. Brent Caldwell.

5. Prepared Direct Testimony of Benjamin F. Smith II.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition and Testimonies, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 1st day of September 2016, to the following:

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ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 160001-EI FILED: September 1, 2016

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "company"), hereby petitions the Commission for approval of the company's proposals concerning fuel and purchased power factors, capacity cost factors, generating performance incentive factors, and the projected wholesale sales incentive benchmark set forth herein, and in support thereof, says:

Fuel and Purchased Power Factors

1. Tampa Electric projects a fuel and purchased power net true-up amount for the period January 1, 2016 through December 31, 2016 will be an over-recovery of $122,639,796 (See Exhibit No. PAR-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2017 through December 31, 2017, when adjusted for the proposed GPIF penalty and true-up over-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2017 through December 31, 2017, produce a fuel and purchased power factor for the new period of 2.956 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. PAR-3, Document No. 2, Schedule E1-E).

3. The company's projected benchmark level for calendar year 2017 for gains on non-separated wholesale energy sales eligible for the shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779 is $1,337,579 as provided in the direct testimony of Tampa Electric witness Penelope A. Rusk.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2016 through December 31, 2016 will be an under-recovery of $2,986,060, as shown in Exhibit No. PAR-3, Document No. 1, page 2 of 4.

5. The company's projected expenditures for the period January 1, 2017 through December 31, 2017, when adjusted for the true-up under-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of 0.00074 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.27 per billed kW as set forth in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF reward of $969,593 for performance during the period January 1, 2015 through December 31, 2015.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2017 through December 31, 2017 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Brian S. Buckley filed herewith.

WHEREFORE, Tampa Electric Company requests that its proposals relative to fuel and purchased power cost recovery, capacity cost recovery and GPIF be approved as they relate to prior period true-up calculations and projected cost recovery charges, and that the Commission approve the company's projected wholesale sales incentive benchmark.

DATED this 1st day of September 2016.

Respectfully submitted,

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Ausley McMullen
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 1st day of September 2016, to the following:

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ATTORNEY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2017 THROUGH DECEMBER 2017

TESTIMONY AND EXHIBIT

OF

PENELOPE A. RUSK

FILED: SEPTEMBER 1, 2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

Q. Please state your name, address, occupation and employer.

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2017 through December 2017. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2017.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. PAR-3, consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document

No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2017 through December 2017 as well as Schedule H1 for January through December, 2014 through 2017. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company’s projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. PAR-3, Document No. 1, Tampa Electric requests recovery of $14,045,318 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2017.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2017 through December 2017.

A.

Rate Class and	**Capacity Cost**	**Recovery Factor**
Metering Voltage	**Cents per kWh**	**$ per kW**
RS Secondary	0.088	
GS and TS Secondary	0.076	
GSD, SBF Standard		
Secondary		0.27
Primary		0.27
Transmission		0.26
IS, IST, SBI		

Primary		0.14
Transmission		0.14
GSD Optional		
Secondary	0.063	
Primary	0.062	
LS1 Secondary	0.017	

These factors are shown in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.074 cents per kWh compare to the factor for January 2016 through December 2016?

A. The proposed capacity cost recovery factor is 0.077 cents per kWh (or $0.77 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.151 cents per kWh for the January 2016 through December 2016 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2017?

A. The appropriate amount for the 2017 period is 2.956 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. PAR-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2017 through December 2017.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $969,593, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2016 through December 2016 period. The net true-up amount for this period is an over-recovery of $122,639,796.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2017 through December 2017. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. PAR-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2017 through December 2017.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	2.956
Tier I (Up to 1,000 kWh)	2.642
Tier II (Over 1,000 kWh)	3.642
Distribution Primary	2.926

Transmission	2.897	
Lighting Service	2.916	
Distribution Secondary	3.166	(on-peak)
	2.865	(off-peak)
Distribution Primary	3.134	(on-peak)
	2.836	(off-peak)
Transmission	3.103	(on-peak)
	2.808	(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 2.956 cents per kWh compare to the levelized fuel adjustment factor for the January 2016 through December 2016 period?

A. The proposed fuel charge factor is 0.720 cents per kWh (or $7.20 per 1,000 kWh) lower than the average fuel charge factor of 3.676 cents per kWh for the January 2016 through December 2016 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2017 fuel and purchased power and capacity cost recovery projections?

A. Yes, the company's highly efficient Polk 2 combined cycle

("CC") unit is anticipated to begin commercial service in January 2017. The unit will provide reliable and efficient natural gas-fired generation for customers. As stated in the testimony of Tampa Electric witness J. Brent Caldwell, the company did not require new natural gas supply or transportation agreements to serve this unit, due to the flexibility of the company's existing natural gas supply portfolio.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project costs for the period January 2017 through December 2017?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2017 through December 2017 are $3,518,938. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Polk Unit 1 ignition oil conversion project fuel savings exceed estimated costs for the period January 2017 through December 2017?

A. Yes, as reflected in Exhibit No. PAR-3, Document No. 4, fuel savings exceed costs for the period January 2017 through December 2017.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2017 through December 2017 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2017 through December 2017?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2017 through December 2017 are $5,260,518. This is shown in Document No. 4 of my exhibit.

Q. Does Tampa Electric's estimated Big Bend ignition oil conversion project fuel savings exceed estimated costs for the period of January 2017 through December 2017?

A. Yes, fuel savings exceed costs for the period January 2017 through December 2017. This information is also presented in Document No. 4 of my exhibit.

Q. Should Tampa Electric's Big Bend Units 1-4 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2017 through December 2017 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates used to calculate the revenue requirement rate of return for these two projects.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company's projects that are approved for recovery through the fuel clause are shown in Document No. 4.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2017?

A. The company's projected 2017 benchmark is $1,337,579, which is the three-year average of $3,298,966, $496,810 and $216,961 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2014, 2015 and 2016 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2017 from non-separated wholesale sales to exceed its 2017 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2017. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its base, capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $1.54 beginning January 2017, when compared to the January 2016 through December 2016 charges. These charges are shown in Exhibit No. PAR-3, Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2017 - DECEMBER 2017

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2017 THROUGH DECEMBER 2017
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	53.13%	8,934,018	1,919	1.07835	1.05122	9,391,609	2,070	46.88%	56.83%	56.06%
GS, TS	62.24%	1,001,850	184	1.07835	1.05120	1,053,149	198	5.26%	5.44%	5.43%
GSD Optional	3.82%	400,105	59	1.07384	1.04767	419,179	64	2.09%	1.76%	1.79%
GSD, SBF	73.08%	7,655,374	1,136	1.07384	1.04767	8,020,323	1,220	40.03%	33.50%	34.00%
IS,SBI	128.17%	908,781	81	1.02975	1.01779	924,945	83	4.62%	2.28%	2.46%
LS1	354.65%	213,951	7	1.07835	1.05122	224,909	7	1.12%	0.19%	0.26%
TOTAL		19,114,079	3,387			20,034,114	3,642	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2016 projected calendar data.
(2) Projected MWH sales for the period January 2017 thru December 2017.
(3) Based on 12 months average CP at meter.
(4) Based on 2016 projected demand losses.
(5) Based on 2016 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2017 THROUGH DECEMBER 2017
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,849,010	1,849,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	11,938,120
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,290)	(843,469)
4	TOTAL CAPACITY DOLLARS	$1,778,721	$1,778,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,720	$11,094,651
5	SEPARATION FACTOR	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	
6	JURISDICTIONAL CAPACITY DOLLARS	$1,771,427	$1,771,427	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,629	$11,049,153
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2016 - DEC. 2016													2,986,060
8	TOTAL													$14,035,213
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$14,045,318

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2017 THROUGH DECEMBER 2017
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	46.88%	56.83%	506,344	7,368,142	7,874,486	8,934,018	8,934,018				0.00088
GS, CS	5.26%	5.44%	56,812	705,309	762,121	1,001,850	1,001,850				0.00076
GSD, SBF											
Secondary						6,308,487	6,308,487			0.27	
Primary						1,332,269	1,318,946			0.27	
Transmission						14,618	14,326			0.26	
GSD, SBF - Standard	40.03%	33.50%	432,358	4,343,353	4,775,711	7,655,374	7,641,759	58.82%	17,796,925		
GSD - Optional	2.09%	1.76%	22,574	228,188	250,762						
Secondary						388,922	388,922				0.00063
Primary						11,183	11,071				0.00062
IS, SBI											
Primary						231,174	228,862			0.14	
Transmission						677,607	664,055			0.14	
Total IS, SBI	4.62%	2.28%	49,900	295,607	345,507	908,781	892,917	48.65%	2,514,473		
LS1	1.12%	0.19%	12,097	24,634	36,731	213,951	213,951				0.00017
TOTAL	100.00%	100.00%	1,080,085	12,965,233	14,045,318	19,114,079	19,084,488				0.00074

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * 0.0769 * Col (1).
(4) Total capacity costs * 0.9231 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2017 through December 2017.
(7) Projected kWh sales at secondary for the period January 2017 through December 2017.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2017 through December 2017.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

REDACTED

TAMPA ELECTRIC COMPANY

CAPACITY COSTS

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
				QF = QUALIFYING FACILITY
DUKE ENERGY FLORIDA	2/1/2016	2/28/2017	LT	LT = LONG TERM
PASCO COGEN	1/1/2009	12/31/2018	LT	ST = SHORT-TERM
SEMINOLE ELECTRIC **	6/1/1992	--------		** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
DUKE ENERGY FLORIDA	250.0	250.0	-	-	-	-	-	-	-	-	-	-
PASCO COGEN	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
SEMINOLE ELECTRIC	1.4	1.4	1.5	1.8	1.3	1.4	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
DUKE ENERGY FLORIDA	[redacted]												
PASCO COGEN - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,778,721	1,778,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,720	11,094,651
TOTAL CAPACITY	**$1,778,721**	**$1,778,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,720**	**$11,094,651**

18

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2017 - DECEMBER 2017

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2017 - DEC. 2017)
3	Schedule E1-A Calculation of Total True-Up	(")
4	Schedule E1-C GPIF & True-Up Adj. Factors	(")
5	Schedule E1-D Fuel Adjustment Factor for TOD	(")
6	Schedule E1-E Fuel Recovery Factor-with Line Losses	(")
7	Schedule E2 Cost Recovery Clause Calculation (By Month)	(")
8-9	Schedule E3 Generating System Comparative Data	(")
10-21	Schedule E4 System Net Generation & Fuel Cost	(")
22-23	Schedule E5 Inventory Analysis	(")
24-25	Schedule E6 Power Sold	(")
26	Schedule E7 Purchased Power	(")
27	Schedule E8 Energy Payment to Qualifying Facilities	(")
28	Schedule E9 Economy Energy Purchases	(")
29	Schedule E10 Residential Bill Comparison	(")
30	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2014-2017)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	663,929,452	19,662,330	3.37666
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Big Bend Units 1-4 Igniters Conversion Project	5,260,518	19,662,330 (1)	0.02675
4b.	Polk 1 Ignition Conversion	3,518,938	19,662,330 (1)	0.01790
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**672,708,908**	**19,662,330**	**3.42131**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	1,172,410	25,290	4.63586
7.	Energy Cost of Economy Purchases (E9)	10,162,220	306,900	3.31125
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,449,180	90,110	2.71799
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**13,783,810**	**422,300**	**3.26399**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,084,630	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	282,200	10,340	2.72921
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	368,909	11,980	3.07937
14.	Gains on Sales	47,795	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**698,904**	**22,320**	**3.13129**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		(175)	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**685,793,814**	**20,062,485**	**3.41829**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,169,055 (1)	34,200	0.00611
22.	T & D Losses	30,759,343 (1)	899,846	0.16080
23.	System MWH Sales	685,793,814	19,128,439	3.58521
24.	Wholesale MWH Sales	(451,166)	(14,360)	3.14182
25.	Jurisdictional MWH Sales	685,342,648	19,114,079	3.58554
26.	Jurisdictional Loss Multiplier			1.00002
27.	Jurisdictional MWH Sales Adjusted for Line Loss	685,355,389	19,114,079	3.58561
28.	True-up [2]	(122,639,796)	19,114,079	(0.64162)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	562,715,593	19,114,079	2.94398
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	563,120,748	19,114,079	2.94610
32.	GPIF Adjusted for Taxes [2]	969,593	19,114,079	0.00507
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	564,090,341	19,114,079	2.95117
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**2.951**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Calculation Based on Jurisdictional MWH Sales

TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2016 - December 2016 (6 months actual, 6 months estimated)	$104,581,497
2.	FINAL TRUE-UP (January 2015 - December 2015) (Per True-Up filed March 2, 2016)	18,058,299
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2017 through December 2017 (Schedule E1, line 28)	$122,639,796
4.	JURISDICTIONAL MWH SALES (Projected January 2017 through December 2017)	19,114,079
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.6416)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2017 through December 2017)	$969,593	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2016 through December 2016)	$122,639,796	
2.	TOTAL SALES (January 2017 through December 2017)	19,114,079	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0051**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.6416)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.12	$24.19
OFF PEAK	69.88	$21.89
	100.00	1.1051

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$685,342,648		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,114,079		
2a	Effective MWH Sales (Jurisd)		19,084,489		
3	Cost Per KWH Sold	(line 1 / line 2)	3.5855		
4	Jurisdictional Loss Factor		1.00002		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($122,639,796)		
7	TOTAL	(line 1 x line 4)+line 6	$562,716,559		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	2.9507		
10	GPIF Factor	(Sch E1-C line 3a)	0.0051		
11	Recovery Factor Including GPIF	(line 9 + line 10)	2.9558	3.1661	2.8651
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		2.956	3.166	2.865

13	Hours: ON PEAK	25.13%
14	OFF PEAK	74.87%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,847,228	16,847,228
Distribution Primary	1,574,626	1,558,880
Transmission	692,225	678,381
Total	19,114,079	19,084,489

	Standard	On-Peak	Off-Peak
Distribution Secondary	2.956	3.166	2.865
Distribution Primary	2.926	3.134	2.836
Transmission	2.897	3.103	2.808
RS 1st Tier	2.642		
RS 2nd Tier	3.642		
Lighting	2.916		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.642	3.642
Distribution Secondary	2.956		
Distribution Primary	2.926		
Transmission	2.897		
Lighting Service [(1)]	2.916		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.166		
Distribution Secondary - Off-Peak	2.865		
Distribution Primary - On-Peak	3.134		
Distribution Primary - Off-Peak	2.836		
Transmission - On-Peak	3.103		
Transmission - Off-Peak	2.808		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	PERIOD
1. Fuel Cost of System Net Generation	48,849,391	42,680,487	48,972,968	51,732,678	56,829,514	62,138,147	66,243,138	68,018,219	63,299,051	57,991,087	46,643,947	50,530,825	663,929,452
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	50,730	49,144	54,115	73,943	49,987	68,157	53,801	72,294	58,033	81,900	44,909	41,891	698,904
4. Fuel Cost of Purchased Power	0	0	36,970	94,160	41,730	201,690	67,350	99,330	170,240	398,720	54,170	8,050	1,172,410
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	265,740	220,310	180,240	151,140	195,940	176,490	210,770	249,340	171,790	229,930	217,840	179,650	2,449,180
7. Energy Cost of Economy Purchases	746,840	829,340	749,990	862,750	715,430	1,128,900	731,910	884,800	790,190	1,201,060	824,330	696,680	10,162,220
8. Big Bend Units 1-4 Igniters Conversion Project	452,629	450,036	447,445	444,855	442,263	439,673	437,080	434,490	431,900	429,308	426,716	424,123	5,260,518
9. Polk 1 Ignition Conversion	304,255	302,253	300,250	298,249	296,247	294,245	292,243	290,242	288,240	286,238	284,238	282,238	3,518,938
10. TOTAL FUEL & NET POWER TRANSACTIONS	**50,568,125**	**44,433,282**	**50,633,748**	**53,509,889**	**58,471,137**	**64,310,988**	**67,928,690**	**69,904,127**	**65,093,378**	**60,454,443**	**48,406,332**	**52,079,675**	**685,793,814**
11. Jurisdictional MWH Sold	1,464,122	1,325,639	1,333,499	1,413,388	1,552,878	1,812,746	1,879,801	1,871,923	1,923,717	1,705,307	1,437,178	1,393,881	19,114,079
12. Jurisdictional % of Total Sales	0.9998103	0.9999385	0.9999800	0.9998259	0.9993573	0.9985997	0.9984870	0.9984497	0.9989864	0.9996746	1.0000000	0.9999217	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	50,558,532	44,430,549	50,632,735	53,500,573	58,433,558	64,220,933	67,825,914	69,795,755	65,027,399	60,434,771	48,406,332	52,075,597	685,342,648
14. Jurisdictional Loss Multiplier	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00000	1.00002	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**50,559,543**	**44,431,438**	**50,633,748**	**53,501,643**	**58,434,727**	**64,222,217**	**67,827,271**	**69,797,151**	**65,028,700**	**60,435,980**	**48,406,332**	**52,076,639**	**685,355,389**
16. Cost Per kWh Sold (Cents/kWh)	3.4532	3.3517	3.7971	3.7853	3.7630	3.5428	3.6082	3.7286	3.3804	3.5440	3.3682	3.7361	3.5856
17. True-up (Cents/kWh) [2]	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)
18. Total (Cents/kWh) (Line 16+17)	2.8116	2.7101	3.1555	3.1437	3.1214	2.9012	2.9666	3.0870	2.7388	2.9024	2.7266	3.0945	2.9440
19. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
20. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.8136	2.7121	3.1578	3.1460	3.1236	2.9033	2.9687	3.0892	2.7408	2.9045	2.7286	3.0967	2.9461
21. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**2.8187**	**2.7172**	**3.1629**	**3.1511**	**3.1287**	**2.9084**	**2.9738**	**3.0943**	**2.7459**	**2.9096**	**2.7337**	**3.1018**	**2.9512**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**2.819**	**2.717**	**3.163**	**3.151**	**3.129**	**2.908**	**2.974**	**3.094**	**2.746**	**2.910**	**2.734**	**3.102**	**2.951**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH JUNE 2017

SCHEDULE E3

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	51,955	54,211	49,104	63,536	48,699	63,017
3. COAL	23,952,767	18,327,084	24,107,497	26,987,734	20,887,421	23,132,938
4. NATURAL GAS	24,844,669	24,299,192	24,816,367	24,681,408	35,893,394	38,942,192
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**48,849,391**	**42,680,487**	**48,972,968**	**51,732,678**	**56,829,514**	**62,138,147**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	220	240	220	280	220	280
10. COAL	781,920	600,450	729,010	835,720	662,230	713,570
11. NATURAL GAS	666,260	679,870	690,520	676,910	1,092,650	1,192,630
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	450	440	570	600	5,620	4,940
14. TOTAL (MWH)	**1,448,850**	**1,281,000**	**1,420,320**	**1,513,510**	**1,760,720**	**1,911,420**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	420	440	400	520	400	520
17. COAL (TON)	338,050	257,240	319,890	363,620	285,430	308,670
18. NATURAL GAS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,663,370	8,395,400
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	2,440	2,600	2,380	3,040	2,360	3,040
23. COAL	8,073,800	6,172,520	7,537,770	8,674,880	6,864,980	7,410,050
24. NATURAL GAS	4,818,400	4,895,090	4,942,920	4,841,780	7,865,540	8,604,760
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,894,640**	**11,070,210**	**12,483,070**	**13,519,700**	**14,732,880**	**16,017,850**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.01	0.01
30. COAL	53.96	46.88	51.32	55.22	37.61	37.34
31. NATURAL GAS	45.99	53.07	48.62	44.72	62.06	62.39
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.03	0.03	0.04	0.04	0.32	0.26
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	123.70	123.21	122.76	122.18	121.75	121.19
37. COAL ($/TON)	70.86	71.25	75.36	74.22	73.18	74.94
38. NATURAL GAS ($/MCF)	5.28	5.08	5.13	5.22	4.68	4.64
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.29	20.85	20.63	20.90	20.64	20.73
43. COAL	2.97	2.97	3.20	3.11	3.04	3.12
44. NATURAL GAS	5.16	4.96	5.02	5.10	4.56	4.53
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.79**	**3.86**	**3.92**	**3.83**	**3.86**	**3.88**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,091	10,833	10,818	10,857	10,727	10,857
50. COAL	10,326	10,280	10,340	10,380	10,366	10,384
51. NATURAL GAS	7,232	7,200	7,158	7,153	7,199	7,215
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,900**	**8,642**	**8,789**	**8,933**	**8,368**	**8,380**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	23.62	22.59	22.32	22.69	22.14	22.51
57. COAL	3.06	3.05	3.31	3.23	3.15	3.24
58. NATURAL GAS	3.73	3.57	3.59	3.65	3.28	3.27
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.37**	**3.33**	**3.45**	**3.42**	**3.23**	**3.25**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2017 THROUGH DECEMBER 2017

SCHEDULE E3

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	48,306	62,518	50,316	62,028	49,928	47,397	651,015
3.	COAL	29,495,002	32,449,216	30,662,100	31,440,579	22,138,218	24,175,762	307,756,318
4.	NATURAL GAS	36,699,830	35,506,485	32,586,635	26,488,480	24,455,801	26,307,666	355,522,119
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**66,243,138**	**68,018,219**	**63,299,051**	**57,991,087**	**46,643,947**	**50,530,825**	**663,929,452**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	220	280	220	280	220	220	2,900
10.	COAL	871,010	955,760	901,400	907,890	634,260	703,830	9,297,050
11.	NATURAL GAS	1,098,360	1,055,040	956,880	740,540	725,740	750,590	10,325,990
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	4,820	4,650	3,860	3,990	3,400	3,050	36,390
14.	**TOTAL (MWH)**	**1,974,410**	**2,015,730**	**1,862,360**	**1,652,700**	**1,363,620**	**1,457,690**	**19,662,330**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	400	520	420	520	420	400	5,380
17.	COAL (TON)	379,310	416,990	392,020	395,620	275,420	303,260	4,035,520
18.	NATURAL GAS (MCF)	7,743,500	7,445,360	6,753,620	5,205,270	5,045,980	5,277,600	72,590,650
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	2,360	2,960	2,440	2,960	2,420	2,360	31,360
23.	COAL	9,045,190	9,912,000	9,330,250	9,421,020	6,568,470	7,257,090	96,268,020
24.	NATURAL GAS	7,931,180	7,634,540	6,921,750	5,331,290	5,151,100	5,403,940	74,342,290
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**16,978,730**	**17,549,500**	**16,254,440**	**14,755,270**	**11,721,990**	**12,663,390**	**170,641,670**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.01	0.02	0.02	0.02	0.01
30.	COAL	44.12	47.42	48.40	54.93	46.51	48.28	47.28
31.	NATURAL GAS	55.63	52.34	51.38	44.81	53.22	51.49	52.52
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.24	0.23	0.21	0.24	0.25	0.21	0.19
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	120.77	120.23	119.80	119.28	118.88	118.49	121.01
37.	COAL ($/TON)	77.76	77.82	78.22	79.47	80.38	79.72	76.26
38.	NATURAL GAS ($/MCF)	4.74	4.77	4.83	5.09	4.85	4.98	4.90
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	20.47	21.12	20.62	20.96	20.63	20.08	20.76
43.	COAL	3.26	3.27	3.29	3.34	3.37	3.33	3.20
44.	NATURAL GAS	4.63	4.65	4.71	4.97	4.75	4.87	4.78
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.90**	**3.88**	**3.89**	**3.93**	**3.98**	**3.99**	**3.89**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,727	10,571	11,091	10,571	11,000	10,727	10,814
50.	COAL	10,385	10,371	10,351	10,377	10,356	10,311	10,355
51.	NATURAL GAS	7,221	7,236	7,234	7,199	7,098	7,200	7,200
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**8,599**	**8,706**	**8,728**	**8,928**	**8,596**	**8,687**	**8,679**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56.	LIGHT OIL	21.96	22.33	22.87	22.15	22.69	21.54	22.45
57.	COAL	3.39	3.40	3.40	3.46	3.49	3.43	3.31
58.	NATURAL GAS	3.34	3.37	3.41	3.58	3.37	3.50	3.44
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**3.36**	**3.37**	**3.40**	**3.51**	**3.42**	**3.47**	**3.38**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	180	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**450**	**19.5**	**-**	**19.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	131,070	-	-	-	10,462	COAL	57,740	23,749,394	1,371,290.0	4,225,626	3.22	73.18
7. TOTAL BIG BEND #1	**395**	**131,070**	**44.6**	**75.4**	**84.9**	**10,462**		**-**	**-**	**1,371,290.0**	**4,225,626**	**3.22**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	179,920	-	-	-	10,271	COAL	79,310	23,301,223	1,848,020.0	5,804,202	3.23	73.18
10. TOTAL BIG BEND #2	**395**	**179,920**	**61.2**	**78.0**	**84.2**	**10,271**		**-**	**-**	**1,848,020.0**	**5,804,202**	**3.23**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	206,650	-	-	-	10,344	COAL	92,940	22,999,032	2,137,530.0	6,801,692	3.29	73.18
13. TOTAL BIG BEND #3	**400**	**206,650**	**69.4**	**86.0**	**81.5**	**10,344**		**-**	**-**	**2,137,530.0**	**6,801,692**	**3.29**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	123,670	-	-	-	10,366	COAL	55,740	22,998,027	1,281,910.0	4,081,918	3.30	73.23
16. TOTAL BIG BEND #4	**442**	**123,670**	**37.6**	**81.9**	**81.1**	**10,366**		**-**	**-**	**1,281,910.0**	**4,081,918**	**3.30**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	95,145	-	5.30
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**641,310**	**52.8**	**80.4**	**82.8**	**10,352**	**COAL**	**285,730**	**23,234,347**	**6,638,750.0**	**20,913,438**	**3.26**	**73.19**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	50	0.1	-	82.0	12,000	GAS	590	1,016,949	600.0	3,127	6.25	5.30
21. B.B.C.T.#4 TOTAL	**61**	**50**	**0.1**	**98.3**	**82.0**	**12,000**	**-**	**-**	**-**	**600.0**	**3,127**	**6.25**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**641,360**	**50.9**	**81.0**	**82.8**	**10,352**	**-**	**-**	**-**	**6,639,350.0**	**21,011,710**	**3.28**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	2,944,184	2.09	56.27
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,050.0**	**2,944,184**	**2.09**	**-**
26. POLK #2 CC GAS	1,195	389,530	43.8	-	58.9	6,744	GAS	2,555,340	1,028,000	2,626,890.0	13,544,728	3.48	5.30
27. POLK #2 CC OIL	187	220	0.2	-	11.8	11,091	LGT OIL	420	5,809,524	2,440.0	51,955	23.62	123.70
28. POLK #2 CC TOTAL	**1,195**	**389,750**	**43.8**	**96.9**	**58.8**	**6,746**	**-**	**-**	**-**	**2,629,330.0**	**13,596,683**	**3.49**	**-**
29. POLK STATION TOTAL	**1,415**	**530,360**	**50.4**	**94.2**	**65.7**	**7,663**	**-**	**-**	**-**	**4,064,380.0**	**16,540,867**	**3.12**	**-**
30. BAYSIDE #1	792	108,500	18.4	96.9	59.8	7,327	GAS	773,300	1,027,997	794,950.0	4,098,921	3.78	5.30
31. BAYSIDE #2	1,047	168,150	21.6	95.9	22.4	8,299	GAS	1,357,510	1,027,992	1,395,510.0	7,195,561	4.28	5.30
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	30	0.1	98.6	49.2	15,000	GAS	440	1,022,727	450.0	2,332	7.77	5.30
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**276,680**	**17.9**	**88.0**	**29.6**	**7,919**	**GAS**	**2,131,250**	**1,027,993**	**2,190,910.0**	**11,296,814**	**4.08**	**5.30**
37. SYSTEM	**5,194**	**1,448,850**	**37.5**	**87.3**	**57.6**	**8,900**	**-**	**-**	**-**	**12,894,640.0**	**48,849,391**	**3.37**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating
[5] Commercial operation scheduled for May 2017
[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	180	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR (5)	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR (3)	**3.1**	**440**	**21.1**	**-**	**21.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	96,840	-	-	-	10,423	COAL	42,500	23,750,824	1,009,410.0	3,138,477	3.24	73.85
7. TOTAL BIG BEND #1	**395**	**96,840**	**36.5**	**51.8**	**89.8**	**10,423**		**-**	**-**	**1,009,410.0**	**3,138,477**	**3.24**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	111,840	-	-	-	10,185	COAL	48,890	23,299,243	1,139,100.0	3,610,353	3.23	73.85
10. TOTAL BIG BEND #2	**395**	**111,840**	**42.1**	**49.8**	**92.8**	**10,185**		**-**	**-**	**1,139,100.0**	**3,610,353**	**3.23**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	194,400	-	-	-	10,305	COAL	87,100	22,999,541	2,003,260.0	6,432,027	3.31	73.85
13. TOTAL BIG BEND #3	**400**	**194,400**	**72.3**	**86.0**	**84.8**	**10,305**		**-**	**-**	**2,003,260.0**	**6,432,027**	**3.31**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	70,460	-	-	-	10,295	COAL	31,540	22,999,049	725,390.0	2,337,395	3.32	74.11
16. TOTAL BIG BEND #4	**442**	**70,460**	**23.7**	**43.9**	**91.1**	**10,295**		**-**	**-**	**725,390.0**	**2,337,395**	**3.32**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	22,120	-	22,740.0	112,878	-	5.10
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**473,540**	**43.2**	**57.5**	**88.5**	**10,299**	**COAL**	**210,030**	**23,221,254**	**4,877,160.0**	**15,518,252**	**3.28**	**73.89**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	20	0.0	-	32.8	14,500	GAS	280	1,035,714	290.0	1,429	7.15	5.10
21. B.B.C.T.#4 TOTAL	**61**	**20**	**0.0**	**98.3**	**32.8**	**14,500**	**-**	**-**	**-**	**290.0**	**1,429**	**7.15**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**473,560**	**41.6**	**59.0**	**88.5**	**10,300**	**-**	**-**	**-**	**4,877,450.0**	**15,632,559**	**3.30**	**-**
23. POLK #1 GASIFIER	220	126,910	85.8	-	97.4	10,207	COAL	47,210	27,438,255	1,295,360.0	2,695,954	2.12	57.11
24. POLK #1 CT GAS (4)	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**126,910**	**85.8**	**79.0**	**97.4**	**10,207**	**-**	**-**	**-**	**1,295,360.0**	**2,695,954**	**2.12**	**-**
26. POLK #2 CC GAS	1,195	439,610	54.7	-	55.3	6,742	GAS	2,883,130	1,028,004	2,963,870.0	14,712,632	3.35	5.10
27. POLK #2 CC OIL	187	240	0.2	-	16.0	10,833	LGT OIL	440	5,909,091	2,600.0	54,211	22.59	123.21
28. POLK #2 CC TOTAL	**1,195**	**439,850**	**54.8**	**96.9**	**55.2**	**6,744**	**-**	**-**	**-**	**2,966,470.0**	**14,766,843**	**3.36**	**-**
29. POLK STATION TOTAL	**1,415**	**566,760**	**59.6**	**94.2**	**61.2**	**7,520**	**-**	**-**	**-**	**4,261,830.0**	**17,462,797**	**3.08**	**-**
30. BAYSIDE #1	792	109,340	20.5	39.8	45.9	7,456	GAS	793,060	1,028,005	815,270.0	4,046,991	3.70	5.10
31. BAYSIDE #2	1,047	130,900	18.6	95.9	19.3	8,523	GAS	1,085,270	1,028,002	1,115,660.0	5,538,140	4.23	5.10
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**240,240**	**17.2**	**63.4**	**26.2**	**8,038**	**GAS**	**1,878,330**	**1,028,004**	**1,930,930.0**	**9,585,131**	**3.99**	**5.10**
37. SYSTEM	**5,194**	**1,281,000**	**36.7**	**70.3**	**53.8**	**8,642**	**-**	**-**	**-**	**11,070,210.0**	**42,680,487**	**3.33**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) As burned fuel cost system total includes ignition.
(2) Fuel burned (MM BTU) system total excludes ignition.
(3) AC rating
(4) Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.
(5) Commercial operation scheduled for May 2017

30

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	330	27.7	-	27.7	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	240	21.5	-	21.5	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**570**	**24.7**	**-**	**24.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	197,020	-	-	-	10,389	COAL	86,180	23,750,870	2,046,850.0	6,534,318	3.32	75.82
7. TOTAL BIG BEND #1	**395**	**197,020**	**67.0**	**80.6**	**91.7**	**10,389**		**-**	**-**	**2,046,850.0**	**6,534,318**	**3.32**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	197,880	-	-	-	10,260	COAL	87,140	23,299,518	2,030,320.0	6,607,105	3.34	75.82
10. TOTAL BIG BEND #2	**395**	**197,880**	**67.3**	**82.0**	**84.8**	**10,260**		**-**	**-**	**2,030,320.0**	**6,607,105**	**3.34**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	208,280	-	-	-	10,323	COAL	93,480	23,000,107	2,150,050.0	7,087,818	3.40	75.82
13. TOTAL BIG BEND #3	**400**	**208,280**	**70.0**	**86.0**	**83.2**	**10,323**		**-**	**-**	**2,150,050.0**	**7,087,818**	**3.40**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	75,960	-	-	-	10,457	COAL	34,530	23,002,896	794,290.0	2,621,144	3.45	75.91
16. TOTAL BIG BEND #4	**442**	**75,960**	**23.1**	**79.3**	**76.7**	**10,457**		**-**	**-**	**794,290.0**	**2,621,144**	**3.45**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	21,710	-	22,310.0	112,049	-	5.16
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**679,140**	**55.9**	**81.9**	**85.1**	**10,339**	**COAL**	**301,330**	**23,301,729**	**7,021,510.0**	**22,850,385**	**3.36**	**75.83**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	300	0.7	-	70.3	12,533	GAS	3,660	1,027,322	3,760.0	18,890	6.30	5.16
21. B.B.C.T.#4 TOTAL	**61**	**300**	**0.7**	**98.3**	**70.3**	**12,533**	**-**	**-**	**-**	**3,760.0**	**18,890**	**6.30**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**679,440**	**53.9**	**82.5**	**85.1**	**10,340**	**-**	**-**	**-**	**7,025,270.0**	**22,981,324**	**3.38**	**-**
23. POLK #1 GASIFIER	220	49,870	30.5	-	97.3	10,352	COAL	18,560	27,815,733	516,260.0	1,145,063	2.30	61.70
24. POLK #1 CT GAS [4]	195	3,390	2.3	-	102.3	8,263	GAS	34,830	804,192	28,010.0	140,590	4.15	4.04
25. POLK #1 TOTAL	**220**	**53,260**	**32.5**	**28.0**	**97.6**	**10,219**	**-**	**-**	**-**	**544,270.0**	**1,285,653**	**2.41**	**-**
26. POLK #2 CC GAS	1,195	484,340	54.5	-	54.3	6,765	GAS	3,187,500	1,028,000	3,276,750.0	16,451,206	3.40	5.16
27. POLK #2 CC OIL	187	220	0.2	-	14.7	10,818	LGT OIL	400	5,950,000	2,380.0	49,104	22.32	122.76
28. POLK #2 CC TOTAL	**1,195**	**484,560**	**54.5**	**96.9**	**54.2**	**6,767**	**-**	**-**	**-**	**3,279,130.0**	**16,500,310**	**3.41**	**-**
29. POLK STATION TOTAL	**1,415**	**537,820**	**51.1**	**86.2**	**56.7**	**7,109**	**-**	**-**	**-**	**3,823,400.0**	**17,785,963**	**3.31**	**-**
30. BAYSIDE #1	792	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BAYSIDE #2	1,047	202,390	26.0	95.9	26.9	8,069	GAS	1,588,680	1,027,998	1,633,160.0	8,199,436	4.05	5.16
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	100	0.2	85.9	82.0	12,400	GAS	1,210	1,024,793	1,240.0	6,245	6.25	5.16
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**202,490**	**13.1**	**50.7**	**26.9**	**8,072**	**GAS**	**1,589,890**	**1,027,996**	**1,634,400.0**	**8,205,681**	**4.05**	**5.16**
37. SYSTEM	**5,194**	**1,420,320**	**36.8**	**70.7**	**56.8**	**8,789**	**-**	**-**	**-**	**12,483,070.0**	**48,972,968**	**3.45**	**-**

LEGEND:
B.B. = BIG BEND   NG = NATURAL GAS
C.T. = COMBUSTION TURBINE   CC = COMBINED CYCLE

[1] **As burned fuel cost system total includes ignition.**
[3] **AC rating**
[5] **Commercial operation scheduled for May 2017**
[2] **Fuel burned (MM BTU) system total excludes ignition.**
[4] **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	280	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR (5)	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR (3)	**3.1**	**600**	**26.9**	**-**	**26.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	191,130	-	-	-	10,536	COAL	84,790	23,748,791	2,013,660.0	6,481,070	3.39	76.44
7. TOTAL BIG BEND #1	**385**	**191,130**	**69.0**	**80.6**	**89.1**	**10,536**		**-**	**-**	**2,013,660.0**	**6,481,070**	**3.39**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	180,720	-	-	-	10,288	COAL	79,790	23,301,166	1,859,200.0	6,098,887	3.37	76.44
10. TOTAL BIG BEND #2	**385**	**180,720**	**65.2**	**82.0**	**86.8**	**10,288**		**-**	**-**	**1,859,200.0**	**6,098,887**	**3.37**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	162,850	-	-	-	10,383	COAL	73,520	22,998,504	1,690,850.0	5,619,626	3.45	76.44
13. TOTAL BIG BEND #3	**395**	**162,850**	**57.3**	**77.4**	**82.5**	**10,383**		**-**	**-**	**1,690,850.0**	**5,619,626**	**3.45**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	165,050	-	-	-	10,443	COAL	74,940	23,000,267	1,723,640.0	5,730,438	3.47	76.47
16. TOTAL BIG BEND #4	**437**	**165,050**	**52.5**	**81.9**	**81.0**	**10,443**		**-**	**-**	**1,723,640.0**	**5,730,438**	**3.47**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	94,064	-	5.24
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**699,750**	**60.7**	**80.5**	**84.9**	**10,414**	**COAL**	**313,040**	**23,279,293**	**7,287,350.0**	**23,930,021**	**3.42**	**76.44**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,040	2.6	-	97.7	11,808	GAS	11,940	1,028,476	12,280.0	62,569	6.02	5.24
21. B.B.C.T.#4 TOTAL	**56**	**1,040**	**2.6**	**81.9**	**97.7**	**11,808**	**-**	**-**	**-**	**12,280.0**	**62,569**	**6.02**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**700,790**	**58.7**	**80.5**	**85.0**	**10,416**	**-**	**-**	**-**	**7,299,630.0**	**24,086,654**	**3.44**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	2,963,649	2.18	58.59
24. POLK #1 CT GAS (4)	195	3,500	2.5	-	94.5	8,469	GAS	30,870	960,155	29,640.0	151,079	4.32	4.89
25. POLK #1 TOTAL	**220**	**139,470**	**88.0**	**79.0**	**97.4**	**10,161**	**-**	**-**	**-**	**1,417,170.0**	**3,114,728**	**2.23**	**-**
26. POLK #2 CC GAS	1,063	456,540	59.7	-	57.4	6,757	GAS	3,000,970	1,027,998	3,084,990.0	15,726,059	3.44	5.24
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,857	LGT OIL	520	5,846,154	3,040.0	63,536	22.69	122.18
28. POLK #2 CC TOTAL	**1,063**	**456,820**	**59.7**	**96.9**	**57.3**	**6,760**	**-**	**-**	**-**	**3,088,030.0**	**15,789,595**	**3.46**	**-**
29. POLK STATION TOTAL	**1,283**	**596,290**	**64.6**	**93.9**	**63.4**	**7,555**	**-**	**-**	**-**	**4,505,200.0**	**18,904,323**	**3.17**	**-**
30. BAYSIDE #1	701	121,550	24.1	59.7	46.4	7,649	GAS	904,460	1,027,995	929,780.0	4,739,665	3.90	5.24
31. BAYSIDE #2	929	92,160	13.8	48.0	28.5	8,242	GAS	738,900	1,027,988	759,580.0	3,872,076	4.20	5.24
32. BAYSIDE #3	56	530	1.3	98.6	94.6	11,830	GAS	6,100	1,027,869	6,270.0	31,966	6.03	5.24
33. BAYSIDE #4	56	420	1.0	98.6	93.8	12,024	GAS	4,910	1,028,513	5,050.0	25,730	6.13	5.24
34. BAYSIDE #5	56	660	1.6	95.3	90.7	12,106	GAS	7,770	1,028,314	7,990.0	40,717	6.17	5.24
35. BAYSIDE #6	56	510	1.3	82.2	91.1	12,157	GAS	6,020	1,029,900	6,200.0	31,547	6.19	5.24
36. BAYSIDE TOTAL	**1,854**	**215,830**	**16.2**	**57.9**	**36.7**	**7,945**	**GAS**	**1,668,160**	**1,028,001**	**1,714,870.0**	**8,741,701**	**4.05**	**5.24**
37. SYSTEM	**4,798**	**1,513,510**	**43.8**	**75.3**	**64.3**	**8,933**	**-**	**-**	**-**	**13,519,700.0**	**51,732,678**	**3.42**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) As burned fuel cost system total includes ignition.
(3) AC rating
(5) Commercial operation scheduled for May 2017
(2) Fuel burned (MM BTU) system total excludes ignition.
(4) Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	290	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,990	37.3	-	37.3	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR (3)	**21.1**	**5,620**	**35.8**	**-**	**35.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	141,070	-	-	-	10,560	COAL	62,730	23,748,605	1,489,750.0	4,771,479	3.38	76.06
7. TOTAL BIG BEND #1	**385**	**141,070**	**49.2**	**80.6**	**86.8**	**10,560**		**-**	**-**	**1,489,750.0**	**4,771,479**	**3.38**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	162,250	-	-	-	10,285	COAL	71,620	23,300,614	1,668,790.0	5,447,687	3.36	76.06
10. TOTAL BIG BEND #2	**385**	**162,250**	**56.6**	**82.0**	**86.9**	**10,285**		**-**	**-**	**1,668,790.0**	**5,447,687**	**3.36**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	0	-	-	-	0	COAL	0	0	0.0	0	0.00	0.00
13. TOTAL BIG BEND #3	**395**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	218,300	-	-	-	10,405	COAL	98,760	22,999,190	2,271,400.0	7,513,907	3.44	76.08
16. TOTAL BIG BEND #4	**437**	**218,300**	**67.1**	**81.9**	**82.7**	**10,405**		**-**	**-**	**2,271,400.0**	**7,513,907**	**3.44**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	10,020	-	10,300.0	47,006	-	4.69
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**521,620**	**43.8**	**61.4**	**85.1**	**10,410**	**COAL**	**233,110**	**23,293,467**	**5,429,940.0**	**17,733,073**	**3.40**	**76.07**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	220	0.5	-	98.2	11,955	GAS	2,560	1,027,344	2,630.0	12,009	5.46	4.69
21. B.B.C.T.#4 TOTAL	**56**	**220**	**0.5**	**98.3**	**98.2**	**11,955**	**-**	**-**	**-**	**2,630.0**	**12,009**	**5.46**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**521,840**	**42.3**	**62.7**	**85.1**	**10,410**	**-**	**-**	**-**	**5,432,570.0**	**17,792,088**	**3.41**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,107,342	2.21	59.39
24. POLK #1 CT GAS (4)	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,040.0**	**3,107,342**	**2.21**	**-**
26. POLK #2 CC GAS	1,063	555,280	70.2	-	70.1	6,749	GAS	3,645,270	1,028,001	3,747,340.0	17,100,485	3.08	4.69
27. POLK #2 CC OIL	159	220	0.2	-	17.3	10,727	LGT OIL	400	5,900,000	2,360.0	48,699	22.14	121.75
28. POLK #2 CC TOTAL	**1,063**	**555,500**	**70.2**	**96.9**	**70.0**	**6,750**	**-**	**-**	**-**	**3,749,700.0**	**17,149,184**	**3.09**	**-**
29. POLK STATION TOTAL	**1,283**	**696,110**	**72.9**	**93.9**	**74.2**	**7,448**	**-**	**-**	**-**	**5,184,740.0**	**20,256,526**	**2.91**	**-**
30. BAYSIDE #1	701	266,210	51.0	96.9	58.8	7,482	GAS	1,937,520	1,028,000	1,991,770.0	9,089,185	3.41	4.69
31. BAYSIDE #2	929	270,540	39.1	95.9	40.6	7,832	GAS	2,061,130	1,027,999	2,118,840.0	9,669,056	3.57	4.69
32. BAYSIDE #3	56	100	0.2	98.6	89.3	13,200	GAS	1,280	1,031,250	1,320.0	6,005	6.01	4.69
33. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	56	150	0.4	98.6	89.3	12,333	GAS	1,800	1,027,778	1,850.0	8,444	5.63	4.69
35. BAYSIDE #6	56	150	0.4	98.6	89.3	11,933	GAS	1,750	1,022,857	1,790.0	8,210	5.47	4.69
36. BAYSIDE TOTAL	**1,854**	**537,150**	**38.9**	**93.6**	**47.9**	**7,662**	**GAS**	**4,003,480**	**1,027,998**	**4,115,570.0**	**18,780,900**	**3.50**	**4.69**
37. SYSTEM	**4,816**	**1,760,720**	**49.1**	**82.6**	**65.9**	**8,368**	**-**	**-**	**-**	**14,732,880.0**	**56,829,514**	**3.23**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) **As burned fuel cost system total includes ignition.**
(3) **AC rating**
(2) **Fuel burned (MM BTU) system total excludes ignition.**
(4) **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,380	33.8	-	33.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	[3] **21.1**	**4,940**	**32.5**	**-**	**32.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	185,940	-	-	-	10,577	COAL	82,810	23,749,185	1,966,670.0	6,406,432	3.45	77.36
7. TOTAL BIG BEND #1	**385**	**185,940**	**67.1**	**80.6**	**86.2**	**10,577**		**-**	**-**	**1,966,670.0**	**6,406,432**	**3.45**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	184,740	-	-	-	10,288	COAL	81,570	23,300,233	1,900,600.0	6,310,502	3.42	77.36
10. TOTAL BIG BEND #2	**385**	**184,740**	**66.6**	**82.0**	**86.8**	**10,288**		**-**	**-**	**1,900,600.0**	**6,310,502**	**3.42**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	0	-	-	-	0	COAL	0	0	0.0	0	0.00	0.00
13. TOTAL BIG BEND #3	**395**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	206,920	-	-	-	10,416	COAL	93,710	22,999,146	2,155,250.0	7,256,800	3.51	77.44
16. TOTAL BIG BEND #4	**437**	**206,920**	**65.8**	**81.9**	**82.2**	**10,416**		**-**	**-**	**2,155,250.0**	**7,256,800**	**3.51**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	22,960	-	23,600.0	106,819	-	4.65
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**577,600**	**50.1**	**61.4**	**84.9**	**10,427**	**COAL**	**258,090**	**23,334,961**	**6,022,520.0**	**19,973,734**	**3.46**	**77.39**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,870	4.6	-	98.2	11,781	GAS	21,430	1,027,998	22,030.0	99,700	5.33	4.65
21. B.B.C.T.#4 TOTAL	**56**	**1,870**	**4.6**	**98.3**	**98.2**	**11,781**	**-**	**-**	**-**	**22,030.0**	**99,700**	**5.33**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**579,470**	**48.5**	**62.7**	**85.0**	**10,431**	**-**	**-**	**-**	**6,044,550.0**	**20,180,253**	**3.48**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	3,052,385	2.24	60.35
24. POLK #1 CT GAS	[4] 195	3,500	2.5	-	94.5	8,460	GAS	30,840	960,117	29,610.0	133,988	3.83	4.34
25. POLK #1 TOTAL	**220**	**139,470**	**88.0**	**79.0**	**97.4**	**10,161**	**-**	**-**	**-**	**1,417,140.0**	**3,186,373**	**2.28**	**-**
26. POLK #2 CC GAS	1,063	571,030	74.6	-	67.0	6,773	GAS	3,762,100	1,028,000	3,867,440.0	17,502,679	3.07	4.65
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,857	LGT OIL	520	5,846,154	3,040.0	63,017	22.51	121.19
28. POLK #2 CC TOTAL	**1,063**	**571,310**	**74.6**	**96.9**	**66.9**	**6,775**	**-**	**-**	**-**	**3,870,480.0**	**17,565,696**	**3.07**	**-**
29. POLK STATION TOTAL	**1,283**	**710,780**	**76.9**	**93.9**	**71.3**	**7,439**	**-**	**-**	**-**	**5,287,620.0**	**20,752,069**	**2.92**	**-**
30. BAYSIDE #1	701	309,390	61.3	96.9	63.3	7,443	GAS	2,240,030	1,028,000	2,302,750.0	10,421,447	3.37	4.65
31. BAYSIDE #2	929	302,950	45.3	95.9	46.9	7,716	GAS	2,273,820	1,028,001	2,337,490.0	10,578,649	3.49	4.65
32. BAYSIDE #3	56	890	2.2	98.6	99.3	11,517	GAS	9,980	1,027,054	10,250.0	46,431	5.22	4.65
33. BAYSIDE #4	56	880	2.2	98.6	98.2	11,659	GAS	9,980	1,028,056	10,260.0	46,431	5.28	4.65
34. BAYSIDE #5	56	1,180	2.9	98.6	95.8	11,797	GAS	13,550	1,027,306	13,920.0	63,040	5.34	4.65
35. BAYSIDE #6	56	940	2.3	98.6	98.7	11,713	GAS	10,710	1,028,011	11,010.0	49,827	5.30	4.65
36. BAYSIDE TOTAL	**1,854**	**616,230**	**46.2**	**96.6**	**54.1**	**7,604**	**GAS**	**4,558,070**	**1,027,996**	**4,685,680.0**	**21,205,825**	**3.44**	**4.65**
37. SYSTEM	**4,816**	**1,911,420**	**55.1**	**83.8**	**67.8**	**8,380**	**-**	**-**	**-**	**16,017,850.0**	**62,138,147**	**3.25**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] **As burned fuel cost system total includes ignition.**
[3] **AC rating**
[2] **Fuel burned (MM BTU) system total excludes ignition.**
[4] **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,260	31.8	-	31.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	(3) **21.1**	**4,820**	**30.7**	**-**	**30.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	193,720	-	-	-	10,572	COAL	86,230	23,751,015	2,048,050.0	6,876,327	3.55	79.74
7. TOTAL BIG BEND #1	**385**	**193,720**	**67.6**	**80.6**	**86.5**	**10,572**		**-**	**-**	**2,048,050.0**	**6,876,327**	**3.55**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	185,130	-	-	-	10,302	COAL	81,850	23,300,428	1,907,140.0	6,527,048	3.53	79.74
10. TOTAL BIG BEND #2	**385**	**185,130**	**64.6**	**82.0**	**86.0**	**10,302**		**-**	**-**	**1,907,140.0**	**6,527,048**	**3.53**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	144,600	-	-	-	10,354	COAL	65,100	22,998,618	1,497,210.0	5,191,336	3.59	79.74
13. TOTAL BIG BEND #3	**395**	**144,600**	**49.2**	**69.4**	**84.5**	**10,354**		**-**	**-**	**1,497,210.0**	**5,191,336**	**3.59**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	206,950	-	-	-	10,426	COAL	93,810	23,001,173	2,157,740.0	7,484,126	3.62	79.78
16. TOTAL BIG BEND #4	**437**	**206,950**	**63.7**	**81.9**	**81.6**	**10,426**		**-**	**-**	**2,157,740.0**	**7,484,126**	**3.62**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	26,300	-	27,030.0	125,105	-	4.76
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**730,400**	**61.3**	**78.5**	**84.6**	**10,419**	**COAL**	**326,990**	**23,273,311**	**7,610,140.0**	**26,078,837**	**3.57**	**79.75**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	560	1.3	-	100.0	11,804	GAS	6,430	1,027,994	6,610.0	30,587	5.46	4.76
21. B.B.C.T.#4 TOTAL	**56**	**560**	**1.3**	**98.3**	**100.0**	**11,804**	**-**	**-**	**-**	**6,610.0**	**30,587**	**5.46**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**730,960**	**59.3**	**79.2**	**84.6**	**10,420**	**-**	**-**	**-**	**7,616,750.0**	**26,234,529**	**3.59**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	3,291,060	2.34	62.90
24. POLK #1 CT GAS	(4) 195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,050.0**	**3,291,060**	**2.34**	**-**
26. POLK #2 CC GAS	1,063	539,080	68.2	-	66.6	6,754	GAS	3,541,520	1,027,999	3,640,680.0	16,846,466	3.13	4.76
27. POLK #2 CC OIL	159	220	0.2	-	17.3	10,727	LGT OIL	400	5,900,000	2,360.0	48,306	21.96	120.77
28. POLK #2 CC TOTAL	**1,063**	**539,300**	**68.2**	**96.9**	**66.6**	**6,755**	**-**	**-**	**-**	**3,643,040.0**	**16,894,772**	**3.13**	**-**
29. POLK STATION TOTAL	**1,283**	**679,910**	**71.2**	**93.9**	**71.2**	**7,469**	**-**	**-**	**-**	**5,078,090.0**	**20,185,832**	**2.97**	**-**
30. BAYSIDE #1	701	291,660	55.9	96.9	57.2	7,498	GAS	2,127,260	1,027,998	2,186,820.0	10,119,049	3.47	4.76
31. BAYSIDE #2	929	266,750	38.6	95.9	40.0	7,847	GAS	2,036,210	1,027,998	2,093,220.0	9,685,938	3.63	4.76
32. BAYSIDE #3	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	56	210	0.5	98.6	93.8	12,048	GAS	2,450	1,032,653	2,530.0	11,654	5.55	4.76
35. BAYSIDE #6	56	100	0.2	98.6	89.3	13,200	GAS	1,290	1,023,256	1,320.0	6,136	6.14	4.76
36. BAYSIDE TOTAL	**1,854**	**558,720**	**40.5**	**90.7**	**47.5**	**7,667**	**GAS**	**4,167,210**	**1,028,000**	**4,283,890.0**	**19,822,777**	**3.55**	**4.76**
37. SYSTEM	**4,816**	**1,974,410**	**55.1**	**87.2**	**65.9**	**8,599**	**-**	**-**	**-**	**16,978,730.0**	**66,243,138**	**3.36**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) **As burned fuel cost system total includes ignition.**
(3) **AC rating**
(2) **Fuel burned (MM BTU) system total excludes ignition.**
(4) **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	250	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,110	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	(3) **21.1**	**4,650**	**29.6**	**-**	**29.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	190,300	-	-	-	10,573	COAL	84,720	23,749,882	2,012,090.0	6,752,881	3.55	79.71
7. TOTAL BIG BEND #1	**385**	**190,300**	**66.4**	**80.6**	**86.4**	**10,573**		**-**	**-**	**2,012,090.0**	**6,752,881**	**3.55**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	197,270	-	-	-	10,277	COAL	87,010	23,300,310	2,027,360.0	6,935,413	3.52	79.71
10. TOTAL BIG BEND #2	**385**	**197,270**	**68.9**	**82.0**	**87.3**	**10,277**		**-**	**-**	**2,027,360.0**	**6,935,413**	**3.52**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	215,640	-	-	-	10,330	COAL	96,850	22,999,174	2,227,470.0	7,719,741	3.58	79.71
13. TOTAL BIG BEND #3	**395**	**215,640**	**73.4**	**86.0**	**86.7**	**10,330**		**-**	**-**	**2,227,470.0**	**7,719,741**	**3.58**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	211,940	-	-	-	10,428	COAL	96,090	22,999,688	2,210,040.0	7,660,992	3.61	79.73
16. TOTAL BIG BEND #4	**437**	**211,940**	**65.2**	**81.9**	**81.4**	**10,428**		**-**	**-**	**2,210,040.0**	**7,660,992**	**3.61**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	16,690	-	17,160.0	79,794	-	4.78
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**815,150**	**68.4**	**82.6**	**85.3**	**10,399**	**COAL**	**364,670**	**23,245,564**	**8,476,960.0**	**29,069,027**	**3.57**	**79.71**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	950	2.3	-	99.8	11,684	GAS	10,800	1,027,778	11,100.0	51,635	5.44	4.78
21. B.B.C.T.#4 TOTAL	**56**	**950**	**2.3**	**98.3**	**99.8**	**11,684**	**-**	**-**	**-**	**11,100.0**	**51,635**	**5.44**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**816,100**	**66.2**	**83.1**	**85.3**	**10,401**	**-**	**-**	**-**	**8,488,060.0**	**29,200,456**	**3.58**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,300,395	2.35	63.08
24. POLK #1 CT GAS	(4) 195	3,390	2.3	-	96.6	8,442	GAS	29,890	957,511	28,620.0	133,150	3.93	4.45
25. POLK #1 TOTAL	**220**	**144,000**	**88.0**	**79.0**	**97.4**	**10,164**	**-**	**-**	**-**	**1,463,660.0**	**3,433,545**	**2.38**	**-**
26. POLK #2 CC GAS	1,063	527,050	66.6	-	64.1	6,760	GAS	3,465,830	1,027,993	3,562,850.0	16,570,024	3.14	4.78
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,571	LGT OIL	520	5,692,308	2,960.0	62,518	22.33	120.23
28. POLK #2 CC TOTAL	**1,063**	**527,330**	**66.7**	**96.9**	**64.0**	**6,762**	**-**	**-**	**-**	**3,565,810.0**	**16,632,542**	**3.15**	**-**
29. POLK STATION TOTAL	**1,283**	**671,330**	**70.3**	**93.9**	**69.1**	**7,492**	**-**	**-**	**-**	**5,029,470.0**	**20,066,087**	**2.99**	**-**
30. BAYSIDE #1	701	256,820	49.2	96.9	56.5	7,509	GAS	1,875,970	1,028,002	1,928,500.0	8,968,954	3.49	4.78
31. BAYSIDE #2	929	265,210	38.4	95.9	39.8	7,859	GAS	2,027,560	1,027,999	2,084,330.0	9,693,700	3.66	4.78
32. BAYSIDE #3	56	280	0.7	98.6	100.0	11,750	GAS	3,210	1,024,922	3,290.0	15,347	5.48	4.78
33. BAYSIDE #4	56	280	0.7	98.6	100.0	11,750	GAS	3,210	1,024,922	3,290.0	15,347	5.48	4.78
34. BAYSIDE #5	56	630	1.5	98.6	93.8	11,857	GAS	7,260	1,028,926	7,470.0	34,710	5.51	4.78
35. BAYSIDE #6	56	430	1.0	98.6	96.0	11,837	GAS	4,940	1,030,364	5,090.0	23,618	5.49	4.78
36. BAYSIDE TOTAL	**1,854**	**523,650**	**38.0**	**96.6**	**46.6**	**7,700**	**GAS**	**3,922,150**	**1,028,000**	**4,031,970.0**	**18,751,676**	**3.58**	**4.78**
37. SYSTEM	**4,816**	**2,015,730**	**56.3**	**90.8**	**66.0**	**8,706**	**-**	**-**	**-**	**17,549,500.0**	**68,018,219**	**3.37**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) **As burned fuel cost system total includes ignition.**
(3) **AC rating**
(2) **Fuel burned (MM BTU) system total excludes ignition.**
(4) **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	210	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	3,390	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	(3) **21.1**	**3,860**	**25.4**	**-**	**25.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	188,830	-	-	-	10,548	COAL	83,860	23,750,298	1,991,700.0	6,724,347	3.56	80.19
7. TOTAL BIG BEND #1	**385**	**188,830**	**68.1**	**80.6**	**87.4**	**10,548**		**-**	**-**	**1,991,700.0**	**6,724,347**	**3.56**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	202,670	-	-	-	10,235	COAL	89,030	23,299,562	2,074,360.0	7,138,902	3.52	80.19
10. TOTAL BIG BEND #2	**385**	**202,670**	**73.1**	**82.0**	**91.4**	**10,235**		**-**	**-**	**2,074,360.0**	**7,138,902**	**3.52**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	193,960	-	-	-	10,340	COAL	87,190	23,001,032	2,005,460.0	6,991,361	3.60	80.19
13. TOTAL BIG BEND #3	**395**	**193,960**	**68.2**	**86.0**	**85.8**	**10,340**		**-**	**-**	**2,005,460.0**	**6,991,361**	**3.60**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	179,970	-	-	-	10,397	COAL	81,360	22,999,017	1,871,200.0	6,526,175	3.63	80.21
16. TOTAL BIG BEND #4	**437**	**179,970**	**57.2**	**81.9**	**85.1**	**10,397**		**-**	**-**	**1,871,200.0**	**6,526,175**	**3.63**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	18,360	-	18,880.0	88,856	-	4.84
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**765,430**	**66.4**	**82.6**	**87.5**	**10,377**	**COAL**	**341,440**	**23,262,418**	**7,942,720.0**	**27,380,785**	**3.58**	**80.19**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,840	4.6	-	99.6	11,685	GAS	20,910	1,028,216	21,500.0	101,198	5.50	4.84
21. B.B.C.T.#4 TOTAL	**56**	**1,840**	**4.6**	**98.3**	**99.6**	**11,685**	**-**	**-**	**-**	**21,500.0**	**101,198**	**5.50**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**767,270**	**64.3**	**83.1**	**87.5**	**10,380**	**-**	**-**	**-**	**7,964,220.0**	**27,570,839**	**3.59**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	3,192,459	2.35	63.12
24. POLK #1 CT GAS	(4) 195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**135,970**	**85.8**	**79.0**	**97.5**	**10,205**	**-**	**-**	**-**	**1,387,530.0**	**3,192,459**	**2.35**	**-**
26. POLK #2 CC GAS	1,063	515,990	67.4	-	64.0	6,760	GAS	3,392,990	1,027,996	3,487,980.0	16,420,988	3.18	4.84
27. POLK #2 CC OIL	159	220	0.2	-	17.3	11,091	LGT OIL	420	5,809,524	2,440.0	50,316	22.87	119.80
28. POLK #2 CC TOTAL	**1,063**	**516,210**	**67.4**	**96.9**	**63.9**	**6,762**	**-**	**-**	**-**	**3,490,420.0**	**16,471,304**	**3.19**	**-**
29. POLK STATION TOTAL	**1,283**	**652,180**	**70.6**	**93.9**	**68.8**	**7,479**	**-**	**-**	**-**	**4,877,950.0**	**19,663,763**	**3.02**	**-**
30. BAYSIDE #1	701	259,030	51.3	96.9	54.2	7,533	GAS	1,898,250	1,027,999	1,951,400.0	9,186,924	3.55	4.84
31. BAYSIDE #2	929	176,990	26.5	73.6	32.9	8,052	GAS	1,386,240	1,028,004	1,425,060.0	6,708,959	3.79	4.84
32. BAYSIDE #3	56	470	1.2	98.6	93.3	12,085	GAS	5,530	1,027,125	5,680.0	26,763	5.69	4.84
33. BAYSIDE #4	56	220	0.5	98.6	98.2	11,727	GAS	2,510	1,027,888	2,580.0	12,148	5.52	4.84
34. BAYSIDE #5	56	1,300	3.2	98.6	92.9	11,792	GAS	14,910	1,028,169	15,330.0	72,160	5.55	4.84
35. BAYSIDE #6	56	1,040	2.6	98.6	92.9	11,750	GAS	11,880	1,028,620	12,220.0	57,495	5.53	4.84
36. BAYSIDE TOTAL	**1,854**	**439,050**	**32.9**	**85.4**	**43.1**	**7,772**	**GAS**	**3,319,320**	**1,028,003**	**3,412,270.0**	**16,064,449**	**3.66**	**4.84**
37. SYSTEM	**4,816**	**1,862,360**	**53.7**	**86.5**	**65.5**	**8,728**	**-**	**-**	**-**	**16,254,440.0**	**63,299,051**	**3.40**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) **As burned fuel cost system total includes ignition.**
(3) **AC rating**

(2) **Fuel burned (MM BTU) system total excludes ignition.**
(4) **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2017

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	210	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	3,490	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR (3)	**21.1**	**3,990**	**25.4**	**-**	**25.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	189,850	-	-	-	10,553	COAL	84,360	23,750,237	2,003,570.0	6,847,690	3.61	81.17
7. TOTAL BIG BEND #1	**385**	**189,850**	**66.3**	**80.6**	**87.1**	**10,553**		**-**	**-**	**2,003,570.0**	**6,847,690**	**3.61**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	202,330	-	-	-	10,281	COAL	89,280	23,298,947	2,080,130.0	7,247,055	3.58	81.17
10. TOTAL BIG BEND #2	**385**	**202,330**	**70.6**	**82.0**	**87.9**	**10,281**		**-**	**-**	**2,080,130.0**	**7,247,055**	**3.58**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	201,820	-	-	-	10,394	COAL	91,200	23,001,096	2,097,700.0	7,402,906	3.67	81.17
13. TOTAL BIG BEND #3	**395**	**201,820**	**68.7**	**86.0**	**81.6**	**10,394**		**-**	**-**	**2,097,700.0**	**7,402,906**	**3.67**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	173,280	-	-	-	10,414	COAL	78,460	22,999,873	1,804,570.0	6,370,765	3.68	81.20
16. TOTAL BIG BEND #4	**437**	**173,280**	**53.3**	**81.9**	**82.1**	**10,414**		**-**	**-**	**1,804,570.0**	**6,370,765**	**3.68**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,120	-	17,590.0	87,442	-	5.11
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**767,280**	**64.4**	**82.6**	**84.6**	**10,408**	**COAL**	**343,300**	**23,262,365**	**7,985,970.0**	**27,868,416**	**3.63**	**81.18**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	4,000	9.6	-	97.8	11,700	GAS	45,520	1,028,120	46,800.0	232,497	5.81	5.11
21. B.B.C.T.#4 TOTAL	**56**	**4,000**	**9.6**	**98.3**	**97.8**	**11,700**	**-**	**-**	**-**	**46,800.0**	**232,497**	**5.81**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**771,280**	**62.5**	**83.1**	**84.7**	**10,415**	**-**	**-**	**-**	**8,032,770.0**	**28,188,355**	**3.65**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	3,484,721	2.48	66.60
24. POLK #1 CT GAS (4)	195	5,810	4.0	-	96.1	8,253	GAS	48,690	984,802	47,950.0	238,269	4.10	4.89
25. POLK #1 TOTAL	**220**	**146,420**	**89.5**	**79.0**	**97.4**	**10,128**	**-**	**-**	**-**	**1,483,000.0**	**3,722,990**	**2.54**	**-**
26. POLK #2 CC GAS	1,063	482,650	61.0	-	51.1	6,847	GAS	3,214,780	1,027,993	3,304,770.0	16,419,751	3.40	5.11
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,571	LGT OIL	520	5,692,308	2,960.0	62,028	22.15	119.28
28. POLK #2 CC TOTAL	**1,063**	**482,930**	**61.1**	**9.4**	**51.1**	**6,849**	**-**	**-**	**-**	**3,307,730.0**	**16,481,779**	**3.41**	**-**
29. POLK STATION TOTAL	**1,283**	**629,350**	**65.9**	**21.3**	**57.4**	**7,612**	**-**	**-**	**-**	**4,790,730.0**	**20,204,769**	**3.21**	**-**
30. BAYSIDE #1	701	239,270	45.9	96.9	46.9	7,639	GAS	1,777,890	1,027,999	1,827,670.0	9,080,718	3.80	5.11
31. BAYSIDE #2	929	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. BAYSIDE #3	56	2,070	5.0	98.6	94.8	11,899	GAS	23,960	1,027,963	24,630.0	122,378	5.91	5.11
33. BAYSIDE #4	56	1,570	3.8	98.6	96.7	11,764	GAS	17,970	1,027,824	18,470.0	91,783	5.85	5.11
34. BAYSIDE #5	56	2,830	6.8	98.6	93.6	11,834	GAS	32,590	1,027,616	33,490.0	166,456	5.88	5.11
35. BAYSIDE #6	56	2,340	5.6	98.6	95.0	11,756	GAS	26,750	1,028,411	27,510.0	136,628	5.84	5.11
36. BAYSIDE TOTAL	**1,854**	**248,080**	**18.0**	**48.5**	**47.7**	**7,787**	**GAS**	**1,879,160**	**1,027,997**	**1,931,770.0**	**9,597,963**	**3.87**	**5.11**
37. SYSTEM	**4,816**	**1,652,700**	**46.1**	**53.0**	**65.4**	**8,928**	**-**	**-**	**-**	**14,755,270.0**	**57,991,087**	**3.51**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) **As burned fuel cost system total includes ignition.**
(3) **AC rating**
(2) **Fuel burned (MM BTU) system total excludes ignition.**
(4) **Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) (2)	AS BURNED FUEL COST ($) (1)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	170	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	2,960	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	(3) **21.1**	**3,400**	**22.4**	**-**	**22.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	102,010	-	-	-	10,527	COAL	45,210	23,752,488	1,073,850.0	3,698,366	3.63	81.80
7. TOTAL BIG BEND #1	**385**	**102,010**	**36.8**	**80.6**	**88.6**	**10,527**		**-**	**-**	**1,073,850.0**	**3,698,366**	**3.63**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	164,580	-	-	-	10,275	COAL	72,570	23,301,502	1,690,990.0	5,936,529	3.61	81.80
10. TOTAL BIG BEND #2	**385**	**164,580**	**59.4**	**82.0**	**87.4**	**10,275**		**-**	**-**	**1,690,990.0**	**5,936,529**	**3.61**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	168,800	-	-	-	10,346	COAL	75,930	22,999,605	1,746,360.0	6,211,390	3.68	81.80
13. TOTAL BIG BEND #3	**395**	**168,800**	**59.4**	**83.1**	**85.3**	**10,346**		**-**	**-**	**1,746,360.0**	**6,211,390**	**3.68**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	94,630	-	-	-	10,434	COAL	42,930	22,999,068	987,350.0	3,515,913	3.72	81.90
16. TOTAL BIG BEND #4	**437**	**94,630**	**30.1**	**54.6**	**81.1**	**10,434**		**-**	**-**	**987,350.0**	**3,515,913**	**3.72**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	27,550	-	28,320.0	134,460	-	4.88
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**530,020**	**46.0**	**74.5**	**85.8**	**10,374**	**COAL**	**236,640**	**23,235,928**	**5,498,550.0**	**19,362,198**	**3.65**	**81.82**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	560	1.4	-	100.0	11,732	GAS	6,400	1,026,563	6,570.0	31,236	5.58	4.88
21. B.B.C.T.#4 TOTAL	**56**	**560**	**1.4**	**98.3**	**100.0**	**11,732**	**-**	**-**	**-**	**6,570.0**	**31,236**	**5.58**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**530,580**	**44.4**	**75.3**	**85.8**	**10,376**	**-**	**-**	**-**	**5,505,120.0**	**19,527,894**	**3.68**	**-**
23. POLK #1 GASIFIER	220	104,240	65.8	-	97.5	10,264	COAL	38,780	27,589,479	1,069,920.0	2,641,560	2.53	68.12
24. POLK #1 CT GAS	(4) 195	3,500	2.5	-	99.7	8,129	GAS	35,270	806,635	28,450.0	135,094	3.86	3.83
25. POLK #1 TOTAL	**220**	**107,740**	**68.0**	**79.0**	**97.6**	**10,195**	**-**	**-**	**-**	**1,098,370.0**	**2,776,654**	**2.58**	**-**
26. POLK #2 CC GAS	1,063	503,210	65.7	-	65.1	6,746	GAS	3,302,310	1,027,996	3,394,760.0	16,117,185	3.20	4.88
27. POLK #2 CC OIL	159	220	0.2	-	17.3	11,000	LGT OIL	420	5,761,905	2,420.0	49,928	22.69	118.88
28. POLK #2 CC TOTAL	**1,063**	**503,430**	**65.8**	**96.9**	**65.0**	**6,748**	**-**	**-**	**-**	**3,397,180.0**	**16,167,113**	**3.21**	**-**
29. POLK STATION TOTAL	**1,283**	**611,170**	**66.2**	**93.9**	**69.1**	**7,356**	**-**	**-**	**-**	**4,495,550.0**	**18,943,767**	**3.10**	**-**
30. BAYSIDE #1	701	158,640	31.4	84.0	43.9	7,688	GAS	1,186,480	1,027,999	1,219,700.0	5,790,710	3.65	4.88
31. BAYSIDE #2	929	58,660	8.8	25.6	27.2	8,315	GAS	474,490	1,027,988	487,770.0	2,315,786	3.95	4.88
32. BAYSIDE #3	56	320	0.8	98.6	95.2	11,844	GAS	3,690	1,027,100	3,790.0	18,009	5.63	4.88
33. BAYSIDE #4	56	160	0.4	98.6	95.2	12,125	GAS	1,890	1,026,455	1,940.0	9,224	5.77	4.88
34. BAYSIDE #5	56	370	0.9	98.6	94.4	11,865	GAS	4,270	1,028,103	4,390.0	20,840	5.63	4.88
35. BAYSIDE #6	56	320	0.8	98.6	95.2	11,656	GAS	3,630	1,027,548	3,730.0	17,717	5.54	4.88
36. BAYSIDE TOTAL	**1,854**	**218,470**	**16.4**	**56.5**	**37.8**	**7,879**	**GAS**	**1,674,450**	**1,027,991**	**1,721,320.0**	**8,172,286**	**3.74**	**4.88**
37. SYSTEM	**4,816**	**1,363,620**	**39.3**	**72.7**	**65.5**	**8,596**	**-**	**-**	**-**	**11,721,990.0**	**46,643,947**	**3.42**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

(1) As burned fuel cost system total includes ignition.
(3) AC rating
(2) Fuel burned (MM BTU) system total excludes ignition.
(4) Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2017

(A) PLANT/UNIT	(B) NET CAPA- BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	150	13.4	-	13.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	2,640	19.7	-	19.7	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR	[3] **21.1**	**3,050**	**19.4**	**-**	**19.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	109,760	-	-	-	10,397	COAL	48,050	23,748,803	1,141,130.0	3,941,552	3.59	82.03
7. TOTAL BIG BEND #1	**395**	**109,760**	**37.3**	**54.6**	**91.4**	**10,397**		**-**	**-**	**1,141,130.0**	**3,941,552**	**3.59**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	109,040	-	-	-	10,293	COAL	48,170	23,299,772	1,122,350.0	3,951,398	3.62	82.03
10. TOTAL BIG BEND #2	**395**	**109,040**	**37.1**	**55.5**	**83.1**	**10,293**		**-**	**-**	**1,122,350.0**	**3,951,398**	**3.62**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	124,970	-	-	-	10,275	COAL	55,830	22,999,284	1,284,050.0	4,579,750	3.66	82.03
13. TOTAL BIG BEND #3	**400**	**124,970**	**42.0**	**61.0**	**87.5**	**10,275**		**-**	**-**	**1,284,050.0**	**4,579,750**	**3.66**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	219,450	-	-	-	10,365	COAL	98,890	23,000,506	2,274,520.0	8,114,894	3.70	82.06
16. TOTAL BIG BEND #4	**442**	**219,450**	**66.7**	**81.9**	**81.1**	**10,365**		**-**	**-**	**2,274,520.0**	**8,114,894**	**3.70**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	18,780	-	19,310.0	93,985	-	5.00
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**563,220**	**46.4**	**63.8**	**84.8**	**10,337**	**COAL**	**250,940**	**23,200,964**	**5,822,050.0**	**20,587,594**	**3.66**	**82.04**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	90	0.2	-	73.8	13,111	GAS	1,150	1,026,087	1,180.0	5,755	6.39	5.00
21. B.B.C.T.#4 TOTAL	**61**	**90**	**0.2**	**98.3**	**73.8**	**13,111**	**-**	**-**	**-**	**1,180.0**	**5,755**	**6.39**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**563,310**	**44.7**	**65.0**	**84.8**	**10,338**	**-**	**-**	**-**	**5,823,230.0**	**20,687,334**	**3.67**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,494,183	2.49	66.78
24. POLK #1 CT GAS	[4] 195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,040.0**	**3,494,183**	**2.49**	**-**
26. POLK #2 CC GAS	1,195	498,440	56.1	-	56.9	6,743	GAS	3,269,500	1,028,001	3,361,050.0	16,362,282	3.28	5.00
27. POLK #2 CC OIL	187	220	0.2	-	14.7	10,727	LGT OIL	400	5,900,000	2,360.0	47,397	21.54	118.49
28. POLK #2 CC TOTAL	**1,195**	**498,660**	**56.1**	**96.9**	**56.8**	**6,745**	**-**	**-**	**-**	**3,363,410.0**	**16,409,679**	**3.29**	**-**
29. POLK STATION TOTAL	**1,415**	**639,270**	**60.7**	**94.2**	**62.6**	**7,506**	**-**	**-**	**-**	**4,798,450.0**	**19,903,862**	**3.11**	**-**
30. BAYSIDE #1	792	85,810	14.6	71.9	33.9	7,675	GAS	640,690	1,028,001	658,630.0	3,206,346	3.74	5.00
31. BAYSIDE #2	1,047	166,010	21.3	95.9	22.1	8,315	GAS	1,342,770	1,028,002	1,380,370.0	6,719,921	4.05	5.00
32. BAYSIDE #3	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
33. BAYSIDE #4	61	60	0.1	98.6	98.4	10,667	GAS	630	1,015,873	640.0	3,153	5.26	5.00
34. BAYSIDE #5	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
35. BAYSIDE #6	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
36. BAYSIDE TOTAL	**2,083**	**252,060**	**16.3**	**87.1**	**25.1**	**8,100**	**GAS**	**1,986,130**	**1,027,984**	**2,041,710.0**	**9,939,629**	**3.94**	**5.00**
37. SYSTEM	**5,212**	**1,457,690**	**37.6**	**81.5**	**54.2**	**8,687**	**-**	**-**	**-**	**12,663,390.0**	**50,530,825**	**3.47**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating
[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH JUNE 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	420	440	400	520	400	520
16. UNIT COST ($/BBL)	72.77	73.11	73.13	72.90	73.04	73.32
17. AMOUNT ($)	30,564	32,170	29,251	37,910	29,215	38,128
18. BURNED:						
19. UNITS (BBL)	420	440	400	520	400	520
20. UNIT COST ($/BBL)	123.70	123.21	122.76	122.18	121.75	121.19
21. AMOUNT ($)	51,955	54,211	49,104	63,536	48,699	63,017
22. ENDING INVENTORY:						
23. UNITS (BBL)	44,488	44,488	44,488	44,488	44,488	44,488
24. UNIT COST ($/BBL)	123.70	123.21	122.76	122.18	121.75	121.19
25. AMOUNT ($)	5,503,265	5,481,224	5,461,371	5,435,745	5,416,262	5,391,373
26. DAYS SUPPLY: NORMAL	3,018	3,274	3,593	3,941	4,511	5,074
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	283,343	253,333	288,333	293,333	313,333	343,333
30. UNIT COST ($/TON)	72.32	74.59	75.25	75.25	75.99	76.10
31. AMOUNT ($)	20,492,710	18,896,679	21,696,295	22,073,629	23,810,294	26,126,974
32. BURNED:						
33. UNITS (TONS)	338,050	257,240	319,890	363,620	285,430	308,670
34. UNIT COST ($/TON)	70.86	71.25	75.36	74.22	73.18	74.94
35. AMOUNT ($)	23,952,767	18,327,084	24,107,497	26,987,734	20,887,421	23,132,938
36. ENDING INVENTORY:						
37. UNITS (TONS)	421,730	417,823	386,266	315,979	343,882	378,545
38. UNIT COST ($/TON)	62.41	64.98	64.67	64.12	67.84	70.21
39. AMOUNT ($)	26,319,598	27,149,491	24,980,731	20,259,600	23,330,269	26,577,625
40. DAYS SUPPLY:	41	40	37	30	32	32
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,955,199	8,395,400
43. UNIT COST ($/MCF)	5.33	5.10	5.15	5.19	4.63	4.66
44. AMOUNT ($)	25,067,627	24,408,980	24,915,929	24,524,982	36,822,910	39,090,182
45. BURNED:						
46. UNITS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,663,370	8,395,400
47. UNIT COST ($/MCF)	5.28	5.08	5.13	5.22	4.68	4.64
48. AMOUNT ($)	24,844,669	24,299,192	24,816,367	24,681,408	35,893,394	38,942,192
49. ENDING INVENTORY:						
50. UNITS (MCF)	875,486	875,486	875,486	875,486	1,167,315	1,167,315
51. UNIT COST ($/MCF)	3.52	3.50	3.44	3.15	3.11	3.13
52. AMOUNT ($)	3,080,520	3,067,020	3,015,360	2,754,180	3,627,120	3,658,800
53. DAYS SUPPLY:	4	4	4	4	5	5
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS (3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2017 THROUGH DECEMBER 2017

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	400	520	420	520	420	400	5,380
16.	UNIT COST ($/BBL)	73.75	74.20	74.71	75.16	75.58	75.94	73.96
17.	AMOUNT ($)	29,499	38,585	31,379	39,081	31,744	30,375	397,901
18.	BURNED:							
19.	UNITS (BBL)	400	520	420	520	420	400	5,380
20.	UNIT COST ($/BBL)	120.77	120.23	119.80	119.28	118.88	118.49	121.01
21.	AMOUNT ($)	48,306	62,518	50,316	62,028	49,928	47,397	651,015
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	44,488	44,488	44,488	44,488	44,488	44,488	44,488
24.	UNIT COST ($/BBL)	120.76	120.23	119.80	119.28	118.88	118.49	118.49
25.	AMOUNT ($)	5,372,567	5,348,634	5,329,696	5,306,749	5,288,565	5,271,542	5,271,542
26.	DAYS SUPPLY: NORMAL	6,059	7,122	9,226	12,118	19,803	40,595	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	378,333	343,333	343,333	338,836	318,333	303,337	3,800,513
30.	UNIT COST ($/TON)	77.03	78.60	78.71	79.36	79.98	79.99	77.06
31.	AMOUNT ($)	29,144,003	26,987,355	27,022,710	26,888,659	25,460,254	24,262,860	292,862,422
32.	BURNED:							
33.	UNITS (TONS)	379,310	416,990	392,020	395,620	275,420	303,260	4,035,520
34.	UNIT COST ($/TON)	77.76	77.82	78.22	79.47	80.38	79.72	76.26
35.	AMOUNT ($)	29,495,002	32,449,216	30,662,100	31,440,579	22,138,218	24,175,762	307,756,318
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	377,568	303,911	255,224	198,440	241,353	241,430	241,430
38.	UNIT COST ($/TON)	70.06	69.65	69.43	67.31	70.17	71.31	71.31
39.	AMOUNT ($)	26,452,655	21,168,561	17,719,120	13,357,071	16,935,831	17,215,343	17,215,343
40.	DAYS SUPPLY:	29	23	22	19	31	43	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	7,743,500	7,445,360	6,753,620	5,010,718	4,802,789	5,277,600	72,444,736
43.	UNIT COST ($/MCF)	4.76	4.78	4.84	5.19	4.97	5.02	4.92
44.	AMOUNT ($)	36,868,719	35,606,112	32,662,084	25,996,861	23,891,505	26,512,360	356,368,251
45.	BURNED:							
46.	UNITS (MCF)	7,743,500	7,445,360	6,753,620	5,205,270	5,045,980	5,277,600	72,590,650
47.	UNIT COST ($/MCF)	4.74	4.77	4.83	5.09	4.85	4.98	4.90
48.	AMOUNT ($)	36,699,830	35,506,485	32,586,635	26,488,480	24,455,801	26,307,666	355,522,119
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,167,315	1,167,315	1,167,315	972,763	729,572	729,572	729,572
51.	UNIT COST ($/MCF)	3.16	3.17	3.15	3.18	3.23	3.36	3.36
52.	AMOUNT ($)	3,692,880	3,702,960	3,679,680	3,090,200	2,354,400	2,454,900	2,454,900
53.	DAYS SUPPLY:	5	4	4	3	2	2	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH JUNE 2017

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE		(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-17	SEMINOLE	JURISD.	SCH. - D	800.0	0.0	800.0	2.824	2.933	22,590.00	23,460.00	870.00
	VARIOUS	JURISD.	MKT. BASE	940.0	0.0	940.0	2.637	2.901	24,788.43	27,270.00	2,481.57
	TOTAL			**1,740.0**	**0.0**	**1,740.0**	**2.723**	**2.916**	**47,378.43**	**50,730.00**	**3,351.57**
Feb-17	SEMINOLE	JURISD.	SCH. - D	680.0	0.0	680.0	2.803	2.911	19,060.00	19,794.00	734.00
	VARIOUS	JURISD.	MKT. BASE	990.0	0.0	990.0	2.695	2.965	26,679.15	29,350.00	2,670.85
	TOTAL			**1,670.0**	**0.0**	**1,670.0**	**2.739**	**2.943**	**45,739.15**	**49,144.00**	**3,404.85**
Mar-17	SEMINOLE	JURISD.	SCH. - D	870.0	0.0	870.0	2.792	2.899	24,290.00	25,225.00	935.00
	VARIOUS	JURISD.	MKT. BASE	940.0	0.0	940.0	2.794	3.073	26,261.01	28,890.00	2,628.99
	TOTAL			**1,810.0**	**0.0**	**1,810.0**	**2.793**	**2.990**	**50,551.01**	**54,115.00**	**3,563.99**
Apr-17	SEMINOLE	JURISD.	SCH. - D	1,080.0	0.0	1,080.0	2.654	2.756	28,660.00	29,763.00	1,103.00
	VARIOUS	JURISD.	MKT. BASE	1,130.0	0.0	1,130.0	3.554	3.910	40,159.62	44,180.00	4,020.38
	TOTAL			**2,210.0**	**0.0**	**2,210.0**	**3.114**	**3.346**	**68,819.62**	**73,943.00**	**5,123.38**
May-17	SEMINOLE	JURISD.	SCH. - D	940.0	0.0	940.0	2.590	2.690	24,350.00	25,287.00	937.00
	VARIOUS	JURISD.	MKT. BASE	900.0	0.0	900.0	2.495	2.744	22,452.30	24,700.00	2,247.70
	TOTAL			**1,840.0**	**0.0**	**1,840.0**	**2.544**	**2.717**	**46,802.30**	**49,987.00**	**3,184.70**
Jun-17	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	2.773	2.879	27,450.00	28,507.00	1,057.00
	VARIOUS	JURISD.	MKT. BASE	1,160.0	0.0	1,160.0	3.107	3.418	36,041.85	39,650.00	3,608.15
	TOTAL			**2,150.0**	**0.0**	**2,150.0**	**2.953**	**3.170**	**63,491.85**	**68,157.00**	**4,665.15**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH						
					WHEELED		CENTS/KWH				
		TYPE		TOTAL	FROM	MWH	(A)	(B)	TOTAL $		
		&		MWH	OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST	GAINS ON
MONTH	SOLD TO	SCHEDULE		SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$	SALES
Jul-17	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	2.651	2.754	26,780.00	27,811.00	1,031.00
	VARIOUS	JURISD.	MKT. BASE	900.0	0.0	900.0	2.625	2.888	23,624.91	25,990.00	2,365.09
	TOTAL			**1,910.0**	**0.0**	**1,910.0**	**2.639**	**2.817**	**50,404.91**	**53,801.00**	**3,396.09**
Aug-17	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	2.736	2.841	27,630.00	28,694.00	1,064.00
	VARIOUS	JURISD.	MKT. BASE	1,130.0	0.0	1,130.0	3.507	3.858	39,632.40	43,600.00	3,967.60
	TOTAL			**2,140.0**	**0.0**	**2,140.0**	**3.143**	**3.378**	**67,262.40**	**72,294.00**	**5,031.60**
Sep-17	SEMINOLE	JURISD.	SCH. - D	1,000.0	0.0	1,000.0	2.683	2.786	26,830.00	27,863.00	1,033.00
	VARIOUS	JURISD.	MKT. BASE	930.0	0.0	930.0	2.949	3.244	27,424.53	30,170.00	2,745.47
	TOTAL			**1,930.0**	**0.0**	**1,930.0**	**2.811**	**3.007**	**54,254.53**	**58,033.00**	**3,778.47**
Oct-17	SEMINOLE	JURISD.	SCH. - D	730.0	0.0	730.0	2.918	3.030	21,300.00	22,120.00	820.00
	VARIOUS	JURISD.	MKT. BASE	1,130.0	0.0	1,130.0	4.809	5.290	54,340.02	59,780.00	5,439.98
	TOTAL			**1,860.0**	**0.0**	**1,860.0**	**4.067**	**4.403**	**75,640.02**	**81,900.00**	**6,259.98**
Nov-17	SEMINOLE	JURISD.	SCH. - D	660.0	0.0	660.0	2.673	2.776	17,640.00	18,319.00	679.00
	VARIOUS	JURISD.	MKT. BASE	930.0	0.0	930.0	2.599	2.859	24,170.31	26,590.00	2,419.69
	TOTAL			**1,590.0**	**0.0**	**1,590.0**	**2.630**	**2.824**	**41,810.31**	**44,909.00**	**3,098.69**
Dec-17	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	2.740	2.846	15,620.00	16,221.00	601.00
	VARIOUS	JURISD.	MKT. BASE	900.0	0.0	900.0	2.593	2.852	23,334.03	25,670.00	2,335.97
	TOTAL			**1,470.0**	**0.0**	**1,470.0**	**2.650**	**2.850**	**38,954.03**	**41,891.00**	**2,936.97**
TOTAL	SEMINOLE	JURISD.	SCH. - D	10,340.0	0.0	10,340.0	2.729	2.834	282,200.00	293,064.00	10,864.00
Jan-17	VARIOUS	JURISD.	MKT. BASE	11,980.0	0.0	11,980.0	3.079	3.388	368,908.56	405,840.00	36,931.44
THRU	**TOTAL**			**22,320.0**	**0.0**	**22,320.0**	**2.917**	**3.131**	**651,108.56**	**698,904.00**	**47,795.44**
Dec-17											

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-17									
	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Feb-17									
	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Mar-17									
	PASCO COGEN	SCH. - D	780.0	0.0	0.0	780.0	4.740	4.740	36,970.00
	TOTAL		**780.0**	**0.0**	**0.0**	**780.0**	**4.740**	**4.740**	**36,970.00**
Apr-17									
	PASCO COGEN	SCH. - D	1,900.0	0.0	0.0	1,900.0	4.956	4.956	94,160.00
	TOTAL		**1,900.0**	**0.0**	**0.0**	**1,900.0**	**4.956**	**4.956**	**94,160.00**
May-17									
	PASCO COGEN	SCH. - D	910.0	0.0	0.0	910.0	4.586	4.586	41,730.00
	TOTAL		**910.0**	**0.0**	**0.0**	**910.0**	**4.586**	**4.586**	**41,730.00**
Jun-17									
	PASCO COGEN	SCH. - D	4,520.0	0.0	0.0	4,520.0	4.462	4.462	201,690.00
	TOTAL		**4,520.0**	**0.0**	**0.0**	**4,520.0**	**4.462**	**4.462**	**201,690.00**
Jul-17									
	PASCO COGEN	SCH. - D	1,470.0	0.0	0.0	1,470.0	4.582	4.582	67,350.00
	TOTAL		**1,470.0**	**0.0**	**0.0**	**1,470.0**	**4.582**	**4.582**	**67,350.00**
Aug-17									
	PASCO COGEN	SCH. - D	2,180.0	0.0	0.0	2,180.0	4.556	4.556	99,330.00
	TOTAL		**2,180.0**	**0.0**	**0.0**	**2,180.0**	**4.556**	**4.556**	**99,330.00**
Sep-17									
	PASCO COGEN	SCH. - D	3,750.0	0.0	0.0	3,750.0	4.540	4.540	170,240.00
	TOTAL		**3,750.0**	**0.0**	**0.0**	**3,750.0**	**4.540**	**4.540**	**170,240.00**
Oct-17									
	PASCO COGEN	SCH. - D	8,470.0	0.0	0.0	8,470.0	4.707	4.707	398,720.00
	TOTAL		**8,470.0**	**0.0**	**0.0**	**8,470.0**	**4.707**	**4.707**	**398,720.00**
Nov-17									
	PASCO COGEN	SCH. - D	1,140.0	0.0	0.0	1,140.0	4.752	4.752	54,170.00
	TOTAL		**1,140.0**	**0.0**	**0.0**	**1,140.0**	**4.752**	**4.752**	**54,170.00**
Dec-17									
	PASCO COGEN	SCH. - D	170.0	0.0	0.0	170.0	4.735	4.735	8,050.00
	TOTAL		**170.0**	**0.0**	**0.0**	**170.0**	**4.735**	**4.735**	**8,050.00**
TOTAL									
Jan-17	PASCO COGEN	SCH. - D	25,290.0	0.0	0.0	25,290.0	4.636	4.636	1,172,410.00
THRU	**TOTAL**		**25,290.0**	**0.0**	**0.0**	**25,290.0**	**4.636**	**4.636**	**1,172,410.00**
Dec-17									

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E8

(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-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,540.0	0.0	0.0	7,540.0	3.524	3.524	265,740.00
	TOTAL		**7,540.0**	**0.0**	**0.0**	**7,540.0**	**3.524**	**3.524**	**265,740.00**
Feb-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,440.0	0.0	0.0	7,440.0	2.961	2.961	220,310.00
	TOTAL		**7,440.0**	**0.0**	**0.0**	**7,440.0**	**2.961**	**2.961**	**220,310.00**
Mar-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,550.0	0.0	0.0	7,550.0	2.387	2.387	180,240.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**2.387**	**2.387**	**180,240.00**
Apr-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.013	2.013	151,140.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.013**	**2.013**	**151,140.00**
May-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.609	2.609	195,940.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.609**	**2.609**	**195,940.00**
Jun-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,550.0	0.0	0.0	7,550.0	2.338	2.338	176,490.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**2.338**	**2.338**	**176,490.00**
Jul-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.825	2.825	210,770.00
	TOTAL		**7,460.0**	**0.0**	**0.0**	**7,460.0**	**2.825**	**2.825**	**210,770.00**
Aug-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,550.0	0.0	0.0	7,550.0	3.303	3.303	249,340.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**3.303**	**3.303**	**249,340.00**
Sep-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.287	2.287	171,790.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.287**	**2.287**	**171,790.00**
Oct-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,520.0	0.0	0.0	7,520.0	3.058	3.058	229,930.00
	TOTAL		**7,520.0**	**0.0**	**0.0**	**7,520.0**	**3.058**	**3.058**	**229,930.00**
Nov-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,600.0	0.0	0.0	7,600.0	2.866	2.866	217,840.00
	TOTAL		**7,600.0**	**0.0**	**0.0**	**7,600.0**	**2.866**	**2.866**	**217,840.00**
Dec-17	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,370.0	0.0	0.0	7,370.0	2.438	2.438	179,650.00
	TOTAL		**7,370.0**	**0.0**	**0.0**	**7,370.0**	**2.438**	**2.438**	**179,650.00**
TOTAL	**VARIOUS**	**CO-GEN.**							
Jan-17		AS AVAIL.	90,110.0	0.0	0.0	90,110.0	2.718	2.718	2,449,180.00
THRU Dec-17	**TOTAL**		**90,110.0**	**0.0**	**0.0**	**90,110.0**	**2.718**	**2.718**	**2,449,180.00**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
				MWH				COST IF GENERATED		
		TYPE	TOTAL	FOR	MWH	TRANSACT.	TOTAL $	(A)	(B)	FUEL
	PURCHASED	&	MWH	INTERRUP-	FOR	COST	FOR FUEL	CENTS		SAVINGS
MONTH	FROM	SCHEDULE	PURCHASED	TIBLE	FIRM	cents/KWH	ADJUSTMENT	PER KWH	($000)	(9B)-(8)
Jan-17	VARIOUS	ECONOMY	23,840.0	0.0	23,840.0	3.133	746,840.00	3.133	746,840.00	0.00
Feb-17	VARIOUS	ECONOMY	26,580.0	0.0	26,580.0	3.120	829,340.00	3.120	829,340.00	0.00
Mar-17	VARIOUS	ECONOMY	23,540.0	0.0	23,540.0	3.186	749,990.00	3.186	749,990.00	0.00
Apr-17	VARIOUS	ECONOMY	26,550.0	0.0	26,550.0	3.250	862,750.00	3.257	864,750.00	2,000.00
May-17	VARIOUS	ECONOMY	24,120.0	0.0	24,120.0	2.966	715,430.00	2.966	715,430.00	0.00
Jun-17	VARIOUS	ECONOMY	29,580.0	0.0	29,580.0	3.816	1,128,900.00	4.005	1,184,790.00	55,890.00
Jul-17	VARIOUS	ECONOMY	23,900.0	0.0	23,900.0	3.062	731,910.00	3.405	813,680.00	81,770.00
Aug-17	VARIOUS	ECONOMY	26,930.0	0.0	26,930.0	3.286	884,800.00	3.737	1,006,350.00	121,550.00
Sep-17	VARIOUS	ECONOMY	24,450.0	0.0	24,450.0	3.232	790,190.00	3.232	790,190.00	0.00
Oct-17	VARIOUS	ECONOMY	27,920.0	0.0	27,920.0	4.302	1,201,060.00	4.875	1,361,210.00	160,150.00
Nov-17	VARIOUS	ECONOMY	26,630.0	0.0	26,630.0	3.095	824,330.00	3.443	916,840.00	92,510.00
Dec-17	VARIOUS	ECONOMY	22,860.0	0.0	22,860.0	3.048	696,680.00	3.206	732,870.00	36,190.00
TOTAL	VARIOUS	ECONOMY	**306,900.0**	**0.0**	**306,900.0**	**3.311**	**10,162,220.00**	**3.490**	**10,712,280.00**	**550,060.00**

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Jan 16 - Dec 16	Projected Jan 17 - Dec 17	Difference $	Difference %
Base Rate Revenue *	61.94	68.62	6.68	10.8%
Fuel Recovery Revenue	33.61	26.42	(7.19)	-21.4%
Conservation Revenue	1.91	2.25	0.34	17.8%
Capacity Revenue	1.78	0.88	(0.90)	-50.6%
Environmental Revenue	4.32	3.89	(0.43)	-10.0%
Florida Gross Receipts Tax Revenue	2.66	2.62	(0.04)	-1.5%
TOTAL REVENUE	**$106.22**	**$104.68**	**($1.54)**	**-1.4%**

*** Base rate change effective January 1, 2017.**

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2014	ACTUAL 2015	ACT/EST 2016	EST 2017	DIFFERENCE (%) 2015-2014	2016-2015	2017-2016
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	0	100,149	2,222,900	651,015	0.0%	2119.6%	-70.7%
3 COAL	413,363,010	315,575,618	258,935,180	307,756,318	-23.7%	-17.9%	18.9%
4 NATURAL GAS	307,201,884	331,614,300	290,482,817	355,522,119	7.9%	-12.4%	22.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**720,564,894**	**647,290,067**	**551,640,897**	**663,929,452**	**-10.2%**	**-14.8%**	**20.4%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	0	264	1,612	2,900	0.0%	510.6%	79.9%
10 COAL	11,594,881	9,118,709	7,483,309	9,297,050	-21.4%	-17.9%	24.2%
11 NATURAL GAS	7,115,927	9,919,007	10,213,009	10,325,990	39.4%	3.0%	1.1%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	3,623	36,390	0.0%	0.0%	904.4%
14 TOTAL (MWH)	**18,710,808**	**19,037,980**	**17,701,553**	**19,662,330**	**1.7%**	**-7.0%**	**11.1%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	0	777	3,192	5,380	0.0%	310.8%	68.5%
17 COAL (TON)	4,989,298	4,016,804	3,250,542	4,035,520	-19.5%	-19.1%	24.1%
18 NATURAL GAS (MCF)	52,983,025	74,846,827	77,575,520	72,590,650	41.3%	3.6%	-6.4%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL [1]	0	4,484	18,511	31,360	896700.0%	312.8%	69.4%
23 COAL	120,048,010	96,061,582	78,016,055	96,268,020	-20.0%	-18.8%	23.4%
24 NATURAL GAS	54,096,745	76,630,631	79,344,737	74,342,290	41.7%	3.5%	-6.3%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**174,144,756**	**172,696,697**	**157,379,303**	**170,641,670**	**-0.8%**	**-8.9%**	**8.4%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL [1]	0.00	0.00	0.01	0.01	0.0%	0.0%	0.0%
30 COAL	61.97	47.90	42.27	47.28	-22.7%	-11.8%	11.9%
31 NATURAL GAS	38.03	52.10	57.70	52.52	37.0%	10.7%	-9.0%
32 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33 OTHER	0.00	0.00	0.02	0.19	0.0%	0.0%	850.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	0.00	128.89	696.40	121.01	0.0%	440.3%	-82.6%
37 COAL ($/TON)	82.85	78.56	79.66	76.26	-5.2%	1.4%	-4.3%
38 NATURAL GAS ($/MCF)	5.80	4.43	3.74	4.90	-23.6%	-15.6%	31.0%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL [1]	0.00	22.33	120.09	20.76	0.0%	437.8%	-82.7%
43 COAL	3.44	3.29	3.32	3.20	-4.4%	0.9%	-3.6%
44 NATURAL GAS	5.68	4.33	3.66	4.78	-23.8%	-15.5%	30.6%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**4.14**	**3.75**	**3.51**	**3.89**	**-9.4%**	**-6.4%**	**10.8%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	0	16,985	11,483	10,814	0.0%	-32.4%	-5.8%
50 COAL	10,354	10,535	10,425	10,355	1.7%	-1.0%	-0.7%
51 NATURAL GAS	7,602	7,726	7,769	7,200	1.6%	0.6%	-7.3%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0	0	0	0	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	**9,307**	**9,071**	**8,891**	**8,679**	**-2.5%**	**-2.0%**	**-2.4%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL [1]	0.00	37.94	137.90	22.45	0.0%	263.5%	-83.7%
57 COAL	3.57	3.46	3.46	3.31	-3.1%	0.0%	-4.3%
58 NATURAL GAS	4.32	3.34	2.84	3.44	-22.7%	-15.0%	21.1%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	**3.85**	**3.40**	**3.12**	**3.38**	**-11.7%**	**-8.2%**	**8.3%**

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE
JANUARY 2017 - DECEMBER 2017

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2017 through December 2017

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	6,081,137	2.956	179,758,406	2.642	160,663,636
TIER II (Over 1,000) kWh	2,783,494	2.956	82,280,087	3.642	101,374,857
Total	8,864,631		262,038,493		262,038,493

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2017 - DECEMBER 2017

POLK 1 IGNITION CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

		PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951
2	ADD INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ -		$ -					$ -
3	LESS RETIREMENTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	ENDING BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951
5														
6														
7	AVERAGE BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	11,297,899	11,567,125	11,836,350	12,105,575	12,374,800	12,644,025	12,913,250	13,182,475	13,451,700	13,720,925	13,990,150	14,259,375	11,297,899
12	ENDING BALANCE DEPRECIATION	11,567,125	11,836,350	12,105,575	12,374,800	12,644,025	12,913,250	13,182,475	13,451,700	13,720,925	13,990,150	14,259,375	14,528,600	14,528,600
13														
14														
15	ENDING NET INVESTMENT	4,576,826	4,307,601	4,038,376	3,769,151	3,499,926	3,230,701	2,961,476	2,692,251	2,423,026	2,153,801	1,884,575	1,615,350	1,615,350
16														
17														
18	AVERAGE INVESTMENT	$ 4,711,439	$ 4,442,214	$ 4,172,989	$ 3,903,763	$ 3,634,538	$ 3,365,313	$ 3,096,088	$ 2,826,863	$ 2,557,638	$ 2,288,413	$ 2,019,188	$ 1,749,963	
19	ALLOWED EQUITY RETURN	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20	EQUITY COMPONENT AFTER-TAX	16,904	15,938	14,972	14,006	13,040	12,074	11,108	10,142	9,176	8,210	7,245	6,279	139,094
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	27,591	26,014	24,437	22,861	21,284	19,707	18,130	16,554	14,977	13,400	11,825	10,249	227,029
23														
24	ALLOWED DEBT RETURN	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25	DEBT COMPONENT	7,439	7,014	6,588	6,163	5,738	5,313	4,888	4,463	4,038	3,613	3,188	2,763	61,208
26														
27	TOTAL RETURN REQUIREMENTS	35,030	33,028	31,025	29,024	27,022	25,020	23,018	21,017	19,015	17,013	15,013	13,012	288,237
28														
29	TOTAL DEPRECIATION & RETURN	304,255	302,253	300,250	298,249	296,247	294,245	292,243	290,242	288,240	286,238	284,238	282,237	3,518,938
30														
31	ESTIMATED FUEL SAVINGS	$0	$0	$615,963	$642,950	$0	$653,800	$0	$623,760	$0	$1,048,705	$659,050	$0	$4,244,228
32	TOTAL DEPRECIATION & RETURN	$304,255	$302,253	$300,250	$298,249	$296,247	$294,245	$292,243	$290,242	$288,240	$286,238	$284,238	$282,237	$3,518,938
33	NET BENEFIT (COST) TO RATEPAYER	($304,255)	($302,253)	$315,713	$344,701	($296,247)	$359,555	($292,243)	$333,518	($288,240)	$762,467	$374,812	($282,237)	$725,290
34														

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

	PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1 BEGINNING BALANCE	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348
2 ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348
5													
6													
7 AVERAGE BALANCE	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9 DEPRECIATION EXPENSE	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	4,182,070
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	6,731,641	7,080,147	7,428,652	7,777,158	8,125,664	8,474,170	8,822,676	9,171,181	9,519,687	9,868,193	10,216,699	10,565,205	6,731,641
12 ENDING BALANCE DEPRECIATION	7,080,147	7,428,652	7,777,158	8,125,664	8,474,170	8,822,676	9,171,181	9,519,687	9,868,193	10,216,699	10,565,205	10,913,710	10,913,710
13													
14													
15 ENDING NET INVESTMENT	13,830,202	13,481,696	13,133,190	12,784,684	12,436,178	12,087,673	11,739,167	11,390,661	11,042,155	10,693,649	10,345,144	9,996,638	9,996,638
16													
17													
18 AVERAGE INVESTMENT	$14,004,454	$13,655,949	$13,307,443	$12,958,937	$12,610,431	$12,261,925	$11,913,420	$11,564,914	$11,216,408	$10,867,902	$10,519,396	$10,170,891	
19 ALLOWED EQUITY RETURN	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20 EQUITY COMPONENT AFTER-TAX	50,246	48,995	47,745	46,495	45,244	43,994	42,743	41,493	40,243	38,992	37,742	36,491	520,423
21 CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22 EQUITY COMPONENT PRE-TAX	$82,012	$79,970	$77,929	$75,889	$73,847	$71,807	$69,765	$67,725	$65,685	$63,643	$61,602	$59,561	$849,435
23													
24 ALLOWED DEBT RETURN	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25 DEBT COMPONENT	$22,111	$21,560	$21,010	$20,460	$19,910	$19,360	$18,809	$18,259	$17,709	$17,159	$16,608	$16,058	$229,013
26													
27 TOTAL RETURN REQUIREMENTS	$104,123	$101,530	$98,939	$96,349	$93,757	$91,167	$88,574	$85,984	$83,394	$80,802	$78,210	$75,619	$1,078,448
28 PRIOR MONTH TRUE-UP													-
29 TOTAL DEPRECIATION & RETURN	$452,629	$450,036	$447,445	$444,855	$442,263	$439,673	$437,080	$434,490	$431,900	$429,308	$426,716	$424,125	$5,260,518
30													
31 ESTIMATED FUEL SAVINGS	$497,845	$571,799	$561,492	$486,476	$165,337	$582,026	$651,776	$508,041	$490,298	$411,939	$739,450	$391,706	$6,058,183
32 TOTAL DEPRECIATION & RETURN	$452,629	$450,036	$447,445	$444,855	$442,263	$439,673	$437,080	$434,490	$431,900	$429,308	$426,716	$424,125	$5,260,518
33 NET BENEFIT (COST) TO RATEPAYER	$45,216	$121,763	$114,047	$41,622	($276,926)	$142,353	$214,696	$73,551	$58,398	($17,369)	$312,735	($32,419)	$797,666

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2017 to December 2017

	(1) Jurisdictional Rate Base Actual May 2016 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,548,383	35.17%	5.17%	1.82%
Short Term Debt	25,435	0.58%	0.90%	0.01%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	106,847	2.43%	2.29%	0.06%
Common Equity	1,847,526	41.96%	10.25%	4.30%
Deferred ITC - Weighted Cost	7,686	0.17%	7.89%	0.01%
Accumulated Deferred Income Taxes & Zero Cost ITCs	866,653	19.69%	0.00%	0.00%
Total	$ 4,402,530	100.00%		6.20%

ITC split between Debt and Equity:

Long Term Debt	$ 1,548,383	Long Term Debt	45.26%
Short Term Debt	25,435	Short Term Debt	0.74%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,847,526	Equity - Common	54.00%
Total	$ 3,421,345	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0100% * 46.00%	0.0046%
Equity = .0100% * 54.00%	0.0054%
Weighted Cost	0.0100%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3000%
Deferred ITC - Weighted Cost	0.0054%
	4.3054%
Times Tax Multiplier	1.632200
Total Equity Component	7.0273%

Total Debt Cost Rate:

Long Term Debt	1.8200%
Short Term Debt	0.0100%
Customer Deposits	0.0600%
Deferred ITC - Weighted Cost	0.0046%
Total Debt Component	1.8946%
	8.9219%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2017 THROUGH DECEMBER 2017

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: SEPTEMBER 1, 2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

Q. Please state your name, business address, occupation and employer.

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. BSB-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2017 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company’s coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2017 through December 2017 represent the top 99 percent of the total forecasted system net generation for this period excluding the new Polk 2 combined cycle unit (“Polk Unit 2 CC”). The Polk Unit 2 CC is expected to enter commercial service in January 2017 and was excluded from the GPIF calculation because the company does not have historical operational data on which to base targets.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. Big Bend Unit 1 and Big Bend Unit 2 forced outages were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes. Big Bend Units 1-4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2017 period.

A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2017 period, the projected EUOF for Bayside Unit 2 is 4.4 percent, and the POF is 19.5 percent. Therefore, the target EAF for Bayside Unit 2 equals 76.1 percent or:

$$100\% - (4.4\% + 19.5\%) = 76.1\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.80 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 2 example:

$$EAF_{MAX} = 1 - [0.80 \ (4.4\%) + 0.95 \ (19.5\%)] = 78.0\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Bayside Unit 2 example,

$$EAF_{MIN} = 1 - [1.40 \ (4.4\%) + 1.10 \ (19.5\%)] = 72.4\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2017 are shown on page 21 of Document No. 1. Three GPIF units have a major outage of 28 days or greater in 2017; therefore, three Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 2 is scheduled for a planned outage from April 15, 2017 to April 29, 2017 and September 26, 2017 to November 20, 2017. There are 1,705 planned outage hours scheduled for the 2017 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 2 is 19.5 percent or:

$$\frac{1{,}705}{8{,}760} \times 100\% = 19.5\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 6.6 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 21.9 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 7.4 percent. Bayside Unit 1 has a POF of 18.6 percent, and Bayside Unit 2 has a POF of 19.5 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 4.4 percent for Bayside Unit 2. The EUOF for Bayside Unit 2 is verified by the data shown on page 20, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

or

$$EUOF = \frac{(135 + 255)}{8{,}760} \times 100\% = 4.4\%$$

Relative to Bayside Unit 2, the EUOF of 4.4 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 12.9 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 80.5 percent.

Big Bend Unit 2

The projected EUOF for this unit is 23.8 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 69.6 percent.

Big Bend Unit 3

The projected EUOF for this unit is 16.7 percent. The unit will have two planned outages in 2017, and the POF is 21.9 percent. Therefore, the target equivalent availability for this unit is 61.4 percent.

Big Bend Unit 4

The projected EUOF for this unit is 14.3 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 79.1 percent.

Polk Unit 1

The projected EUOF for this unit is 10.5 percent. The unit will have two planned outages in 2017, and the POF is 7.4 percent. Therefore, the target equivalent availability for this unit is 82.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 6.1 percent. The unit will have two planned outages in 2017, and the POF is 18.6 percent. Therefore, the target equivalent availability for this unit is 75.3 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.4 percent. The unit will have two planned outages in 2017, and the POF is 19.5 percent. Therefore, the target equivalent availability for this unit is 76.1 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.4 percent is shown on Page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 2 on page 20 of Document No. 1. Except for the months of April, September, and November, the Equivalent Unplanned Outage

Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of April, September, and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology and co-firing.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2017 period.

A. The heat rate target for Big Bend Unit 1 is 10,698 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 289 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,545 Btu/Net kWh with a range of ± 447 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,588 Btu/Net kWh, with a range of ± 264 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,447 Btu/Net kWh with a range of ± 204 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,048 Btu/Net kWh with a range of ± 520 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,517 Btu/Net kWh with a range of ± 135 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,683 Btu/Net kWh with a range of ± 179 Btu/Net kWh. A zone of tolerance of ± 75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $695,758,070 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $18,187,737 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 2, the weighting factor for average net operating heat rate is 12.03 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 2, page 13, if the unit operates at 7,504 average net operating heat rate, fuel savings would equal $2,187,738 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $18,187,737. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2017 is $2,455,955,733. This produces the maximum allowed jurisdictional incentive of $10,013,992 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-13-0665-FOF-EI issued in Docket No. 130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings.

Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $9,093,869.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$
\begin{aligned}
GPIP: = (&0.0661\ EAP_{BB1} + 0.0870\ EAP_{BB2} \\
&+ 0.0555\ EAP_{BB3} + 0.0782\ EAP_{BB4} \\
&+ 0.0429\ EAP_{PK1} + 0.0274\ EAP_{BAY1} \\
&+ 0.0062\ EAP_{BAY2} + 0.0922\ HRP_{BB1} \\
&+ 0.1261\ HRP_{BB2} + 0.0625\ HRP_{BB3} \\
&+ 0.0720\ HRP_{BB4} + 0.0701\ HRP_{PK1} \\
&+ 0.0933\ HRP_{BAY1} + 0.1203\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/ deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2017 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2017 - DECEMBER 2017

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2017 - DECEMBER 2017
TARGETS
TABLE OF CONTENTS

SCHEDULE	**PAGE**
GPIF REWARD / PENALTY TABLE	2
GPIF CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS	3
GPIF TARGET AND RANGE SUMMARY	4
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE	5
DERIVATION OF WEIGHTING FACTORS	6
GPIF TARGET AND RANGE SUMMARY	7 - 13
ESTIMATED UNIT PERFORMANCE DATA	14 - 20
ESTIMATED PLANNED OUTAGE SCHEDULE	21
CRITICAL PATH METHOD DIAGRAMS	22 - 23
FORCED & MAINTENANCE OUTAGE FACTOR GRAPHS	24 - 30
HEAT RATE VS NET OUTPUT FACTOR GRAPHS	31 - 37
GENERATING UNITS IN GPIF (TABLE 4.2 IN THE MANUAL)	38
UNIT RATINGS AS OF JULY 2016	39
PROJECTED PERCENT GENERATION BY UNIT	40

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2017 - DECEMBER 2017

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	18,187.7	9,093.9
+9	16,369.0	8,184.5
+8	14,550.2	7,275.1
+7	12,731.4	6,365.7
+6	10,912.6	5,456.3
+5	9,093.9	4,546.9
+4	7,275.1	3,637.5
+3	5,456.3	2,728.2
+2	3,637.5	1,818.8
+1	1,818.8	909.4
0	0.0	0.0
-1	(2,581.8)	(909.4)
-2	(5,163.6)	(1,818.8)
-3	(7,745.4)	(2,728.2)
-4	(10,327.2)	(3,637.5)
-5	(12,908.9)	(4,546.9)
-6	(15,490.7)	(5,456.3)
-7	(18,072.5)	(6,365.7)
-8	(20,654.3)	(7,275.1)
-9	(23,236.1)	(8,184.5)
-10	(25,817.9)	(9,093.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2017 - DECEMBER 2017

Line 1	Beginning of period balance of common equity: End of month common equity:		$2,425,777,000	
Line 2	Month of January	2017	$2,366,384,000	
Line 3	Month of February	2017	$2,386,596,863	
Line 4	Month of March	2017	$2,406,982,378	
Line 5	Month of April	2017	$2,446,336,641	
Line 6	Month of May	2017	$2,467,232,433	
Line 7	Month of June	2017	$2,488,306,710	
Line 8	Month of July	2017	$2,428,236,665	
Line 9	Month of August	2017	$2,448,977,853	
Line 10	Month of September	2017	$2,469,896,205	
Line 11	Month of October	2017	$2,509,403,740	
Line 12	Month of November	2017	$2,530,838,231	
Line 13	Month of December	2017	$2,552,455,807	
Line 14	(Summation of line 1 through line 13 divided by 13)		$2,455,955,733	
Line 15	25 Basis points		0.0025	
Line 16	Revenue Expansion Factor		61.27%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$10,021,516	
Line 18	Jurisdictional Sales		19,114,079	MWH
Line 19	Total Sales		19,128,439	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		99.92%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$10,013,992	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$9,093,869	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$9,093,869	

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

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2017 - DECEMBER 2017

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	6.61%	80.5	83.4	74.7	1,202.8	(2,645.5)
BIG BEND 2	8.70%	69.6	74.7	59.4	1,583.0	(2,015.7)
BIG BEND 3	5.55%	61.4	65.8	52.6	1,008.9	(2,918.2)
BIG BEND 4	7.82%	79.1	82.3	72.7	1,422.8	(2,981.1)
POLK 1	4.29%	82.1	84.6	77.2	779.9	(1,476.4)
BAYSIDE 1	2.74%	75.3	77.5	71.0	498.6	(1,194.0)
BAYSIDE 2	0.62%	76.1	78.0	72.4	113.7	(1,008.8)
GPIF SYSTEM	**36.34%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	9.22%	10,698	87.7	10,409	10,987	1,677.5	(1,677.5)
BIG BEND 2	12.61%	10,545	86.9	10,098	10,992	2,294.1	(2,294.1)
BIG BEND 3	6.25%	10,588	84.3	10,324	10,852	1,136.4	(1,136.4)
BIG BEND 4	7.20%	10,447	82.0	10,243	10,652	1,309.3	(1,309.3)
POLK 1	7.01%	10,048	97.3	9,528	10,568	1,275.5	(1,275.5)
BAYSIDE 1	9.33%	7,517	52.7	7,382	7,653	1,697.4	(1,697.4)
BAYSIDE 2	12.03%	7,683	32.6	7,504	7,862	2,187.7	(2,187.7)
GPIF SYSTEM	**63.66%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 17 - DEC 17 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 15 - DEC 15 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 14 - DEC 14 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 13 - DEC 13 POF	EUOF	EUOR
BIG BEND 1	6.61%	18.2%	6.6	12.9	13.8	27.0	14.0	19.2	5.6	10.8	11.5	10.8	17.6	19.8
BIG BEND 2	8.70%	24.0%	6.6	23.8	25.5	7.5	46.8	50.5	8.4	10.6	11.6	6.1	18.3	19.5
BIG BEND 3	5.55%	15.3%	21.9	16.7	21.3	3.7	24.1	25.0	5.1	15.8	16.7	25.0	8.5	11.3
BIG BEND 4	7.82%	21.5%	6.6	14.3	15.3	3.8	15.1	15.7	20.7	11.2	14.2	4.8	17.6	18.5
POLK 1	4.29%	11.8%	7.4	10.5	11.3	13.5	16.0	19.0	5.0	8.7	10.6	15.3	6.7	8.8
BAYSIDE 1	2.74%	7.5%	18.6	6.1	7.5	11.8	2.3	2.7	6.2	11.5	14.1	3.8	7.5	8.7
BAYSIDE 2	0.62%	1.7%	19.5	4.4	5.5	7.2	3.7	4.1	5.0	5.4	5.7	4.1	12.2	13.1
GPIF SYSTEM	**36.34%**	**100.0%**	**10.1**	**15.5**	**17.2**	**10.7**	**22.8**	**25.3**	**9.4**	**11.3**	**12.9**	**10.4**	**14.2**	**15.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**74.4**			**66.5**			**79.3**			**75.3**	

	3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
	10.2	**16.1**	**18.0**	**73.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 17 - DEC 17	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 14 - DEC 14	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 13 - DEC 13
BIG BEND 1	9.22%	14.5%	10,698	10,600	10,594	10,535
BIG BEND 2	12.61%	19.8%	10,545	10,428	10,313	10,339
BIG BEND 3	6.25%	9.8%	10,588	10,352	10,437	10,567
BIG BEND 4	7.20%	11.3%	10,447	10,381	10,275	10,482
POLK 1	7.01%	11.0%	10,048	10,298	10,167	10,618
BAYSIDE 1	9.33%	14.7%	7,517	7,525	7,470	7,379
BAYSIDE 2	12.03%	18.9%	7,683	7,696	7,640	7,614
GPIF SYSTEM	**63.66%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,521**	**9,484**	**9,424**	**9,488**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2017 - DECEMBER 2017
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	695,758.1	694,555.3	1,202.8	6.61%
EA_2 BIG BEND 2	695,758.1	694,175.0	1,583.0	8.70%
EA_3 BIG BEND 3	695,758.1	694,749.2	1,008.9	5.55%
EA_4 BIG BEND 4	695,758.1	694,335.3	1,422.8	7.82%
EA_5 POLK 1	695,758.1	694,978.2	779.9	4.29%
EA_6 BAYSIDE 1	695,758.1	695,259.5	498.6	2.74%
EA_7 BAYSIDE 2	695,758.1	695,644.4	113.7	0.62%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	695,758.1	694,080.5	1,677.5	9.22%
AHR_2 BIG BEND 2	695,758.1	693,463.9	2,294.1	12.61%
AHR_3 BIG BEND 3	695,758.1	694,621.7	1,136.4	6.25%
AHR_4 BIG BEND 4	695,758.1	694,448.7	1,309.3	7.20%
AHR_5 POLK 1	695,758.1	694,482.6	1,275.5	7.01%
AHR_6 BAYSIDE 1	695,758.1	694,060.6	1,697.4	9.33%
AHR_7 BAYSIDE 2	695,758.1	693,570.3	2,187.7	12.03%
TOTAL SAVINGS			**18,187.7**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,202.8	83.4	+10	1,677.5	10,409
+9	1,082.5	83.1	+9	1,509.8	10,430
+8	962.2	82.9	+8	1,342.0	10,451
+7	841.9	82.6	+7	1,174.3	10,473
+6	721.7	82.3	+6	1,006.5	10,494
+5	601.4	82.0	+5	838.8	10,516
+4	481.1	81.7	+4	671.0	10,537
+3	360.8	81.4	+3	503.3	10,559
+2	240.6	81.1	+2	335.5	10,580
+1	120.3	80.8	+1	167.8	10,601
					10,623
0	0.0	80.5	0	0.0	10,698
					10,773
-1	(264.6)	79.9	-1	(167.8)	10,794
-2	(529.1)	79.4	-2	(335.5)	10,816
-3	(793.7)	78.8	-3	(503.3)	10,837
-4	(1,058.2)	78.2	-4	(671.0)	10,859
-5	(1,322.8)	77.6	-5	(838.8)	10,880
-6	(1,587.3)	77.0	-6	(1,006.5)	10,901
-7	(1,851.9)	76.5	-7	(1,174.3)	10,923
-8	(2,116.4)	75.9	-8	(1,342.0)	10,944
-9	(2,381.0)	75.3	-9	(1,509.8)	10,966
-10	(2,645.5)	74.7	-10	(1,677.5)	10,987
	Weighting Factor =	6.61%		Weighting Factor =	9.22%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,583.0	74.7	+10	2,294.1	10,098
+9	1,424.7	74.2	+9	2,064.7	10,135
+8	1,266.4	73.7	+8	1,835.3	10,172
+7	1,108.1	73.1	+7	1,605.9	10,209
+6	949.8	72.6	+6	1,376.5	10,247
+5	791.5	72.1	+5	1,147.1	10,284
+4	633.2	71.6	+4	917.7	10,321
+3	474.9	71.1	+3	688.2	10,358
+2	316.6	70.6	+2	458.8	10,396
+1	158.3	70.1	+1	229.4	10,433
					10,470
0	0.0	69.6	0	0.0	10,545
					10,620
-1	(201.6)	68.6	-1	(229.4)	10,657
-2	(403.1)	67.5	-2	(458.8)	10,695
-3	(604.7)	66.5	-3	(688.2)	10,732
-4	(806.3)	65.5	-4	(917.7)	10,769
-5	(1,007.9)	64.5	-5	(1,147.1)	10,806
-6	(1,209.4)	63.5	-6	(1,376.5)	10,843
-7	(1,411.0)	62.4	-7	(1,605.9)	10,881
-8	(1,612.6)	61.4	-8	(1,835.3)	10,918
-9	(1,814.1)	60.4	-9	(2,064.7)	10,955
-10	(2,015.7)	59.4	-10	(2,294.1)	10,992
	Weighting Factor =	8.70%		Weighting Factor =	12.61%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,008.9	65.8	+10	1,136.4	10,324
+9	908.0	65.4	+9	1,022.7	10,343
+8	807.1	65.0	+8	909.1	10,361
+7	706.2	64.5	+7	795.5	10,380
+6	605.4	64.1	+6	681.8	10,399
+5	504.5	63.6	+5	568.2	10,418
+4	403.6	63.2	+4	454.6	10,437
+3	302.7	62.7	+3	340.9	10,456
+2	201.8	62.3	+2	227.3	10,475
+1	100.9	61.9	+1	113.6	10,494
					10,513
0	0.0	61.4	0	0.0	10,588
					10,663
-1	(291.8)	60.5	-1	(113.6)	10,682
-2	(583.6)	59.6	-2	(227.3)	10,701
-3	(875.5)	58.8	-3	(340.9)	10,720
-4	(1,167.3)	57.9	-4	(454.6)	10,738
-5	(1,459.1)	57.0	-5	(568.2)	10,757
-6	(1,750.9)	56.1	-6	(681.8)	10,776
-7	(2,042.7)	55.2	-7	(795.5)	10,795
-8	(2,334.5)	54.3	-8	(909.1)	10,814
-9	(2,626.4)	53.4	-9	(1,022.7)	10,833
-10	(2,918.2)	52.6	-10	(1,136.4)	10,852

Weighting Factor = 5.55%

Weighting Factor = 6.25%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,422.8	82.3	+10	1,309.3	10,243
+9	1,280.5	82.0	+9	1,178.4	10,256
+8	1,138.2	81.6	+8	1,047.5	10,269
+7	995.9	81.3	+7	916.5	10,282
+6	853.7	81.0	+6	785.6	10,295
+5	711.4	80.7	+5	654.7	10,308
+4	569.1	80.4	+4	523.7	10,320
+3	426.8	80.0	+3	392.8	10,333
+2	284.6	79.7	+2	261.9	10,346
+1	142.3	79.4	+1	130.9	10,359
					10,372
0	0.0	79.1	0	0.0	10,447
					10,522
-1	(298.1)	78.4	-1	(130.9)	10,535
-2	(596.2)	77.8	-2	(261.9)	10,548
-3	(894.3)	77.2	-3	(392.8)	10,561
-4	(1,192.5)	76.5	-4	(523.7)	10,574
-5	(1,490.6)	75.9	-5	(654.7)	10,587
-6	(1,788.7)	75.2	-6	(785.6)	10,600
-7	(2,086.8)	74.6	-7	(916.5)	10,613
-8	(2,384.9)	74.0	-8	(1,047.5)	10,626
-9	(2,683.0)	73.3	-9	(1,178.4)	10,639
-10	(2,981.1)	72.7	-10	(1,309.3)	10,652
	Weighting Factor =	7.82%		Weighting Factor =	7.20%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	779.9	84.6	+10	1,275.5	9,528
+9	701.9	84.3	+9	1,148.0	9,572
+8	623.9	84.1	+8	1,020.4	9,617
+7	545.9	83.8	+7	892.9	9,661
+6	467.9	83.6	+6	765.3	9,706
+5	389.9	83.3	+5	637.8	9,750
+4	311.9	83.1	+4	510.2	9,795
+3	234.0	82.8	+3	382.7	9,839
+2	156.0	82.6	+2	255.1	9,884
+1	78.0	82.3	+1	127.6	9,928
					9,973
0	0.0	82.1	0	0.0	10,048
					10,123
-1	(147.6)	81.6	-1	(127.6)	10,167
-2	(295.3)	81.1	-2	(255.1)	10,212
-3	(442.9)	80.6	-3	(382.7)	10,256
-4	(590.5)	80.1	-4	(510.2)	10,301
-5	(738.2)	79.6	-5	(637.8)	10,345
-6	(885.8)	79.1	-6	(765.3)	10,390
-7	(1,033.5)	78.6	-7	(892.9)	10,434
-8	(1,181.1)	78.1	-8	(1,020.4)	10,479
-9	(1,328.7)	77.7	-9	(1,148.0)	10,523
-10	(1,476.4)	77.2	-10	(1,275.5)	10,568
	Weighting Factor =	4.29%		Weighting Factor =	7.01%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	498.6	77.5	+10	1,697.4	7,382
+9	448.8	77.2	+9	1,527.7	7,388
+8	398.9	77.0	+8	1,357.9	7,394
+7	349.0	76.8	+7	1,188.2	7,400
+6	299.2	76.6	+6	1,018.5	7,406
+5	249.3	76.4	+5	848.7	7,412
+4	199.4	76.2	+4	679.0	7,418
+3	149.6	76.0	+3	509.2	7,424
+2	99.7	75.7	+2	339.5	7,430
+1	49.9	75.5	+1	169.7	7,436
					7,442
0	0.0	75.3	0	0.0	7,517
					7,592
-1	(119.4)	74.9	-1	(169.7)	7,598
-2	(238.8)	74.5	-2	(339.5)	7,604
-3	(358.2)	74.0	-3	(509.2)	7,610
-4	(477.6)	73.6	-4	(679.0)	7,616
-5	(597.0)	73.2	-5	(848.7)	7,622
-6	(716.4)	72.7	-6	(1,018.5)	7,628
-7	(835.8)	72.3	-7	(1,188.2)	7,635
-8	(955.2)	71.9	-8	(1,357.9)	7,641
-9	(1,074.6)	71.4	-9	(1,527.7)	7,647
-10	(1,194.0)	71.0	-10	(1,697.4)	7,653
	Weighting Factor =	2.74%		Weighting Factor =	9.33%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	113.7	78.0	+10	2,187.7	7,504
+9	102.3	77.8	+9	1,969.0	7,515
+8	90.9	77.6	+8	1,750.2	7,525
+7	79.6	77.4	+7	1,531.4	7,535
+6	68.2	77.2	+6	1,312.6	7,546
+5	56.8	77.0	+5	1,093.9	7,556
+4	45.5	76.8	+4	875.1	7,567
+3	34.1	76.6	+3	656.3	7,577
+2	22.7	76.5	+2	437.5	7,587
+1	11.4	76.3	+1	218.8	7,598
					7,608
0	0.0	76.1	0	0.0	7,683
					7,758
-1	(100.9)	75.7	-1	(218.8)	7,768
-2	(201.8)	75.3	-2	(437.5)	7,779
-3	(302.7)	75.0	-3	(656.3)	7,789
-4	(403.5)	74.6	-4	(875.1)	7,800
-5	(504.4)	74.2	-5	(1,093.9)	7,810
-6	(605.3)	73.9	-6	(1,312.6)	7,820
-7	(706.2)	73.5	-7	(1,531.4)	7,831
-8	(807.1)	73.1	-8	(1,750.2)	7,841
-9	(908.0)	72.7	-9	(1,969.0)	7,851
-10	(1,008.8)	72.4	-10	(2,187.7)	7,862

Weighting Factor = 0.62%

Weighting Factor = 12.03%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	75.1	55.4	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	58.4	80.5
2. POF	12.9	35.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	12.0	8.9	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	9.4	12.9
4. EUOR	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	391	273	544	557	422	560	582	572	561	566	299	304	5,631
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	353	399	199	163	322	160	162	172	159	178	422	440	3,129
9. POH	96	240	0	0	0	0	0	0	0	0	0	240	576
10. EFOH	71	48	82	79	82	79	82	82	79	82	79	55	900
11. EMOH	18	12	21	20	21	20	21	21	20	21	20	14	230
12. OPER BTU (GBTU)	1,408	1,033	2,095	2,040	1,511	1,994	2,076	2,040	2,021	2,033	1,090	1,168	20,514
13. NET GEN (MWH)	131,070	96,850	197,020	191,140	141,080	185,950	193,730	190,300	188,830	189,850	102,010	109,760	1,917,590
14. ANOHR (Btu/kwh)	10,743	10,664	10,635	10,675	10,712	10,721	10,717	10,718	10,702	10,707	10,683	10,639	10,698
15. NOF (%)	84.9	89.8	91.7	89.1	86.8	86.2	86.5	86.4	87.4	87.1	88.6	91.4	87.7
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388

17. ANOHR EQUATION ANOHR = NOF(-15.843) + 12,087

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	67.3	45.2	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	50.4	69.6
2. POF	9.7	39.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	23.1	15.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	17.3	23.8
4. EUOR	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	541	305	591	541	485	553	560	587	576	598	489	332	6,158
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	203	367	152	179	259	167	184	157	144	146	232	412	2,602
9. POH	72	264	0	0	0	0	0	0	0	0	0	240	576
10. EFOH	150	91	166	161	166	161	166	166	161	166	161	112	1,825
11. EMOH	22	13	24	23	24	23	24	24	23	24	23	16	264
12. OPER BTU (GBTU)	1,900	1,175	2,089	1,906	1,711	1,948	1,957	2,080	2,132	2,132	1,735	1,152	21,921
13. NET GEN (MWH)	179,920	111,840	197,880	180,720	162,270	184,740	185,480	197,280	202,680	202,330	164,580	109,040	2,078,760
14. ANOHR (Btu/kwh)	10,561	10,510	10,558	10,546	10,545	10,546	10,550	10,543	10,518	10,539	10,542	10,568	10,545
15. NOF (%)	84.2	92.8	84.8	86.8	86.9	86.8	86.0	87.3	91.4	87.9	87.4	83.1	86.9
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		-5.963	) +	11,063								

35

DOCKET NO. 160001-EI
GPIF 2017 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 15 OF 40

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	78.7	78.7	78.7	70.8	0.0	0.0	63.4	78.7	78.7	78.7	76.0	55.8	61.4
2. POF	0.0	0.0	0.0	10.0	100.0	100.0	19.4	0.0	0.0	0.0	3.3	29.0	21.9
3. EUOF	21.3	21.3	21.3	19.2	0.0	0.0	17.2	21.3	21.3	21.3	20.6	15.1	16.7
4. EUOR	21.3	21.3	21.3	21.3	0.0	0.0	21.3	21.3	21.3	21.3	21.3	21.3	21.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	634	573	626	500	0	0	433	630	572	626	501	357	5,452
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	110	99	117	220	744	720	311	114	148	118	220	387	3,308
9. POH	0	0	0	72	744	720	144	0	0	0	24	216	1,920
10. EFOH	146	132	146	127	0	0	118	146	142	146	137	104	1,346
11. EMOH	12	11	12	11	0	0	10	12	12	12	12	9	114
12. OPER BTU (GBTU)	2,192	2,058	2,207	1,726	0	0	1,531	2,280	2,052	2,141	1,786	1,320	19,292
13. NET GEN (MWH)	206,650	194,410	208,290	162,870	0	0	144,640	215,650	193,990	201,840	168,800	124,970	1,822,110
14. ANOHR (Btu/kwh)	10,607	10,584	10,595	10,600	0	0	10,586	10,571	10,577	10,606	10,581	10,565	10,588
15. NOF (%)	81.5	84.8	83.2	82.5	0.0	0.0	84.6	86.7	85.9	81.6	85.3	87.5	84.3
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397

17. ANOHR EQUATION ANOHR = NOF(-6.885) + 11,168

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	84.7	45.3	81.9	84.7	84.7	84.7	84.7	84.7	84.7	84.7	56.5	84.7	79.1
2. POF	0.0	46.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	15.3	8.2	14.9	15.3	15.3	15.3	15.3	15.3	15.3	15.3	10.2	15.3	14.3
4. EUOR	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	345	175	224	466	604	576	580	596	484	483	267	612	5,412
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	399	497	519	254	140	144	164	148	236	261	454	132	3,348
9. POH	0	312	24	0	0	0	0	0	0	0	240	0	576
10. EFOH	83	40	80	80	83	80	83	83	80	83	54	83	915
11. EMOH	31	15	30	30	31	30	31	31	30	31	20	31	341
12. OPER BTU (GBTU)	1,293	733	796	1,725	2,280	2,162	2,163	2,215	1,877	1,810	989	2,294	20,337
13. NET GEN (MWH)	123,680	70,460	75,960	165,050	218,320	206,930	206,960	211,940	179,970	173,280	94,630	219,440	1,946,620
14. ANOHR (Btu/kwh)	10,452	10,402	10,474	10,452	10,444	10,446	10,449	10,450	10,432	10,447	10,452	10,452	10,447
15. NOF (%)	81.1	91.1	76.7	81.0	82.7	82.2	81.7	81.4	85.1	82.1	81.1	81.1	82.0
16. NPC (MW)	442	442	442	437	437	437	437	437	437	437	437	442	439
17. ANOHR EQUATION		ANOHR = NOF(	-4.982	) +	10,856								

37

DOCKET NO. 160001-EI
GPIF 2017 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 17 OF 40

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	88.7	88.7	31.5	88.7	88.7	88.7	88.7	88.7	88.7	88.7	67.9	88.7	82.1
2. POF	0.0	0.0	64.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.4	0.0	7.4
3. EUOF	11.3	11.3	4.0	11.3	11.3	11.3	11.3	11.3	11.3	11.3	8.7	11.3	10.5
4. EUOR	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	656	592	250	653	656	653	656	674	634	687	504	656	7,271
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	88	80	493	67	88	67	88	70	86	57	217	88	1,489
9. POH	0	0	479	0	0	0	0	0	0	0	169	0	648
10. EFOH	70	63	25	68	70	68	70	70	68	70	52	70	762
11. EMOH	14	13	5	14	14	14	14	14	14	14	11	14	158
12. OPER BTU (GBTU)	1,413	1,275	535	1,401	1,413	1,401	1,413	1,447	1,366	1,471	1,082	1,413	15,631
13. NET GEN (MWH)	140,610	126,910	53,260	139,470	140,610	139,470	140,610	144,000	135,970	146,420	107,740	140,610	1,555,680
14. ANOHR (Btu/kwh)	10,049	10,049	10,044	10,046	10,049	10,046	10,049	10,046	10,050	10,044	10,047	10,049	10,048
15. NOF (%)	97.4	97.4	96.8	97.1	97.4	97.1	97.4	97.1	97.5	96.9	97.2	97.4	97.3
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220

17. ANOHR EQUATION ANOHR = NOF(9.523) + 9,121

38

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	92.5	43.0	0.0	61.7	92.5	92.5	92.5	92.5	92.5	92.5	80.2	68.7	75.3
2. POF	0.0	53.6	100.0	33.3	0.0	0.0	0.0	0.0	0.0	0.0	13.3	25.8	18.6
3. EUOF	7.5	3.5	0.0	5.0	7.5	7.5	7.5	7.5	7.5	7.5	6.5	5.5	6.1
4. EUOR	7.5	7.5	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	230	289	0	374	646	666	689	649	666	689	516	320	5,734
7. RSH	459	0	0	70	43	0	0	40	0	0	62	191	863
8. UH	55	383	743	276	55	54	55	55	54	55	143	233	2,163
9. POH	0	360	743	240	0	0	0	0	0	0	96	192	1,631
10. EFOH	24	10	0	15	24	23	24	24	23	24	20	18	226
11. EMOH	32	13	0	21	32	31	32	32	31	32	27	24	305
12. OPER BTU (GBTU)	810	828	0	923	1,987	2,286	2,172	1,923	1,942	1,808	1,208	662	16,604
13. NET GEN (MWH)	108,720	109,470	0	121,820	266,470	309,620	291,880	257,060	259,280	239,540	158,920	85,990	2,208,770
14. ANOHR (Btu/kwh)	7,448	7,566	0	7,579	7,456	7,382	7,441	7,480	7,489	7,548	7,604	7,703	7,517
15. NOF (%)	59.7	47.8	0.0	46.5	58.8	66.3	60.4	56.5	55.5	49.6	43.9	33.9	52.7
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION		ANOHR = NOF(	-9.906	) +	8,039								

39

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	94.5	94.5	94.5	47.2	94.5	94.5	94.5	94.5	78.7	0.0	31.4	94.5	76.1
2. POF	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	16.7	100.0	66.7	0.0	19.5
3. EUOF	5.5	5.5	5.5	2.8	5.5	5.5	5.5	5.5	4.6	0.0	1.8	5.5	4.4
4. EUOR	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	0.0	5.5	5.5	5.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	703	635	702	340	703	680	703	703	567	0	227	703	6,666
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	41	37	41	380	41	40	41	41	153	744	494	41	2,095
9. POH	0	0	0	360	0	0	0	0	120	744	481	0	1,705
10. EFOH	14	13	14	7	14	14	14	14	11	0	5	14	135
11. EMOH	27	24	27	13	27	26	27	27	22	0	9	27	255
12. OPER BTU (GBTU)	1,307	1,021	1,566	712	2,062	2,294	2,033	2,024	1,361	0	454	1,290	16,164
13. NET GEN (MWH)	168,480	131,140	202,770	92,380	270,870	303,320	266,890	265,670	177,300	0	58,790	166,180	2,103,790
14. ANOHR (Btu/kwh)	7,759	7,783	7,722	7,709	7,614	7,563	7,619	7,620	7,675	0	7,719	7,761	7,683
15. NOF (%)	22.9	19.7	27.6	29.2	41.5	48.0	40.9	40.7	33.7	0.0	27.9	22.6	32.6
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968

17. ANOHR EQUATION ANOHR = NOF(-7.777) + 7,937

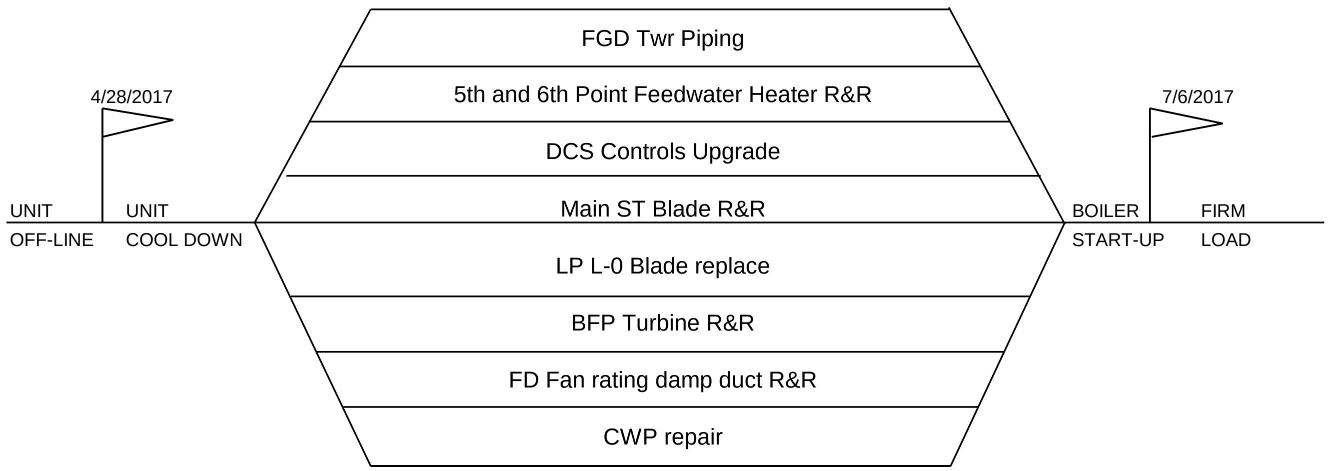
40

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2017 - DECEMBER 2017

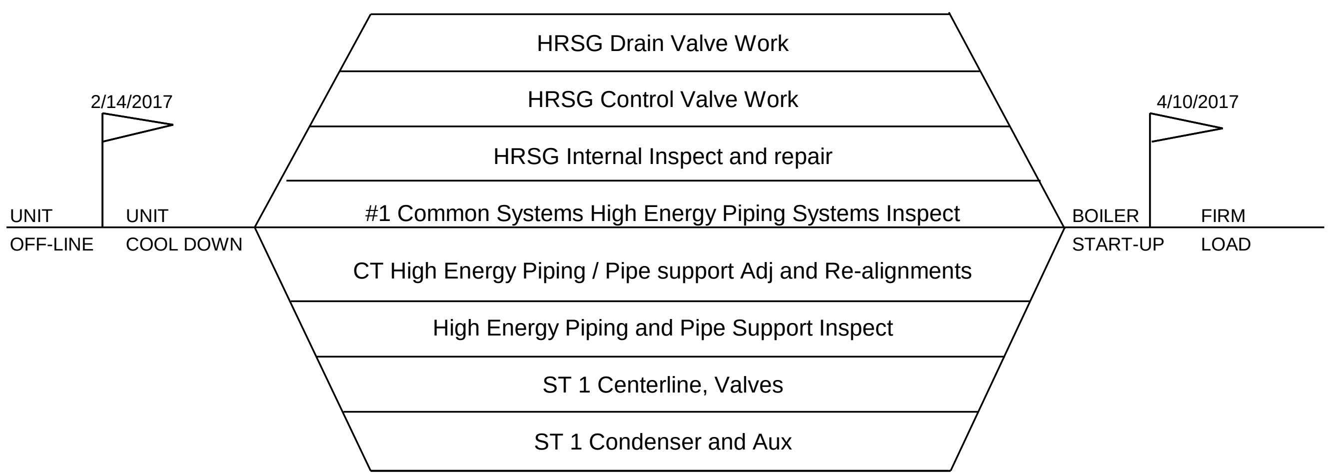
	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
	BIG BEND 1	Jan 28 - Feb 10	Fuel System Cleanup and FGD/SCR work
		Dec 12 - Dec 21	Fuel System Cleanup and FGD/SCR work
	BIG BEND 2	Jan 29 - Feb 11	Fuel System Cleanup and FGD/SCR work
		Dec 13 - Dec 22	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 3	Apr 28 - Jul 06	Main ST Blade R&R, LP L-0 Blade replace, BFP Turbine R&R, DCS Controls Upgrade, 5th and 6th Point Feedwater Heater R&R, FD Fan rating damp duct R&R, CWP repair, FGD Twr Piping
		Nov 30 - Dec 09	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Feb 16 - Mar 01	Fuel System Cleanup and FGD/SCR work
		Nov 10 - Nov 19	Fuel System Cleanup and FGD/SCR work
	POLK 1	Mar 03 - Mar 22	Gasifier Outage
		Nov 03 - Nov 09	Gasifier Outage
+	BAYSIDE 1	Feb 14 - Apr 10	ST 1 Centerline, Valves, Condenser and Aux, HRSG Internal Inspect and repair, HRSG Control Valve Work, HRSG Drain Valve Work, High Energy Piping and Pipe Support Inspect, #1 Common Systems High Energy Piping Systems Inspect, CT High Energy Piping / Pipe support Adj and Re-alignments
		Nov 27 - Dec 08	Fuel System Cleanup
+	BAYSIDE 2	Apr 15 - Apr 29	Fuel System Cleanup
		Sep 26 - Nov 20	ST 2 Centerline, Valves, Condenser and Aux, HRSG Internal Inspect and repair, HRSG Control Valve Work, HRSG Drain Valve Work, High Energy Piping and Pipe Support Inspect, #2 Common Systems High Energy Piping Systems Inspect, CT High Energy Piping / Pipe support Adj and Re-alignments

+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2017 - DECEMBER 2017

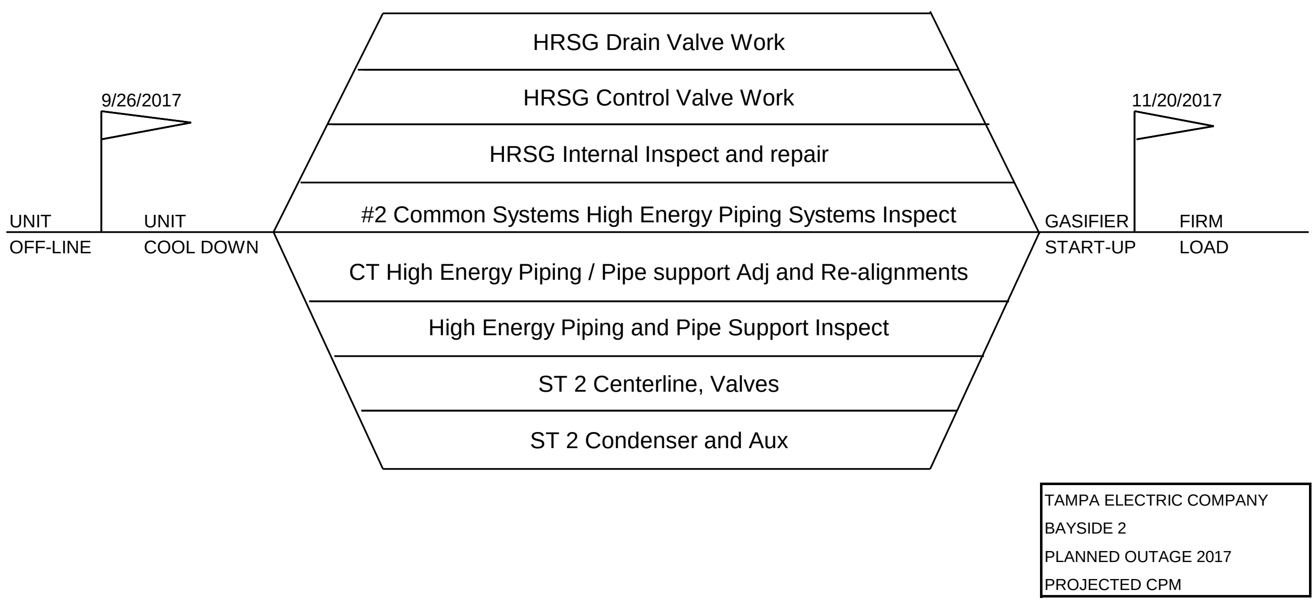


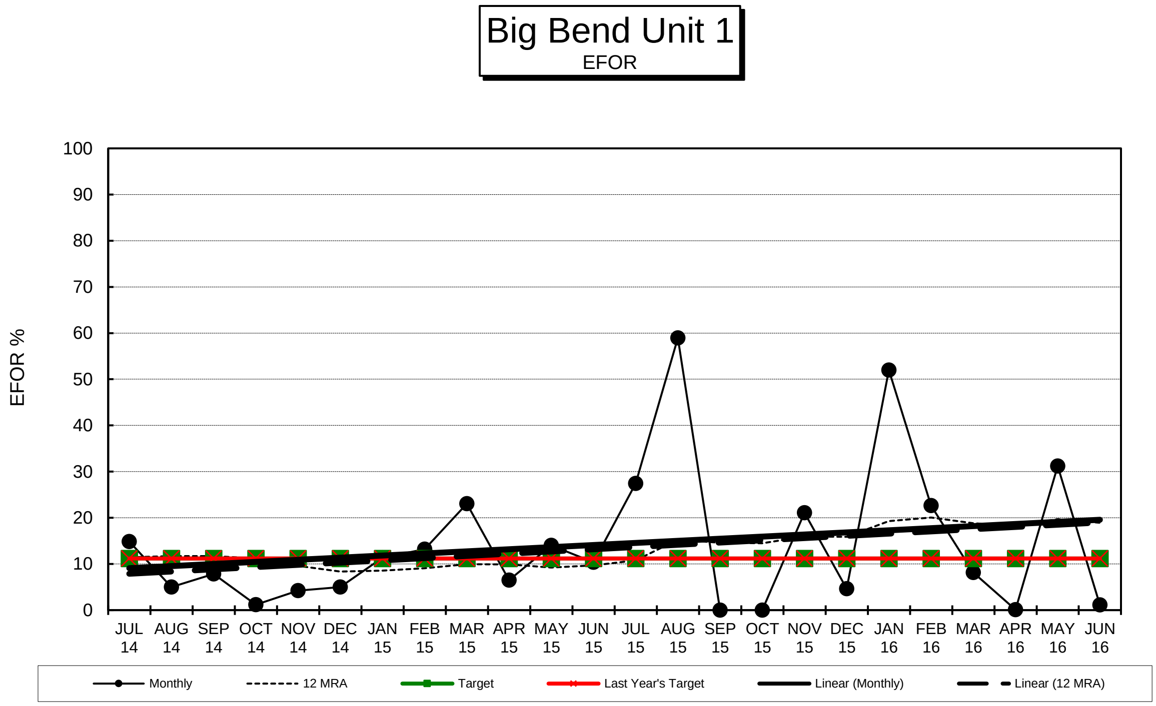
TAMPA ELECTRIC COMPANY
BIG BEND 3
PLANNED OUTAGE 2017
PROJECTED CPM



TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2017
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2017 - DECEMBER 2017

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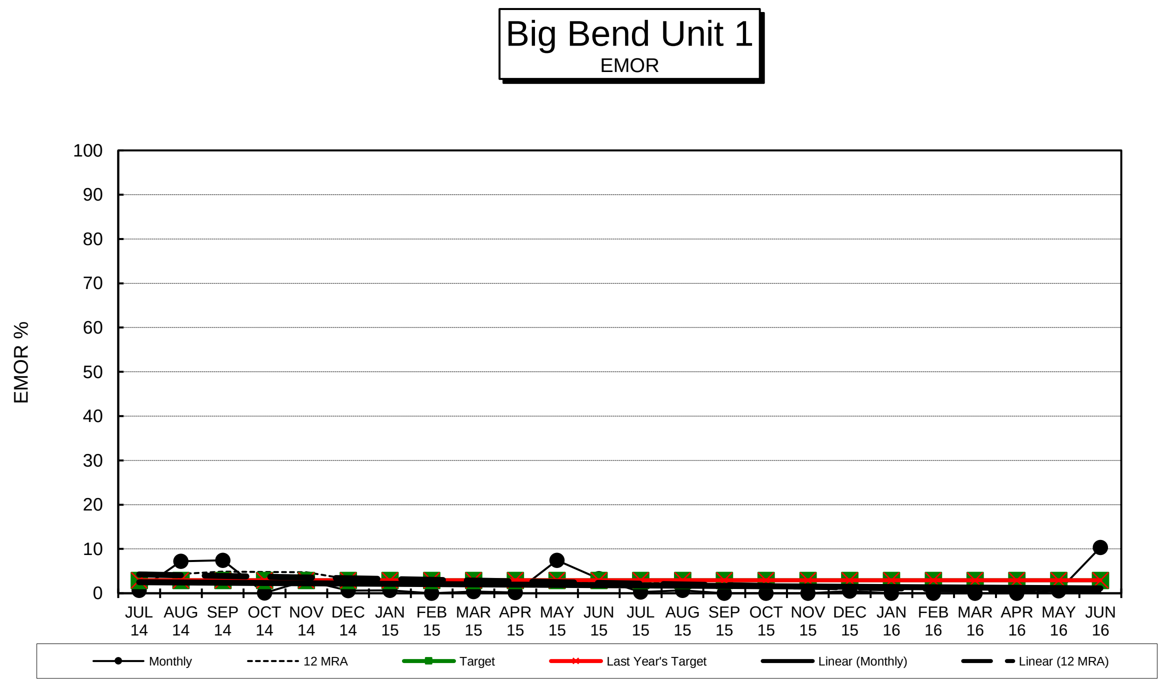
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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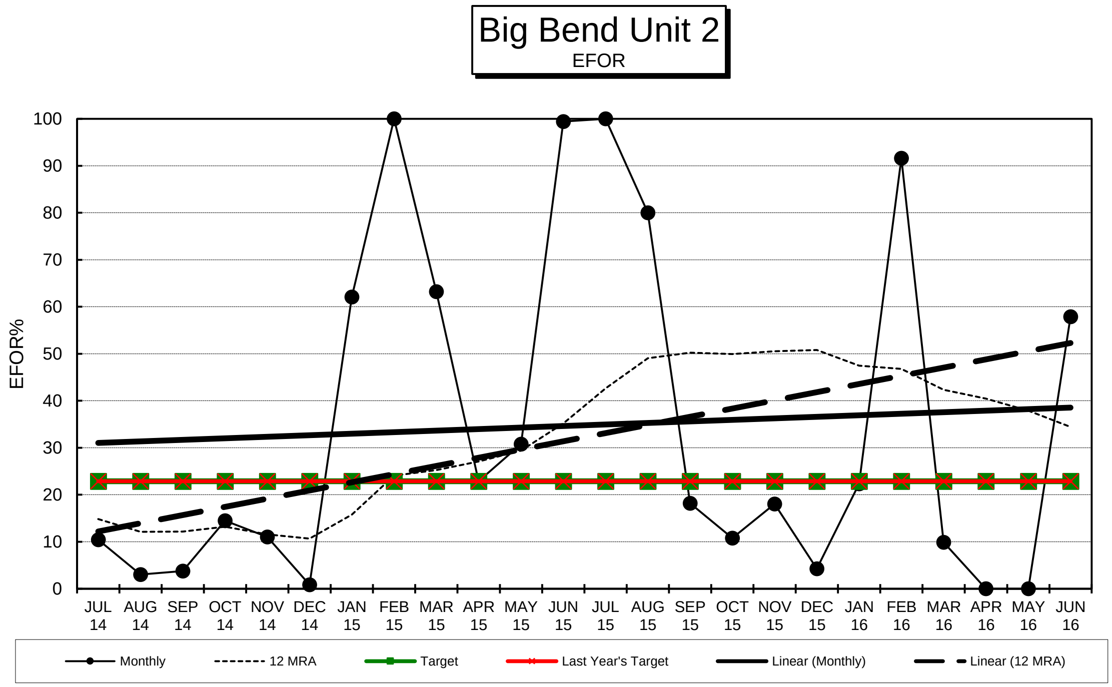
EMOR
EMOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EFOR
EFOR%
0
10
20
30
40
50
60
70
80
90
100
JUL 14
AUG 14
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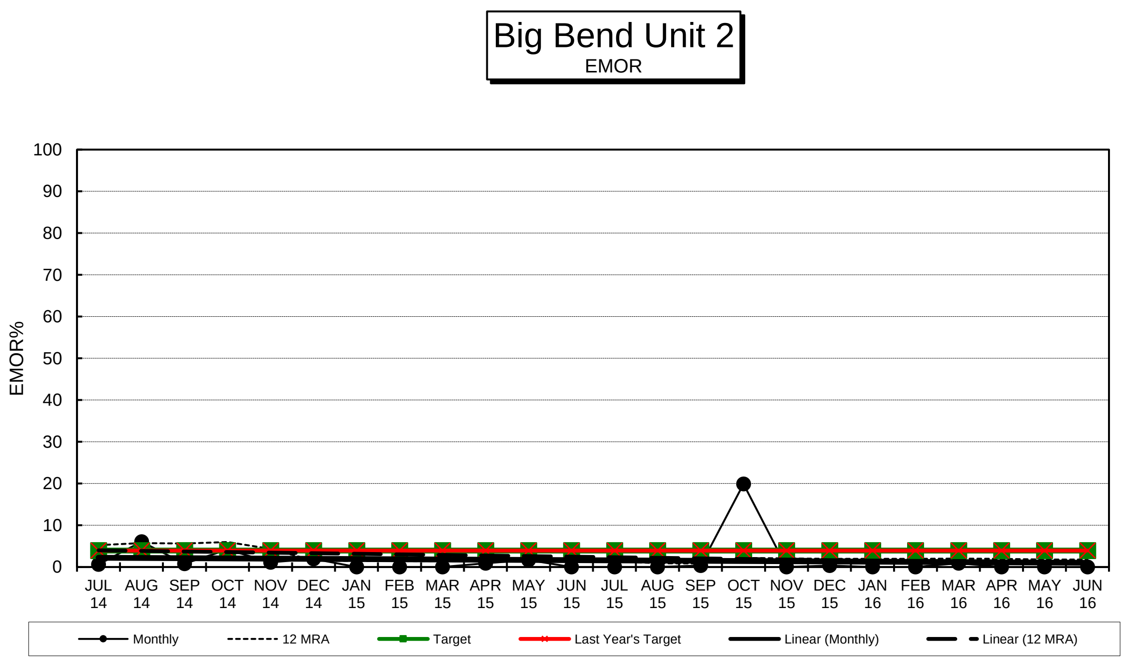
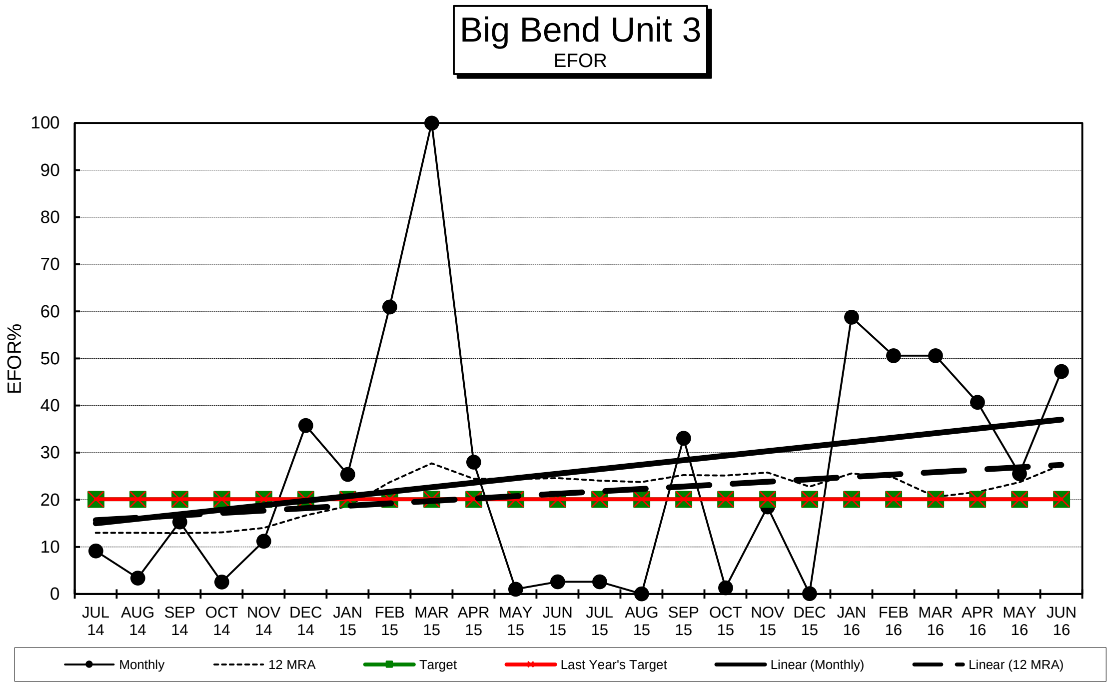
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EMOR
EMOR%
0
10
20
30
40
50
60
70
80
90
100
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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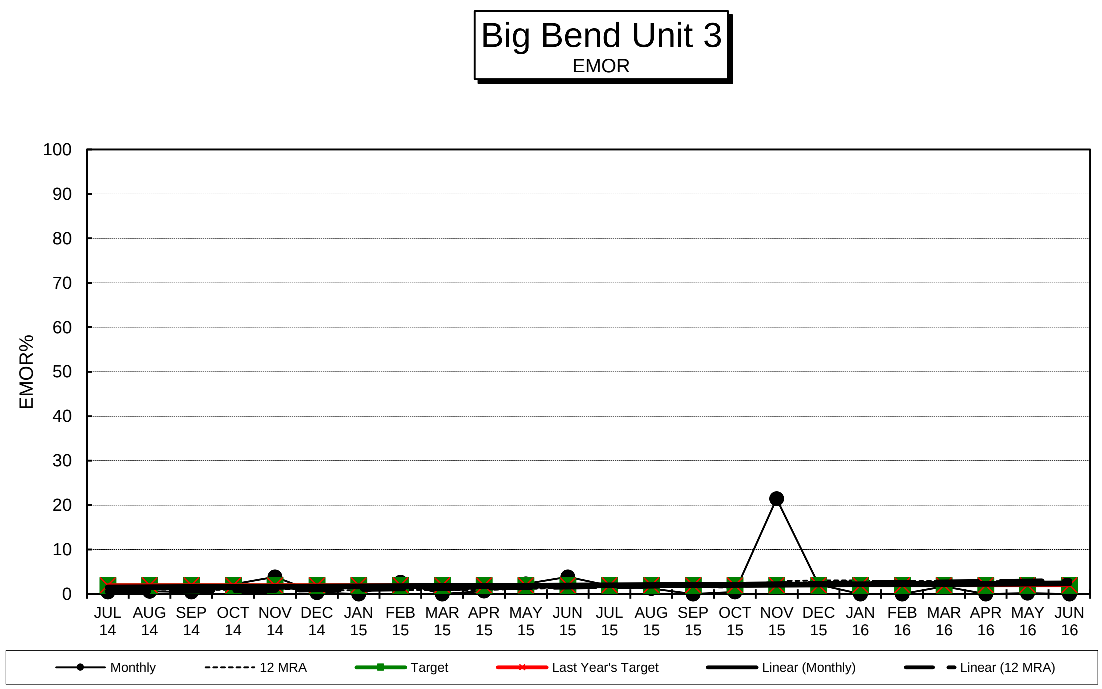
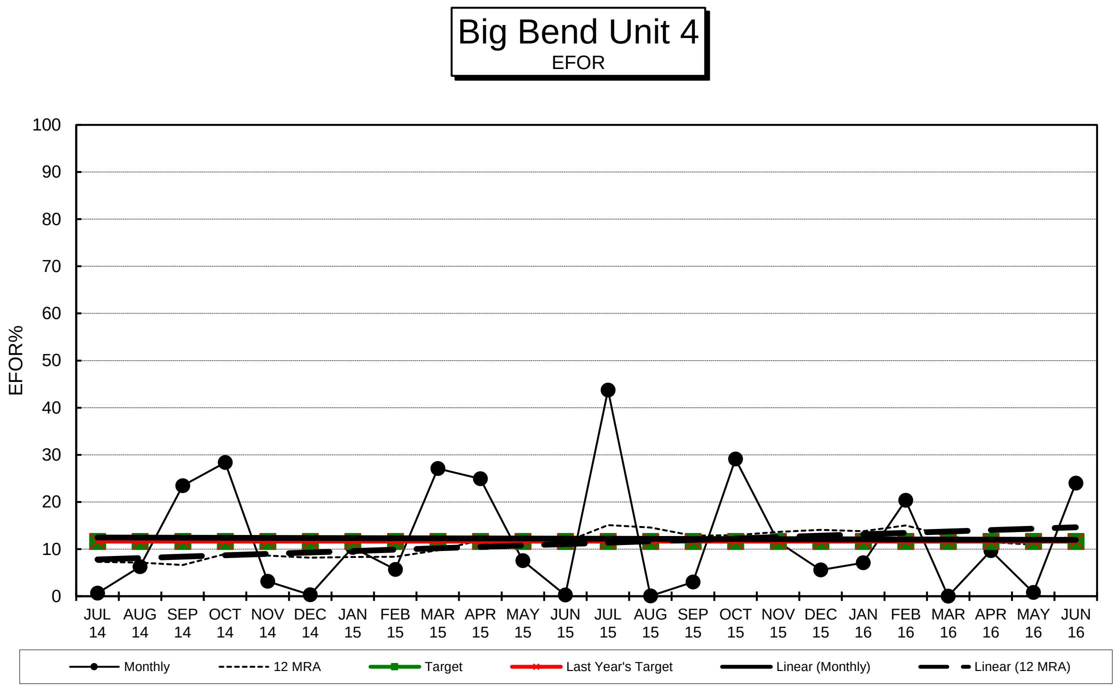
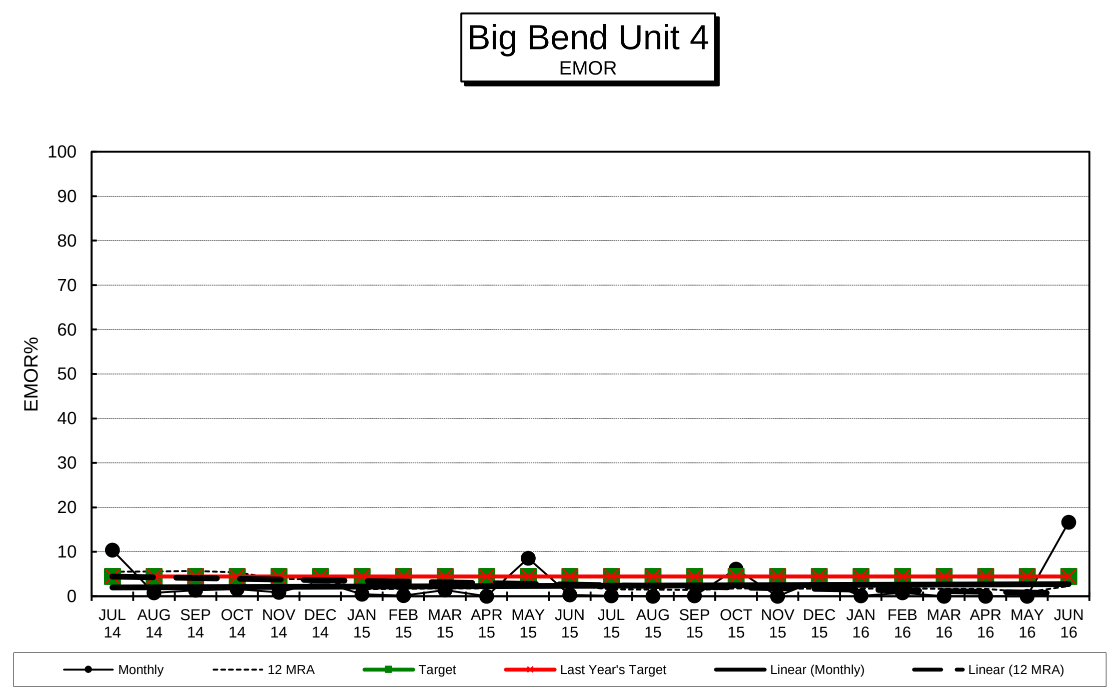
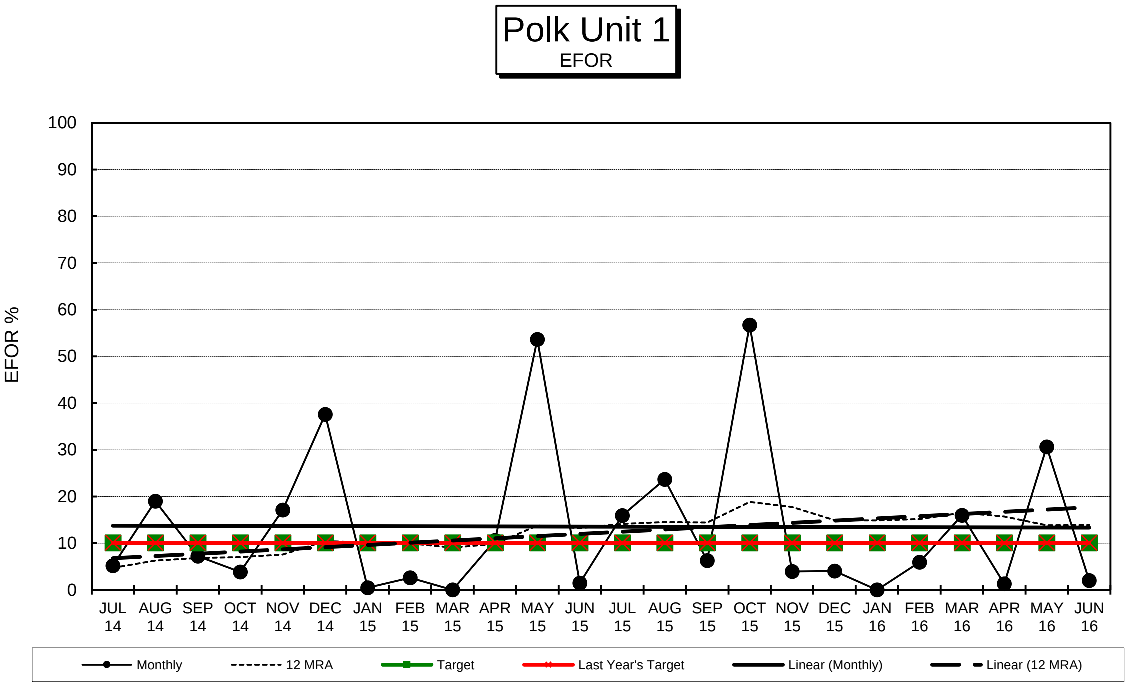
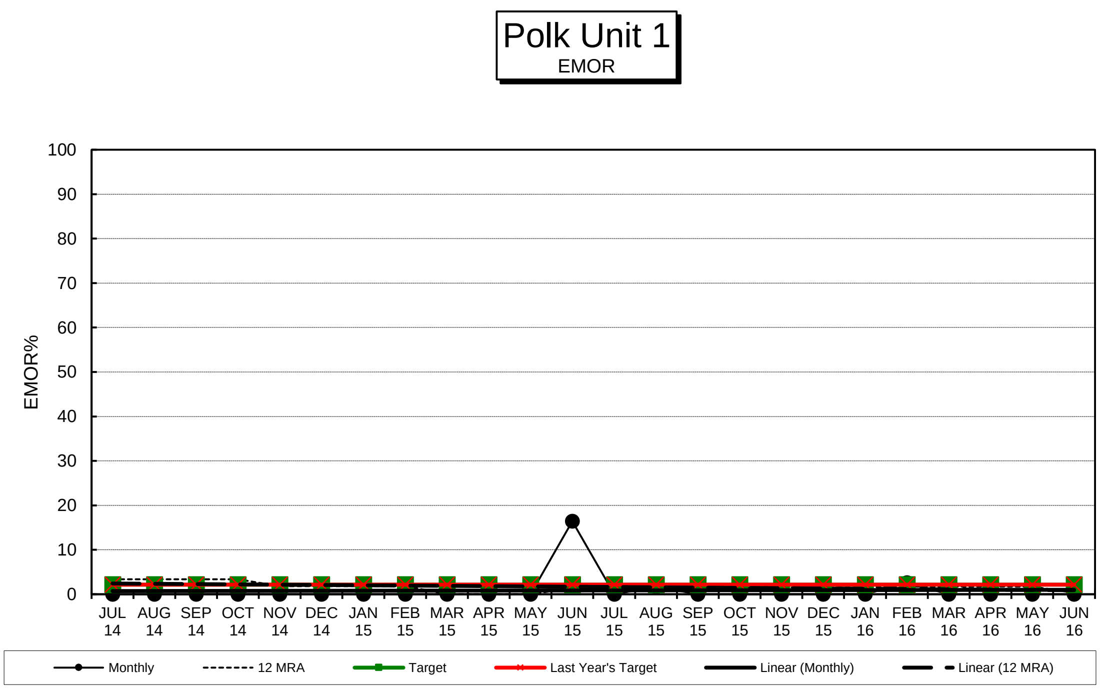
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
100
90
80
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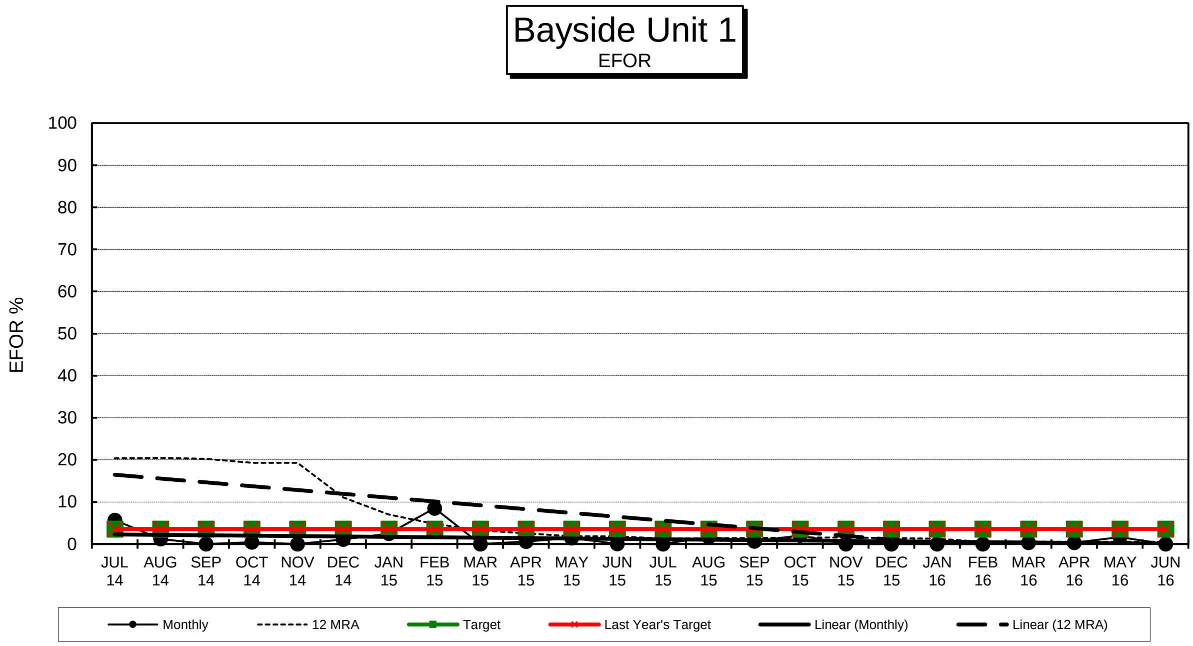
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
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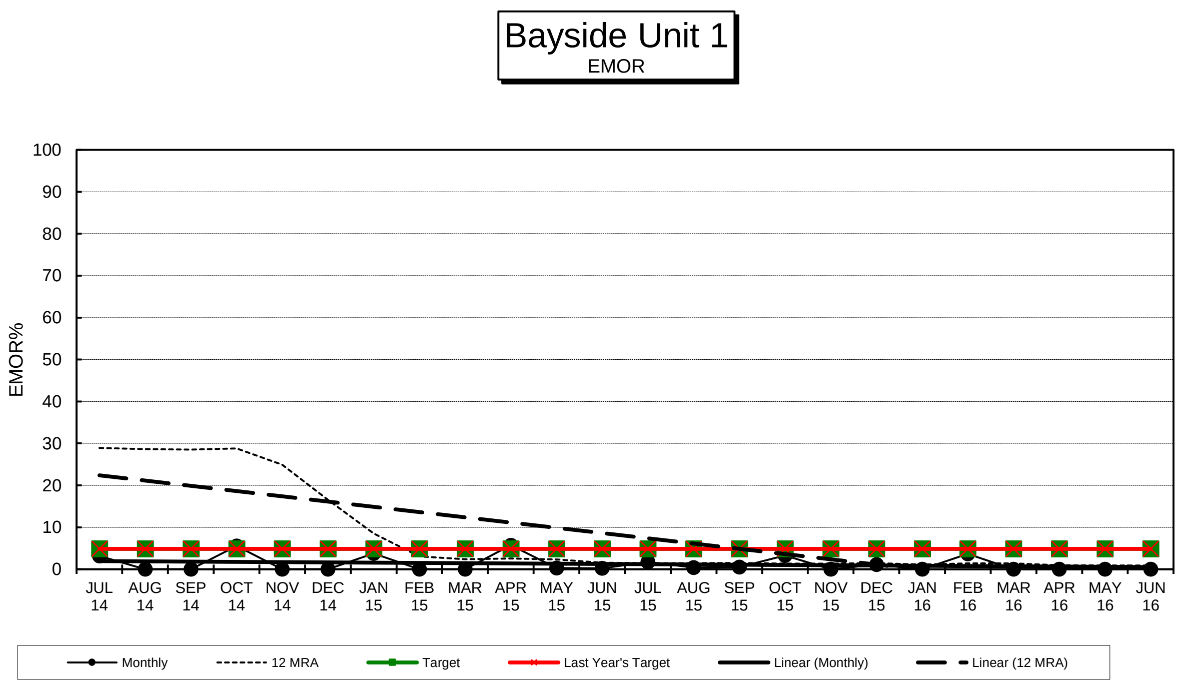
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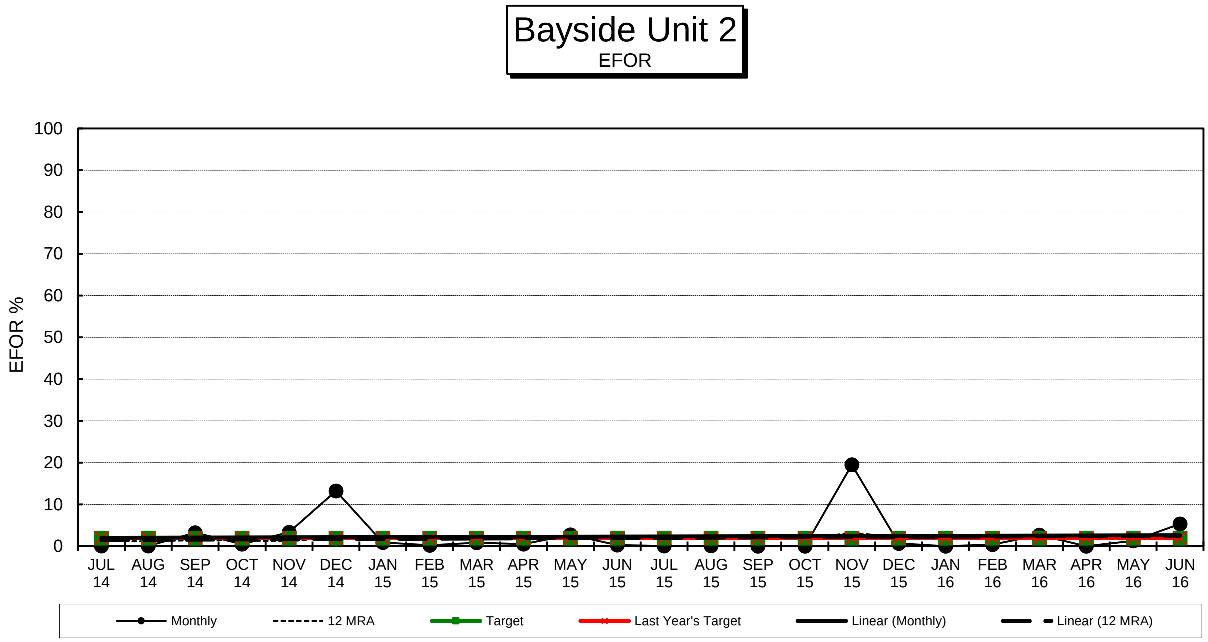
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
EFOR %
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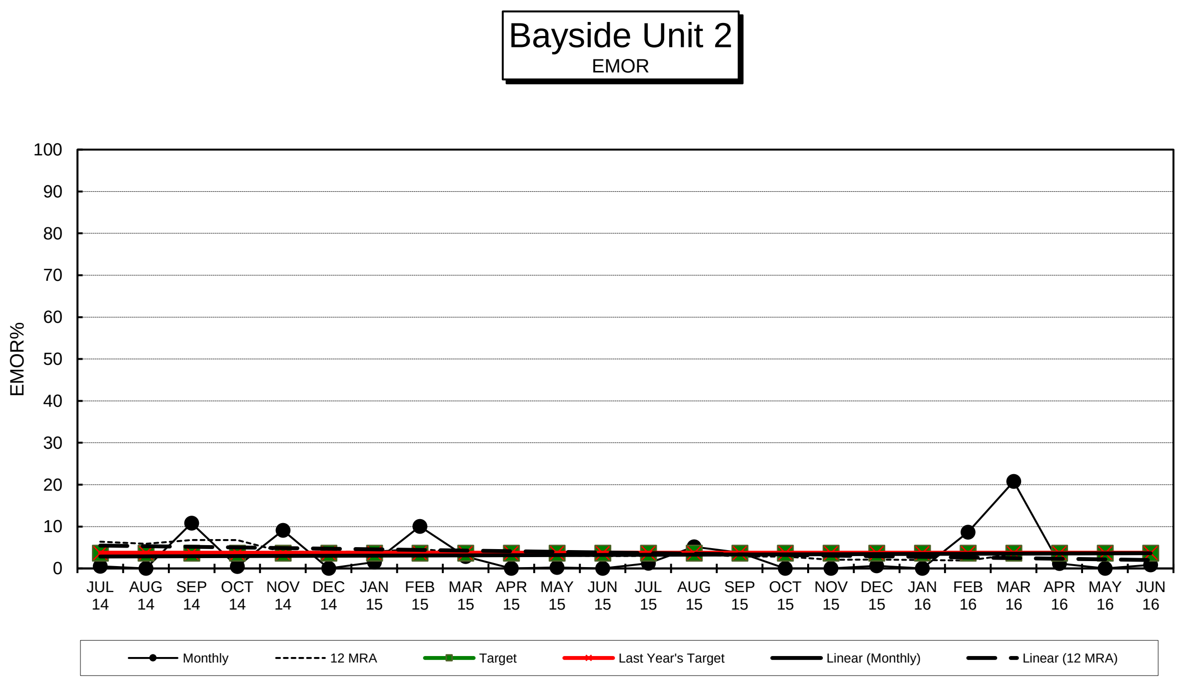
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
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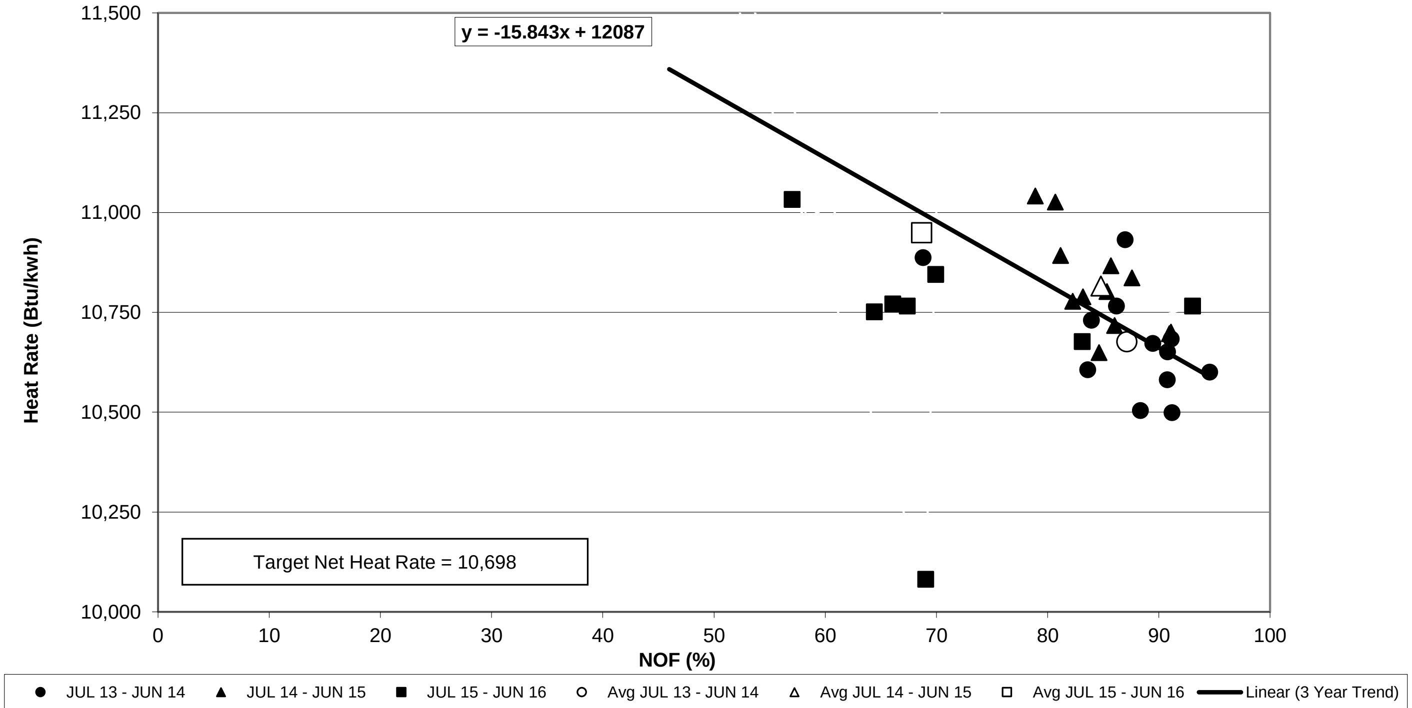
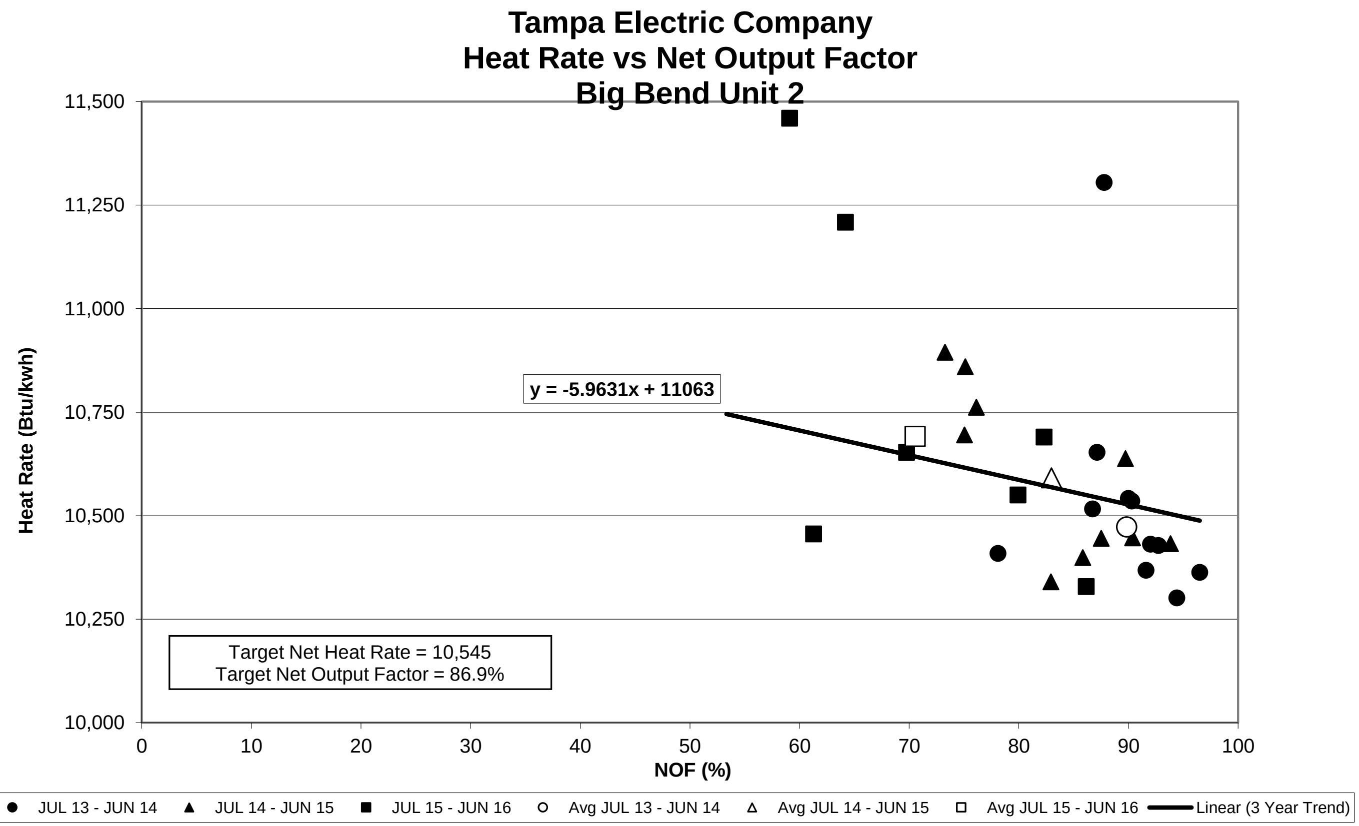
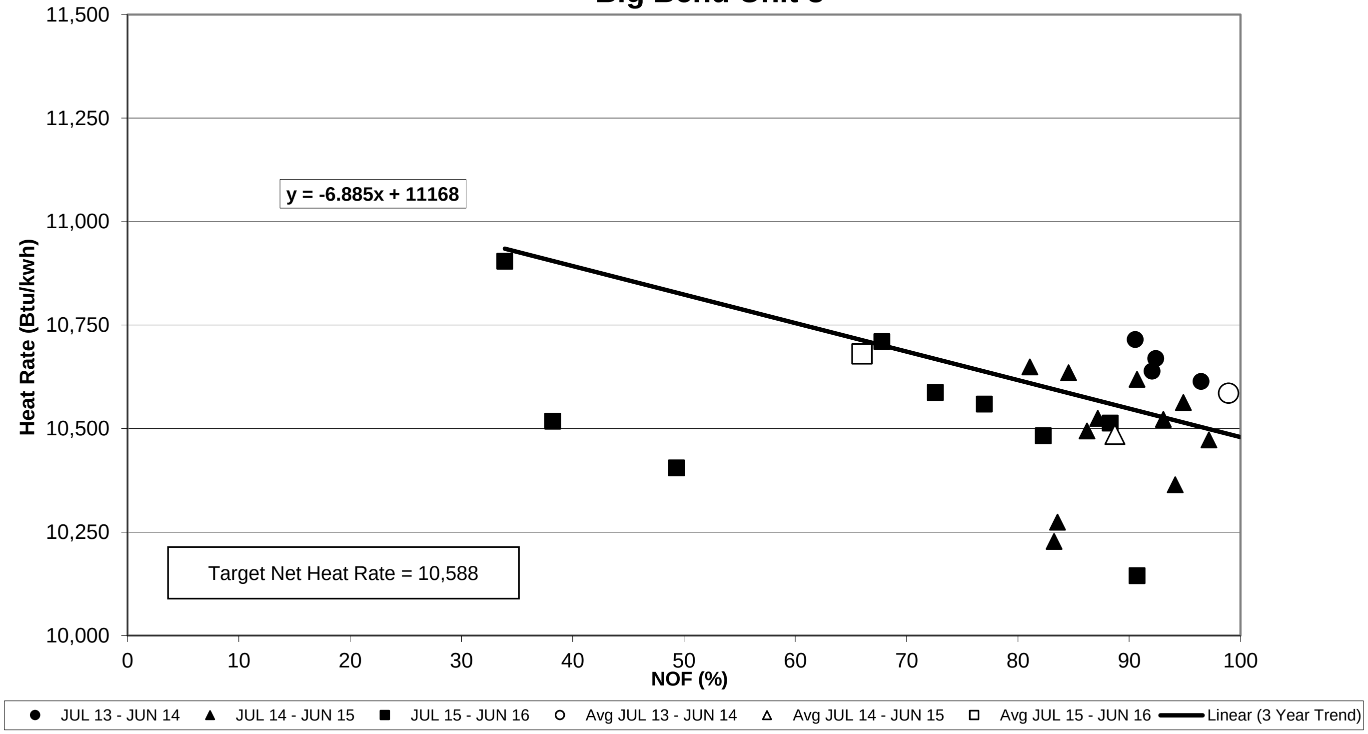
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1



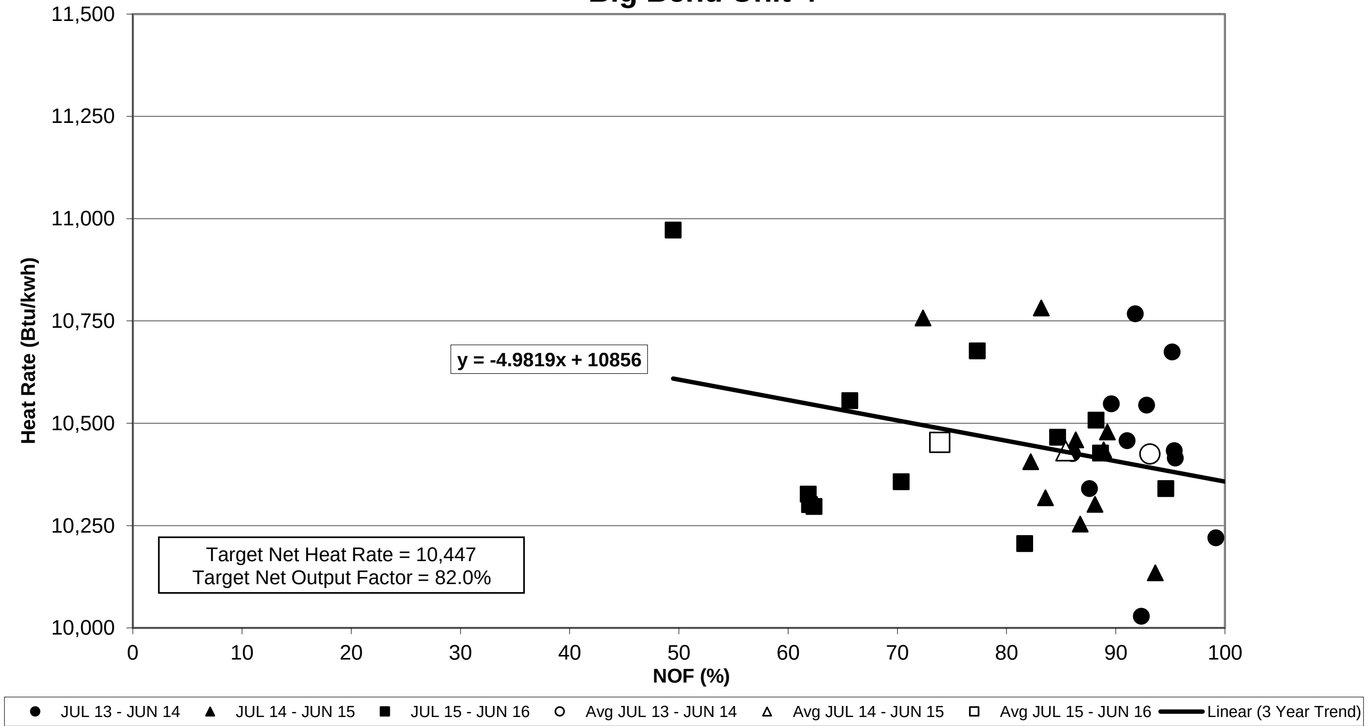

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
Heat Rate (Btu/kwh)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
y = -5.9631x + 11063
Target Net Heat Rate = 10,545
Target Net Output Factor = 86.9%
0
10
20
30
40
50
60
70
80
90
100
NOF (%)
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)

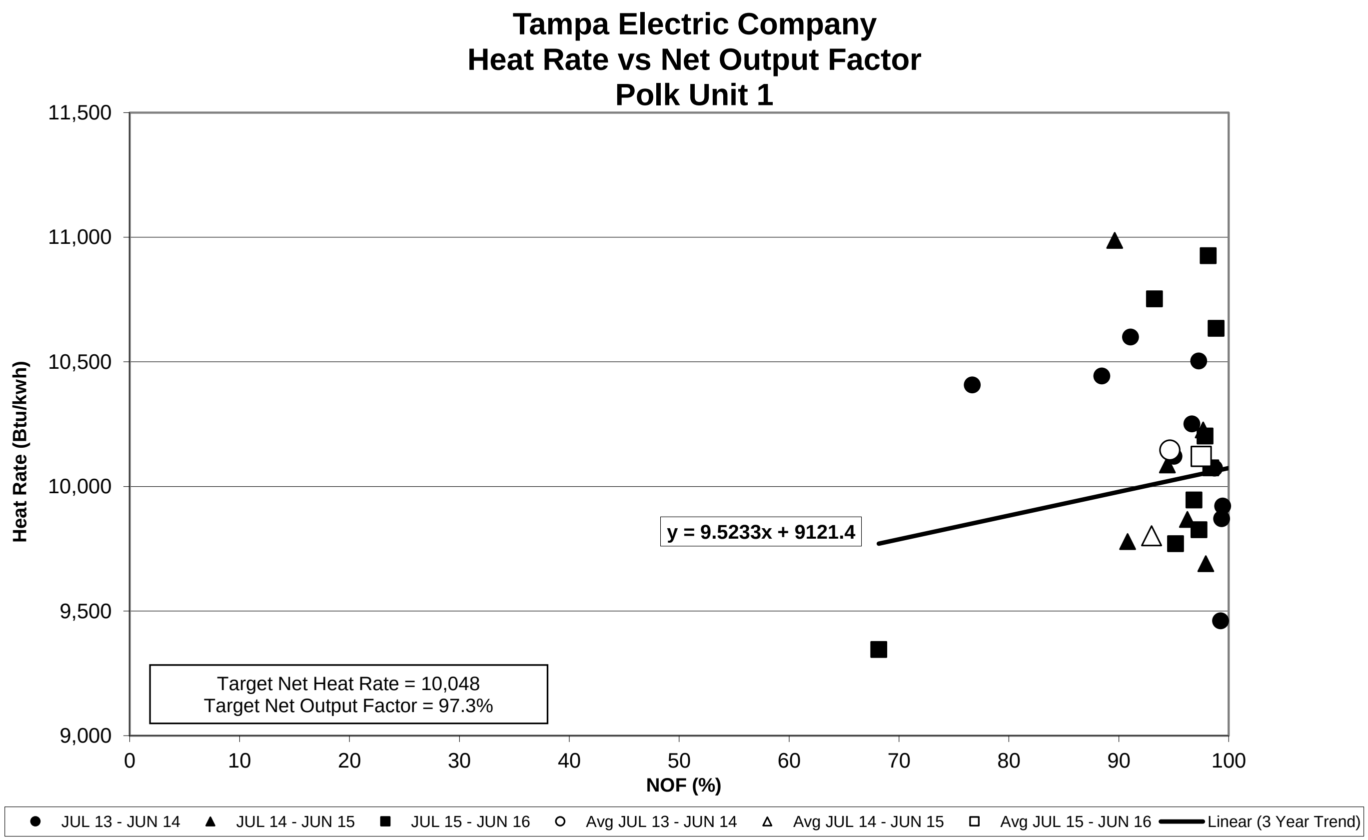
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3



DOCKET NO. 160001-EI
GPIF 2017 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 33 OF 40

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4





DOCKET NO. 160001-EI
GPIF 2017 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 35 OF 40

Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1

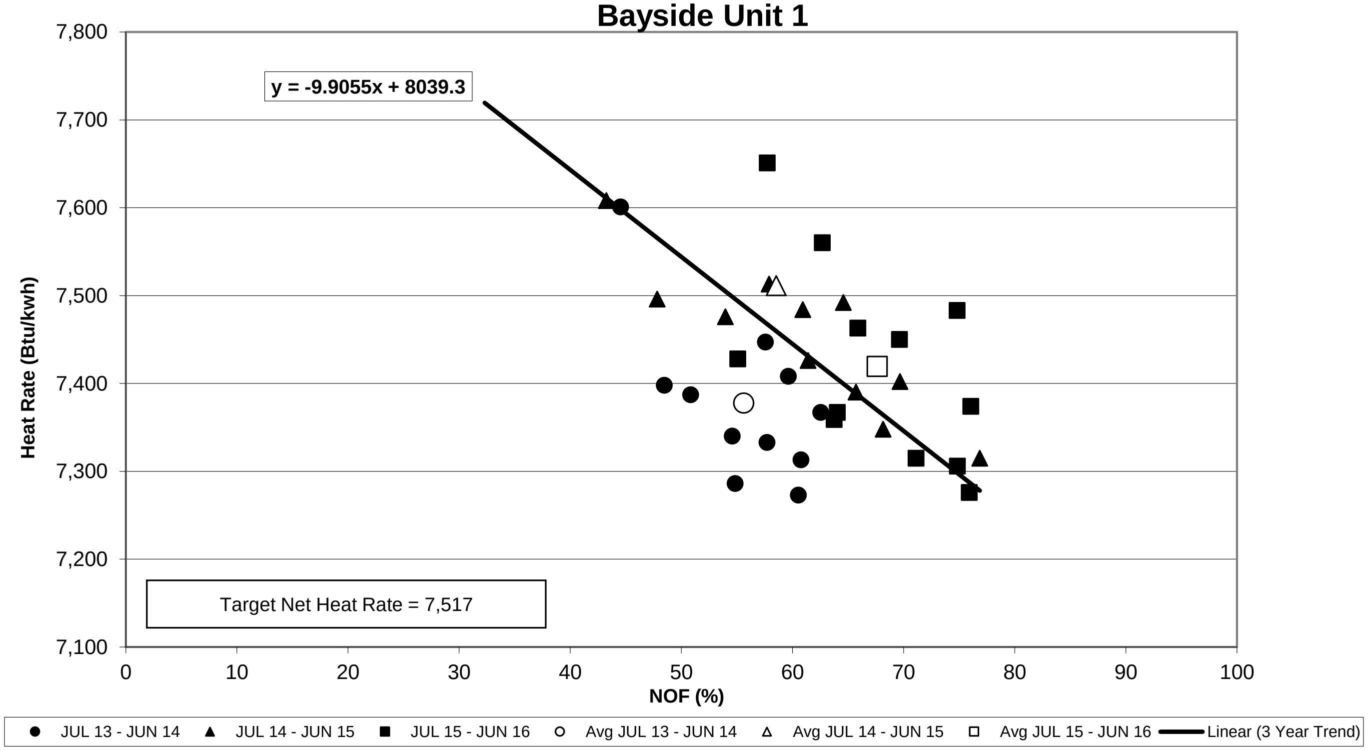


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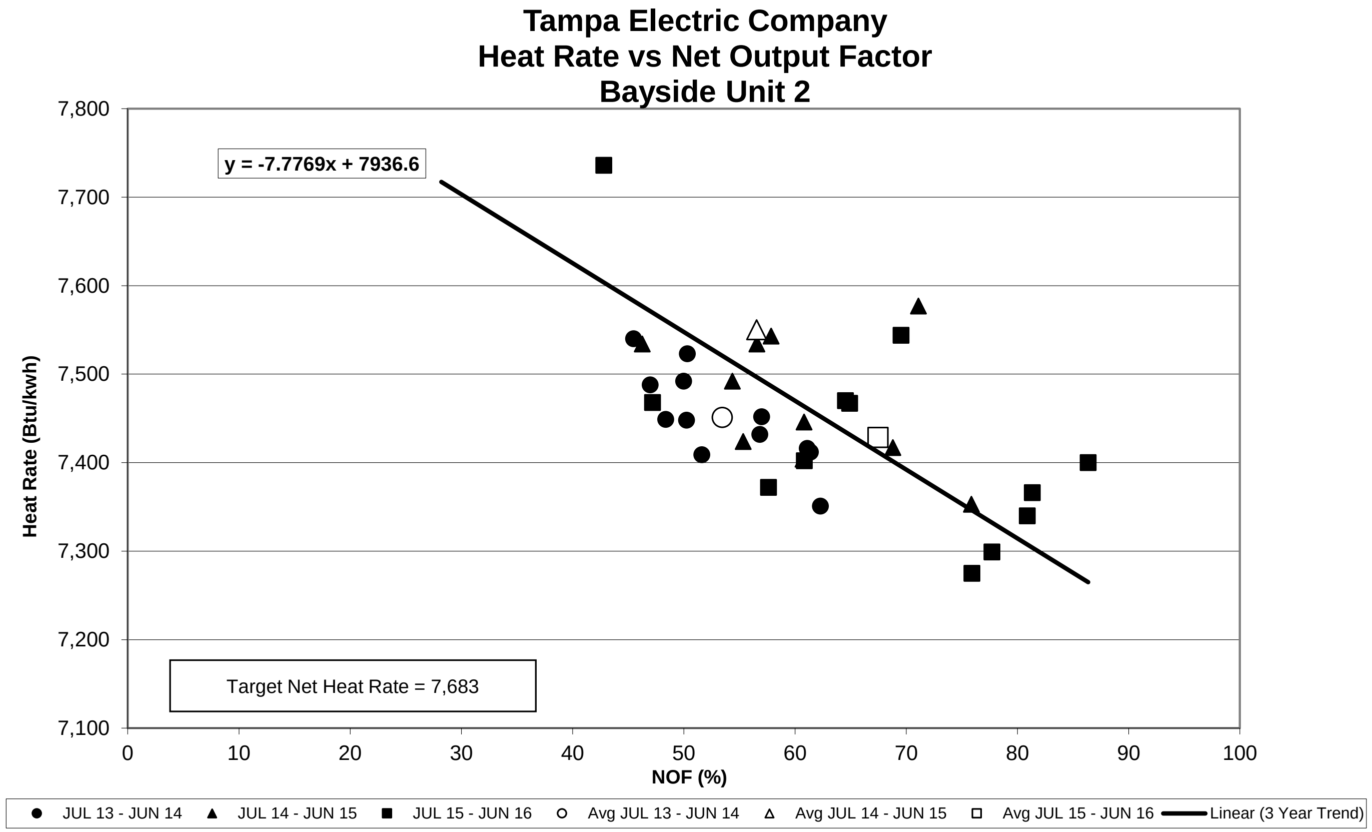
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 36 OF 40



57

DOCKET NO. 160001-EI
GPIF 2017 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.17E
PAGE 37 OF 40

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2017 - DECEMBER 2017

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,730	3,532
	SYSTEM TOTAL	**5,157**	**4,978**
	% OF SYSTEM TOTAL	**72.3%**	**70.9%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2017 - DECEMBER 2017

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,779	1,670
POLK 1		290	220
POLK 2		1,113	1,137
	POLK TOTAL	1,403	1,357
SOLAR		21	21
	SOLAR TOTAL	21	21
	SYSTEM TOTAL	**5,157**	**4,978**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2017 - DECEMBER 2017

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	5,957,150	30.30%	30.30%
BAYSIDE	1	2,208,770	11.23%	41.53%
BAYSIDE	2	2,103,790	10.70%	52.24%
BIG BEND	2	2,078,760	10.57%	62.81%
BIG BEND	4	1,946,620	9.90%	72.71%
BIG BEND	1	1,917,590	9.75%	82.46%
BIG BEND	3	1,822,110	9.27%	91.73%
POLK	1	1,555,680	7.91%	99.64%
SOLAR		36,390	0.19%	99.83%
BIG BEND CT	4	11,630	0.06%	99.89%
BAYSIDE	5	7,600	0.04%	99.93%
BAYSIDE	6	5,930	0.03%	99.96%
BAYSIDE	3	4,720	0.02%	99.98%
BAYSIDE	4	3,630	0.02%	100.00%
TOTAL GENERATION		19,660,370	100.00%	

GENERATION BY COAL UNITS: 9,320,760 MWH   GENERATION BY NATURAL GAS UNITS: 10,303,220 MWH

% GENERATION BY COAL UNITS 47.41%   % GENERATION BY NATURAL GAS UNITS: 52.41%

GENERATION BY SOLAR UNITS: 36,390 MWH   GENERATION BY GPIF UNITS: 13,633,320 MWH

% GENERATION BY SOLAR UNIT 0.19%   % GENERATION BY GPIF UNITS: 69.34%

* Polk 2 CC will be a new CC unit.

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2017 - DECEMBER 2017

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2017 - DECEMBER 2017

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1[1]	80.5	6.6	12.9	10,698
Big Bend 2[2]	69.6	6.6	23.8	10,545
Big Bend 3[3]	61.4	21.9	16.7	10,588
Big Bend 4[4]	79.1	6.6	14.3	10,447
Polk 1[5]	82.1	7.4	10.5	10,048
Bayside 1[6]	75.3	18.6	6.1	7,517
Bayside 2[7]	76.1	19.5	4.4	7,683

1 Original Sheet 8.401.17E, Page 14

2 Original Sheet 8.401.17E, Page 15

3 Original Sheet 8.401.17E, Page 16

4 Original Sheet 8.401.17E, Page 17

5 Original Sheet 8.401.17E, Page 18

6 Original Sheet 8.401.17E, Page 19

7 Original Sheet 8.401.17E, Page 20

TECO

TAMPA ELECTRIC

AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2017 THROUGH DECEMBER 2017

TESTIMONY

OF

J. BRENT CALDWELL

FILED: SEPTEMBER 1, 2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

Q. Please state your name, address, occupation and employer.

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Fuel Planning and Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long-term fuel supply planning and procurement for Tampa Electric's generating stations.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2011. In 2015, I testified in Docket No. 150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle ("CC") Conversion project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes coal, natural gas, and oil. Coal is the primary fuel for Big Bend Station, and natural gas is a secondary fuel. The Polk Unit 1 integrated gasification combined-cycle unit utilizes coal as the primary fuel and natural gas as a secondary fuel; and Bayside Station combined-cycle units and the company's collection of peakers (*i.e.*, simple cycle and aero-derivative combustion turbines) utilize natural gas. Some of Tampa Electric's peakers utilize oil as a secondary fuel, but oil consumption as a percentage of system generation is minute (*i.e.*, less than one percent). During the first half of 2016, very low natural gas prices resulted in greater use of natural gas, compared to the original projection. Based upon the 2016 actual-estimate projections, the company expects 2016 total system generation to be 42 percent coal and 58 percent natural gas, with oil making up a fraction of a percentage point.

In 2017, coal-fired and natural gas-fired generation are expected to be approximately 47 percent and 53 percent of total generation, respectively. Generation from oil is expected to remain less than one percent of the total generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and lower costs for Tampa Electric’s customers.

Coal Supply Strategy

Q. Please describe Tampa Electric’s solid fuel usage and procurement strategy.

A. Tampa Electric uses solid fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content. Coal is not a homogenous product, and the variability of the product dictates Tampa Electric select fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources while still allowing the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric's solid fuel, coal, and petroleum coke supply through 2017.

A. Tampa Electric supplies Big Bend Station's coal needs through a combination of three coal supply agreements that continue through 2017 and a collection of shorter term contracts and spot purchases. These shorter term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2017 delivery?

A. Yes, Tampa Electric has contracted for and has available from inventory over 75 percent of its 2017 expected coal needs through agreements with coal suppliers to mitigate price volatility and ensure the reliability of supply. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases or consumed from inventory during 2016 and 2017.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, Polk Unit 1 solid fuel is trucked to Polk Station.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Transportation options provide benefits to customers. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal portfolio, 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2016 and 2017?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2016 and is in the process of evaluating how much coal to receive by rail in 2017.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive the balance of its solid fuel supply needs as waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River system through United Bulk Terminal or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Please describe the replacement for the river barge transportation contract with a term ending December 31, 2016.

A. One of two river barge transportation agreements expire at the end of 2016. Tampa Electric is currently assessing the most economic replacement option for this agreement. Due to the flexibility in the company's delivery and supply portfolio, Tampa Electric can meet its 2017 solid fuel delivery needs without replacing this agreement.

Q. Please describe any other changes to the solid fuel transportation agreements.

A. Tampa Electric has taken advantage of a number of spot market transportation opportunities. Tampa Electric has used delivered coal, a different river transportation provider, and three new terminals during 2016 to manage its portfolio during changing coal consumption levels, increase reliability during outages, and increase flexibility in its supply and transportation portfolio.

Q. Do you have any other updates to provide with regard to Tampa Electric's solid fuel transportation portfolio?

A. Tampa Electric monitors the financial strength and ability to perform of its solid fuel suppliers and transportation providers. On August 1, 2016 United Ocean Services ("UOS"), Tampa Electric's gulf transportation provider, filed for protection under Chapter 11 bankruptcy law. While this has not become a performance issue yet and Tampa Electric believes UOS fully intends to emerge from the filing as an operationally sufficient and financially stronger transportation service provider, the company must consider the uncertainty of UOS's future. Tampa Electric is closely monitoring the situation, actively engaged in communication with UOS, and developing contingency plans to ensure reliable and cost-effective solid fuel supply to its power plants. Tampa Electric expects UOS to continue to provide service as the bankruptcy hearings proceed. It is likely that at least several months will pass before more definitive information about the UOS bankruptcy outcome is available.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2017 solid fuel supply portfolio.

A. Tampa Electric continues to place an emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. New or pending environmental regulations may affect the types of coal, the quantities of coal that can be consumed at the stations or, most likely, both. Also, the use of different types of fuel within the state continue to evolve as generation assets are built, upgraded or retired. For instance, Tampa Electric's Polk Unit 2 CC is anticipated to enter commercial service in January 2017. The Polk Unit 2 CC project converts the existing natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined-cycle unit. Similarly, several new natural gas combined-cycle units recently have been built within the state. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary significantly each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Similar to its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. Such actions improve the reliability and cost effectiveness of the physical delivery of natural gas to the company's power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero-derivative combustion turbine and natural gas co-firing in the coal units. Polk Station receives natural gas from FGT to support the four existing natural gas combustion turbines that are being converted to Polk Unit 2 CC and Polk Unit 1 as an alternate fuel.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. Currently, the company reserves 1,250,000 MMBtu of long-term storage capacity and has 250,000 MMBtu of shorter term storage capacity.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH") and the Transco lateral. SESH and the Transco lateral connect the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase. Thus, SESH and the Transco lateral give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Does Tampa Electric have plans to secure additional natural gas supply for 2017 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately 65 percent of the company's expected natural gas requirements for 2017. The balance of Tampa Electric's natural gas supply will be acquired through seasonal, monthly, and daily purchases to meet its varying operational needs.

Q. Will Tampa Electric need to enter additional supply or transportation contracts for natural gas once Polk Unit 2 CC is declared to be commercially in-service?

A. No, Tampa Electric does not expect to enter additional supply or transportation agreements for the natural gas to be used at Polk Station. Tampa Electric's portfolio approach to natural gas fuel supply and delivery allows it to absorb the new unit without significant changes to its contracts.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company’s fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2016 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange (“NYMEX”), PIRA Energy, Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences. Tampa Electric utilized the average of the five daily NYMEX natural gas futures settlement prices for the period June 28, 2016 through July 5, 2016 to prepare the fuel price forecast.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices. Also, the price projections are specific to the particular quality and mined location of coal utilized by Tampa Electric’s Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2017 projected fuel prices compare to the fuel prices projected for 2016?

A. The commodity price for natural gas during 2017 is projected to be slightly higher than the prices projected for 2016. Reductions to natural gas production combined with increased gas-fired generation demand have put upward pressure on natural gas prices.

The 2017 coal commodity price projection is about the same as the price projected for 2016. Lower national coal demand resulting from coal-fired unit closures is expected to keep coal prices low despite consolidation and production cuts in domestic coal supply. However, in the long term these production cuts are expected to put upward pressure on coal prices.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. While 2017 projected prices for coal and natural gas are expected to be relatively similar to 2016 prices, Tampa Electric recognizes that there is uncertainty in future prices. Therefore, Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 40 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 40 percent. Due to Tampa Electric's generating mix and Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa

Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on August 4, 2016 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2016 and 2017 natural gas requirements?

A. Yes. As a part of its Risk Management Plan, Tampa Electric hedged a significant portion of its 2016 natural gas supply needs and a portion of its expected 2017 natural gas supply needs in accordance with the company's hedge plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 18, 2016.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2016 and 2017 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are also described in detail in Tampa Electric's Risk Management Plan.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the volume of natural gas expected to be consumed in its power plants. The volume hedged is driven by the projected total natural gas consumption in its combined-cycle plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee and monitored by the Risk Management department. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2016 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the Risk Management Plan approved by the company's Risk Authorizing Committee and filed with this Commission. On April 6, 2016, the company filed its 2015 Natural Gas Hedging Activities report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2016, in this docket on August 18, 2016.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. Tampa Electric's hedged quantity of natural gas may or may not generate fuel savings. Fuel savings is not the focus of the hedge program. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission, not speculate on the price of fuel. Tampa Electric's hedging program requires consistent hedging based on expected needs. The company does not engage in speculative hedging strategies aimed at out-guessing the market. This discipline ensures the needed hedge volumes will be in place for customers regardless of the price movements of natural gas.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2017 THROUGH DECEMBER 2017

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: SEPTEMBER 1, 2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

Q. Please state your name, address, occupation and employer.

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of Wholesale Business Development in Tampa Electric's Fuels Management department. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structures, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to provide a description of Tampa Electric's power purchase agreements the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company aggressively searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs and improve reliability. The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2016 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately ten percent of the company's expected energy needs for 2016 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, and pre-existing firm purchased power agreements with Pasco Cogen and Calpine. The company also entered three additional firm power purchase agreements with Duke Energy Florida

("Duke"), Florida Power & Light ("FPL"), and Exelon Generation Company, formerly known as Constellation Energy Commodities Group ("Exelon").

My testimony in previous years' dockets described the agreements with Pasco Cogen and Calpine. However, in summary, both pre-existing purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is for 121 MW of intermediate capacity and continues through 2018, and the Calpine agreement is a peaking purchase with a capacity of 117 MW. The Calpine purchase continues through 2016. These two purchases were previously approved by the Commission as being cost-effective for Tampa Electric customers.

The three new power purchase agreements sum to 500 MW of capacity and are of various sizes and end dates, the last of which concludes in February 2017. The Duke purchase is for250 MW of efficient combined-cycle capacity for the term February 2016 through February 2017. The FPL purchase is for 100 MW of system capacity for the period May through November 2016, and the Exelon purchase is for 150 MW of efficient combined-cycle capacity, also for the period May through November 2016.

Q. How did Tampa Electric determine that the three new purchases were the most beneficial options for Tampa Electric's customers?

A. As stated in my 2016 projection testimony, the Commission approved Tampa Electric's determination of need for the Polk Unit 2-5 combined cycle conversion ("Polk Unit 2 CC") in Docket No. 120234-EI. Polk Unit 2 CC is expected to begin commercial service in January 2017, and its construction timeline often requires at least two of the existing 150 MW Polk combustion turbine ("CT") units to be unavailable from May through November of this year for combined cycle tie-in and testing. This tie-in and testing requirement created a projected need for capacity and energy to meet system reserve margin requirements and ensure operational flexibility. Therefore, Tampa Electric included a 300 MW purchase in the 2016 projected costs submitted in Docket No. 150001-EI.

On August 31, 2015, Tampa Electric issued a market solicitation for proposals to provide the needed firm power, with the objective of securing necessary purchased power for customers at the best possible price. Upon evaluating the solicitation responses and the company's demand and energy forecasts, Tampa Electric secured 500 MW of capacity purchases over varying periods at terms more economical for customers than the projected costs included in the 2016 projection submitted in Docket No. 150001-EI. This allowed Tampa Electric to make the purchases both for economics and to ensure reliability while various CTs at Polk were unavailable for equipment tie-in and testing activities.

The terms of the FPL and Exelon transactions are coincident with the projected Polk CT tie-in and testing activities. The Duke transaction extends beyond the duration of the projected construction testing. After consideration of the favorable terms for this purchase, it was more cost-effective to Tampa Electric and its customers to start the purchase in February of 2016 and extend it through February of 2017. Notably, the Duke purchase is within the Tampa Electric balancing authority area. Thus, the purchase has the economic benefit of having no transmission wheeling costs.

All three new purchases are needed to help meet Tampa Electric’s reserve margin needs during the Polk Unit 2 CC construction window in 2016 and together provide a fuel savings to customers of approximately $8 million on an energy basis. These new purchases are prudent and beneficial for customers, and the company asks the Commission to approve them for cost recovery.

All of the aforementioned purchases provide supply reliability and help reduce energy price volatility. In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during the company's peak periods and spring and fall generation maintenance periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2016?

A. No.

Q. Does Tampa Electric anticipate entering into any other new wholesale energy purchases for 2017 and beyond?

A. Although Tampa Electric does not anticipate making other long-term purchases at this time, the company always evaluates the merits of long-term purchases as opportunities are presented. In doing so, Tampa Electric will consider entering into additional long-term purchases that bring value to customers. In addition, Tampa Electric will continue to evaluate and utilize economically the short-term purchased power market, as part of its purchasing strategy for 2017 and beyond. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2017 energy needs. This energy includes contributions from the previously mentioned firm purchases.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and no Florida trading hub exists where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity and standard financial instruments, Tampa Electric has not purchased any financial wholesale power hedges. However, the company employs a diversified physical power supply strategy, which includes self-generation and short- and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power in 2016?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For instance, the 121 MW purchased from Pasco Cogen and 117 MW from Calpine are reliable, cost-based call options for power. Likewise, the same sentiment applies for the three new firm purchases. The Duke purchase is from the Osprey combined cycle within the Tampa Electric balancing authority area and provides economic natural-gas energy. The FPL purchase is a system product, which not only provides economic energy but also has greater reliability than a single unit source. Similarly, the Exelon product is a site-wide purchase from a multi-unit natural gas combined cycle facility, which makes it more reliable than a single unit purchase in addition to being economic. These purchases serve as both a physical hedge and reliable source of economic power. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continues to evaluate its options in light of changing circumstances and new opportunities. Tampa Electric also maintains a mix of short- and long-term capacity and energy purchases to augment the company’s own generation for the year 2016 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather-related events such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's Pasco Cogen and Calpine power agreements are from dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Also, the FPL purchase, being a system product, helps mitigate power supply risks that may arise because of unavailability of a specific fuel type. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2016 and 2017.

A. Tampa Electric entered into various non-separated wholesale sales in 2016, and the company anticipates making additional non-separated sales during the balance of 2016 and in 2017. The gains from these sales are distributed among Tampa Electric and its customers in accordance with the company's current incentive mechanism established in Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI. The current incentive mechanism provides that all gains from non-separated sales be returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2016, Tampa Electric projects the company's gains from non-separated wholesale sales to be $216,961, which is less than the 2016 threshold of $1,563,273. Therefore, Tampa Electric expects customers to receive 100 percent of the 2016 non-separated sales gains. Likewise, in 2017, the company projects gains to be $47,795, of which customers would receive 100 percent, since the amount is less than the 2017 projected three-year rolling average threshold of $1,337,579.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company’s operations. However, Tampa Electric does employ a diversified physical power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.