AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

August 30 2013

HAND DELIVERED

Ms. Ann Cole, Director
Office of 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. 130001-EI

Dear Ms. Cole:

Enclosed for filing in the above docket on behalf of Tampa Electric Company are the original and fifteen (15) copies 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.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

J. Jeffry Wahlen

JJW/pp
Enclosures

cc: All Parties of Record (w/encls.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 130001-EI FILED: August 30, 2013

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, 2013 through December 31, 2013 will be an over-recovery of $15,630,547 (See Exhibit No. ____ (PAR-3), Document No. 3, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2014 through December 31, 2014, 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, 2014 through December 31, 2014, produce a fuel and purchased power factor for the new period of 3.911 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. 3, Schedule E1-E).

3. The company's projected benchmark level for calendar year 2014 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 $650,665 as provided in the direct testimony of Tampa Electric witness Penelope Rusk.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2013 through December 31, 2013 will be an over-recovery of $591,765, 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, 2014 through December 31, 2014, 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 0.172 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.65 per billed kW as set forth in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

6. Tampa Electric provides alternative capacity cost recovery billing factors for the period January 1, 2014 through December 31, 2014, which are calculated using the rate design methodology proposed by the company in Docket No. 130040-EI. These alternative factors are appropriate if the Commission approves the company's proposed rate design.

GPIF

7. Tampa Electric has calculated that it is subject to a GPIF penalty of $1,177,059 for performance experienced during the period January 1, 2012 through December 31, 2012.

8. The company is also proposing GPIF targets and ranges for the period January 1, 2014 through December 31, 2014 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 20th day of August 2013.

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley & McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

<u>CERTIFICATE OF SERVICE</u>

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 30th day of August 2013, to the following:

Ms. Martha F. Barrera*
Senior Attorney
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Mr. John T. Burnett
Ms. Dianne M. Triplett
Duke Energy Florida, Inc.
Post Office Box 14042
St. Petersburg, FL 33733

Mr. Paul Lewis, Jr.
Duke Energy Florida, Inc.
106 East College Avenue
Suite 800
Tallahassee, FL 32301-7740

Mr. Jon C. Moyle, Jr.
Moyle Law Firm
118 N. Gadsden Street
Tallahassee, FL 32301

Ms. Patricia A. Christensen
Associate Public Counsel
Office of Public Counsel
111 West Madison Street – Room 812
Tallahassee, FL 32399-1400

Ms. Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 S. Monroe St., Suite 601
Tallahassee, FL 32301

Ms. Cheryl Martin
Director/Regulatory Affairs
Florida Public Utilities Company
1641 Worthington Road, Suite 220
West Palm Beach, FL 33409

Mr. John T. Butler
Assistant General Counsel - Regulatory
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Mr. Kenneth Hoffman
Vice President, Regulatory Relations
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859

Mr. Robert L. McGee, Jr.
Regulatory and Pricing Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780

Mr. Jeffrey A. Stone
Mr. Russell A. Badders
Mr. Steven R. Griffin
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32591-2950

Mr. Robert Scheffel Wright
Mr. John T. LaVia, III
Gardner, Bist, Wiener, Wadsworth,
Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308

Mr. Randy B. Miller
White Springs Agricultural Chemicals, Inc.
Post Office Box 300
White Springs, FL 32096

Ms. Cecilia Bradley
Senior Assistant Attorney General
Office of the Attorney General
The Capitol – PL01
Tallahassee, FL 32399-1050

Mr. James W. Brew
Mr. F. Alvin Taylor
Brickfield, Burchette, Ritts & Stone, P.C.
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, D.C. 20007-5201

Jeff Wa

ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2014 THROUGH DECEMBER 2014

TESTIMONY AND EXHIBIT

OF

PENELOPE A. RUSK

FILED: AUGUST 30, 2013

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 Administrator, Rates in the Regulatory Affairs Department.

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. 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 in the areas of fuel and capacity cost recovery. I have accumulated 16 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as 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, and capacity payments.

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 2014 through December 2014. 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 2014.

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

A. Yes. Exhibit No. _____ (PAR-3), consisting of five 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 utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, consisting of three pages, provides the projected capacity cost recovery factors utilizing the company's proposed allocation methodology submitted in Docket No. 130040-EI, based on 12 Coincident Peak ("CP") and 50 percent Average Demand ("AD"). Document No. 3, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2014 through December 2014 as well as Schedule H1 for January through December, 2011 through 2014. Document No. 4 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. 5 provides the projected monthly Polk Unit 1 ignition oil conversion capital costs as well as the related fuel savings.

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. The capacity factors reflect Tampa Electric's approved rate design from Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009. In addition, capacity factors reflecting the company's proposed rate design, as submitted in Docket No. 130040-EI, are shown in Exhibit No. ___ (PAR-3), Document No. 2, page 3 of 3.

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 $31,495,469 after jurisdictional separation and prior year true-up, for estimated expenses in 2014.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2014 through December 2014.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.196	
GS and TS Secondary	0.183	
GSD, SBF Standard		
Secondary		0.65
Primary		0.64
Transmission		0.64
IS, IST, SBI		
Primary		0.45
Transmission		0.44
GSD Optional		
Secondary	0.154	
Primary	0.152	
LS1 Secondary	0.053	

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 0.172 cents per kWh compare to the factor for January 2013 through December 2013?

A. The proposed capacity cost recovery factor is 0.029 cents per kWh (or $0.29 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.201 cents per kWh for the January 2013 through December 2013 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 2014?

A. The appropriate amount for the 2014 period is 3.911 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. 3, 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 2014 through December 2014.

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 penalty of $1,177,059, 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 2013 through December 2013 period. The net true-up amount for this period is an over-recovery of $15,630,547.

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 2014 through December 2014. 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. 4.

A. Exhibit No. ____ (PAR-3), Document No. 4 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 2014 through December 2014.

A.

Metering Voltage Level	Fuel Charge Factor (cents per kWh)
Secondary	3.911
Tier I (Up to 1,000 kWh)	3.599
Tier II (Over 1,000 kWh)	4.599
Distribution Primary	3.872
Transmission	3.833
Lighting Service	3.872
Distribution Secondary	4.125 (on-peak)
	3.820 (off-peak)
Distribution Primary	4.084 (on-peak)
	3.782 (off-peak)
Transmission	4.043 (on-peak)
	3.744 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.911 cents per kWh compare to the levelized fuel adjustment factor for the January 2013 through December 2013 period?

A. The proposed fuel charge factor is 0.192 cents per kWh (or $1.92 per 1,000 kWh) higher than the average fuel charge factor of 3.719 cents per kWh for the January 2013 through December 2013 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2014 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events reflected in the 2014 projections: an increase in natural gas prices compared to 2013 and the inclusion of Polk 1 capital conversion costs, which is more than offset by the anticipated fuel savings of that project.

Q. Please describe current expectations regarding natural gas prices.

A. Tampa Electric expects a small increase in natural gas commodity prices in 2014, compared to anticipated prices for 2013. The projected natural gas price increase is driven by expectations that domestic and international economies will continue to strengthen. The recent prolonged economic downturn resulted in a decline in fuel commodity prices, particularly natural gas, which translated into a significant decrease in fuel and purchased power costs through 2012. Natural gas price expectations through the end of 2013 are for a small increase. The projected 2014 natural gas prices are 2.6 percent greater than 2013 prices on a dollar-per-mmBtu basis.

To mitigate fuel price volatility and comply with the company's Commission-approved Risk Management Plan, financial hedges have been entered into for natural gas in 2013 and 2014. The foundation for the company's natural gas forecast is the average of the New York Mercantile Exchange ("NYMEX") natural gas futures contract closing price published during the five consecutive business days between August 6, 2013 and August 12, 2013. Tampa Electric witness J. Brent Caldwell's direct testimony describes existing and forecasted natural gas costs and associated hedge results in more detail.

Q. What are the 2014 projected fuel savings for the Polk Unit 1 ignition oil conversion project?

A. The Commission approved Tampa Electric's recovery of the capital costs associated with the Polk Unit 1 ignition oil conversion in Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2013. Exhibit No. _____ (PAR-3), Document No. 5, displays the projected depreciation costs and return as well as the projected fuel savings for the project. As reflected on line 31 of that document, the project is expected to provide $6,148,946 in fuel savings in 2014.

Q. Do projected 2014 fuel savings for the Polk Unit 1 ignition oil conversion exceed the project depreciation and return expense?

A. Yes. The projected fuel savings of $6,418,946 exceed the 2014 depreciation and return expense of $4,329,501, as shown on Document No. 5 of my exhibit.

Q. Should the company's Polk Unit 1 ignition oil conversion project depreciation and return expense be approved for recovery through the fuel clause?

A. Yes. Tampa Electric has complied with the requirements of Order No. PSC-12-0498-PAA-EI, and the project's expected fuel savings exceed the costs. The 2014 projected net benefit of the project is $1,819,445, as shown on line 33 of Document No. 5. Therefore, the project costs should be approved for recovery through the fuel clause.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2014?

A. The company's projected 2014 benchmark is $650,665, which is the three-year average of $902,388, $246,932 and $802,676 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2011, 2012 and 2013 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2014 from non-separated wholesale sales to exceed its 2014 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2014. 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 an increase of $11.86 beginning January 2014, when the impact of the company's proposed base rate change is considered. These charges are shown in Exhibit No. _____ (PAR-3), Document No. 3, 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 2014.

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 2014 - DECEMBER 2014

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
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 & 25% AVG DEMAND FACTOR (%)
RS,RSVP	54.87%	8,568,132	1,783	1.07880	1.05641	9,051,474	1,923	46.84%	55.51%	53.34%
GS, TS	59.77%	1,014,542	194	1.07880	1.05640	1,071,759	209	5.55%	6.03%	5.91%
GSD Optional	3.29%	332,164	50	1.07454	1.05252	349,609	54	1.81%	1.56%	1.62%
GSD, SBF	72.26%	7,305,930	1,104	1.07454	1.05252	7,689,640	1,186	39.80%	34.24%	35.63%
IS,SBI	121.20%	912,924	86	1.03010	1.01750	928,901	89	4.81%	2.57%	3.13%
LS1	793.34%	218,515	3	1.07880	1.05641	230,842	3	1.19%	0.09%	0.37%
TOTAL		18,352,207	3,220			19,322,225	3,464	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2013 projected calendar data.
(2) Projected MWH sales for the period January 2014 thru December 2014.
(3) Based on 12 months average CP at meter.
(4) Based on 2013 projected demand losses.
(5) Based on 2013 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) * 25% + Col (9) * 75%

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	18,163,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
3	(UNIT POWER CAPACITY REVENUES)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,536)	(1,518,476)
4	TOTAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2013 - DEC. 2013													591,765
8	TOTAL													$31,472,809
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,495,469

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
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	46.84%	55.51%	3,688,119	13,112,351	16,800,470	8,568,132	8,568,132				0.00196
GS, TS	5.55%	6.03%	437,000	1,424,383	1,861,383	1,014,542	1,014,542				0.00183
GSD, SBF											
Secondary						6,051,001	6,051,001			0.65	
Primary						1,250,425	1,237,921			0.64	
Transmission						4,504	4,414			0.64	
GSD, SBF - Standard	39.80%	34.24%	3,133,799	8,088,037	11,221,836	7,305,930	7,293,336	57.91%	17,253,768		
GSD - Optional	1.81%	1.56%	142,517	368,497	511,014						
Secondary						321,510	321,510				0.00154
Primary						10,654	10,547				0.00152
IS, SBI											
Primary						228,187	225,905			0.45	
Transmission						684,737	671,042			0.44	
Total IS, SBI	4.81%	2.57%	378,733	607,075	985,808	912,924	896,947	56.10%	2,190,267		
LS1	1.19%	0.09%	93,699	21,259	114,958	218,515	218,515				0.00053
TOTAL	100.00%	100.00%	7,873,867	23,621,602	31,495,469	18,352,207	18,323,529				0.00172

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * .25 * Col (1).
(4) Total capacity costs * .75 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2014 through December 2014.
(7) Projected kWh sales at secondary for the period January 2014 through December 2014.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2014 through December 2014.
(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 2014 THROUGH DECEMBER 2014

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
ORANGE COGEN LP	4/17/1989	12/31/2015	QF	QF = QUALIFYING FACILITY
CALPINE	11/1/2011	12/31/2016	LT	LT = LONG TERM
PASCO COGEN	1/1/2009	12/31/2018	LT	ST = SHORT-TERM
OLEANDER	1/1/2013	12/31/2015	LT	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
SEMINOLE ELECTRIC **	6/1/1992	12/31/2016		

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
PASCO COGEN	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
OLEANDER	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
SEMINOLE ELECTRIC	1.4	1.4	1.5	1.8	1.3	1.4	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
TOTAL COGENERATION	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
CALPINE - D	[redacted]												
PASCO COGEN - D													
OLEANDER - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,084	16,644,964
TOTAL CAPACITY	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,424**	**$30,881,044**

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 1, Page 4 of 4

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED CAPACITY COST RECOVERY

JANUARY 2014 - DECEMBER 2014

CALCULATIONS UTILIZING PROPOSED RATE DESIGN

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
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 & 50% AVG DEMAND FACTOR (%)
RS,RSVP	54.87%	8,568,132	1,783	1.07880	1.05641	9,051,474	1,923	46.85%	55.52%	51.18%
GS, TS	59.77%	1,014,542	194	1.07880	1.05640	1,071,759	209	5.55%	6.03%	5.79%
GSD Optional	3.06%	332,164	48	1.07146	1.04897	348,430	52	1.80%	1.50%	1.65%
GSD, SBF, IS, SBI	75.65%	8,218,854	1,192	1.07146	1.04897	8,621,318	1,277	44.61%	36.86%	40.74%
LS1	793.34%	218,515	3	1.07880	1.05641	230,842	3	1.19%	0.09%	0.64%
TOTAL		18,352,207	3,220			19,323,823	3,464	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2013 projected calendar data.
(2) Projected MWH sales for the period January 2014 thru December 2014.
(3) Based on 12 months average CP at meter.
(4) Based on 2013 projected demand losses.
(5) Based on 2013 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) * 50% + Col (9) * 50%

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	18,163,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
3	(UNIT POWER CAPACITY REVENUES)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,536)	(1,518,476)
4	TOTAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2013 - DEC. 2013													591,765
8	TOTAL													$31,472,809
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,495,469

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
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	46.85%	55.52%	7,377,814	8,743,143	16,120,957	8,568,132	8,568,132				0.00188
GS, TS	5.55%	6.03%	873,999	949,588	1,823,587	1,014,542	1,014,542				0.00180
GSD, SBF, IS, SBI											
Secondary						6,051,001	6,051,001			0.66	
Primary						1,478,612	1,463,826			0.65	
Transmission						689,241	675,456			0.65	
GSD,SBF,IS,SBI-Standard	44.61%	36.86%	7,025,065	5,804,615	12,829,680	8,218,854	8,190,283	57.70%	19,444,035		
GSD - Optional	1.80%	1.50%	283,459	236,216	519,675						
Secondary						321,510	321,510				0.00157
Primary						10,654	10,547				0.00155
LS1	1.19%	0.09%	187,398	14,173	201,571	218,515	218,515				0.00092
TOTAL	100.00%	100.00%	15,747,735	15,747,735	31,495,470	18,352,207	18,323,529				0.00172

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * .50 * Col (1).
(4) Total capacity costs * .50 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2014 through December 2014.
(7) Projected kWh sales at secondary for the period January 2014 through December 2014.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2014 through December 2014.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2014 - DECEMBER 2014

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	697,757,539	18,522,902	3.76700
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Polk 1 Conversion Depreciation & ROI	4,329,501	18,522,902 [1]	0.02337
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)**	**702,087,040**	**18,522,902**	**3.79037**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	7,983,730	182,710	4.36962
7.	Energy Cost of Economy Purchases (E9)	20,352,480	495,850	4.10456
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	8,348,560	266,600	3.13149
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**36,684,770**	**945,160**	**3.88133**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,468,062	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	327,980	10,320	3.17810
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,053,522	150,010	3.36879
14.	Gains on Sales	522,912	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**5,904,414**	**160,330**	**3.68266**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		2,739	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**732,867,396**	**19,304,993**	**3.79626**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,261,877 [1]	33,240	0.00688
22.	T & D Losses	34,908,350 [1]	919,546	0.19021
23.	System MWH Sales	732,867,396	18,352,207	3.99335
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	732,867,396	18,352,207	3.99335
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	732,867,396	18,352,207	3.99335
28.	True-up [2]	(15,630,547)	18,352,207	(0.08517)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	717,236,849	18,352,207	3.90818
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	717,753,260	18,352,207	3.91099
32.	GPIF Adjusted for Taxes [2]	(1,177,059)	18,352,207	(0.00641)
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	716,576,201	18,352,207	3.90458
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.905**

[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 2014 THROUGH DECEMBER 2014

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2013 - December 2013 (6 months actual, 6 months estimated)	$14,727,476
2.	FINAL TRUE-UP (January 2012 - December 2012) (Per True-Up filed March 1, 2013)	903,071
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2014 through December 2014 (Schedule E1, line 28)	$15,630,547
4.	JURISDICTIONAL MWH SALES (Projected January 2014 through December 2014)	18,352,207
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0852)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2014 through December 2014)	($1,177,059)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2013 through December 2013)	$15,630,547	
2.	TOTAL SALES (January 2014 through December 2014)	18,352,207	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0064)**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0852)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	29.77	$30.45
OFF PEAK	70.23	$28.20
	100.00	1.0798

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$732,867,396		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,352,207		
2a	Effective MWH Sales (Jurisd)		18,323,529		
3	Cost Per KWH Sold	(line 1 / line 2)	3.9933		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($15,630,547)		
7	TOTAL	(line 1 x line 4)+line 6	$717,236,849		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.9171		
10	GPIF Factor	(Sch E1-C line 3a)	-0.0064		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.9107	4.1247	3.8199
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.911	4.125	3.820

13	Hours: ON PEAK	24.91%
14	OFF PEAK	75.09%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,173,700	16,173,700
Distribution Primary	1,489,266	1,474,373
Transmission	689,241	675,456
Total	18,352,207	18,323,529

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.911	4.125	3.820
Distribution Primary	3.872	4.084	3.782
Transmission	3.833	4.043	3.744
RS 1st Tier	3.599		
RS 2nd Tier	4.599		
Lighting	3.872		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		3.599	4.599
Distribution Secondary	3.911		
Distribution Primary	3.872		
Transmission	3.833		
Lighting Service [1]	3.872		
TIME-OF-USE			
Distribution Secondary - On-Peak	4.125		
Distribution Secondary - Off-Peak	3.820		
Distribution Primary - On-Peak	4.084		
Distribution Primary - Off-Peak	3.782		
Transmission - On-Peak	4.043		
Transmission - Off-Peak	3.744		

(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 2014 THROUGH DECEMBER 2014

	(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL PERIOD
1. Fuel Cost of System Net Generation	54,026,073	46,518,588	50,183,232	51,302,298	61,032,207	66,536,436	69,894,111	69,152,707	65,462,249	60,042,905	50,544,871	53,061,862	697,757,539
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	652,887	554,727	677,617	677,247	397,987	429,767	371,467	389,687	390,397	419,717	376,377	566,537	5,904,414
4. Fuel Cost of Purchased Power	89,300	145,200	318,620	445,600	693,330	737,440	1,108,000	1,628,410	1,425,970	653,690	669,860	68,310	7,983,730
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	719,520	588,340	805,950	672,500	731,650	704,150	744,650	768,740	679,460	720,410	719,170	496,020	8,348,560
7. Energy Cost of Economy Purchases	1,118,480	1,107,530	1,496,400	1,405,270	1,843,880	1,865,250	2,517,540	1,967,230	2,439,700	1,942,060	1,308,440	1,340,720	20,352,480
8. Polk 1 Conversion Depreciation & ROI	372,670	370,510	368,350	366,190	364,031	361,872	359,711	357,552	355,393	353,234	351,074	348,914	4,329,501
9. TOTAL FUEL & NET POWER TRANSACTIONS	**55,673,156**	**48,175,441**	**52,494,935**	**53,514,611**	**64,267,091**	**69,775,381**	**74,252,545**	**73,482,952**	**69,972,375**	**63,292,582**	**53,217,038**	**54,749,289**	**732,867,396**
10. Jurisdictional MWH Sold	1,441,299	1,307,512	1,275,034	1,313,445	1,476,467	1,741,216	1,808,913	1,766,966	1,827,507	1,635,979	1,398,110	1,359,759	18,352,207
11. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12. Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	55,673,156	48,175,441	52,494,935	53,514,611	64,267,091	69,775,381	74,252,545	73,482,952	69,972,375	63,292,582	53,217,038	54,749,289	732,867,396
13. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
14. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 12 * Line 13)	**55,673,156**	**48,175,441**	**52,494,935**	**53,514,611**	**64,267,091**	**69,775,381**	**74,252,545**	**73,482,952**	**69,972,375**	**63,292,582**	**53,217,038**	**54,749,289**	**732,867,396**
15. Cost Per kWh Sold (Cents/kWh)	3.8627	3.6845	4.1171	4.0744	4.3528	4.0073	4.1048	4.1587	3.8288	3.8688	3.8064	4.0264	3.9933
16. True-up (Cents/kWh) [2]	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)
17. Total (Cents/kWh) (Line 15+16)	3.7775	3.5993	4.0319	3.9892	4.2676	3.9221	4.0196	4.0735	3.7436	3.7836	3.7212	3.9412	3.9081
18. 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
19. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.7802	3.6019	4.0348	3.9921	4.2707	3.9249	4.0225	4.0764	3.7463	3.7863	3.7239	3.9440	3.9109
20. GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)
21. TOTAL RECOVERY FACTOR (LINE 19+20)	**3.7738**	**3.5955**	**4.0284**	**3.9857**	**4.2643**	**3.9185**	**4.0161**	**4.0700**	**3.7399**	**3.7799**	**3.7175**	**3.9376**	**3.9045**
22. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.774**	**3.596**	**4.028**	**3.986**	**4.264**	**3.919**	**4.016**	**4.070**	**3.740**	**3.780**	**3.718**	**3.938**	**3.905**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E3

	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	80,865	107,291	102,000	49,256	49,743	105,938
3. COAL	38,040,790	27,394,532	31,207,087	28,242,538	31,661,806	36,835,660
4. NATURAL GAS	15,904,418	19,016,765	18,874,145	23,010,504	29,320,658	29,594,838
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	54,026,073	46,518,588	50,183,232	51,302,298	61,032,207	66,536,436
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	337	446	424	191	203	419
10. COAL	1,101,920	791,140	911,930	827,440	930,410	1,092,280
11. NATURAL GAS	339,142	469,457	446,736	537,049	704,587	701,571
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,441,399	1,261,043	1,359,090	1,364,680	1,635,200	1,794,270
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
17. COAL (TON)	469,920	335,860	390,690	352,470	396,480	466,490
18. NATURAL GAS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,192,270	5,256,930
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	3,620	4,800	4,560	2,050	2,190	4,510
23. COAL	11,249,400	8,085,790	9,292,300	8,489,470	9,528,280	11,161,760
24. NATURAL GAS	2,490,780	3,408,790	3,319,970	4,031,560	5,322,830	5,395,630
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	13,743,800	11,499,380	12,616,830	12,523,080	14,853,300	16,561,900
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.04	0.03	0.01	0.01	0.02
30. COAL	76.45	62.73	67.10	60.64	56.90	60.88
31. NATURAL GAS	23.53	37.23	32.87	39.35	43.09	39.10
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	24.07	20.09	23.13	16.31	15.94	40.28
37. COAL ($/TON)	80.95	81.57	79.88	80.13	79.86	78.96
38. NATURAL GAS ($/MCF)	6.55	5.73	5.83	5.86	5.65	5.63
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.34	22.35	22.37	24.03	22.71	23.49
43. COAL	3.38	3.39	3.36	3.33	3.32	3.30
44. NATURAL GAS	6.39	5.58	5.69	5.71	5.51	5.48
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)	3.93	4.05	3.98	4.10	4.11	4.02
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,747	10,751	10,747	10,741	10,768	10,755
50. COAL	10,209	10,220	10,190	10,260	10,241	10,219
51. NATURAL GAS	7,344	7,261	7,432	7,507	7,555	7,691
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	9,535	9,119	9,283	9,177	9,083	9,230
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	24.01	24.03	24.04	25.81	24.46	25.26
57. COAL	3.45	3.46	3.42	3.41	3.40	3.37
58. NATURAL GAS	4.69	4.05	4.22	4.28	4.16	4.22
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)	3.75	3.69	3.69	3.76	3.73	3.71

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

SCHEDULE E3

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	99,673	78,747	113,976	78,870	91,700	81,599	1,039,658
3.	COAL	38,892,495	38,919,999	30,786,167	31,006,213	30,667,179	35,800,345	399,454,811
4.	NATURAL GAS	30,901,943	30,153,961	34,562,106	28,957,822	19,785,992	17,179,918	297,263,070
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	TOTAL ($)	69,894,111	69,152,707	65,462,249	60,042,905	50,544,871	53,061,862	697,757,539
	SYSTEM NET GENERATION (MWH)							
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	408	326	452	326	363	339	4,233
10.	COAL	1,131,040	1,121,820	876,320	885,750	858,300	1,016,320	11,544,670
11.	NATURAL GAS	720,382	707,384	835,108	694,384	453,377	364,821	6,973,999
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	TOTAL (MWH)	1,851,830	1,829,530	1,711,880	1,580,460	1,312,040	1,381,480	18,522,902
	UNITS OF FUEL BURNED							
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
17.	COAL (TON)	482,940	478,770	372,780	376,770	366,520	433,360	4,923,050
18.	NATURAL GAS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,464,380	2,693,610	51,846,020
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	4,380	3,500	4,860	3,500	3,900	3,640	45,510
23.	COAL	11,554,910	11,456,680	8,965,510	9,066,340	8,786,200	10,392,360	118,029,000
24.	NATURAL GAS	5,632,140	5,438,350	6,541,770	5,302,110	3,537,490	2,749,120	53,170,540
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	TOTAL (MMBTU)	17,191,430	16,898,530	15,512,140	14,371,950	12,327,590	13,145,120	171,245,050
	GENERATION MIX (% MWH)							
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.02	0.02	0.03	0.02	0.03	0.02	0.02
30.	COAL	61.08	61.32	51.19	56.04	65.41	73.57	62.33
31.	NATURAL GAS	38.90	38.66	48.78	43.94	34.56	26.41	37.65
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST PER UNIT							
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	28.48	32.14	31.84	50.56	21.33	51.64	26.76
37.	COAL ($/TON)	80.53	81.29	82.59	82.29	83.67	82.61	81.14
38.	NATURAL GAS ($/MCF)	5.63	5.69	5.42	5.60	5.71	6.38	5.73
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)							
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	22.76	22.50	23.45	22.53	23.51	22.42	22.84
43.	COAL	3.37	3.40	3.43	3.42	3.49	3.44	3.38
44.	NATURAL GAS	5.49	5.54	5.28	5.46	5.59	6.25	5.59
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	TOTAL ($/MMBTU)	4.07	4.09	4.22	4.18	4.10	4.04	4.07
	BTU BURNED PER KWH (BTU/KWH)							
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,747	10,747	10,755	10,747	10,755	10,747	10,751
50.	COAL	10,216	10,213	10,231	10,236	10,237	10,225	10,224
51.	NATURAL GAS	7,818	7,688	7,833	7,636	7,803	7,536	7,624
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	TOTAL (BTU/KWH)	9,283	9,237	9,061	9,094	9,396	9,515	9,245
	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	24.46	24.18	25.22	24.22	25.29	24.09	24.56
57.	COAL	3.44	3.47	3.51	3.50	3.57	3.52	3.46
58.	NATURAL GAS	4.29	4.26	4.14	4.17	4.36	4.71	4.26
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)	3.77	3.78	3.82	3.80	3.85	3.84	3.77

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	227,690	77.5	81.0	88.7	10,075	COAL	97,880	23,436,453	2,293,960.0	7,726,846	3.39	78.94
2. B.B.#2	395	238,440	81.1	85.9	90.4	10,228	COAL	104,100	23,427,089	2,438,760.0	8,217,868	3.45	78.94
3. B.B.#3	365	217,230	80.0	88.0	88.2	10,515	COAL	97,460	23,436,795	2,284,150.0	7,693,692	3.54	78.94
4. B.B.#4	417	262,570	84.6	89.1	94.0	10,098	COAL	113,140	23,435,920	2,651,540.0	8,931,509	3.40	78.94
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	369,886	-	134.99
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**945,930**	**80.9**	**86.0**	**90.4**	**10,221**	-	-	-	-	**32,939,801**	**3.48**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	1,020	2.2	-	83.6	10,961	GAS	10,890	1,026,630	11,180.0	71,354	7.00	6.55
8. B.B.C.T.#4 TOTAL	**61**	**1,020**	**2.2**	**99.4**	**83.6**	**10,961**	-	-	-	**11,180.0**	**71,354**	**7.00**	-
9. BIG BEND STATION TOTAL	**1,633**	**946,950**	**77.9**	**86.5**	**90.4**	**10,222**	-	-	-	**9,679,590.0**	**33,011,155**	**3.49**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,100,989	3.27	88.96
11. POLK #1 CT GAS	235	2,420	1.4	-	73.6	7,764	GAS	22,660	829,214	18,790.0	148,474	6.14	6.55
12. POLK #1 TOTAL	**220**	**158,410**	**96.8**	**92.8**	**98.2**	**10,099**	-	-	-	**1,599,780.0**	**5,249,463**	**3.31**	-
13. POLK #2 CT GAS	183	102	0.1	-	27.8	33,658	GAS	3,340	1,026,946	3,430.0	21,884	21.47	6.55
14. POLK #2 CT OIL	187	168	0.1	-	22.5	10,768	LGT OIL	310	5,838,710	1,810.0	40,432	24.05	130.43
15. POLK #2 TOTAL	**187**	**270**	**0.2**	**98.0**	**24.2**	**19,407**	-	-	-	**5,240.0**	**62,316**	**23.08**	-
16. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	187	169	0.1	-	22.6	10,727	LGT OIL	310	5,838,710	1,810.0	40,433	23.96	130.43
18. POLK #3 TOTAL	**187**	**169**	**0.1**	**98.0**	**22.6**	**10,727**	-	-	-	**1,810.0**	**40,433**	**23.96**	-
19. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**158,849**	**22.2**	**59.5**	**97.4**	**10,115**	-	-	-	**1,606,830.0**	**5,352,212**	**3.37**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	163,830	27.8	89.0	55.6	7,261	GAS	1,157,240	1,027,998	1,189,640.0	7,582,499	4.63	6.55
24. BAYSIDE #2	1,047	171,110	22.0	88.9	24.2	7,366	GAS	1,226,010	1,028,010	1,260,350.0	8,033,096	4.69	6.55
25. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
26. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. BAYSIDE #5	61	560	1.2	98.6	83.5	11,018	GAS	6,010	1,026,622	6,170.0	39,379	7.03	6.55
28. BAYSIDE #6	61	100	0.2	98.6	82.0	12,200	GAS	1,180	1,033,898	1,220.0	7,732	7.73	6.55
29. BAYSIDE TOTAL	**2,083**	**335,600**	**21.7**	**84.3**	**33.5**	**7,322**	**GAS**	**2,390,440**	**1,028,003**	**2,457,380.0**	**15,662,706**	**4.67**	**6.55**
30. SYSTEM	**4,676**	**1,441,399**	**41.4**	**80.0**	**65.1**	**9,535**	-	-	-	**13,743,800.0**	**54,026,073**	**3.75**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] **As burned fuel cost system total includes ignition oil/gas.**
[3] **City of Tampa on long term reserve standby.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil/gas.**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	100,530	37.9	40.5	86.6	10,106	COAL	43,350	23,435,525	1,015,930.0	3,382,959	3.37	78.04
2. B.B.#2	395	104,870	39.5	43.0	87.9	10,270	COAL	45,970	23,427,670	1,076,970.0	3,587,417	3.42	78.04
3. B.B.#3	365	203,750	83.1	88.0	91.7	10,468	COAL	91,010	23,435,666	2,132,880.0	7,102,263	3.49	78.04
4. B.B.#4	417	241,000	86.0	89.1	95.5	10,086	COAL	103,710	23,436,795	2,430,630.0	8,093,355	3.36	78.04
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,520	-	26,180.0	612,580	-	135.53
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**650,150**	**61.5**	**65.1**	**91.6**	**10,238**	-	-	-	-	**22,778,574**	**3.50**	-
6. B.B.C.T.#4 OIL	61	20	0.0	-	4.8	10,823	LGT OIL	40	5,500,000	220.0	5,421	26.67	135.53
7. B.B.C.T.#4 GAS	61	990	2.4	-	85.4	10,963	GAS	10,540	1,029,412	10,850.0	60,386	6.10	5.73
8. B.B.C.T.#4 TOTAL	**61**	**1,010**	**2.5**	**99.4**	**63.7**	**10,960**	-	-	-	**11,070.0**	**65,807**	**6.52**	-
9. BIG BEND STATION TOTAL	**1,633**	**651,160**	**59.3**	**66.4**	**91.5**	**10,239**	-	-	-	**6,667,480.0**	**22,844,381**	**3.51**	-
10. POLK #1 GASIFIER	220	140,990	95.4	-	98.7	10,138	COAL	51,820	27,583,558	1,429,380.0	4,615,958	3.27	89.08
11. POLK #1 CT GAS	235	2,150	1.4	-	83.2	7,637	GAS	20,350	806,880	16,420.0	116,590	5.42	5.73
12. POLK #1 TOTAL	**220**	**143,140**	**96.8**	**92.8**	**98.5**	**10,101**	-	-	-	**1,445,800.0**	**4,732,548**	**3.31**	-
13. POLK #2 CT GAS	183	2,847	2.3	-	81.9	11,734	GAS	32,500	1,028,000	33,410.0	186,201	6.54	5.73
14. POLK #2 CT OIL	187	213	0.2	-	22.7	10,768	LGT OIL	390	5,871,795	2,290.0	50,935	23.95	130.60
15. POLK #2 TOTAL	**187**	**3,060**	**2.4**	**98.0**	**69.4**	**11,667**	-	-	-	**35,700.0**	**237,136**	**7.75**	-
16. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	187	213	0.2	-	22.8	10,727	LGT OIL	390	5,871,795	2,290.0	50,935	23.86	130.60
18. POLK #3 TOTAL	**187**	**213**	**0.2**	**98.0**	**22.8**	**10,727**	-	-	-	**2,290.0**	**50,935**	**23.86**	-
19. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**146,413**	**22.7**	**59.5**	**97.1**	**10,134**	-	-	-	**1,483,790.0**	**5,020,619**	**3.43**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	300,370	56.4	89.0	68.2	7,182	GAS	2,098,610	1,027,999	2,157,370.0	12,023,467	4.00	5.73
24. BAYSIDE #2	1,047	160,170	22.8	60.3	37.0	7,235	GAS	1,127,250	1,027,971	1,158,780.0	6,458,301	4.03	5.73
25. BAYSIDE #3	61	690	1.7	98.6	87.0	11,058	GAS	7,430	1,026,918	7,630.0	42,568	6.17	5.73
26. BAYSIDE #4	61	100	0.2	98.6	82.0	11,500	GAS	0	0	1,150.0	0	0.00	0.00
27. BAYSIDE #5	61	1,180	2.9	98.6	87.9	10,839	GAS	12,450	1,027,309	12,790.0	71,329	6.04	5.73
28. BAYSIDE #6	61	960	2.3	98.6	67.4	10,823	GAS	10,110	1,027,695	10,390.0	57,923	6.03	5.73
29. BAYSIDE TOTAL	**2,083**	**463,470**	**33.1**	**75.7**	**52.8**	**7,224**	**GAS**	**3,255,850**	**1,028,337**	**3,348,110.0**	**18,653,588**	**4.02**	**5.73**
30. SYSTEM	**4,676**	**1,261,043**	**40.1**	**69.1**	**72.5**	**9,119**	-	-	-	**11,499,380.0**	**46,518,588**	**3.69**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

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Docket No. 130001-EI
Exhibit No.____ (PAR-3)
Document No. 3, Page 11 of 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	231,230	78.7	81.0	90.1	10,066	COAL	99,310	23,437,317	2,327,560.0	7,710,710	3.33	77.64
2. B.B.#2	395	240,020	81.7	85.9	91.0	10,223	COAL	104,740	23,427,153	2,453,760.0	8,132,308	3.39	77.64
3. B.B.#3	365	116,450	42.9	48.3	86.2	10,542	COAL	52,380	23,435,662	1,227,560.0	4,066,927	3.49	77.64
4. B.B.#4	417	238,650	76.9	80.5	94.6	10,096	COAL	102,800	23,437,938	2,409,420.0	7,981,670	3.34	77.64
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	21,030.0	493,320	-	135.90
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**826,350**	**70.7**	**74.5**	**91.0**	**10,187**	-	-	-	-	**28,384,935**	**3.43**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	2,820	6.2	-	90.6	10,752	GAS	29,500	1,027,797	30,320.0	171,936	6.10	5.83
8. B.B.C.T.#4 TOTAL	**61**	**2,820**	**6.2**	**99.4**	**90.6**	**10,752**	-	-	-	**30,320.0**	**171,936**	**6.10**	-
9. BIG BEND STATION TOTAL	**1,633**	**829,170**	**68.2**	**75.5**	**91.0**	**10,189**	-	-	-	**8,448,620.0**	**28,556,871**	**3.44**	-
10. POLK #1 GASIFIER	220	85,580	52.3	-	98.7	10,213	COAL	31,460	27,781,310	874,000.0	2,822,152	3.30	89.71
11. POLK #1 CT GAS	235	3,080	1.8	-	93.6	7,247	GAS	30,470	732,524	22,320.0	177,590	5.77	5.83
12. POLK #1 TOTAL	**220**	**88,660**	**54.2**	**50.9**	**98.5**	**10,110**	-	-	-	**896,320.0**	**2,999,742**	**3.38**	-
13. POLK #2 CT GAS	183	4,218	3.1	-	92.2	11,249	GAS	46,160	1,027,946	47,450.0	269,036	6.38	5.83
14. POLK #2 CT OIL	187	212	0.2	-	22.6	10,768	LGT OIL	390	5,846,154	2,280.0	51,000	24.09	130.77
15. POLK #2 TOTAL	**187**	**4,430**	**3.2**	**98.0**	**80.4**	**11,226**	-	-	-	**49,730.0**	**320,036**	**7.22**	-
16. POLK #3 CT GAS	183	1,047	0.8	-	81.8	12,822	GAS	13,060	1,028,331	13,430.0	76,118	7.27	5.83
17. POLK #3 CT OIL	187	213	0.2	-	22.7	10,727	LGT OIL	390	5,846,154	2,280.0	51,000	23.99	130.77
18. POLK #3 TOTAL	**187**	**1,260**	**0.9**	**98.0**	**56.9**	**12,468**	-	-	-	**15,710.0**	**127,118**	**10.09**	-
19. POLK #4 CT GAS	**183**	**2,990**	**2.2**	**98.7**	**96.1**	**10,742**	**GAS**	**31,250**	**1,027,840**	**32,120.0**	**182,136**	**6.09**	**5.83**
20. POLK #5 CT GAS	**183**	**1,230**	**0.9**	**98.7**	**96.0**	**10,797**	**GAS**	**12,920**	**1,027,864**	**13,280.0**	**75,302**	**6.12**	**5.83**
21. POLK STATION TOTAL	**960**	**98,570**	**13.8**	**87.5**	**96.6**	**10,218**	-	-	-	**1,007,160.0**	**3,704,334**	**3.76**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	196,310	33.3	63.2	54.6	7,261	GAS	1,386,560	1,027,997	1,425,380.0	8,081,342	4.12	5.83
24. BAYSIDE #2	1,047	228,760	29.4	88.9	32.3	7,288	GAS	1,621,720	1,027,995	1,667,120.0	9,451,936	4.13	5.83
25. BAYSIDE #3	61	1,100	2.4	89.1	85.9	11,155	GAS	11,940	1,027,638	12,270.0	69,590	6.33	5.83
26. BAYSIDE #4	61	320	0.7	98.6	87.4	12,000	GAS	3,740	1,026,738	3,840.0	21,798	6.81	5.83
27. BAYSIDE #5	61	2,500	5.5	98.6	89.1	10,772	GAS	26,200	1,027,863	26,930.0	152,702	6.11	5.83
28. BAYSIDE #6	61	2,360	5.2	98.6	87.9	10,809	GAS	24,820	1,027,800	25,510.0	144,659	6.13	5.83
29. BAYSIDE TOTAL	**2,083**	**431,350**	**27.8**	**80.0**	**40.1**	**7,328**	**GAS**	**3,074,980**	**1,027,990**	**3,161,050.0**	**17,922,027**	**4.15**	**5.83**
30. SYSTEM	**4,676**	**1,359,090**	**39.1**	**79.9**	**65.1**	**9,283**	-	-	-	**12,616,830.0**	**50,183,232**	**3.69**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

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Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	222,490	80.3	81.0	91.9	10,145	COAL	96,310	23,436,611	2,257,180.0	7,447,070	3.35	77.32
2. B.B.#2	385	232,850	84.0	85.9	93.5	10,233	COAL	101,700	23,428,417	2,382,670.0	7,863,850	3.38	77.32
3. B.B.#3	365	221,120	84.1	88.0	92.8	10,489	COAL	98,960	23,436,439	2,319,270.0	7,651,976	3.46	77.32
4. B.B.#4	407	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,670	-	15,450.0	363,477	-	136.13
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,542**	**676,460**	**60.9**	**62.5**	**92.7**	**10,288**	-	-	-	-	**23,326,373**	**3.45**	-
6. B.B.C.T.#4 OIL	56	28	0.1	-	16.5	10,823	LGT OIL	50	6,000,000	300.0	10,007	36.10	200.14
7. B.B.C.T.#4 GAS	56	2,322	5.8	-	92.2	11,131	GAS	25,140	1,028,242	25,850.0	147,343	6.34	5.86
8. B.B.C.T.#4 TOTAL	**56**	**2,350**	**5.8**	**82.9**	**67.4**	**11,128**	-	-	-	**26,150.0**	**157,350**	**6.70**	-
9. BIG BEND STATION TOTAL	**1,598**	**678,810**	**59.0**	**63.2**	**92.7**	**10,290**	-	-	-	**6,985,270.0**	**23,483,723**	**3.46**	-
10. POLK #1 GASIFIER	220	150,980	95.3	-	98.7	10,136	COAL	55,500	27,573,874	1,530,350.0	4,916,165	3.26	88.58
11. POLK #1 CT GAS	218	3,480	2.2	-	99.8	7,253	GAS	28,930	872,451	25,240.0	169,556	4.87	5.86
12. POLK #1 TOTAL	**220**	**154,460**	**97.5**	**92.8**	**98.6**	**10,071**	-	-	-	**1,555,590.0**	**5,085,721**	**3.29**	-
13. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #2 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**0.0**	**0**	**0.00**	-
16. POLK #3 CT GAS	151	7,427	6.8	-	94.6	11,302	GAS	81,660	1,027,921	83,940.0	478,602	6.44	5.86
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,249	24.06	130.83
18. POLK #3 TOTAL	**159**	**7,590**	**6.6**	**98.0**	**89.4**	**11,290**	-	-	-	**85,690.0**	**517,851**	**6.82**	-
19. POLK #4 CT GAS	**151**	**3,680**	**3.4**	**98.7**	**97.5**	**10,995**	**GAS**	**39,360**	**1,027,947**	**40,460.0**	**230,685**	**6.27**	**5.86**
20. POLK #5 CT GAS	**151**	**2,420**	**2.2**	**98.7**	**100.2**	**11,062**	**GAS**	**26,040**	**1,028,034**	**26,770.0**	**152,618**	**6.31**	**5.86**
21. POLK STATION TOTAL	**840**	**168,150**	**27.8**	**78.4**	**98.3**	**10,161**	-	-	-	**1,708,510.0**	**5,986,875**	**3.56**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	168,470	33.4	89.0	54.9	7,355	GAS	1,205,320	1,028,017	1,239,090.0	7,064,268	4.19	5.86
24. BAYSIDE #2	929	344,130	51.4	88.9	56.6	7,361	GAS	2,464,120	1,028,006	2,533,130.0	14,441,977	4.20	5.86
25. BAYSIDE #3	56	590	1.5	92.0	95.8	11,186	GAS	6,420	1,028,037	6,600.0	37,627	6.38	5.86
26. BAYSIDE #4	56	660	1.6	82.2	90.7	11,121	GAS	7,150	1,026,573	7,340.0	41,905	6.35	5.86
27. BAYSIDE #5	56	2,270	5.6	82.2	92.1	11,119	GAS	24,550	1,028,106	25,240.0	143,885	6.34	5.86
28. BAYSIDE #6	56	1,600	4.0	82.2	92.2	11,188	GAS	17,410	1,028,145	17,900.0	102,038	6.38	5.86
29. BAYSIDE TOTAL	**1,854**	**517,720**	**38.8**	**88.4**	**56.3**	**7,396**	**GAS**	**3,724,970**	**1,028,008**	**3,829,300.0**	**21,831,700**	**4.22**	**5.86**
30. SYSTEM	**4,292**	**1,364,680**	**44.2**	**77.1**	**74.8**	**9,177**	-	-	-	**12,523,080.0**	**51,302,298**	**3.76**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	231,710	80.9	81.0	92.6	10,136	COAL	100,210	23,436,483	2,348,570.0	7,732,186	3.34	77.16
2. B.B.#2	385	243,730	85.1	85.9	94.8	10,214	COAL	106,260	23,427,066	2,489,360.0	8,198,999	3.36	77.16
3. B.B.#3	365	232,220	85.5	88.0	94.3	10,469	COAL	103,730	23,436,229	2,431,040.0	8,003,790	3.45	77.16
4. B.B.#4	407	66,760	22.0	23.0	94.8	10,160	COAL	28,940	23,438,493	678,310.0	2,233,003	3.34	77.16
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	373,540	-	136.33
B.B. IGNITION	-	-	-	-	-	-	GAS	10,020	-	10,300.0	56,692	-	5.66
5. B.B. COAL	**1,542**	**774,420**	**67.5**	**68.6**	**94.0**	**10,262**	-	-	-	-	**26,598,210**	**3.43**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	5,450	13.1	-	93.6	10,994	GAS	58,280	1,028,140	59,920.0	329,743	6.05	5.66
8. B.B.C.T.#4 TOTAL	**56**	**5,450**	**13.1**	**99.4**	**93.6**	**10,994**	-	-	-	**59,920.0**	**329,743**	**6.05**	-
9. BIG BEND STATION TOTAL	**1,598**	**779,870**	**65.6**	**69.7**	**94.0**	**10,267**	-	-	-	**8,007,200.0**	**26,927,953**	**3.45**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,375	1,581,000.0	5,063,596	3.25	88.31
11. POLK #1 CT GAS	218	3,390	2.1	-	97.2	7,280	GAS	28,390	869,320	24,680.0	160,628	4.74	5.66
12. POLK #1 TOTAL	**220**	**159,380**	**97.4**	**92.8**	**98.7**	**10,075**	-	-	-	**1,605,680.0**	**5,224,224**	**3.28**	-
13. POLK #2 CT GAS	151	11,037	9.8	-	94.9	11,273	GAS	121,030	1,028,010	124,420.0	684,775	6.20	5.66
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,743	24.46	130.90
15. POLK #2 TOTAL	**159**	**11,240**	**9.5**	**98.0**	**90.5**	**11,264**	-	-	-	**126,610.0**	**734,518**	**6.53**	-
16. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
18. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**0.0**	**0**	**0.00**	-
19. POLK #4 CT GAS	**151**	**8,820**	**7.9**	**98.7**	**97.4**	**11,009**	**GAS**	**94,450**	**1,028,057**	**97,100.0**	**534,389**	**6.06**	**5.66**
20. POLK #5 CT GAS	**151**	**4,800**	**4.3**	**98.7**	**99.3**	**10,979**	**GAS**	**51,270**	**1,027,892**	**52,700.0**	**290,081**	**6.04**	**5.66**
21. POLK STATION TOTAL	**840**	**184,240**	**29.5**	**78.4**	**98.1**	**10,215**	-	-	-	**1,882,090.0**	**6,783,212**	**3.68**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	252,720	48.5	89.0	56.7	7,355	GAS	1,808,110	1,027,991	1,858,720.0	10,230,107	4.05	5.66
24. BAYSIDE #2	929	406,900	58.9	88.9	64.8	7,320	GAS	2,897,240	1,028,006	2,978,380.0	16,392,297	4.03	5.66
25. BAYSIDE #3	56	1,800	4.3	98.6	91.8	11,183	GAS	19,580	1,028,090	20,130.0	110,782	6.15	5.66
26. BAYSIDE #4	56	820	2.0	98.6	91.5	11,220	GAS	8,960	1,026,786	9,200.0	50,695	6.18	5.66
27. BAYSIDE #5	56	5,110	12.3	98.6	93.1	10,994	GAS	54,660	1,027,808	56,180.0	309,261	6.05	5.66
28. BAYSIDE #6	56	3,740	9.0	98.6	92.8	11,070	GAS	40,280	1,027,805	41,400.0	227,900	6.09	5.66
29. BAYSIDE TOTAL	**1,854**	**671,090**	**48.7**	**90.1**	**61.8**	**7,397**	**GAS**	**4,828,830**	**1,027,994**	**4,964,010.0**	**27,321,042**	**4.07**	**5.66**
30. SYSTEM	**4,292**	**1,635,200**	**51.2**	**80.2**	**77.7**	**9,083**	-	-	-	**14,853,300.0**	**61,032,207**	**3.73**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] **As burned fuel cost system total includes ignition oil/gas.**
[3] **City of Tampa on long term reserve standby.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil/gas.**

Docket No. 130001-EI
Exhibit No. _____ (PAR-3)
Document No. 3, Page 14 of 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	223,860	80.8	81.0	92.4	10,137	COAL	96,820	23,437,203	2,269,190.0	7,458,902	3.33	77.04
2. B.B.#2	385	235,540	85.0	85.9	94.6	10,215	COAL	102,700	23,428,432	2,406,100.0	7,911,889	3.36	77.04
3. B.B.#3	365	224,370	85.4	88.0	94.1	10,471	COAL	100,240	23,437,450	2,349,370.0	7,722,373	3.44	77.04
4. B.B.#4	407	257,520	87.9	89.1	97.6	10,122	COAL	111,230	23,435,045	2,606,680.0	8,569,028	3.33	77.04
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,850	-	10,730.0	252,417	-	136.44
B.B. IGNITION	-	-	-	-	-	-	GAS	4,460	-	5,150.0	25,130	-	5.63
5. B.B. COAL	**1,542**	**941,290**	**84.8**	**86.1**	**94.8**	**10,232**	-	-	-	-	**31,939,739**	**3.39**	-
6. B.B.C.T.#4 OIL	56	53	0.1	-	15.7	10,823	LGT OIL	100	5,700,000	570.0	16,844	31.98	168.44
7. B.B.C.T.#4 GAS	56	4,897	12.1	-	92.1	11,159	GAS	53,160	1,028,029	54,650.0	299,528	6.12	5.63
8. B.B.C.T.#4 TOTAL	**56**	**4,950**	**12.3**	**99.4**	**87.5**	**11,156**	-	-	-	**55,220.0**	**316,372**	**6.39**	-
9. BIG BEND STATION TOTAL	**1,598**	**946,240**	**82.2**	**86.5**	**94.7**	**10,237**	-	-	-	**9,686,560.0**	**32,256,111**	**3.41**	-
10. POLK #1 GASIFIER	220	150,990	95.3	-	98.8	10,136	COAL	55,500	27,575,135	1,530,420.0	4,895,921	3.24	88.21
11. POLK #1 CT GAS	218	3,500	2.2	-	100.3	7,346	GAS	29,380	875,085	25,710.0	165,540	4.73	5.63
12. POLK #1 TOTAL	**220**	**154,490**	**97.6**	**92.8**	**98.8**	**10,073**	-	-	-	**1,556,130.0**	**5,061,461**	**3.28**	-
13. POLK #2 CT GAS	151	18,617	17.1	-	96.3	11,195	GAS	202,740	1,028,016	208,420.0	1,142,332	6.14	5.63
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,306	24.19	131.02
15. POLK #2 TOTAL	**159**	**18,780**	**16.4**	**98.0**	**94.1**	**11,191**	-	-	-	**210,170.0**	**1,181,638**	**8.29**	-
16. POLK #3 CT GAS	151	12,156	11.2	-	95.8	11,228	GAS	132,770	1,028,018	136,490.0	748,087	6.15	5.63
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,788	24.39	131.02
18. POLK #3 TOTAL	**159**	**12,360**	**10.8**	**98.0**	**91.7**	**11,220**	-	-	-	**138,680.0**	**797,875**	**6.46**	-
19. POLK #4 CT GAS	**151**	**10,400**	**9.6**	**98.7**	**98.4**	**11,117**	**GAS**	**112,480**	**1,027,916**	**115,620.0**	**633,764**	**6.09**	**5.63**
20. POLK #5 CT GAS	**151**	**6,320**	**5.8**	**98.7**	**99.7**	**11,125**	**GAS**	**68,400**	**1,027,924**	**70,310.0**	**385,397**	**6.10**	**5.63**
21. POLK STATION TOTAL	**840**	**202,350**	**33.5**	**96.9**	**97.9**	**10,333**	-	-	-	**2,090,910.0**	**8,060,135**	**3.98**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	248,270	49.2	89.0	58.3	7,369	GAS	1,779,760	1,027,998	1,829,590.0	10,027,988	4.04	5.63
24. BAYSIDE #2	929	384,770	57.5	88.9	63.3	7,316	GAS	2,738,250	1,027,996	2,814,910.0	15,428,564	4.01	5.63
25. BAYSIDE #3	56	2,600	6.4	98.6	92.9	11,142	GAS	28,180	1,028,034	28,970.0	158,779	6.11	5.63
26. BAYSIDE #4	56	1,480	3.7	98.6	94.4	11,230	GAS	15,570	1,067,437	16,620.0	87,729	5.93	5.63
27. BAYSIDE #5	56	4,670	11.6	98.6	92.7	11,015	GAS	50,040	1,027,978	51,440.0	281,948	6.04	5.63
28. BAYSIDE #6	56	3,890	9.6	98.6	92.6	11,028	GAS	41,740	1,027,791	42,900.0	235,182	6.05	5.63
29. BAYSIDE TOTAL	**1,854**	**645,680**	**48.4**	**90.1**	**61.7**	**7,410**	**GAS**	**4,653,540**	**1,026,127**	**4,784,430.0**	**26,220,190**	**4.06**	**5.63**
30. SYSTEM	**4,292**	**1,794,270**	**58.1**	**90.1**	**79.7**	**9,230**	-	-	-	**16,561,900.0**	**66,536,436**	**3.71**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2014

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. B.B.#1	385	231,750	80.9	81.0	92.6	10,135	COAL	100,220	23,435,642	2,348,720.0	7,870,243	3.40	78.53
2. B.B.#2	385	243,960	85.2	85.9	94.9	10,211	COAL	106,330	23,428,571	2,491,160.0	8,350,052	3.42	78.53
3. B.B.#3	365	232,290	85.5	88.0	94.3	10,468	COAL	103,750	23,437,590	2,431,650.0	8,147,453	3.51	78.53
4. B.B.#4	407	267,050	88.2	89.1	97.9	10,119	COAL	115,300	23,437,901	2,702,390.0	9,054,466	3.39	78.53
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	374,221	-	136.58
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,235	-	5.64
5. B.B. COAL	**1,542**	**975,050**	**85.0**	**86.1**	**95.0**	**10,229**	-	-	-	-	**33,824,670**	**3.47**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	6,060	14.5	-	95.8	10,975	GAS	64,700	1,027,975	66,510.0	364,638	6.02	5.64
8. B.B.C.T.#4 TOTAL	**56**	**6,060**	**14.5**	**99.4**	**95.8**	**10,975**	-	-	-	**66,510.0**	**364,638**	**6.02**	-
9. BIG BEND STATION TOTAL	**1,598**	**981,110**	**82.5**	**86.5**	**95.0**	**10,234**	-	-	-	**10,040,430.0**	**34,189,308**	**3.48**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,067,825	3.25	88.38
11. POLK #1 CT GAS	218	2,420	1.5	-	100.9	7,438	GAS	21,890	822,293	18,000.0	123,368	5.10	5.64
12. POLK #1 TOTAL	**220**	**158,410**	**96.8**	**92.8**	**98.8**	**10,094**	-	-	-	**1,598,990.0**	**5,191,193**	**3.28**	-
13. POLK #2 CT GAS	151	20,927	18.6	-	94.3	11,174	GAS	227,460	1,028,005	233,830.0	1,281,924	6.13	5.64
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,837	24.50	131.15
15. POLK #2 TOTAL	**159**	**21,130**	**17.9**	**98.0**	**91.9**	**11,170**	-	-	-	**236,020.0**	**1,331,761**	**6.30**	-
16. POLK #3 CT GAS	151	18,376	16.4	-	95.8	11,171	GAS	199,690	1,027,943	205,270.0	1,125,417	6.12	5.64
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,836	24.41	131.15
18. POLK #3 TOTAL	**159**	**18,580**	**15.7**	**98.0**	**93.0**	**11,166**	-	-	-	**207,460.0**	**1,175,253**	**6.33**	-
19. POLK #4 CT GAS	**151**	**16,460**	**14.7**	**98.7**	**98.2**	**10,967**	**GAS**	**175,610**	**1,027,960**	**180,520.0**	**989,707**	**6.01**	**5.64**
20. POLK #5 CT GAS	**151**	**13,680**	**12.2**	**98.7**	**98.5**	**11,050**	**GAS**	**147,070**	**1,027,878**	**151,170.0**	**828,860**	**6.08**	**5.64**
21. POLK STATION TOTAL	**840**	**228,260**	**36.5**	**96.9**	**97.6**	**10,401**	-	-	-	**2,374,160.0**	**9,516,774**	**4.17**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	244,650	46.9	89.0	55.4	7,380	GAS	1,756,330	1,028,002	1,805,510.0	9,898,363	4.05	5.64
24. BAYSIDE #2	929	382,920	55.4	88.9	61.0	7,332	GAS	2,731,060	1,028,004	2,807,540.0	15,391,767	4.02	5.64
25. BAYSIDE #3	56	3,400	8.2	98.6	94.9	11,029	GAS	36,480	1,027,961	37,500.0	205,595	6.05	5.64
26. BAYSIDE #4	56	2,100	5.0	98.6	96.2	11,143	GAS	22,760	1,028,120	23,400.0	128,271	6.11	5.64
27. BAYSIDE #5	56	5,040	12.1	98.6	95.7	10,948	GAS	53,670	1,028,135	55,180.0	302,475	6.00	5.64
28. BAYSIDE #6	56	4,350	10.4	98.6	95.9	10,968	GAS	46,410	1,028,011	47,710.0	261,558	6.01	5.64
29. BAYSIDE TOTAL	**1,854**	**642,460**	**46.8**	**90.1**	**59.2**	**7,435**	**GAS**	**4,646,710**	**1,028,005**	**4,778,840.0**	**26,188,029**	**4.08**	**5.64**
30. SYSTEM	**4,292**	**1,851,830**	**58.0**	**90.1**	**78.7**	**9,283**	-	-	-	**17,191,430.0**	**69,894,111**	**3.77**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2014

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) (2)	AS BURNED FUEL COST ($) (1)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. B.B.#1	385	217,190	75.8	75.8	92.8	10,133	COAL	93,910	23,435,630	2,200,840.0	7,483,797	3.45	79.69
2. B.B.#2	385	244,850	85.5	85.9	95.2	10,208	COAL	106,690	23,426,844	2,499,410.0	8,502,254	3.47	79.69
3. B.B.#3	365	235,850	86.9	88.0	95.7	10,451	COAL	105,170	23,436,246	2,464,790.0	8,381,124	3.55	79.69
4. B.B.#4	407	267,940	88.5	89.1	98.3	10,117	COAL	115,660	23,436,365	2,710,650.0	9,217,079	3.44	79.69
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,850	-	10,730.0	252,817	-	136.66
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,533	-	5.70
5. B.B. COAL	**1,542**	**965,830**	**84.2**	**84.8**	**95.6**	**10,225**	-	-	-	-	**33,865,604**	**3.51**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	7,250	17.4	-	94.5	11,001	GAS	77,580	1,028,100	79,760.0	441,835	6.09	5.70
8. B.B.C.T.#4 TOTAL	**56**	**7,250**	**17.4**	**99.4**	**94.5**	**11,001**	-	-	-	**79,760.0**	**441,835**	**6.09**	-
9. BIG BEND STATION TOTAL	**1,598**	**973,080**	**81.8**	**85.3**	**95.6**	**10,231**	-	-	-	**9,955,450.0**	**34,307,439**	**3.53**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,054,395	3.24	88.15
11. POLK #1 CT GAS	218	0	0.0	-	0.0	0	GAS	4,380	0	0.0	24,945	0.00	5.70
12. POLK #1 TOTAL	**220**	**155,990**	**95.3**	**92.8**	**98.8**	**10,135**	-	-	-	**1,580,990.0**	**5,079,340**	**3.26**	-
13. POLK #2 CT GAS	151	23,167	20.6	-	94.7	11,230	GAS	253,090	1,027,974	260,170.0	1,441,403	6.22	5.70
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,373	24.23	131.24
15. POLK #2 TOTAL	**159**	**23,330**	**19.7**	**98.0**	**93.0**	**11,227**	-	-	-	**261,920.0**	**1,480,776**	**6.35**	-
16. POLK #3 CT GAS	151	16,697	14.9	-	97.9	11,174	GAS	181,490	1,027,991	186,570.0	1,033,625	6.19	5.70
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,374	24.13	131.25
18. POLK #3 TOTAL	**159**	**16,860**	**14.3**	**98.0**	**95.3**	**11,170**	-	-	-	**188,320.0**	**1,072,999**	**6.36**	-
19. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**840**	**196,180**	**31.4**	**61.4**	**97.7**	**10,354**	-	-	-	**2,031,230.0**	**7,633,115**	**3.89**	-
22. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	239,900	46.0	89.0	52.9	7,372	GAS	1,720,320	1,028,006	1,768,500.0	9,797,598	4.08	5.70
24. BAYSIDE #2	929	402,730	58.3	88.9	64.1	7,322	GAS	2,868,660	1,027,999	2,948,980.0	16,337,646	4.06	5.70
25. BAYSIDE #3	56	3,780	9.1	98.6	96.4	11,016	GAS	40,510	1,027,894	41,640.0	230,713	6.10	5.70
26. BAYSIDE #4	56	2,180	5.2	98.6	97.3	11,083	GAS	23,500	1,028,085	24,160.0	133,838	6.14	5.70
27. BAYSIDE #5	56	6,370	15.3	98.6	94.8	10,995	GAS	68,140	1,027,884	70,040.0	388,072	6.09	5.70
28. BAYSIDE #6	56	5,310	12.7	98.6	94.8	11,023	GAS	56,940	1,027,924	58,530.0	324,286	6.11	5.70
29. BAYSIDE TOTAL	**1,854**	**660,270**	**47.9**	**90.1**	**60.0**	**7,439**	**GAS**	**4,778,070**	**1,027,999**	**4,911,850.0**	**27,212,153**	**4.12**	**5.70**
30. SYSTEM	**4,292**	**1,829,530**	**57.3**	**82.7**	**78.9**	**9,237**	-	-	-	**16,898,530.0**	**69,152,707**	**3.78**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

(1) As burned fuel cost system total includes ignition oil/gas.
(3) City of Tampa on long term reserve standby.
(2) Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	237,170	85.6	85.9	95.2	10,209	COAL	103,350	23,428,060	2,421,290.0	8,306,466	3.50	80.37
3. B.B.#3	365	228,540	87.0	88.0	95.9	10,448	COAL	101,880	23,437,181	2,387,780.0	8,188,315	3.58	80.37
4. B.B.#4	407	259,570	88.6	89.1	98.4	10,115	COAL	112,030	23,436,847	2,625,630.0	9,004,092	3.47	80.37
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	374,721	-	136.76
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	27,192	-	5.43
5. B.B. COAL	**1,542**	**725,280**	**65.3**	**65.6**	**96.6**	**10,251**	-	-	-	-	**25,900,786**	**3.57**	-
6. B.B.C.T.#4 OIL	56	44	0.1	-	15.8	10,823	LGT OIL	80	6,000,000	480.0	14,141	31.89	176.76
7. B.B.C.T.#4 GAS	56	7,786	19.3	-	91.5	11,101	GAS	84,080	1,027,950	86,430.0	456,346	5.86	5.43
8. B.B.C.T.#4 TOTAL	**56**	**7,830**	**19.4**	**99.4**	**89.1**	**11,100**	-	-	-	**88,910.0**	**470,487**	**6.01**	-
9. BIG BEND STATION TOTAL	**1,598**	**733,110**	**63.7**	**67.0**	**96.5**	**10,260**	-	-	-	**7,521,610.0**	**26,371,273**	**3.60**	-
10. POLK #1 GASIFIER	220	151,040	95.4	-	98.8	10,135	COAL	55,520	27,572,226	1,530,810.0	4,885,381	3.23	87.99
11. POLK #1 CT GAS	218	0	0.0	-	0.0	0	GAS	4,380	0	0.0	23,773	0.00	5.43
12. POLK #1 TOTAL	**220**	**151,040**	**95.4**	**92.8**	**98.8**	**10,135**	-	-	-	**1,530,810.0**	**4,909,154**	**3.25**	-
13. POLK #2 CT GAS	151	32,747	30.1	-	94.7	11,127	GAS	354,460	1,027,986	364,380.0	1,923,838	5.87	5.43
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,917	24.54	131.36
15. POLK #2 TOTAL	**159**	**32,950**	**28.8**	**98.0**	**93.1**	**11,125**	-	-	-	**366,570.0**	**1,973,755**	**5.99**	-
16. POLK #3 CT GAS	151	26,906	24.7	-	96.3	11,110	GAS	290,770	1,028,029	298,920.0	1,578,159	5.87	5.43
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,918	24.45	131.36
18. POLK #3 TOTAL	**159**	**27,110**	**23.7**	**98.0**	**94.4**	**11,107**	-	-	-	**301,110.0**	**1,628,077**	**6.01**	-
19. POLK #4 CT GAS	**151**	**19,580**	**18.0**	**49.4**	**99.0**	**10,958**	**GAS**	**208,700**	**1,028,031**	**214,550.0**	**1,132,723**	**5.79**	**5.43**
20. POLK #5 CT GAS	**151**	**13,170**	**12.1**	**49.4**	**99.1**	**11,092**	**GAS**	**142,100**	**1,028,008**	**146,080.0**	**771,250**	**5.86**	**5.43**
21. POLK STATION TOTAL	**840**	**243,850**	**40.3**	**79.2**	**97.5**	**10,495**	-	-	-	**2,559,120.0**	**10,414,959**	**4.27**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	288,940	57.2	89.0	62.7	7,318	GAS	2,056,720	1,028,006	2,114,320.0	11,162,884	3.86	5.43
24. BAYSIDE #2	929	426,840	63.8	88.9	70.3	7,278	GAS	3,021,840	1,028,003	3,106,460.0	16,401,090	3.84	5.43
25. BAYSIDE #3	56	3,870	9.6	98.6	96.0	11,023	GAS	41,500	1,027,952	42,660.0	225,242	5.82	5.43
26. BAYSIDE #4	56	2,080	5.2	98.6	97.7	10,981	GAS	22,210	1,028,366	22,840.0	120,545	5.80	5.43
27. BAYSIDE #5	56	7,110	17.6	98.6	92.7	11,010	GAS	76,150	1,027,971	78,280.0	413,305	5.81	5.43
28. BAYSIDE #6	56	6,080	15.1	98.6	94.4	10,995	GAS	65,030	1,027,987	66,850.0	352,951	5.81	5.43
29. BAYSIDE TOTAL	**1,854**	**734,920**	**55.1**	**90.1**	**67.5**	**7,390**	**GAS**	**5,283,450**	**1,028,004**	**5,431,410.0**	**28,678,017**	**3.90**	**5.43**
30. SYSTEM	**4,292**	**1,711,880**	**55.4**	**79.4**	**81.6**	**9,061**	-	-	-	**15,512,140.0**	**65,462,249**	**3.82**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	228,630	79.8	80.4	95.0	10,211	COAL	99,650	23,426,693	2,334,470.0	8,051,037	3.52	80.79
3. B.B.#3	365	233,720	86.1	88.0	94.9	10,462	COAL	104,330	23,436,020	2,445,080.0	8,429,146	3.61	80.79
4. B.B.#4	407	267,410	88.3	89.1	98.1	10,119	COAL	115,450	23,436,986	2,705,800.0	9,327,564	3.49	80.79
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	960	-	5,580.0	131,316	-	136.79
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,105	-	5.61
5. B.B. COAL	**1,542**	**729,760**	**63.6**	**64.4**	**96.1**	**10,257**	-	-	-	-	**25,967,168**	**3.56**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	5,460	13.1	-	93.8	10,949	GAS	58,160	1,027,854	59,780.0	326,260	5.98	5.61
8. B.B.C.T.#4 TOTAL	**56**	**5,460**	**13.1**	**99.4**	**93.8**	**10,949**	-	-	-	**59,780.0**	**326,260**	**5.98**	-
9. BIG BEND STATION TOTAL	**1,598**	**735,220**	**61.8**	**65.7**	**96.0**	**10,262**	-	-	-	**7,545,130.0**	**26,293,428**	**3.58**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,039,045	3.23	87.88
11. POLK #1 CT GAS	218	3,390	2.1	-	97.2	7,398	GAS	28,770	871,741	25,080.0	161,391	4.76	5.61
12. POLK #1 TOTAL	**220**	**159,380**	**97.4**	**92.8**	**98.7**	**10,077**	-	-	-	**1,606,070.0**	**5,200,436**	**3.26**	-
13. POLK #2 CT GAS	151	17,287	15.4	-	94.6	11,204	GAS	188,410	1,028,024	193,690.0	1,056,924	6.11	5.61
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,435	24.26	131.45
15. POLK #2 TOTAL	**159**	**17,450**	**14.8**	**98.0**	**92.3**	**11,200**	-	-	-	**195,440.0**	**1,096,359**	**8.28**	-
16. POLK #3 CT GAS	151	9,947	8.9	-	95.5	11,309	GAS	109,440	1,027,869	112,490.0	613,925	6.17	5.61
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,435	24.17	131.45
18. POLK #3 TOTAL	**159**	**10,110**	**8.5**	**98.0**	**91.5**	**11,300**	-	-	-	**114,240.0**	**653,360**	**6.46**	-
19. POLK #4 CT GAS	**151**	**6,590**	**5.9**	**98.7**	**97.0**	**11,106**	**GAS**	**71,200**	**1,027,949**	**73,190.0**	**399,410**	**6.06**	**5.61**
20. POLK #5 CT GAS	**151**	**2,570**	**2.3**	**98.7**	**100.1**	**11,027**	**GAS**	**27,560**	**1,028,302**	**28,340.0**	**154,603**	**6.02**	**5.61**
21. POLK STATION TOTAL	**840**	**196,100**	**31.4**	**96.9**	**97.7**	**10,287**	-	-	-	**2,017,280.0**	**7,504,168**	**3.83**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	238,810	45.8	89.0	57.9	7,350	GAS	1,707,480	1,027,994	1,755,280.0	9,578,447	4.01	5.61
24. BAYSIDE #2	929	396,000	57.3	88.9	63.1	7,312	GAS	2,816,570	1,028,002	2,895,440.0	15,800,108	3.99	5.61
25. BAYSIDE #3	56	3,390	8.1	98.6	91.7	11,189	GAS	36,910	1,027,635	37,930.0	207,054	6.11	5.61
26. BAYSIDE #4	56	1,480	3.6	98.6	91.1	11,345	GAS	16,330	1,028,169	16,790.0	91,606	6.19	5.61
27. BAYSIDE #5	56	5,000	12.0	98.6	93.0	10,988	GAS	53,450	1,027,877	54,940.0	299,838	6.00	5.61
28. BAYSIDE #6	56	4,460	10.7	98.6	92.6	11,022	GAS	47,820	1,028,022	49,160.0	268,256	6.01	5.61
29. BAYSIDE TOTAL	**1,854**	**649,140**	**47.1**	**90.1**	**61.5**	**7,409**	**GAS**	**4,678,580**	**1,027,996**	**4,809,540.0**	**26,245,309**	**4.04**	**5.61**
30. SYSTEM	**4,292**	**1,580,460**	**49.5**	**82.3**	**78.2**	**9,094**	-	-	-	**14,371,950.0**	**60,042,905**	**3.80**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	167,610	60.5	62.1	90.3	10,166	COAL	72,700	23,436,589	1,703,840.0	5,904,985	3.52	81.22
2. B.B.#2	385	167,340	60.4	63.0	91.7	10,258	COAL	73,270	23,428,961	1,716,640.0	5,951,285	3.56	81.22
3. B.B.#3	365	143,460	54.6	58.7	90.4	10,519	COAL	64,390	23,436,558	1,509,080.0	5,230,008	3.65	81.22
4. B.B.#4	407	254,090	86.7	89.1	96.3	10,139	COAL	109,920	23,438,046	2,576,310.0	8,928,142	3.51	81.22
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	21,030.0	496,824	-	136.87
B.B. IGNITION	-	-	-	-	-	-	GAS	14,500	-	15,450.0	83,161	-	5.74
5. B.B. COAL	**1,542**	**732,500**	**66.0**	**68.7**	**92.7**	**10,247**	-	-	-	-	**26,594,405**	**3.63**	-
6. B.B.C.T.#4 OIL	56	37	0.1	-	16.5	10,823	LGT OIL	70	5,714,286	400.0	12,781	34.58	182.59
7. B.B.C.T.#4 GAS	56	3,883	9.6	-	91.2	11,205	GAS	42,320	1,028,119	43,510.0	242,717	6.25	5.74
8. B.B.C.T.#4 TOTAL	**56**	**3,920**	**9.7**	**99.4**	**87.5**	**11,202**	-	-	-	**43,910.0**	**255,498**	**6.52**	-
9. BIG BEND STATION TOTAL	**1,598**	**736,420**	**64.0**	**69.7**	**92.6**	**10,252**	-	-	-	**7,549,780.0**	**26,649,903**	**3.65**	-
10. POLK #1 GASIFIER	220	125,800	79.4	-	98.8	10,178	COAL	46,240	27,688,798	1,280,330.0	4,072,774	3.24	88.08
11. POLK #1 CT GAS	218	6,210	4.0	-	98.2	7,287	GAS	52,760	857,657	45,250.0	302,593	4.87	5.74
12. POLK #1 TOTAL	**220**	**132,010**	**83.3**	**77.3**	**98.7**	**10,042**	-	-	-	**1,325,580.0**	**4,375,367**	**3.31**	-
13. POLK #2 CT GAS	151	14,827	13.6	-	91.8	11,281	GAS	162,710	1,028,025	167,270.0	933,186	6.29	5.74
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,459	24.28	131.53
15. POLK #2 TOTAL	**159**	**14,990**	**13.1**	**88.2**	**89.3**	**11,278**	-	-	-	**169,020.0**	**972,645**	**8.49**	-
16. POLK #3 CT GAS	151	11,937	11.0	-	91.9	11,403	GAS	132,410	1,028,019	136,120.0	759,407	6.36	5.74
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,460	24.19	131.53
18. POLK #3 TOTAL	**159**	**12,100**	**10.6**	**88.2**	**88.8**	**11,394**	-	-	-	**137,870.0**	**798,867**	**8.60**	-
19. POLK #4 CT GAS	**151**	**7,080**	**6.5**	**98.7**	**97.7**	**11,068**	**GAS**	**76,220**	**1,028,077**	**78,360.0**	**437,142**	**6.17**	**5.74**
20. POLK #5 CT GAS	**151**	**4,960**	**4.6**	**98.7**	**99.5**	**11,058**	**GAS**	**53,360**	**1,027,924**	**54,850.0**	**306,034**	**6.17**	**5.74**
21. POLK STATION TOTAL	**640**	**171,140**	**28.3**	**89.2**	**97.0**	**10,317**	-	-	-	**1,765,680.0**	**6,890,055**	**4.03**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	202,350	40.1	89.0	57.4	7,355	GAS	1,447,730	1,028,002	1,488,270.0	8,303,122	4.10	5.74
24. BAYSIDE #2	929	194,290	29.0	62.2	45.7	7,390	GAS	1,396,720	1,028,001	1,435,830.0	8,010,564	4.12	5.74
25. BAYSIDE #3	56	1,520	3.8	98.6	90.5	11,474	GAS	16,970	1,027,696	17,440.0	97,328	6.40	5.74
26. BAYSIDE #4	56	1,010	2.5	98.6	90.2	11,386	GAS	11,200	1,026,786	11,500.0	64,235	6.36	5.74
27. BAYSIDE #5	56	3,230	8.0	98.6	91.6	11,102	GAS	34,890	1,027,802	35,860.0	200,104	6.20	5.74
28. BAYSIDE #6	56	2,080	5.2	98.6	90.6	11,168	GAS	22,590	1,028,331	23,230.0	129,560	6.23	5.74
29. BAYSIDE TOTAL	**1,854**	**404,480**	**30.3**	**78.7**	**51.4**	**7,447**	**GAS**	**2,930,100**	**1,027,996**	**3,012,130.0**	**16,804,913**	**4.15**	**5.74**
30. SYSTEM	**4,292**	**1,312,040**	**42.5**	**76.6**	**74.6**	**9,396**	-	-	-	**12,327,590.0**	**50,544,871**	**3.85**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] **As burned fuel cost system total includes ignition oil/gas.**
[3] **City of Tampa on long term reserve standby.**
[2] **Fuel burned (MM BTU) system total excludes ignition oil/gas.**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2014

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	230,310	78.4	81.0	89.7	10,071	COAL	98,970	23,435,789	2,319,440.0	8,038,678	3.49	81.22
2. B.B.#2	395	237,100	80.7	85.9	89.9	10,242	COAL	103,650	23,427,786	2,428,290.0	8,418,808	3.55	81.22
3. B.B.#3	365	220,930	81.4	88.0	89.7	10,495	COAL	98,930	23,436,369	2,318,560.0	8,035,430	3.64	81.22
4. B.B.#4	417	172,000	55.4	60.4	90.9	10,147	COAL	74,470	23,434,940	1,745,200.0	6,048,703	3.52	81.22
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	960	-	5,580.0	131,404	-	136.88
B.B. IGNITION	-	-	-	-	-	-	GAS	15,030	-	15,450.0	96,400	-	6.41
5. B.B. COAL	**1,572**	**860,340**	**73.6**	**78.4**	**90.0**	**10,242**	-	-	-	-	**30,769,423**	**3.58**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	1,240	2.7	-	84.7	10,960	GAS	13,210	1,028,766	13,590.0	84,726	6.83	6.41
8. B.B.C.T.#4 TOTAL	**61**	**1,240**	**2.7**	**99.4**	**84.7**	**10,960**	-	-	-	**13,590.0**	**84,726**	**6.83**	-
9. BIG BEND STATION TOTAL	**1,633**	**861,580**	**70.9**	**79.2**	**90.0**	**10,243**	-	-	-	**8,825,080.0**	**30,854,149**	**3.58**	-
10. POLK #1 GASIFIER	220	155,980	95.3	-	98.7	10,135	COAL	57,340	27,570,108	1,580,870.0	5,030,922	3.23	87.74
11. POLK #1 CT GAS	235	0	0.0	-	0.0	0	GAS	4,380	0	0.0	28,093	0.00	6.41
12. POLK #1 TOTAL	**220**	**155,980**	**95.3**	**92.8**	**98.7**	**10,135**	-	-	-	**1,580,870.0**	**5,059,015**	**3.24**	-
13. POLK #2 CT GAS	183	8,381	6.2	-	80.3	11,341	GAS	92,460	1,028,012	95,050.0	593,021	7.08	6.41
14. POLK #2 CT OIL	187	169	0.1	-	22.6	10,768	LGT OIL	310	5,870,968	1,820.0	40,799	24.14	131.61
15. POLK #2 TOTAL	**187**	**8,550**	**6.1**	**98.0**	**76.5**	**11,330**	-	-	-	**96,870.0**	**633,820**	**7.41**	-
16. POLK #3 CT GAS	183	5,360	3.9	-	83.7	11,348	GAS	59,170	1,028,055	60,830.0	379,506	7.08	6.41
17. POLK #3 CT OIL	187	170	0.1	-	22.7	10,727	LGT OIL	310	5,870,968	1,820.0	40,800	24.05	131.61
18. POLK #3 TOTAL	**187**	**5,530**	**4.0**	**98.0**	**77.3**	**11,329**	-	-	-	**82,850.0**	**420,306**	**7.60**	-
19. POLK #4 CT GAS	**183**	**2,460**	**1.8**	**98.7**	**96.0**	**10,984**	**GAS**	**26,290**	**1,027,767**	**27,020.0**	**168,619**	**6.85**	**6.41**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**172,520**	**24.2**	**78.3**	**96.5**	**10,245**	-	-	-	**1,767,410.0**	**6,281,760**	**3.64**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	113,310	19.2	63.2	46.8	7,352	GAS	810,290	1,028,027	833,000.0	5,197,051	4.59	6.41
24. BAYSIDE #2	1,047	231,630	29.7	88.9	32.7	7,309	GAS	1,646,920	1,027,998	1,693,030.0	10,563,040	4.56	6.41
25. BAYSIDE #3	61	630	1.4	98.6	86.1	10,937	GAS	6,710	1,026,826	6,890.0	43,037	6.83	6.41
26. BAYSIDE #4	61	160	0.4	98.6	87.4	11,188	GAS	1,740	1,028,736	1,790.0	11,160	6.98	6.41
27. BAYSIDE #5	61	710	1.6	98.6	83.1	10,873	GAS	7,500	1,029,333	7,720.0	48,104	6.78	6.41
28. BAYSIDE #6	61	940	2.1	98.6	85.6	10,851	GAS	9,910	1,029,263	10,200.0	63,561	6.76	6.41
29. BAYSIDE TOTAL	**2,083**	**347,380**	**22.4**	**80.2**	**36.5**	**7,348**	**GAS**	**2,483,070**	**1,028,014**	**2,552,630.0**	**15,925,953**	**4.58**	**6.41**
30. SYSTEM	**4,676**	**1,381,480**	**39.7**	**79.5**	**66.1**	**9,515**	-	-	-	**13,145,120.0**	**53,061,862**	**3.84**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
16. UNIT COST ($/BBL)	140.75	140.85	140.60	140.04	139.57	139.08
17. AMOUNT ($)	472,915	752,116	620,058	422,931	435,464	365,784
18. BURNED:						
19. UNITS (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
20. UNIT COST ($/BBL)	24.07	20.09	23.13	16.31	15.94	40.28
21. AMOUNT ($)	80,865	107,291	102,000	49,256	49,743	105,938
22. ENDING INVENTORY:						
23. UNITS (BBL)	91,441	91,441	91,441	91,441	91,441	91,441
24. UNIT COST ($/BBL)	132.71	133.06	133.33	133.48	133.61	133.73
25. AMOUNT ($)	12,134,847	12,167,092	12,191,830	12,205,227	12,217,409	12,228,038
26. DAYS SUPPLY: NORMAL	538	545	561	573	564	574
27. DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13
COAL						
28. PURCHASES:						
29. UNITS (TONS)	466,600	376,600	361,600	431,600	426,600	446,600
30. UNIT COST ($/TON)	78.48	77.42	77.20	77.80	77.86	79.00
31. AMOUNT ($)	36,619,875	29,154,812	27,916,217	33,580,595	33,215,556	35,280,102
32. BURNED:						
33. UNITS (TONS)	469,920	335,860	390,690	352,470	396,480	466,490
34. UNIT COST ($/TON)	80.95	81.57	79.88	80.13	79.86	78.96
35. AMOUNT ($)	38,040,790	27,394,532	31,207,087	28,242,538	31,661,806	36,835,660
36. ENDING INVENTORY:						
37. UNITS (TONS)	555,960	596,700	567,610	646,740	676,860	656,970
38. UNIT COST ($/TON)	80.69	79.36	78.79	78.16	77.79	78.39
39. AMOUNT ($)	44,860,231	47,356,658	44,722,675	50,547,776	52,655,325	51,500,881
40. DAYS SUPPLY:	42	49	46	48	46	42
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,435,461	5,256,930
43. UNIT COST ($/MCF)	6.32	5.73	5.82	5.85	5.58	5.64
44. AMOUNT ($)	15,334,418	19,019,165	18,849,845	22,973,304	30,305,550	29,652,568
45. BURNED:						
46. UNITS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,192,270	5,256,930
47. UNIT COST ($/MCF)	6.55	5.73	5.83	5.86	5.65	5.63
48. AMOUNT ($)	15,904,418	19,016,765	18,874,145	23,010,504	29,320,658	29,594,838
49. ENDING INVENTORY:						
50. UNITS (MCF)	729,572	729,572	729,572	729,572	972,762	972,762
51. UNIT COST ($/MCF)	3.81	3.81	3.78	3.72	3.75	3.78
52. AMOUNT ($)	2,776,500	2,778,900	2,754,600	2,717,400	3,645,600	3,678,200
53. DAYS SUPPLY:	5	5	5	5	7	7
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
16.	UNIT COST ($/BBL)	138.83	138.65	138.40	138.14	137.83	137.47	139.40
17.	AMOUNT ($)	485,909	339,701	495,486	215,491	592,682	217,207	5,415,744
18.	BURNED:							
19.	UNITS (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
20.	UNIT COST ($/BBL)	28.48	32.14	31.84	50.56	21.33	51.64	26.76
21.	AMOUNT ($)	99,673	78,747	113,976	78,870	91,700	81,599	1,039,658
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	91,441	91,441	91,441	91,441	91,441	91,441	91,441
24.	UNIT COST ($/BBL)	133.86	133.95	134.06	134.11	134.19	134.24	134.24
25.	AMOUNT ($)	12,240,053	12,248,190	12,258,180	12,263,484	12,270,841	12,275,046	12,275,046
26.	DAYS SUPPLY: NORMAL	576	582	591	591	572	599	-
27.	DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	446,600	521,600	376,600	356,600	371,600	410,400	4,993,000
30.	UNIT COST ($/TON)	82.39	82.23	82.27	82.51	82.41	82.43	80.17
31.	AMOUNT ($)	36,795,271	42,891,858	30,984,676	29,423,753	30,623,085	33,827,920	400,313,720
32.	BURNED:							
33.	UNITS (TONS)	482,940	478,770	372,780	376,770	366,520	433,360	4,923,050
34.	UNIT COST ($/TON)	80.53	81.29	82.59	82.29	83.67	82.61	81.14
35.	AMOUNT ($)	38,892,495	38,919,999	30,786,167	31,006,213	30,667,179	35,800,345	399,454,811
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	620,630	663,460	667,280	647,110	652,190	629,230	629,230
38.	UNIT COST ($/TON)	80.51	81.91	82.53	83.09	83.52	83.99	83.99
39.	AMOUNT ($)	49,967,180	54,343,956	55,067,945	53,768,473	54,472,931	52,851,873	52,851,873
40.	DAYS SUPPLY:	43	50	54	51	50	45	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,221,189	2,693,610	51,846,020
43.	UNIT COST ($/MCF)	5.64	5.70	5.43	5.61	5.90	6.46	5.73
44.	AMOUNT ($)	30,963,378	30,198,894	34,591,098	29,007,927	18,995,303	17,404,718	297,296,168
45.	BURNED:							
46.	UNITS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,464,380	2,693,610	51,846,020
47.	UNIT COST ($/MCF)	5.63	5.69	5.42	5.60	5.71	6.38	5.73
48.	AMOUNT ($)	30,901,943	30,153,961	34,562,106	28,957,822	19,785,992	17,179,918	297,263,070
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	972,762	972,762	972,762	972,762	729,572	729,572	729,572
51.	UNIT COST ($/MCF)	3.82	3.83	3.83	3.86	3.94	4.12	4.12
52.	AMOUNT ($)	3,711,400	3,727,800	3,729,600	3,751,600	2,877,750	3,006,150	3,006,150
53.	DAYS SUPPLY:	7	7	7	7	5	5	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-14	SEMINOLE	JURISD.	SCH. - D	800.0	0.0	800.0	3.148	3.325	25,180.00	26,597.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	17,580.0	0.0	17,580.0	3.238	3.563	569,297.61	626,290.00	56,992.39
	TOTAL			**18,380.0**	**0.0**	**18,380.0**	**3.234**	**3.552**	**594,477.61**	**652,887.00**	**58,409.39**
Feb-14	SEMINOLE	JURISD.	SCH. - D	680.0	0.0	680.0	3.037	3.245	20,650.00	22,067.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	15,930.0	0.0	15,930.0	3.039	3.344	484,187.94	532,660.00	48,472.06
	TOTAL			**16,610.0**	**0.0**	**16,610.0**	**3.039**	**3.340**	**504,837.94**	**554,727.00**	**49,889.06**
Mar-14	SEMINOLE	JURISD.	SCH. - D	880.0	0.0	880.0	2.972	3.133	26,150.00	27,567.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	19,700.0	0.0	19,700.0	2.999	3.300	590,895.45	650,050.00	59,154.55
	TOTAL			**20,580.0**	**0.0**	**20,580.0**	**2.998**	**3.293**	**617,045.45**	**677,617.00**	**60,571.55**
Apr-14	SEMINOLE	JURISD.	SCH. - D	1,080.0	0.0	1,080.0	3.134	3.265	33,850.00	35,267.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	17,660.0	0.0	17,660.0	3.304	3.635	583,559.82	641,980.00	58,420.18
	TOTAL			**18,740.0**	**0.0**	**18,740.0**	**3.295**	**3.614**	**617,409.82**	**677,247.00**	**59,837.18**
May-14	SEMINOLE	JURISD.	SCH. - D	920.0	0.0	920.0	3.027	3.181	27,850.00	29,267.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	10,050.0	0.0	10,050.0	3.335	3.669	335,166.48	368,720.00	33,553.52
	TOTAL			**10,970.0**	**0.0**	**10,970.0**	**3.309**	**3.628**	**363,016.48**	**397,987.00**	**34,970.52**
Jun-14	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	3.161	3.304	31,290.00	32,707.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	10,080.0	0.0	10,080.0	3.581	3.939	360,927.54	397,060.00	36,132.46
	TOTAL			**11,070.0**	**0.0**	**11,070.0**	**3.543**	**3.882**	**392,217.54**	**429,767.00**	**37,549.46**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

(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
Jul-14	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.198	3.338	32,300.00	33,717.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	8,300.0	0.0	8,300.0	3.699	4.069	307,014.75	337,750.00	30,735.25
	TOTAL			**9,310.0**	**0.0**	**9,310.0**	**3.645**	**3.990**	**339,314.75**	**371,467.00**	**32,152.25**
Aug-14	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	3.449	3.593	34,150.00	35,567.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	7,710.0	0.0	7,710.0	4.175	4.593	321,895.08	354,120.00	32,224.92
	TOTAL			**8,700.0**	**0.0**	**8,700.0**	**4.092**	**4.479**	**356,045.08**	**389,687.00**	**33,641.92**
Sep-14	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.303	3.443	33,360.00	34,777.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	8,240.0	0.0	8,240.0	3.923	4.316	323,258.58	355,620.00	32,361.42
	TOTAL			**9,250.0**	**0.0**	**9,250.0**	**3.855**	**4.221**	**356,618.58**	**390,397.00**	**33,778.42**
Oct-14	SEMINOLE	JURISD.	SCH. - D	730.0	0.0	730.0	3.279	3.474	23,940.00	25,357.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	10,160.0	0.0	10,160.0	3.528	3.881	358,473.24	394,360.00	35,886.76
	TOTAL			**10,890.0**	**0.0**	**10,890.0**	**3.512**	**3.854**	**382,413.24**	**419,717.00**	**37,303.76**
Nov-14	SEMINOLE	JURISD.	SCH. - D	650.0	0.0	650.0	3.169	3.387	20,600.00	22,017.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	9,600.0	0.0	9,600.0	3.355	3.691	322,113.24	354,360.00	32,246.76
	TOTAL			**10,250.0**	**0.0**	**10,250.0**	**3.344**	**3.672**	**342,713.24**	**376,377.00**	**33,663.76**
Dec-14	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	3.217	3.462	18,660.00	20,077.00	1,417.00
	VARIOUS	JURISD.	MKT. BASE	15,000.0	0.0	15,000.0	3.312	3.643	496,732.14	546,460.00	49,727.86
	TOTAL			**15,580.0**	**0.0**	**15,580.0**	**3.308**	**3.636**	**515,392.14**	**566,537.00**	**51,144.86**
TOTAL	SEMINOLE	JURISD.	SCH. - D	10,320.0	0.0	10,320.0	3.178	3.343	327,980.00	344,984.00	17,004.00
	VARIOUS	JURISD.	MKT. BASE	150,010.0	0.0	150,010.0	3.369	3.706	5,053,521.87	5,559,430.00	505,908.13
	TOTAL			**160,330.0**	**0.0**	**160,330.0**	**3.357**	**3.683**	**5,381,501.87**	**5,904,414.00**	**522,912.13**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	TOTAL $
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	FOR FUEL
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	ADJUSTMENT
Jan-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	2,320.0	0.0	0.0	2,320.0	3.849	3.849	89,300.00
	TOTAL		**2,320.0**	**0.0**	**0.0**	**2,320.0**	**3.849**	**3.849**	**89,300.00**
Feb-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	3,830.0	0.0	0.0	3,830.0	3.791	3.791	145,200.00
	TOTAL		**3,830.0**	**0.0**	**0.0**	**3,830.0**	**3.791**	**3.791**	**145,200.00**
Mar-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	300.0	0.0	0.0	300.0	7.810	7.810	23,430.00
	PASCO COGEN	SCH. - D	7,940.0	0.0	0.0	7,940.0	3.718	3.718	295,190.00
	TOTAL		**8,240.0**	**0.0**	**0.0**	**8,240.0**	**3.867**	**3.867**	**318,620.00**
Apr-14									
	OLEANDER	SCH. - D	780.0	0.0	0.0	780.0	7.060	7.060	55,070.00
	CALPINE	SCH. - D	350.0	0.0	0.0	350.0	6.094	6.094	21,330.00
	PASCO COGEN	SCH. - D	9,590.0	0.0	0.0	9,590.0	3.850	3.850	369,200.00
	TOTAL		**10,720.0**	**0.0**	**0.0**	**10,720.0**	**4.157**	**4.157**	**445,600.00**
May-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	17,940.0	0.0	0.0	17,940.0	3.865	3.865	693,330.00
	TOTAL		**17,940.0**	**0.0**	**0.0**	**17,940.0**	**3.865**	**3.865**	**693,330.00**
Jun-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	1,290.0	0.0	0.0	1,290.0	6.836	6.836	88,190.00
	PASCO COGEN	SCH. - D	16,730.0	0.0	0.0	16,730.0	3.881	3.881	649,250.00
	TOTAL		**18,020.0**	**0.0**	**0.0**	**18,020.0**	**4.092**	**4.092**	**737,440.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jul-14									
	OLEANDER	SCH. - D	3,530.0	0.0	0.0	3,530.0	6.465	6.465	228,230.00
	CALPINE	SCH. - D	3,370.0	0.0	0.0	3,370.0	6.432	6.432	216,750.00
	PASCO COGEN	SCH. - D	16,880.0	0.0	0.0	16,880.0	3.928	3.928	663,020.00
	TOTAL		**23,780.0**	**0.0**	**0.0**	**23,780.0**	**4.659**	**4.659**	**1,108,000.00**
Aug-14									
	OLEANDER	SCH. - D	7,640.0	0.0	0.0	7,640.0	6.603	6.603	504,480.00
	CALPINE	SCH. - D	5,580.0	0.0	0.0	5,580.0	6.716	6.716	374,760.00
	PASCO COGEN	SCH. - D	19,100.0	0.0	0.0	19,100.0	3.922	3.922	749,170.00
	TOTAL		**32,320.0**	**0.0**	**0.0**	**32,320.0**	**5.038**	**5.038**	**1,628,410.00**
Sep-14									
	OLEANDER	SCH. - D	3,880.0	0.0	0.0	3,880.0	6.006	6.006	233,030.00
	CALPINE	SCH. - D	4,200.0	0.0	0.0	4,200.0	6.635	6.635	278,680.00
	PASCO COGEN	SCH. - D	23,340.0	0.0	0.0	23,340.0	3.917	3.917	914,260.00
	TOTAL		**31,420.0**	**0.0**	**0.0**	**31,420.0**	**4.538**	**4.538**	**1,425,970.00**
Oct-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	540.0	0.0	0.0	540.0	6.931	6.931	37,430.00
	PASCO COGEN	SCH. - D	15,690.0	0.0	0.0	15,690.0	3.928	3.928	616,260.00
	TOTAL		**16,230.0**	**0.0**	**0.0**	**16,230.0**	**4.028**	**4.028**	**653,690.00**
Nov-14									
	OLEANDER	SCH. - D	1,510.0	0.0	0.0	1,510.0	5.902	5.902	89,120.00
	CALPINE	SCH. - D	550.0	0.0	0.0	550.0	5.718	5.718	31,450.00
	PASCO COGEN	SCH. - D	14,170.0	0.0	0.0	14,170.0	3.876	3.876	549,290.00
	TOTAL		**16,230.0**	**0.0**	**0.0**	**16,230.0**	**4.127**	**4.127**	**669,860.00**
Dec-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	1,660.0	0.0	0.0	1,660.0	4.115	4.115	68,310.00
	TOTAL		**1,660.0**	**0.0**	**0.0**	**1,660.0**	**4.115**	**4.115**	**68,310.00**
TOTAL	OLEANDER	SCH. - D	17,340.0	0.0	0.0	17,340.0	6.401	6.401	1,109,930.00
Jan-14	CALPINE	SCH. - D	16,180.0	0.0	0.0	16,180.0	6.626	6.626	1,072,020.00
THRU	PASCO COGEN	SCH. - D	149,190.0	0.0	0.0	149,190.0	3.889	3.889	5,801,780.00
Dec-14	**TOTAL**		**182,710.0**	**0.0**	**0.0**	**182,710.0**	**4.370**	**4.370**	**7,983,730.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUST-
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	MENT
Jan-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.300	3.300	188,120.00
		AS AVAIL.	16,230.0	0.0	0.0	16,230.0	3.274	3.274	531,400.00
	TOTAL		21,930.0	0.0	0.0	21,930.0	3.281	3.281	719,520.00
Feb-14	VARIOUS	CO-GEN.							
		FIRM	5,150.0	0.0	0.0	5,150.0	3.261	3.261	167,960.00
		AS AVAIL.	16,140.0	0.0	0.0	16,140.0	2.605	2.605	420,380.00
	TOTAL		21,290.0	0.0	0.0	21,290.0	2.763	2.763	588,340.00
Mar-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.246	3.246	185,040.00
		AS AVAIL.	16,190.0	0.0	0.0	16,190.0	3.835	3.835	620,910.00
	TOTAL		21,890.0	0.0	0.0	21,890.0	3.682	3.682	805,950.00
Apr-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.230	3.230	200,580.00
		AS AVAIL.	16,080.0	0.0	0.0	16,080.0	2.935	2.935	471,920.00
	TOTAL		22,290.0	0.0	0.0	22,290.0	3.017	3.017	672,500.00
May-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.222	3.222	206,880.00
		AS AVAIL.	16,180.0	0.0	0.0	16,180.0	3.243	3.243	524,770.00
	TOTAL		22,600.0	0.0	0.0	22,600.0	3.237	3.237	731,650.00
Jun-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.218	3.218	199,840.00
		AS AVAIL.	16,100.0	0.0	0.0	16,100.0	3.132	3.132	504,310.00
	TOTAL		22,310.0	0.0	0.0	22,310.0	3.156	3.156	704,150.00
Jul-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.279	3.279	210,540.00
		AS AVAIL.	16,220.0	0.0	0.0	16,220.0	3.293	3.293	534,110.00
	TOTAL		22,640.0	0.0	0.0	22,640.0	3.289	3.289	744,650.00
Aug-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.327	3.327	213,620.00
		AS AVAIL.	16,080.0	0.0	0.0	16,080.0	3.440	3.440	553,120.00
	TOTAL		22,500.0	0.0	0.0	22,500.0	3.408	3.408	766,740.00
Sep-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.358	3.358	208,530.00
		AS AVAIL.	16,180.0	0.0	0.0	16,180.0	2.911	2.911	470,930.00
	TOTAL		22,390.0	0.0	0.0	22,390.0	3.035	3.035	679,460.00
Oct-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.373	3.373	216,570.00
		AS AVAIL.	16,260.0	0.0	0.0	16,260.0	3.099	3.099	503,840.00
	TOTAL		22,680.0	0.0	0.0	22,680.0	3.176	3.176	720,410.00
Nov-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.393	3.393	210,710.00
		AS AVAIL.	16,020.0	0.0	0.0	16,020.0	3.174	3.174	508,460.00
	TOTAL		22,230.0	0.0	0.0	22,230.0	3.235	3.235	719,170.00
Dec-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.395	3.395	193,540.00
		AS AVAIL.	16,150.0	0.0	0.0	16,150.0	1.873	1.873	302,480.00
	TOTAL		21,850.0	0.0	0.0	21,850.0	2.270	2.270	496,020.00
TOTAL	VARIOUS	CO-GEN.							
Jan-14		FIRM	72,770.0	0.0	0.0	72,770.0	3.301	3.301	2,401,930.00
THRU		AS AVAIL.	193,830.0	0.0	0.0	193,830.0	3.068	3.068	5,946,630.00
Dec-14	TOTAL		266,600.0	0.0	0.0	266,600.0	3.131	3.131	8,348,560.00

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
Jan-14	VARIOUS	ECONOMY	27,960.0	0.0	27,960.0	4.000	1,118,480.00	4.562	1,275,406.73	156,926.73
Feb-14	VARIOUS	ECONOMY	27,690.0	0.0	27,690.0	4.000	1,107,530.00	4.561	1,262,941.34	155,411.34
Mar-14	VARIOUS	ECONOMY	37,410.0	0.0	37,410.0	4.000	1,496,400.00	4.561	1,706,365.27	209,965.27
Apr-14	VARIOUS	ECONOMY	35,130.0	0.0	35,130.0	4.000	1,405,270.00	4.561	1,602,438.67	197,168.67
May-14	VARIOUS	ECONOMY	46,100.0	0.0	46,100.0	4.000	1,843,860.00	4.561	2,102,598.28	258,738.28
Jun-14	VARIOUS	ECONOMY	46,630.0	0.0	46,630.0	4.000	1,865,250.00	4.561	2,126,962.93	261,712.93
Jul-14	VARIOUS	ECONOMY	58,190.0	0.0	58,190.0	4.326	2,517,540.00	4.830	2,810,739.30	293,199.30
Aug-14	VARIOUS	ECONOMY	45,370.0	0.0	45,370.0	4.336	1,967,230.00	4.838	2,194,987.04	227,757.04
Sep-14	VARIOUS	ECONOMY	56,590.0	0.0	56,590.0	4.311	2,439,700.00	4.818	2,726,332.62	286,632.62
Oct-14	VARIOUS	ECONOMY	48,550.0	0.0	48,550.0	4.000	1,942,060.00	4.561	2,214,549.01	272,489.01
Nov-14	VARIOUS	ECONOMY	32,710.0	0.0	32,710.0	4.000	1,308,440.00	4.561	1,492,026.32	183,586.32
Dec-14	VARIOUS	ECONOMY	33,520.0	0.0	33,520.0	4.000	1,340,720.00	4.561	1,528,852.48	188,132.48
TOTAL	VARIOUS	ECONOMY	495,850.0	0.0	495,850.0	4.105	20,352,480.00	4.647	23,044,200.00	2,691,720.00

SCHEDULE E10

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

	Current Jan 13 - Dec 13	Projected Jan 14 - Dec 14	Difference $	Difference %
Base Rate Revenue *	55.45	65.78	10.33	19%
Fuel Recovery Revenue	33.69	35.99	2.30	7%
Conservation Revenue	2.98	2.87	(0.11)	-4%
Capacity Revenue	2.32	1.96	(0.36)	-16%
Environmental Revenue	5.58	4.98	(0.60)	-11%
Florida Gross Receipts Tax Revenue	2.56	2.86	0.30	12%
TOTAL REVENUE	**$102.58**	**$114.44**	**$11.86**	**12%**

*** Reflects proposed 2014 base rate change, as submitted in Docket No. 130040-EI.**

SCHEDULE H1

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

		ACTUAL 2011	ACTUAL 2012	ACT/EST 2013	EST 2014	DIFFERENCE (%) 2012-2011	2013-2012	2014-2013
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
2	LIGHT OIL (1)	2,915,586	4,902,843	3,662,424	1,039,658	68.2%	-25.3%	-71.6%
3	COAL	386,430,361	395,142,292	383,830,271	399,454,811	2.3%	-2.9%	4.1%
4	NATURAL GAS	348,457,572	305,701,892	314,247,742	297,263,070	-12.3%	2.8%	-5.4%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**737,803,519**	**705,747,027**	**701,740,437**	**697,757,539**	**-4.3%**	**-0.6%**	**-0.6%**
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
9	LIGHT OIL (1)	13,423	20,242	10,553	4,233	50.8%	-47.9%	-59.9%
10	COAL	10,888,182	10,690,533	10,940,725	11,544,670	-1.8%	2.3%	5.5%
11	NATURAL GAS	7,392,465	7,567,891	7,550,325	6,973,999	2.4%	-0.2%	-7.6%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	0	0	0	0.0%	0.0%	0.0%
14	**TOTAL (MWH)**	**18,294,070**	**18,278,666**	**18,501,603**	**18,522,902**	**-0.1%**	**1.2%**	**0.1%**
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL) (1)	0	0	0	0	0.0%	0.0%	0.0%
16	LIGHT OIL (BBL) (1)	27,473	40,791	52,693	38,850	48.5%	29.2%	-26.3%
17	COAL (TON)	4,763,638	4,671,399	4,729,963	4,923,050	-1.9%	1.3%	4.1%
18	NATURAL GAS (MCF)	55,514,960	56,591,885	56,474,119	51,846,020	1.9%	-0.2%	-8.2%
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)	146,019	208,086	167,608	45,510	42.5%	-19.5%	-72.8%
23	COAL	114,391,211	112,307,550	113,314,456	118,029,000	-1.8%	0.9%	4.2%
24	NATURAL GAS	56,296,514	57,395,050	57,620,198	53,170,540	2.0%	0.4%	-7.7%
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)**	**170,833,745**	**169,910,686**	**171,102,262**	**171,245,050**	**-0.5%**	**0.7%**	**0.1%**
	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)	0.07	0.11	0.06	0.02	57.1%	-45.5%	-66.7%
30	COAL	59.52	58.49	59.13	62.33	-1.7%	1.1%	5.4%
31	NATURAL GAS	40.41	41.40	40.81	37.85	2.4%	-1.4%	-7.7%
32	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
	FUEL COST PER UNIT							
35	HEAVY OIL ($/BBL) (1)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36	LIGHT OIL ($/BBL) (1)	106.13	120.19	69.50	26.76	13.2%	-42.2%	-61.5%
37	COAL ($/TON)	81.12	84.59	81.15	81.14	4.3%	-4.1%	0.0%
38	NATURAL GAS ($/MCF)	6.28	5.40	5.56	5.73	-14.0%	3.0%	3.1%
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)	19.97	23.56	21.85	22.84	18.0%	-7.3%	4.5%
43	COAL	3.38	3.52	3.39	3.38	4.1%	-3.7%	-0.3%
44	NATURAL GAS	6.19	5.33	5.45	5.59	-13.9%	2.3%	2.6%
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)**	**4.32**	**4.15**	**4.10**	**4.07**	**-3.9%**	**-1.2%**	**-0.7%**
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL (1)	0	0	0	0	0.0%	0.0%	0.0%
49	LIGHT OIL (1)	10,878	10,280	15,883	10,751	-5.5%	54.5%	-32.3%
50	COAL	10,506	10,505	10,357	10,224	0.0%	-1.4%	-1.3%
51	NATURAL GAS	7,615	7,584	7,831	7,624	-0.4%	0.6%	-0.1%
52	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54	**TOTAL (BTU/KWH)**	9,338	9,296	9,248	9,245	-0.4%	-0.5%	0.0%
	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)	21.72	24.22	34.71	24.56	11.5%	43.3%	-29.2%
57	COAL	3.55	3.70	3.51	3.46	4.2%	-5.1%	-1.4%
58	NATURAL GAS	4.71	4.04	4.16	4.26	-14.2%	3.0%	2.4%
59	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	**TOTAL (cents/KWH)**	4.03	3.86	3.79	3.77	-4.2%	-1.8%	-0.5%

(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. 4

LEVELIZED AND TIERED FUEL RATE

JANUARY 2014 - DECEMBER 2014

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2014 through December 2014

	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	5,868,210	3.911	229,505,693	3.599	211,196,878
TIER II (Over 1,000) kWh	2,661,165	3.911	104,078,163	4.599	122,386,978
Total	8,529,375		333,583,856		333,583,856

Docket No. 130001-EI
Exhibit No._____ (PAR-3)
Document No. 4, Page 1 of 1

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 5

POLK UNIT 1 IGNITION OIL CONVERSION

JANUARY 2014 - DECEMBER 2014

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2014 THROUGH DECEMBER 2014

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062
2	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062
5														
6														
7	AVERAGE BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	
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	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	3,085,612
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	1,542,806	1,799,941	2,057,075	2,314,209	2,571,344	2,828,478	3,085,612	3,342,747	3,599,881	3,857,015	4,114,150	4,371,284	1,542,806
12	ENDING BALANCE DEPRECIATION	1,799,941	2,057,075	2,314,209	2,571,344	2,828,478	3,085,612	3,342,747	3,599,881	3,857,015	4,114,150	4,371,284	4,628,418	4,628,418
13														
14														
15	ENDING NET INVESTMENT	13,628,121	13,370,987	13,113,852	12,856,718	12,599,584	12,342,449	12,085,315	11,828,181	11,571,046	11,313,912	11,056,778	10,799,643	10,799,643
16														
17														
18	AVERAGE INVESTMENT	$ 13,756,688	$ 13,499,554	$ 13,242,420	$ 12,985,285	$ 12,728,151	$ 12,471,017	$ 12,213,882	$ 11,956,748	$ 11,699,613	$ 11,442,479	$ 11,185,345	$ 10,928,210	
19	ALLOWED EQUITY RETURN	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	
20	EQUITY COMPONENT AFTER-TAX	55,278	54,245	53,211	52,178	51,145	50,112	49,078	48,045	47,012	45,979	44,946	43,912	595,141
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	89,993	88,311	86,628	84,946	83,264	81,582	79,899	78,217	76,536	74,854	73,172	71,489	968,891
23														
24	ALLOWED DEBT RETURN	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	
25	DEBT COMPONENT	$ 25,543	$ 25,065	$ 24,588	$ 24,110	$ 23,633	$ 23,156	22,678	22,201	21,723	21,246	20,768	20,291	275,002
26														
27	TOTAL RETURN REQUIREMENTS	$ 115,536	$ 113,376	$ 111,216	$ 109,056	$ 106,897	$ 104,738	102,577	100,418	98,259	96,100	93,940	91,780	1,243,893
28														
29	TOTAL DEPRECIATION & RETURN	$ 372,670	$ 370,510	$ 368,350	$ 366,190	$ 364,031	$ 361,872	359,711	357,552	355,393	353,234	351,074	348,914	4,329,501
30														
31	ESTIMATED FUEL SAVINGS	$467,544	$429,570	$610,456	$749,244	$688,170	$736,400	$488,114	$0	$0	$679,695	$1,299,753	$0	$6,148,946
32	TOTAL DEPRECIATION & RETURN	$372,670	$370,510	$368,350	$366,190	$364,031	$361,872	$359,711	$357,552	$355,393	$353,234	$351,074	$348,914	4,329,501
33	NET BENEFIT (COST) TO RATEPAYER	$94,874	$59,060	$242,106	$383,054	$324,139	$374,528	$128,403	($357,552)	($355,393)	$326,461	$948,679	($348,914)	$1,819,445

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 10.08% (EQUITY 7.8501% , DEBT 2.2281%)
36 THE RATES ARE FROM THE MAY 2013 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
38 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2014 THROUGH DECEMBER 2014

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: AUGUST 30, 2013

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 2014 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, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. 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. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and 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. One Big Bend Unit 3 outage was identified as an outlying outage; therefore, the associated forced outage hours were removed from the study.

Q. Should the current GPIF methodology be eliminated or modified, and if the latter, how should it be modified?

A. No. The current GPIF methodology should not be eliminated or significantly modified. It continues to perform the function it was designed to accomplish when it was established in 1980 by Commission Order No. 9558 in Docket No. 800400-CI, issued September 19, 1980. There may be room for slight modifications to the various GPIF implementation methodologies to gain some uniformity in the manner in which the utilities administer the GPIF program, but there is no reason to eliminate or significantly modify the methodology.

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 2014 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 2014 period, the projected EUOF for Bayside Unit 1 is 1.1 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit 1 equals 94.0 percent or:

$$100\% - (1.1\% + 4.9\%) = 94.0\%$$

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 and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80 \ (1.1\%) + 0.95 \ (4.9\%)] = 94.4\%$$

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 1 example,

$$EAF_{MIN} = 1 - [1.40 \ (1.1\%) + 1.10 \ (4.9\%)] = 93.1\%$$

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 2014 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2014; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from March 17, 2014 to March 25, 2014 and December 2, 2014 to December 10, 2014. There are 432 planned outage hours scheduled for the 2014 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 4.9 percent or:

$$\frac{432}{8{,}760} \times 100\% = 4.9\%$$

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 23.0 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 18.1 percent. Polk Unit 1 has a POF of 5.2 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 4.9 percent.

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

A. For each unit the most current 12-month ending value, June 2013, was used as a basis for the projection. All projected factors are based upon historical unit performance. These target factors are additive and result in a EUOF of 1.1 percent for Bayside Unit 1. The EUOF for Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

or

$$EUOF = \frac{(18 + 77)}{8,760} \times 100\% = 1.1\%$$

Relative to Bayside Unit 1, the EUOF of 1.1 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 16.4 percent. The unit will have two planned outages in 2014, and the POF is 23.0 percent. Therefore, the target equivalent availability for this unit is 60.6 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.6 percent. The unit will have two planned outages in 2014, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.9 percent.

Big Bend Unit 3

The projected EUOF for this unit is 19.4 percent. The unit will have two planned outages in 2014, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.1 percent.

Big Bend Unit 4

The projected EUOF for this unit is 19.3 percent. The unit will have two planned outages in 2014, and the POF is 18.1 percent. Therefore, the target equivalent availability for this unit is 62.6 percent.

Polk Unit 1

The projected EUOF for this unit is 10.8 percent. The unit will have two planned outages in 2014, and the POF is 5.2 percent. Therefore, the target equivalent availability for this unit is 84.0 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.1 percent. The unit will have two planned outages in 2014, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 94.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 9.3 percent. The unit will have two planned outages in 2014, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 85.8 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 76.9 percent is shown on Page 5 of Document No. 1. This target is greater than last year's January through December actual performance.

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 will not 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 1 on page 19 of Document No. 1. Except for the months of March and December, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March and December, the Equivalent Unplanned Outage Rate exceeds the EUOF 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.

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.

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 2014 period.

A. The heat rate target for Big Bend Unit 1 is 10,501 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±301 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,271 Btu/Net kWh with a range of ±214 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,696 Btu/Net kWh, with a range of ±174 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,381 Btu/Net kWh with a range of ±186 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,506 Btu/Net kWh with a range of ±141 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,283 Btu/Net kWh with a range of ±118 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,387 Btu/Net kWh with a range of ±77 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 $724,400,390 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 $14,961,899 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 1, the weighting factor for average net operating heat rate is 10.47 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 1, page 12, if the unit operates at 7,164 average net operating heat rate, fuel savings would equal $1,566,079 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 $14,961,899. 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 2014 is $2,066,528,003. This produces the maximum allowed jurisdictional incentive of $8,446,336 shown on line 21.

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

A. Yes. 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 $7,480,950.

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):

$$
\begin{aligned}
GPIP: = (&0.0803\ EAP_{BB1} + 0.0071\ EAP_{BB2} \\
&+ 0.0489\ EAP_{BB3} + 0.0306\ EAP_{BB4} \\
&+ 0.0166\ EAP_{PK1} + 0.0589\ EAP_{BAY1} \\
&+ 0.0867\ EAP_{BAY2} + 0.1320\ HRP_{BB1} \\
&+ 0.1167\ HRP_{BB2} + 0.0877\ HRP_{BB3} \\
&+ 0.0896\ HRP_{BB4} + 0.0505\ HRP_{PK1} \\
&+ 0.1047\ HRP_{BAY1} + 0.0899\ HRP_{BAY2})
\end{aligned}
$$

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 2014 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 2014 - DECEMBER 2014

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2014 - DECEMBER 2014
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2014 - DECEMBER 2014

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	14,961.9	7,480.9
+9	13,465.7	6,732.9
+8	11,969.5	5,984.8
+7	10,473.3	5,236.7
+6	8,977.1	4,488.6
+5	7,480.9	3,740.5
+4	5,984.8	2,992.4
+3	4,488.6	2,244.3
+2	2,992.4	1,496.2
+1	1,496.2	748.1
0	0.0	0.0
-1	(1,454.1)	(748.1)
-2	(2,908.1)	(1,496.2)
-3	(4,362.2)	(2,244.3)
-4	(5,816.3)	(2,992.4)
-5	(7,270.4)	(3,740.5)
-6	(8,724.4)	(4,488.6)
-7	(10,178.5)	(5,236.7)
-8	(11,632.6)	(5,984.8)
-9	(13,086.6)	(6,732.9)
-10	(14,540.7)	(7,480.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2014 - DECEMBER 2014

Line 1	Beginning of period balance of common equity: End of month common equity:		$2,034,838,000	
Line 2	Month of January	2014	$1,988,303,000	
Line 3	Month of February	2014	$2,006,943,341	
Line 4	Month of March	2014	$2,025,758,434	
Line 5	Month of April	2014	$2,053,829,485	
Line 6	Month of May	2014	$2,073,084,137	
Line 7	Month of June	2014	$2,092,519,301	
Line 8	Month of July	2014	$2,045,375,803	
Line 9	Month of August	2014	$2,064,551,201	
Line 10	Month of September	2014	$2,083,906,369	
Line 11	Month of October	2014	$2,112,055,923	
Line 12	Month of November	2014	$2,131,856,447	
Line 13	Month of December	2014	$2,151,842,601	
Line 14	(Summation of line 1 through line 13 divided by 13)		$2,066,528,003	
Line 15	25 Basis points		0.0025	
Line 16	Revenue Expansion Factor		61.17%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$8,446,336	
Line 18	Jurisdictional Sales		18,352,207	MWH
Line 19	Total Sales		18,352,207	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		100.00%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$8,446,336**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2014 - DECEMBER 2014

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	8.03%	60.6	65.0	51.8	1,201.3	(428.6)
BIG BEND 2	0.71%	74.9	78.9	66.8	106.0	(550.0)
BIG BEND 3	4.89%	74.1	78.3	65.7	732.4	(564.5)
BIG BEND 4	3.06%	62.6	67.4	53.1	457.2	(271.5)
POLK 1	1.66%	84.0	86.4	79.1	248.0	(259.2)
BAYSIDE 1	5.89%	94.0	94.4	93.1	880.8	(341.8)
BAYSIDE 2	8.67%	85.8	87.9	81.6	1,296.6	(2,085.3)
GPIF SYSTEM	**32.90%**					

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	13.20%	10,501	94.0	10,200	10,802	1,975.3	(1,975.3)
BIG BEND 2	11.67%	10,271	93.0	10,057	10,485	1,746.0	(1,746.0)
BIG BEND 3	8.77%	10,696	82.1	10,523	10,870	1,312.2	(1,312.2)
BIG BEND 4	8.96%	10,381	88.3	10,195	10,568	1,340.6	(1,340.6)
POLK 1	5.05%	10,506	96.5	10,365	10,647	755.0	(755.0)
BAYSIDE 1	10.47%	7,283	60.4	7,164	7,401	1,566.1	(1,566.1)
BAYSIDE 2	8.99%	7,387	59.1	7,310	7,463	1,344.6	(1,344.6)
GPIF SYSTEM	**67.10%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 14 - DEC 14 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 12 - DEC 12 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 11 - DEC 11 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 10 - DEC 10 POF	EUOF	EUOR
BIG BEND 1	8.03%	24.4%	23.0	16.4	21.2	6.8	26.2	28.3	5.8	13.5	14.4	24.5	15.1	19.9
BIG BEND 2	0.71%	2.2%	6.6	18.6	19.9	4.0	17.9	18.7	17.1	25.4	30.6	5.5	26.1	27.6
BIG BEND 3	4.89%	14.9%	6.6	19.4	20.7	2.8	25.0	25.7	8.6	17.9	19.5	8.4	11.9	13.1
BIG BEND 4	3.06%	9.3%	18.1	19.3	23.5	8.2	16.2	17.6	9.4	15.1	16.7	19.3	14.2	17.5
POLK 1	1.66%	5.0%	5.2	10.8	11.4	12.7	17.3	18.9	4.4	17.3	17.6	4.8	5.2	5.7
BAYSIDE 1	5.89%	17.9%	4.9	1.1	1.1	1.9	3.0	2.0	21.0	3.3	2.0	4.2	2.9	1.1
BAYSIDE 2	8.67%	26.3%	4.9	9.3	9.8	16.5	7.5	2.9	3.7	7.4	3.2	7.6	4.3	1.9
GPIF SYSTEM	**32.90%**	**100.0%**	**10.9**	**12.2**	**14.2**	**8.3**	**15.4**	**14.9**	**8.9**	**11.3**	**10.7**	**12.1**	**9.3**	**10.0**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**76.9**			**76.4**			**79.8**			**78.6**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
9.8	**12.0**	**11.9**	**78.3**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 14 - DEC 14	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 11 - DEC 11	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 10 - DEC 10
BIG BEND 1	13.20%	19.7%	10,501	10,470	10,665	10,213
BIG BEND 2	11.67%	17.4%	10,271	10,328	10,224	10,107
BIG BEND 3	8.77%	13.1%	10,696	10,690	10,628	10,852
BIG BEND 4	8.96%	13.4%	10,381	10,417	10,349	10,383
POLK 1	5.05%	7.5%	10,506	10,167	10,687	10,203
BAYSIDE 1	10.47%	15.6%	7,283	7,261	7,244	7,245
BAYSIDE 2	8.99%	13.4%	7,387	7,349	7,358	7,384
GPIF SYSTEM	**67.10%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,552**	**9,526**	**9,566**	**9,458**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2014 - DECEMBER 2014
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	724,400.4	723,199.1	1,201.3	8.03%
EA_2 BIG BEND 2	724,400.4	724,294.4	106.0	0.71%
EA_3 BIG BEND 3	724,400.4	723,668.0	732.4	4.89%
EA_4 BIG BEND 4	724,400.4	723,943.2	457.2	3.06%
EA_5 POLK 1	724,400.4	724,152.4	248.0	1.66%
EA_6 BAYSIDE 1	724,400.4	723,519.6	880.8	5.89%
EA_7 BAYSIDE 2	724,400.4	723,103.8	1,296.6	8.67%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	724,400.4	722,425.1	1,975.3	13.20%
AHR_2 BIG BEND 2	724,400.4	722,654.4	1,746.0	11.67%
AHR_3 BIG BEND 3	724,400.4	723,088.2	1,312.2	8.77%
AHR_4 BIG BEND 4	724,400.4	723,059.8	1,340.6	8.96%
AHR_5 POLK 1	724,400.4	723,645.4	755.0	5.05%
AHR_6 BAYSIDE 1	724,400.4	722,834.3	1,566.1	10.47%
AHR_7 BAYSIDE 2	724,400.4	723,055.8	1,344.6	8.99%
TOTAL SAVINGS			**14,961.9**	**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 2014 - DECEMBER 2014

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	1,201.3	65.0	+10	1,975.3	10,200
+9	1,081.2	64.6	+9	1,777.7	10,223
+8	961.0	64.2	+8	1,580.2	10,245
+7	840.9	63.7	+7	1,382.7	10,268
+6	720.8	63.3	+6	1,185.2	10,290
+5	600.6	62.8	+5	987.6	10,313
+4	480.5	62.4	+4	790.1	10,336
+3	360.4	61.9	+3	592.6	10,358
+2	240.3	61.5	+2	395.1	10,381
+1	120.1	61.1	+1	197.5	10,404
					10,426
0	0.0	60.6	0	0.0	10,501
					10,576
-1	(42.9)	59.7	-1	(197.5)	10,599
-2	(85.7)	58.9	-2	(395.1)	10,621
-3	(128.6)	58.0	-3	(592.6)	10,644
-4	(171.4)	57.1	-4	(790.1)	10,667
-5	(214.3)	56.2	-5	(987.6)	10,689
-6	(257.2)	55.3	-6	(1,185.2)	10,712
-7	(300.0)	54.4	-7	(1,382.7)	10,734
-8	(342.9)	53.5	-8	(1,580.2)	10,757
-9	(385.7)	52.7	-9	(1,777.7)	10,780
-10	(428.6)	51.8	-10	(1,975.3)	10,802
	Weighting Factor =	8.03%		Weighting Factor =	13.20%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

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	106.0	78.9	+10	1,746.0	10,057
+9	95.4	78.5	+9	1,571.4	10,071
+8	84.8	78.1	+8	1,396.8	10,085
+7	74.2	77.7	+7	1,222.2	10,099
+6	63.6	77.3	+6	1,047.6	10,113
+5	53.0	76.9	+5	873.0	10,127
+4	42.4	76.5	+4	698.4	10,140
+3	31.8	76.1	+3	523.8	10,154
+2	21.2	75.7	+2	349.2	10,168
+1	10.6	75.3	+1	174.6	10,182
					10,196
0	0.0	74.9	0	0.0	10,271
					10,346
-1	(55.0)	74.1	-1	(174.6)	10,360
-2	(110.0)	73.2	-2	(349.2)	10,374
-3	(165.0)	72.4	-3	(523.8)	10,388
-4	(220.0)	71.6	-4	(698.4)	10,401
-5	(275.0)	70.8	-5	(873.0)	10,415
-6	(330.0)	70.0	-6	(1,047.6)	10,429
-7	(385.0)	69.2	-7	(1,222.2)	10,443
-8	(440.0)	68.4	-8	(1,396.8)	10,457
-9	(495.0)	67.6	-9	(1,571.4)	10,471
-10	(550.0)	66.8	-10	(1,746.0)	10,485
	Weighting Factor =	0.71%		Weighting Factor =	11.67%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

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	732.4	78.3	+10	1,312.2	10,523
+9	659.1	77.9	+9	1,181.0	10,533
+8	585.9	77.4	+8	1,049.7	10,542
+7	512.7	77.0	+7	918.5	10,552
+6	439.4	76.6	+6	787.3	10,562
+5	366.2	76.2	+5	656.1	10,572
+4	292.9	75.8	+4	524.9	10,582
+3	219.7	75.3	+3	393.7	10,592
+2	146.5	74.9	+2	262.4	10,602
+1	73.2	74.5	+1	131.2	10,611
					10,621
0	0.0	74.1	0	0.0	10,696
					10,771
-1	(56.5)	73.2	-1	(131.2)	10,781
-2	(112.9)	72.4	-2	(262.4)	10,791
-3	(169.4)	71.6	-3	(393.7)	10,801
-4	(225.8)	70.7	-4	(524.9)	10,811
-5	(282.3)	69.9	-5	(656.1)	10,821
-6	(338.7)	69.0	-6	(787.3)	10,831
-7	(395.2)	68.2	-7	(918.5)	10,840
-8	(451.6)	67.4	-8	(1,049.7)	10,850
-9	(508.1)	66.5	-9	(1,181.0)	10,860
-10	(564.5)	65.7	-10	(1,312.2)	10,870
	Weighting Factor =	4.89%		Weighting Factor =	8.77%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

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	457.2	67.4	+10	1,340.6	10,195
+9	411.5	66.9	+9	1,206.5	10,206
+8	365.8	66.4	+8	1,072.5	10,217
+7	320.1	66.0	+7	938.4	10,229
+6	274.3	65.5	+6	804.3	10,240
+5	228.6	65.0	+5	670.3	10,251
+4	182.9	64.5	+4	536.2	10,262
+3	137.2	64.1	+3	402.2	10,273
+2	91.4	63.6	+2	268.1	10,284
+1	45.7	63.1	+1	134.1	10,295
					10,306
0	0.0	62.6	0	0.0	10,381
					10,456
-1	(27.2)	61.7	-1	(134.1)	10,468
-2	(54.3)	60.7	-2	(268.1)	10,479
-3	(81.5)	59.8	-3	(402.2)	10,490
-4	(108.6)	58.8	-4	(536.2)	10,501
-5	(135.8)	57.9	-5	(670.3)	10,512
-6	(162.9)	56.9	-6	(804.3)	10,523
-7	(190.1)	56.0	-7	(938.4)	10,534
-8	(217.2)	55.0	-8	(1,072.5)	10,546
-9	(244.4)	54.1	-9	(1,206.5)	10,557
-10	(271.5)	53.1	-10	(1,340.6)	10,568

	Weighting Factor =	3.06%		Weighting Factor =	8.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

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	248.0	86.4	+10	755.0	10,365
+9	223.2	86.2	+9	679.5	10,372
+8	198.4	85.9	+8	604.0	10,379
+7	173.6	85.7	+7	528.5	10,385
+6	148.8	85.4	+6	453.0	10,392
+5	124.0	85.2	+5	377.5	10,398
+4	99.2	84.9	+4	302.0	10,405
+3	74.4	84.7	+3	226.5	10,412
+2	49.6	84.5	+2	151.0	10,418
+1	24.8	84.2	+1	75.5	10,425
					10,431
0	0.0	84.0	0	0.0	10,506
					10,581
-1	(25.9)	83.5	-1	(75.5)	10,588
-2	(51.8)	83.0	-2	(151.0)	10,595
-3	(77.8)	82.5	-3	(226.5)	10,601
-4	(103.7)	82.0	-4	(302.0)	10,608
-5	(129.6)	81.6	-5	(377.5)	10,614
-6	(155.5)	81.1	-6	(453.0)	10,621
-7	(181.5)	80.6	-7	(528.5)	10,627
-8	(207.4)	80.1	-8	(604.0)	10,634
-9	(233.3)	79.6	-9	(679.5)	10,641
-10	(259.2)	79.1	-10	(755.0)	10,647
	Weighting Factor =	1.66%		Weighting Factor =	5.05%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

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	880.8	94.45	+10	1,566.1	7,164
+9	792.8	94.40	+9	1,409.5	7,169
+8	704.7	94.35	+8	1,252.9	7,173
+7	616.6	94.31	+7	1,096.3	7,177
+6	528.5	94.26	+6	939.6	7,182
+5	440.4	94.21	+5	783.0	7,186
+4	352.3	94.17	+4	626.4	7,190
+3	264.3	94.12	+3	469.8	7,195
+2	176.2	94.07	+2	313.2	7,199
+1	88.1	94.03	+1	156.6	7,203
					7,208
0	0.0	93.98	0	0.0	7,283
					7,358
-1	(34.2)	93.89	-1	(156.6)	7,362
-2	(68.4)	93.80	-2	(313.2)	7,366
-3	(102.5)	93.71	-3	(469.8)	7,371
-4	(136.7)	93.61	-4	(626.4)	7,375
-5	(170.9)	93.52	-5	(783.0)	7,379
-6	(205.1)	93.43	-6	(939.6)	7,384
-7	(239.3)	93.34	-7	(1,096.3)	7,388
-8	(273.5)	93.24	-8	(1,252.9)	7,392
-9	(307.6)	93.15	-9	(1,409.5)	7,397
-10	(341.8)	93.06	-10	(1,566.1)	7,401
	Weighting Factor =	5.89%		Weighting Factor =	10.47%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,296.6	87.9	+10	1,344.6	7,310
+9	1,166.9	87.7	+9	1,210.1	7,310
+8	1,037.2	87.5	+8	1,075.7	7,310
+7	907.6	87.3	+7	941.2	7,310
+6	777.9	87.0	+6	806.8	7,311
+5	648.3	86.8	+5	672.3	7,311
+4	518.6	86.6	+4	537.8	7,311
+3	389.0	86.4	+3	403.4	7,311
+2	259.3	86.2	+2	268.9	7,311
+1	129.7	86.0	+1	134.5	7,311
					7,312
0	0.0	85.8	0	0.0	7,387
					7,462
-1	(208.5)	85.4	-1	(134.5)	7,462
-2	(417.1)	84.9	-2	(268.9)	7,462
-3	(625.6)	84.5	-3	(403.4)	7,462
-4	(834.1)	84.1	-4	(537.8)	7,462
-5	(1,042.6)	83.7	-5	(672.3)	7,463
-6	(1,251.2)	83.3	-6	(806.8)	7,463
-7	(1,459.7)	82.8	-7	(941.2)	7,463
-8	(1,668.2)	82.4	-8	(1,075.7)	7,463
-9	(1,876.7)	82.0	-9	(1,210.1)	7,463
-10	(2,085.3)	81.6	-10	(1,344.6)	7,463
	Weighting Factor =	8.67%		Weighting Factor =	8.99%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	78.8	39.4	78.8	78.8	78.8	78.8	78.8	73.7	0.0	0.0	60.3	78.8	60.6
2. POF	0.0	50.0	0.0	0.0	0.0	0.0	0.0	6.5	100.0	100.0	23.4	0.0	23.0
3. EUOF	21.2	10.6	21.2	21.2	21.2	21.2	21.2	19.9	0.0	0.0	16.3	21.2	16.4
4. EUOR	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	0.0	0.0	21.2	21.2	21.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	609	275	609	590	609	590	609	570	0	0	452	609	5,522
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	135	397	134	130	135	130	135	174	720	744	269	135	3,238
9. POH	0	336	0	0	0	0	0	48	720	744	169	0	2,017
10. EFOH	153	69	153	148	153	148	153	143	0	0	114	153	1,390
11. EMOH	5	2	5	5	5	5	5	4	0	0	3	5	42
12. OPER BTU (GBTU)	2,336	1,015	2,361	2,256	2,341	2,271	2,351	2,203	0	0	1,702	2,321	21,157
13. NET GEN (MWH)	222,320	96,390	224,790	214,940	223,060	216,350	224,070	209,950	0	0	162,060	220,790	2,014,720
14. ANOHR (Btu/kwh)	10,509	10,526	10,504	10,498	10,495	10,495	10,493	10,493	0	0	10,505	10,512	10,501
15. NOF (%)	92.4	88.7	93.4	94.6	95.1	95.2	95.6	95.7	0.0	0.0	93.1	91.8	94.0
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF (	-4.808	) +		10,953								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	80.1	40.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	75.0	58.7	80.1	74.9
2. POF	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.5	26.8	0.0	6.6
3. EUOF	19.9	9.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	18.6	14.5	19.9	18.6
4. EUOR	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	625	282	625	605	625	605	625	625	605	585	444	625	6,876
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	119	390	118	115	119	115	119	119	115	159	277	119	1,884
9. POH	0	336	0	0	0	0	0	0	0	48	193	0	577
10. EFOH	116	52	116	112	116	112	116	116	112	109	82	116	1,278
11. EMOH	32	14	31	31	32	31	32	32	31	29	22	32	347
12. OPER BTU (GBTU)	2,313	999	2,325	2,235	2,336	2,261	2,331	2,342	2,263	2,189	1,608	2,307	25,514
13. NET GEN (MWH)	224,660	96,460	225,980	217,760	227,890	220,560	227,390	228,620	220,860	213,650	156,240	223,990	2,484,060
14. ANOHR (Btu/kwh)	10,298	10,355	10,291	10,265	10,249	10,249	10,252	10,245	10,248	10,247	10,292	10,301	10,271
15. NOF (%)	91.0	86.6	91.5	93.5	94.7	94.7	94.5	95.0	94.8	94.9	91.4	90.7	93.0
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF (	-13.110	) +		11,491								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	79.3	79.3	43.5	79.3	79.3	79.3	79.3	79.3	79.3	79.3	52.9	79.3	74.1
2. POF	0.0	0.0	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	20.7	20.7	11.4	20.7	20.7	20.7	20.7	20.7	20.7	20.7	13.8	20.7	19.4
4. EUOR	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	699	632	384	677	699	677	699	699	677	699	451	699	7,692
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	45	40	359	43	45	43	45	45	43	45	270	45	1,068
9. POH	0	0	335	0	0	0	0	0	0	0	240	0	575
10. EFOH	97	87	53	94	97	94	97	97	94	97	63	97	1,064
11. EMOH	57	52	32	56	57	56	57	57	56	57	37	57	632
12. OPER BTU (GBTU)	2,193	1,998	1,205	2,163	2,254	2,190	2,268	2,270	2,209	2,262	1,438	2,196	24,649
13. NET GEN (MWH)	203,990	186,220	112,130	202,100	211,080	205,190	212,740	212,930	207,490	211,940	134,300	204,350	2,304,460
14. ANOHR (Btu/kwh)	10,752	10,731	10,750	10,704	10,679	10,671	10,663	10,661	10,647	10,671	10,709	10,748	10,696
15. NOF (%)	80.0	80.7	80.0	81.8	82.7	83.0	83.4	83.5	84.0	83.1	81.6	80.1	82.1
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365

17. ANOHR EQUATION ANOHR = NOF (-25.960) + 12,827

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	76.5	76.5	69.0	0.0	19.7	76.5	76.5	76.5	76.5	76.5	76.5	51.8	62.6
2. POF	0.0	0.0	9.7	100.0	74.2	0.0	0.0	0.0	0.0	0.0	0.0	32.3	18.1
3. EUOF	23.5	23.5	21.3	0.0	6.1	23.5	23.5	23.5	23.5	23.5	23.5	15.9	19.3
4. EUOR	23.5	23.5	23.5	0.0	23.5	23.5	23.5	23.5	23.5	23.5	23.5	23.5	23.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	634	573	573	0	164	614	634	634	614	634	614	430	6,118
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	110	99	170	720	580	106	110	110	106	110	107	314	2,642
9. POH	0	0	72	720	552	0	0	0	0	0	0	240	1,584
10. EFOH	149	135	134	0	38	144	149	149	144	149	144	101	1,438
11. EMOH	26	24	24	0	7	25	26	26	25	26	25	18	252
12. OPER BTU (GBTU)	2,365	2,129	2,162	0	610	2,324	2,399	2,405	2,332	2,400	2,297	1,595	23,016
13. NET GEN (MWH)	226,790	204,090	207,740	0	58,670	224,460	231,690	232,380	225,340	231,750	221,310	152,790	2,217,010
14. ANOHR (Btu/kwh)	10,427	10,433	10,406	11,953	10,389	10,355	10,355	10,351	10,348	10,355	10,377	10,437	10,381
15. NOF (%)	85.8	85.4	86.9	0.0	87.9	89.8	89.8	90.1	90.2	89.8	88.6	85.2	88.3
16. NPC (MW)	417	417	417	407	407	407	407	407	407	407	407	417	410
17. ANOHR EQUATION	ANOHR = NOF (	-17.797	) +		11,953								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	88.6	88.6	48.6	88.6	88.6	88.6	88.6	88.6	88.6	88.6	73.8	88.6	84.0
2. POF	0.0	0.0	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	5.2
3. EUOF	11.4	11.4	6.3	11.4	11.4	11.4	11.4	11.4	11.4	11.4	9.5	11.4	10.8
4. EUOR	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	682	616	374	671	699	678	711	701	678	698	567	702	7,777
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	62	56	369	49	45	42	33	43	42	46	154	42	983
9. POH	0	0	335	0	0	0	0	0	0	0	120	0	455
10. EFOH	59	53	32	57	59	57	59	59	57	59	47	59	656
11. EMOH	26	24	14	25	26	25	26	26	25	26	21	26	292
12. OPER BTU (GBTU)	1,521	1,374	834	1,498	1,560	1,513	1,585	1,563	1,512	1,557	1,265	1,567	17,348
13. NET GEN (MWH)	144,990	130,960	79,510	141,990	148,270	143,810	151,180	149,020	144,250	148,380	120,430	148,380	1,651,170
14. ANOHR (Btu/kwh)	10,489	10,489	10,490	10,549	10,518	10,519	10,487	10,490	10,480	10,490	10,501	10,563	10,506
15. NOF (%)	96.6	96.6	96.6	96.2	96.4	96.4	96.7	96.6	96.7	96.6	96.5	96.1	96.5
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF (	-132.175	) +		23,262								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	98.9	98.9	70.1	98.9	98.9	98.9	98.9	98.9	98.9	98.9	98.9	70.2	94.0
2. POF	0.0	0.0	29.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.0	4.9
3. EUOF	1.1	1.1	0.8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.8	1.1
4. EUOR	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	560	604	483	573	675	691	713	710	712	656	530	482	7,389
7. RSH	175	60	38	139	60	21	22	25	0	79	183	40	844
8. UH	9	8	222	8	9	8	9	9	8	9	8	222	527
9. POH	0	0	216	0	0	0	0	0	0	0	0	216	432
10. EFOH	2	1	1	2	2	2	2	2	2	2	2	1	18
11. EMOH	7	6	5	7	7	7	7	7	7	7	7	5	77
12. OPER BTU (GBTU)	1,795	2,437	1,781	1,446	2,013	2,166	2,227	2,147	2,429	2,062	1,721	1,522	23,770
13. NET GEN (MWH)	244,970	338,820	245,690	195,890	275,700	297,780	306,050	294,340	336,360	283,510	237,330	207,470	3,263,910
14. ANOHR (Btu/kwh)	7,328	7,192	7,249	7,384	7,301	7,273	7,276	7,294	7,222	7,272	7,252	7,335	7,283
15. NOF (%)	55.2	70.8	64.2	48.8	58.3	61.5	61.2	59.1	67.4	61.7	63.9	54.3	60.4
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF (	-8.710	) +		7,809								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

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-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	90.2	61.2	90.2	90.2	90.2	90.2	90.2	90.2	90.2	90.2	63.2	90.2	85.8
2. POF	0.0	32.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	4.9
3. EUOF	9.8	6.6	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	6.8	9.8	9.3
4. EUOR	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	671	411	670	650	671	650	671	671	650	671	456	671	7,514
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	73	261	73	70	73	70	73	73	70	73	265	73	1,246
9. POH	0	216	0	0	0	0	0	0	0	0	216	0	432
10. EFOH	61	38	61	59	61	59	61	61	59	61	42	61	687
11. EMOH	11	7	11	11	11	11	11	11	11	11	8	11	127
12. OPER BTU (GBTU)	1,409	1,553	1,950	2,929	3,303	3,225	3,360	3,429	3,631	3,370	1,867	1,562	31,771
13. NET GEN (MWH)	185,470	208,380	259,090	398,990	452,410	441,980	460,760	470,820	501,940	462,170	252,930	206,200	4,301,140
14. ANOHR (Btu/kwh)	7,595	7,455	7,528	7,342	7,301	7,297	7,293	7,282	7,234	7,291	7,383	7,576	7,387
15. NOF (%)	26.4	48.4	36.9	66.1	72.5	73.2	73.9	75.5	83.2	74.1	59.7	29.3	59.1
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968

17. ANOHR EQUATION ANOHR = NOF (-6.365) + 7,763

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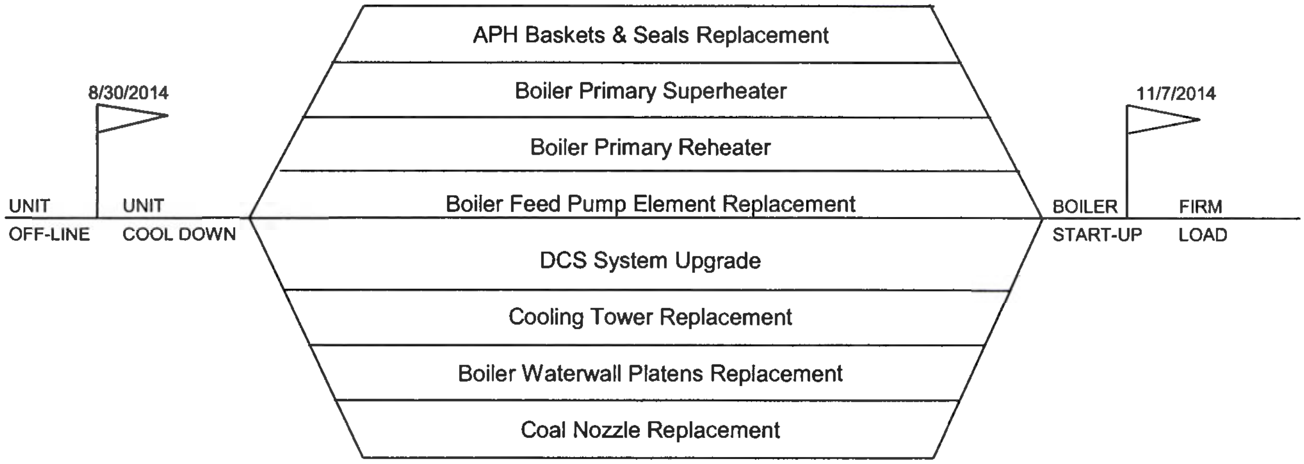
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2014 - DECEMBER 2014

	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
+	BIG BEND 1	Feb 02 - Feb 15	Fuel System Cleanup and FGD/SCR work
		Aug 30 - Nov 07	APH Baskets & Seals Replacement, Boiler Feed Pump Turbine Blade, Coal Nozzle Replacement, Boiler Feed Pump Element Replacement, DCS System Upgrade, Cooling Tower Replacement, High Temp SH Dissimilar Metal Weld, Boiler Primary Reheater Replacement, Boiler Primary Superheater Replacement, Boiler Waterwall Platens Replacement
	BIG BEND 2	Feb 01 - Feb 14	Fuel System Cleanup and FGD/SCR work
		Oct 30 - Nov 08	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Mar 01 - Mar 14	Fuel System Cleanup and FGD/SCR work
		Nov 15 - Nov 24	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 4	Mar 29 - May 23	Air Heater Rotor & Element, Boiler Feed Pump Element, Bunker Liners, Burner Assembly & Coal Nozzles, Coal Feeder Replacement, Cooling Tower Replacement, DCS Upgrades, EH5 & EH6 Replacement, FGD C Booster Fan, FGD Tower Lined Piping, Finishing Reheater Replacement, BFP Turbine Overhaul, HP/IP/LP Turbine work, Precipitator work, Circulating Water Discharge Outfall Structure
		Dec 06 - Dec 15	Fuel System Cleanup and FGD/SCR work
	POLK 1	Mar 02 - Mar 15	Gasifier & Power Block Outage
		Nov 09 - Nov 13	Gasifier Outage
	BAYSIDE 1	Mar 17 - Mar 25	Fuel System Cleanup
		Dec 02 - Dec 10	Fuel System Cleanup
	BAYSIDE 2	Feb 19 - Feb 27	Fuel System Cleanup
		Nov 15 - Nov 23	Fuel System Cleanup

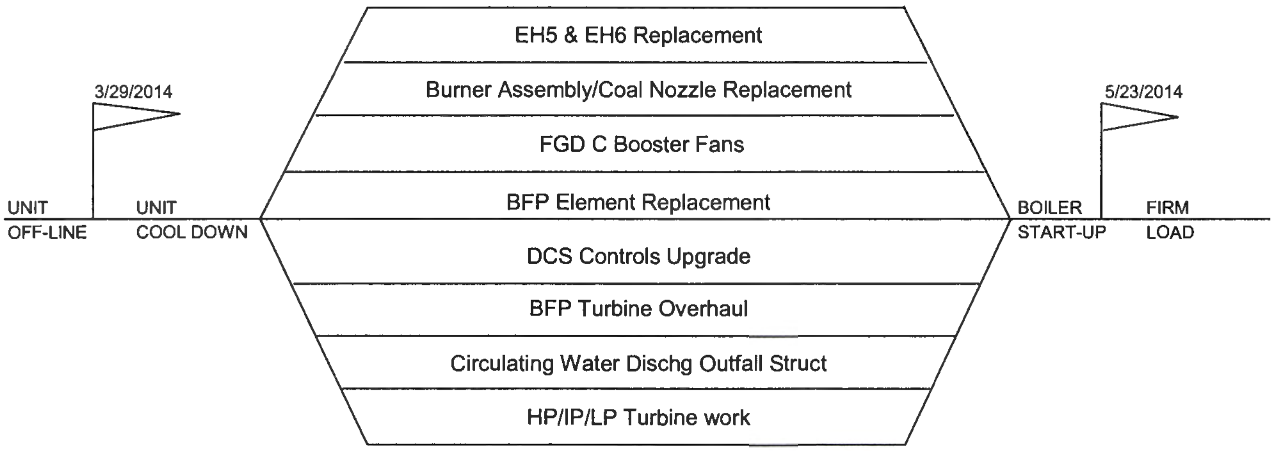
\+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2014 - DECEMBER 2014

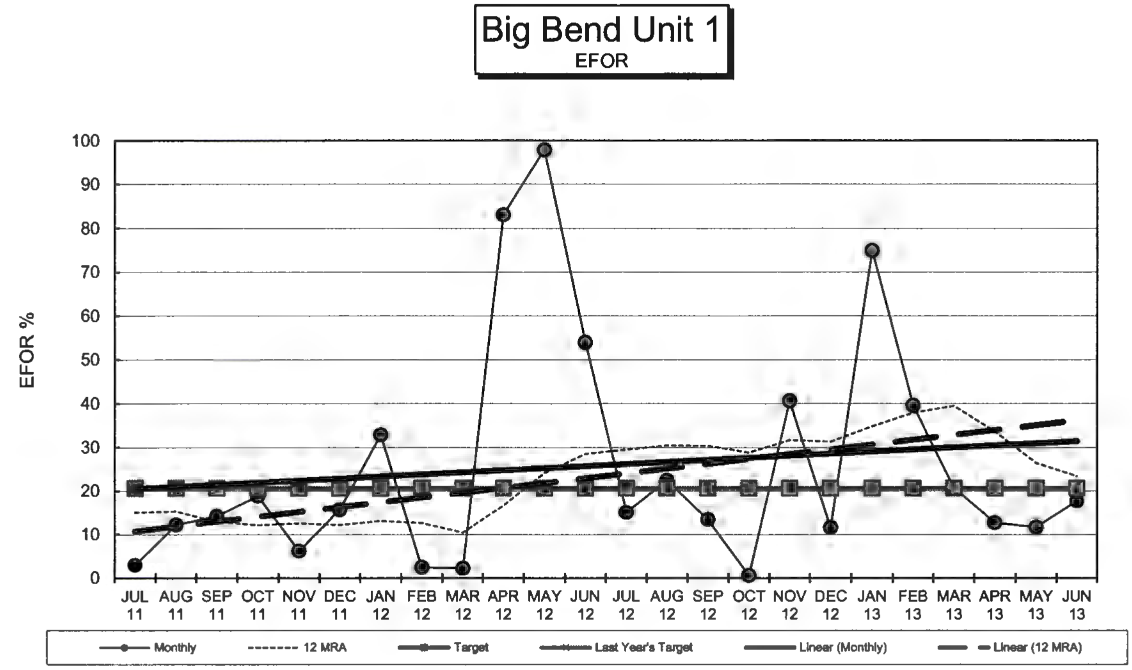


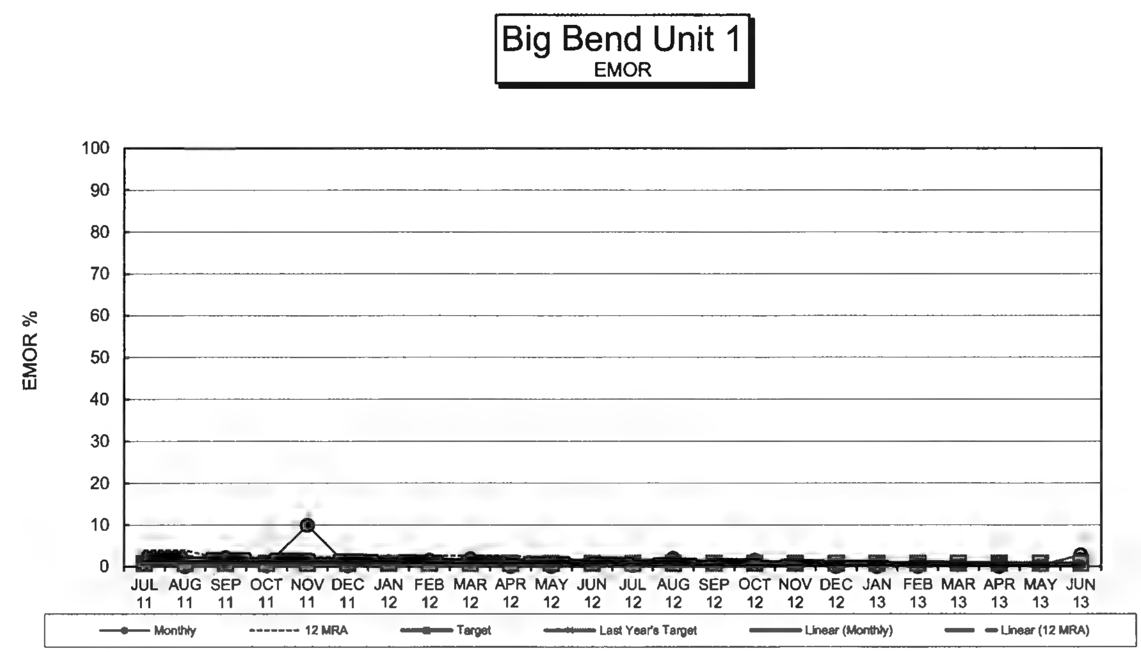
TAMPA ELECTRIC COMPANY
BIG BEND 1
PLANNED OUTAGE 2014
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2014 - DECEMBER 2014



TAMPA ELECTRIC COMPANY
BIG BEND 4
PLANNED OUTAGE 2014
PROJECTED CPM


Big Bend Unit 1
EFOR
100
90
80
70
60
50
40
30
20
10
0
EFOR %
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 1
EMOR
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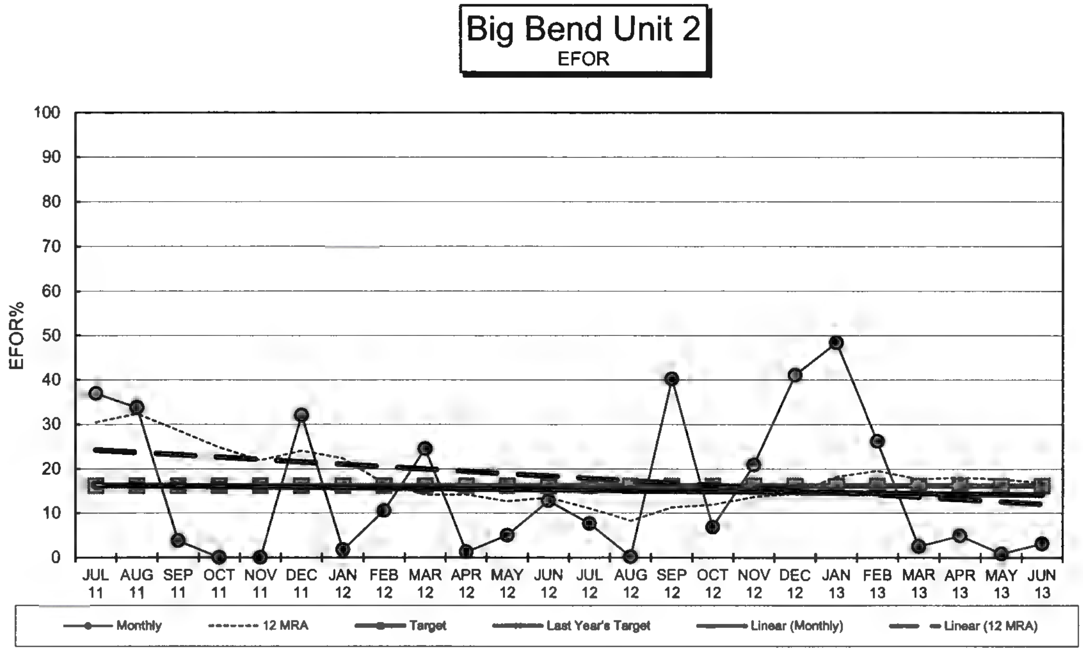
10
0
EMOR %
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EFOR
EFOR%
100
90
80
70
60
50
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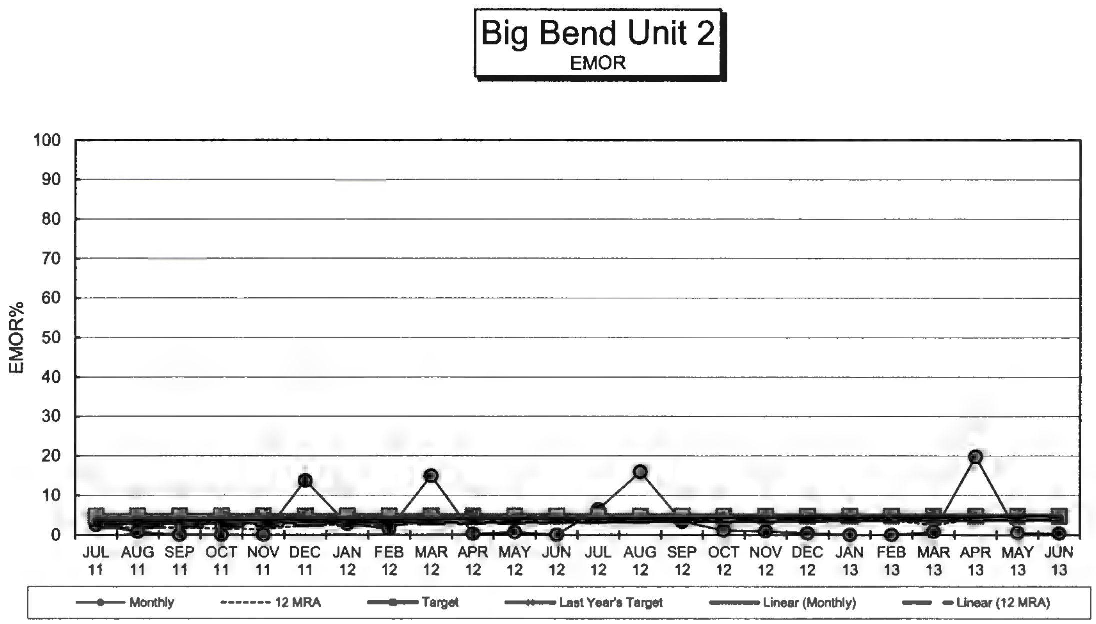
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EMOR
EMOR%
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60
50
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JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
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APR 13
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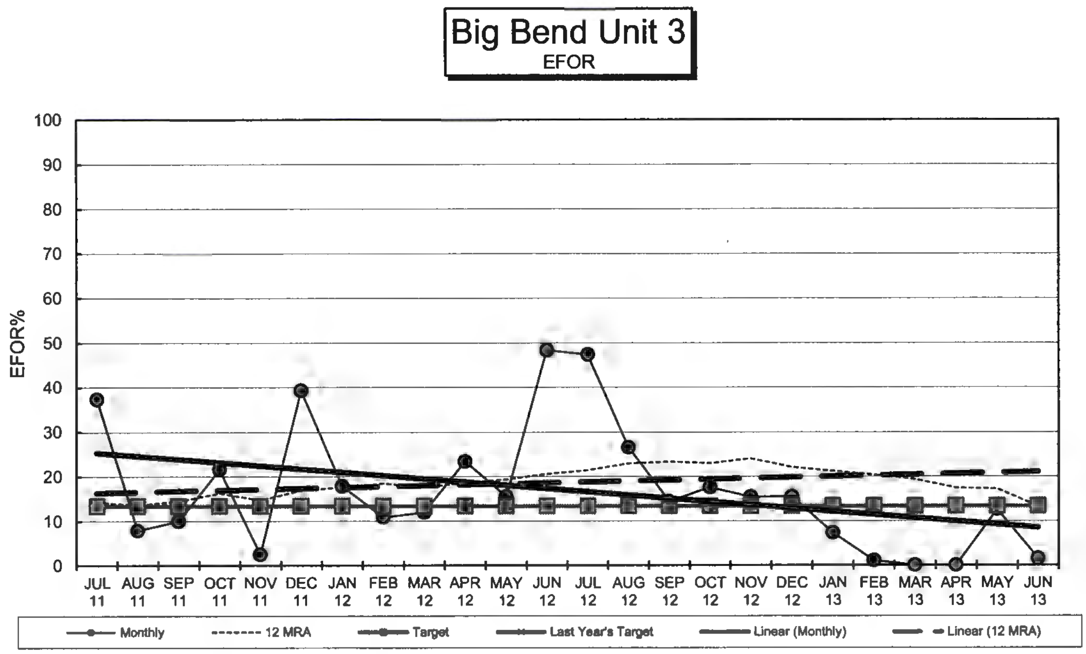
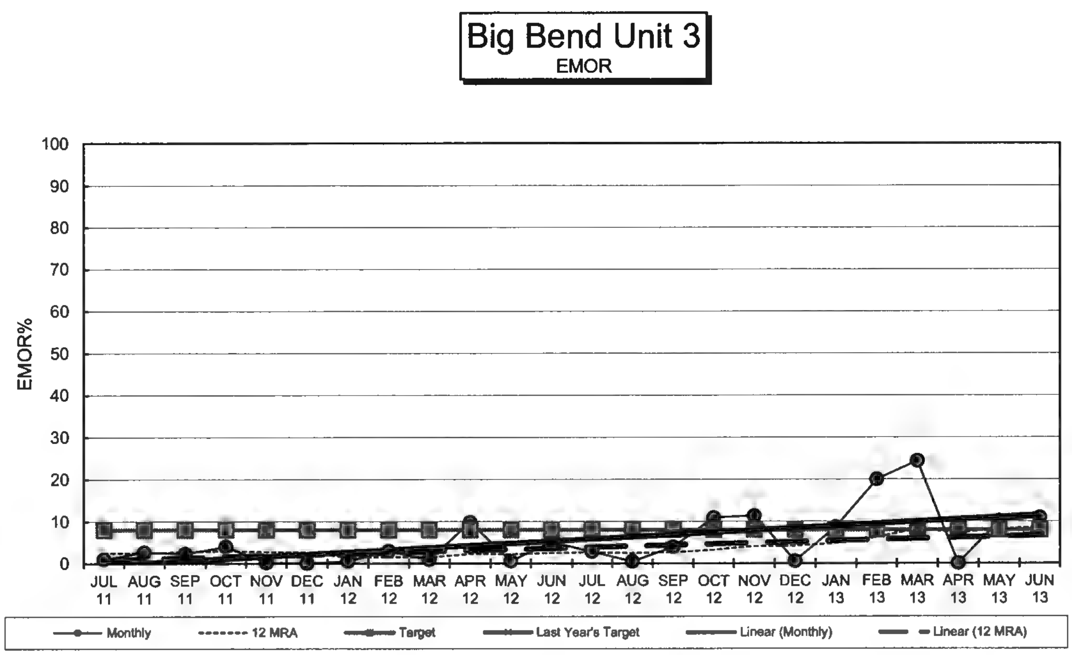
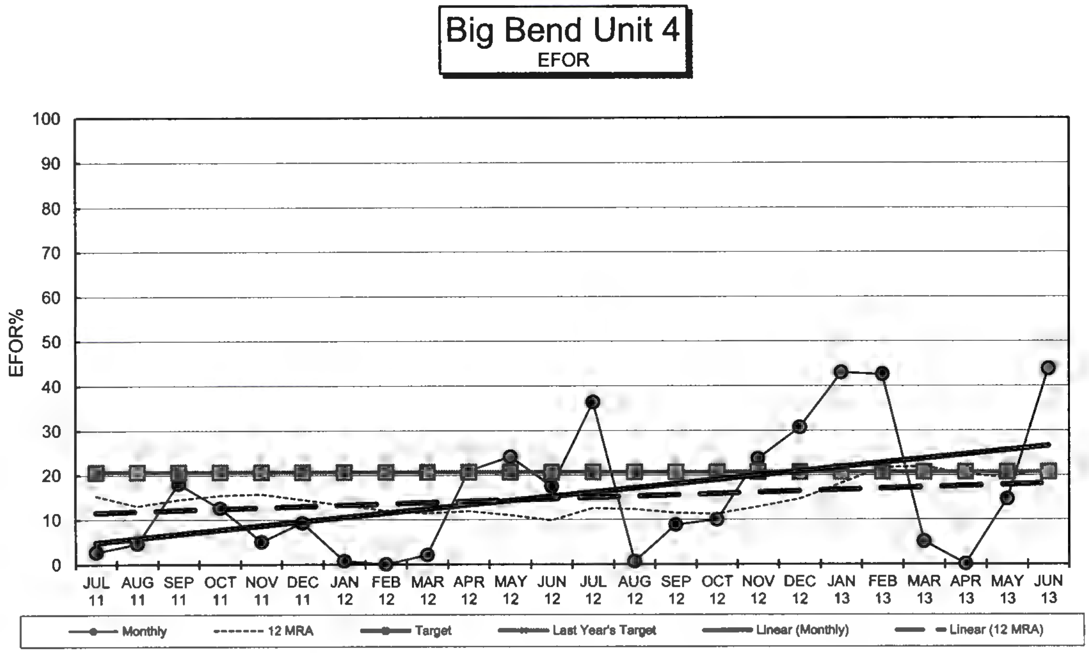
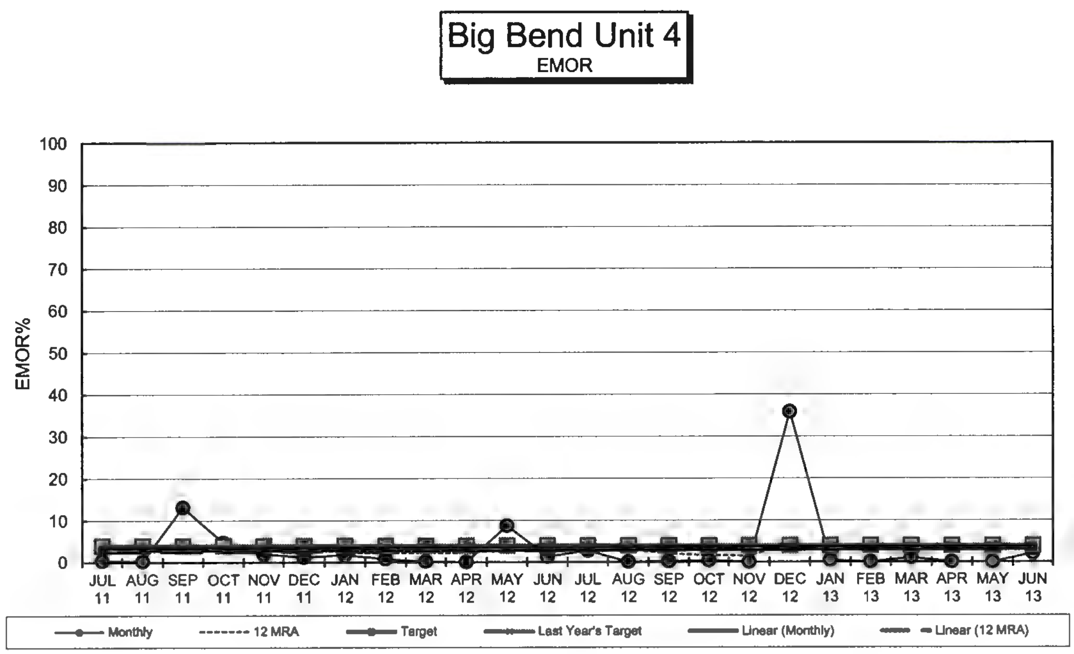
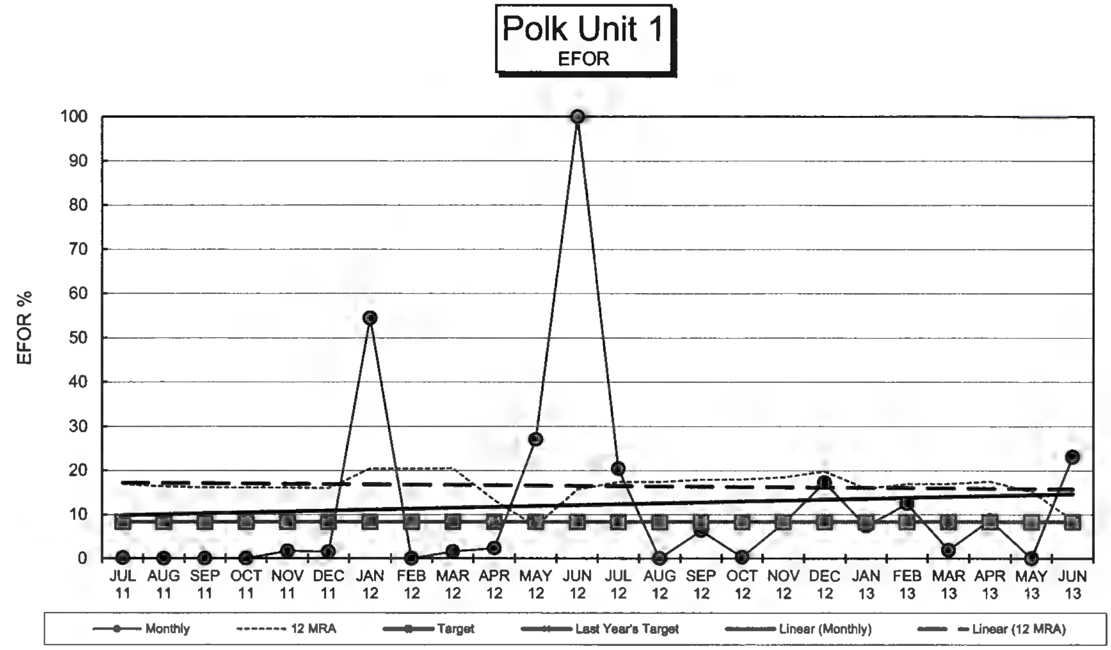
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

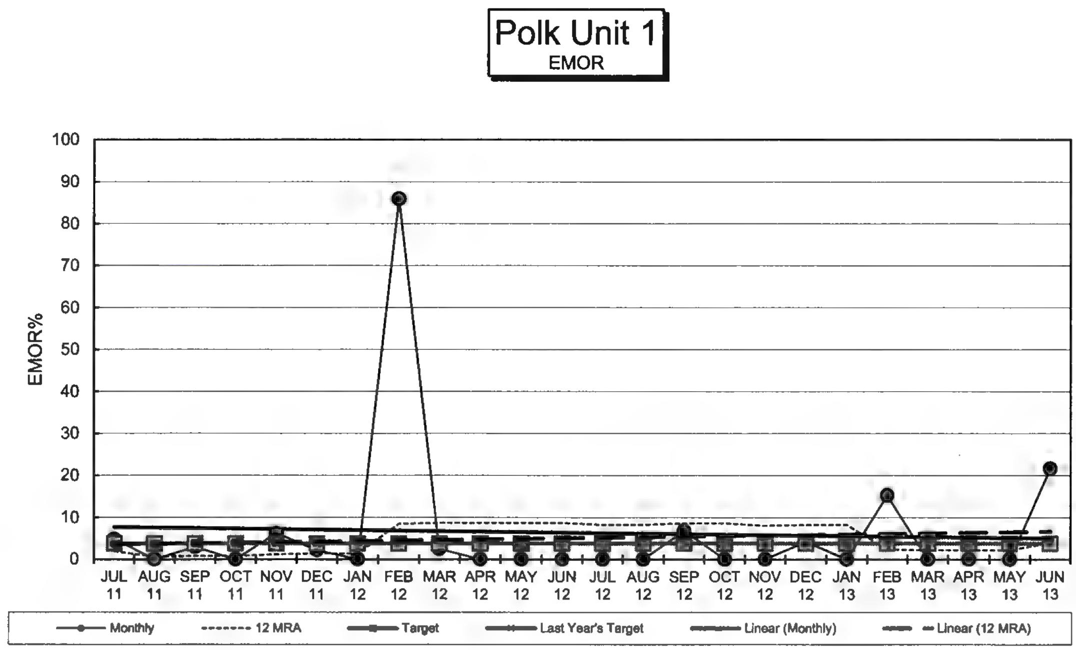

Big Bend Unit 3
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

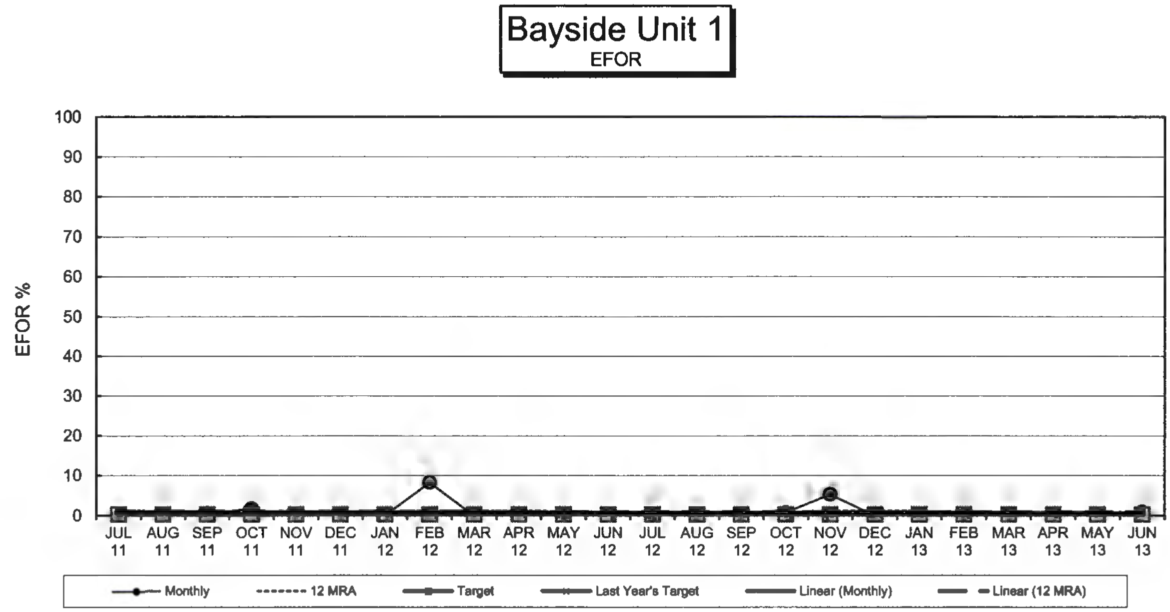

Big Bend Unit 3
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

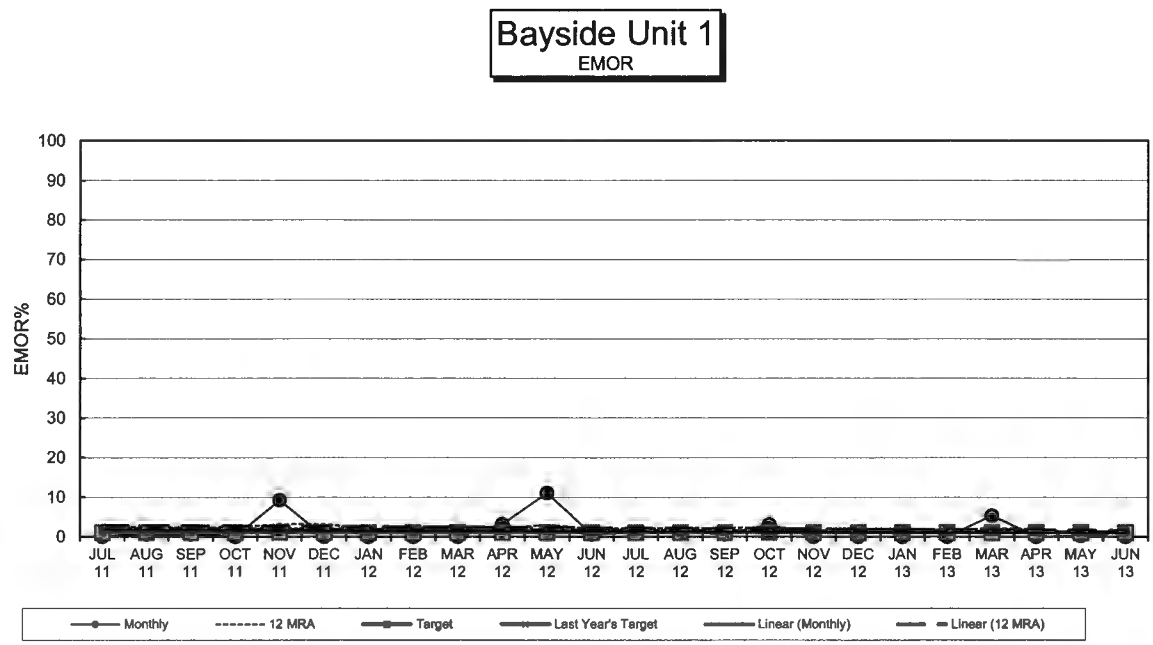

Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

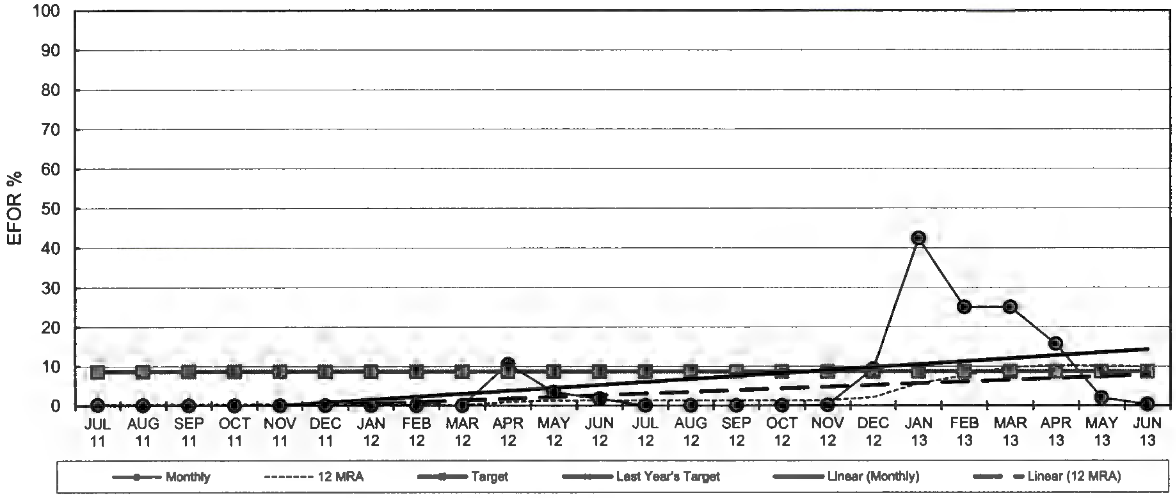

Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

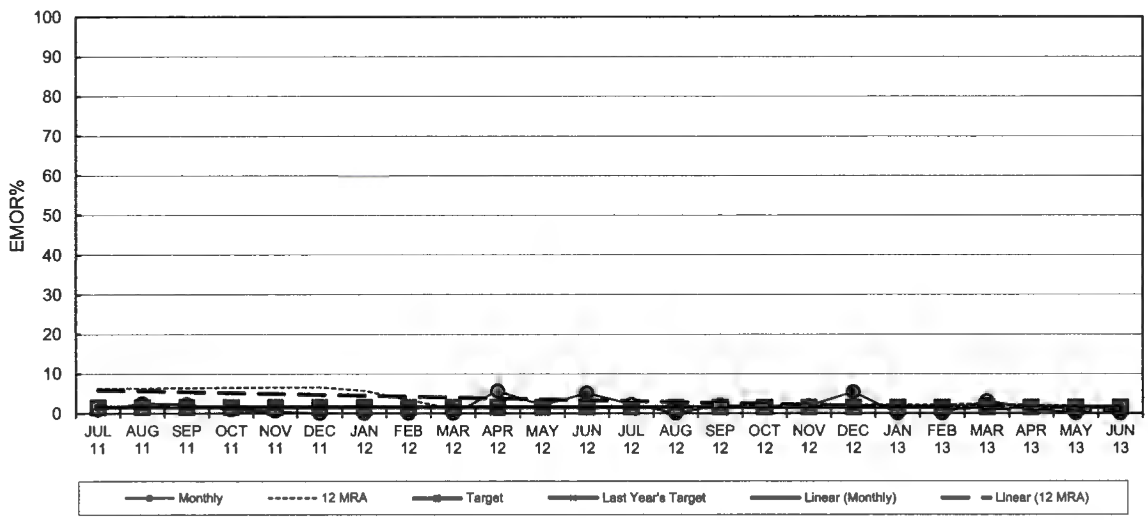

Bayside Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Bayside Unit 2
EFOR



Bayside Unit 2
EMOR



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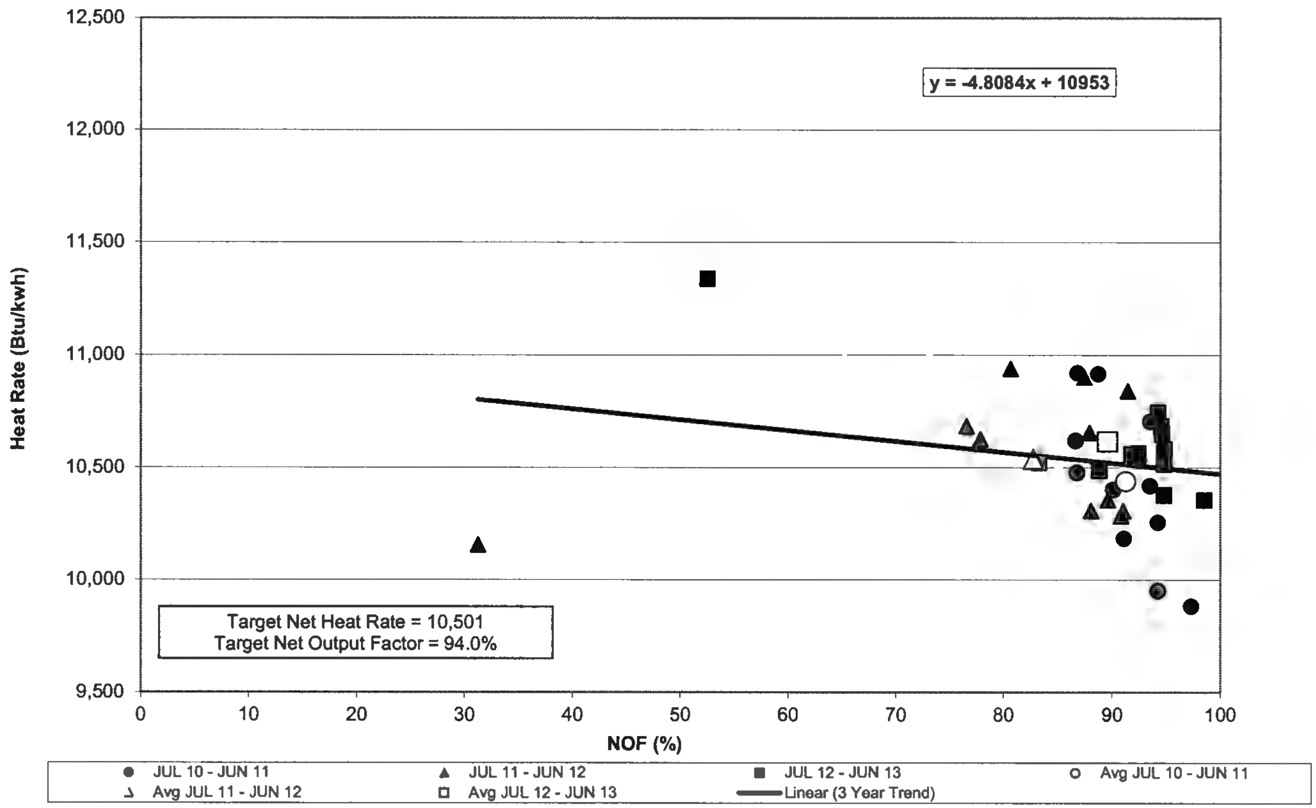
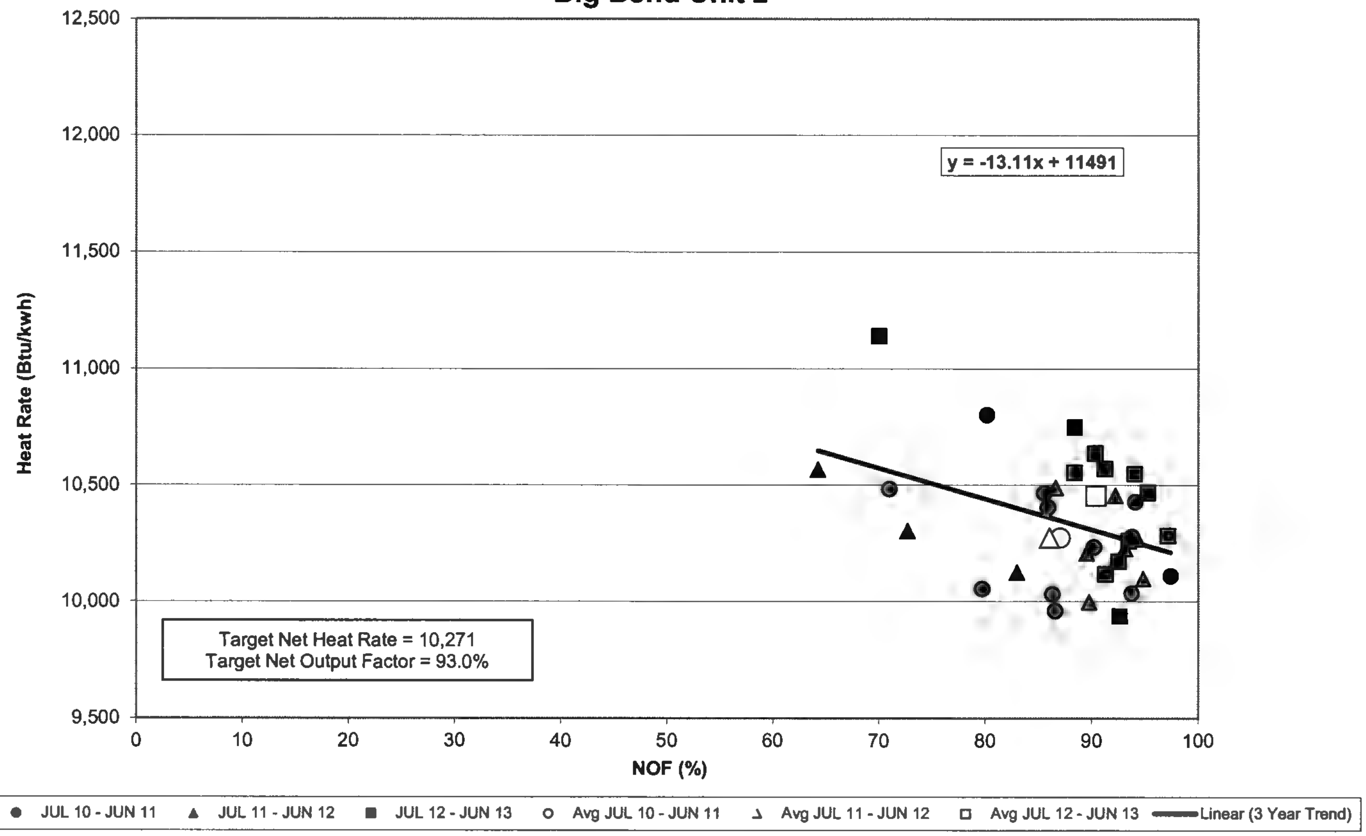
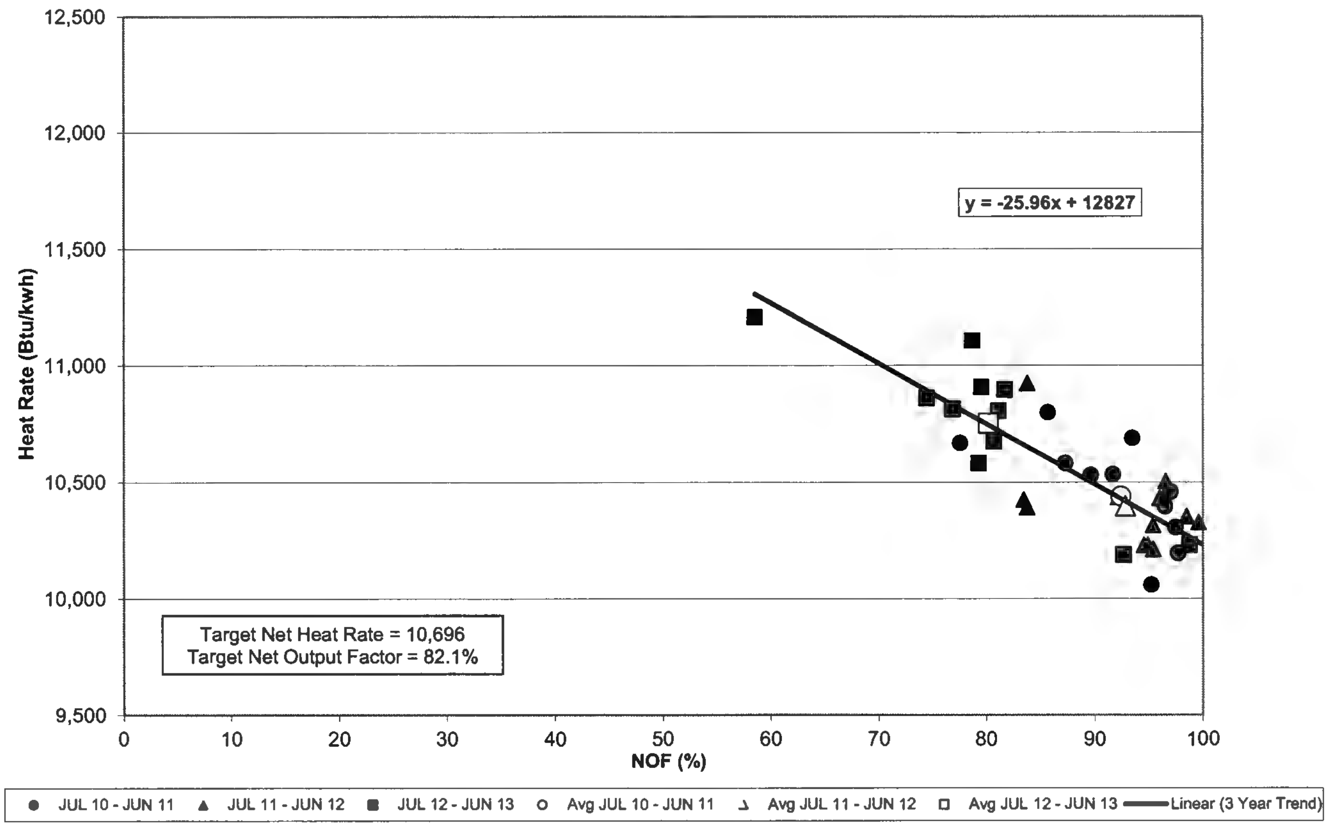
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



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



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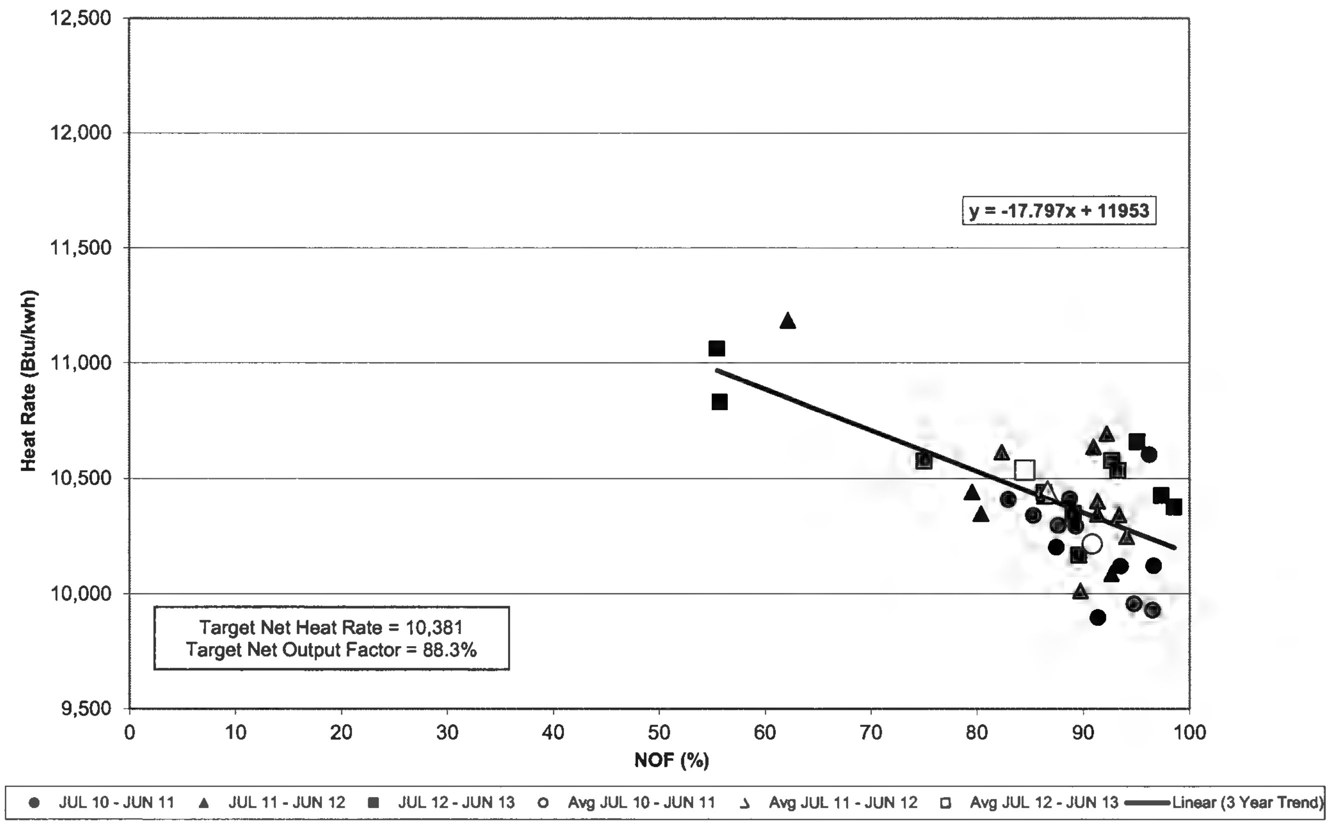
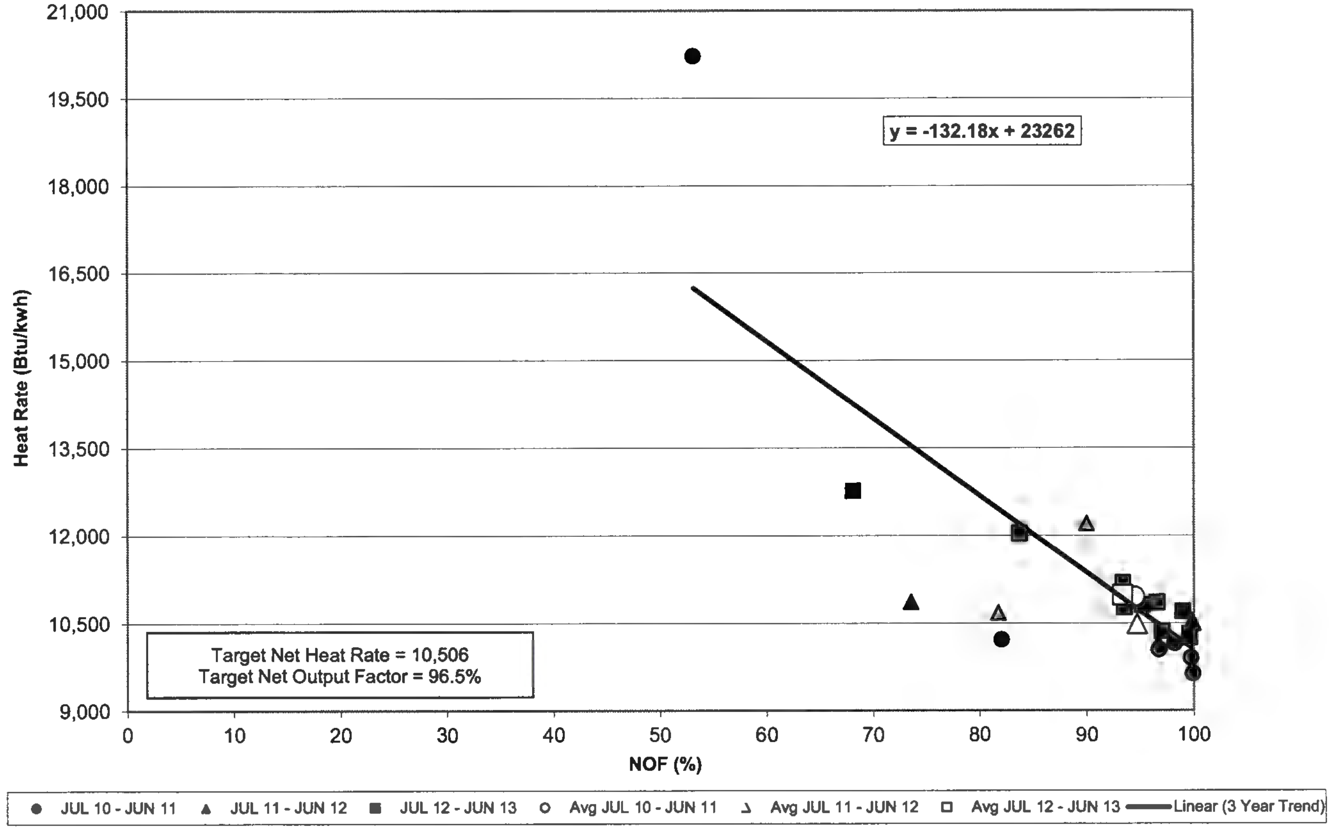
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4

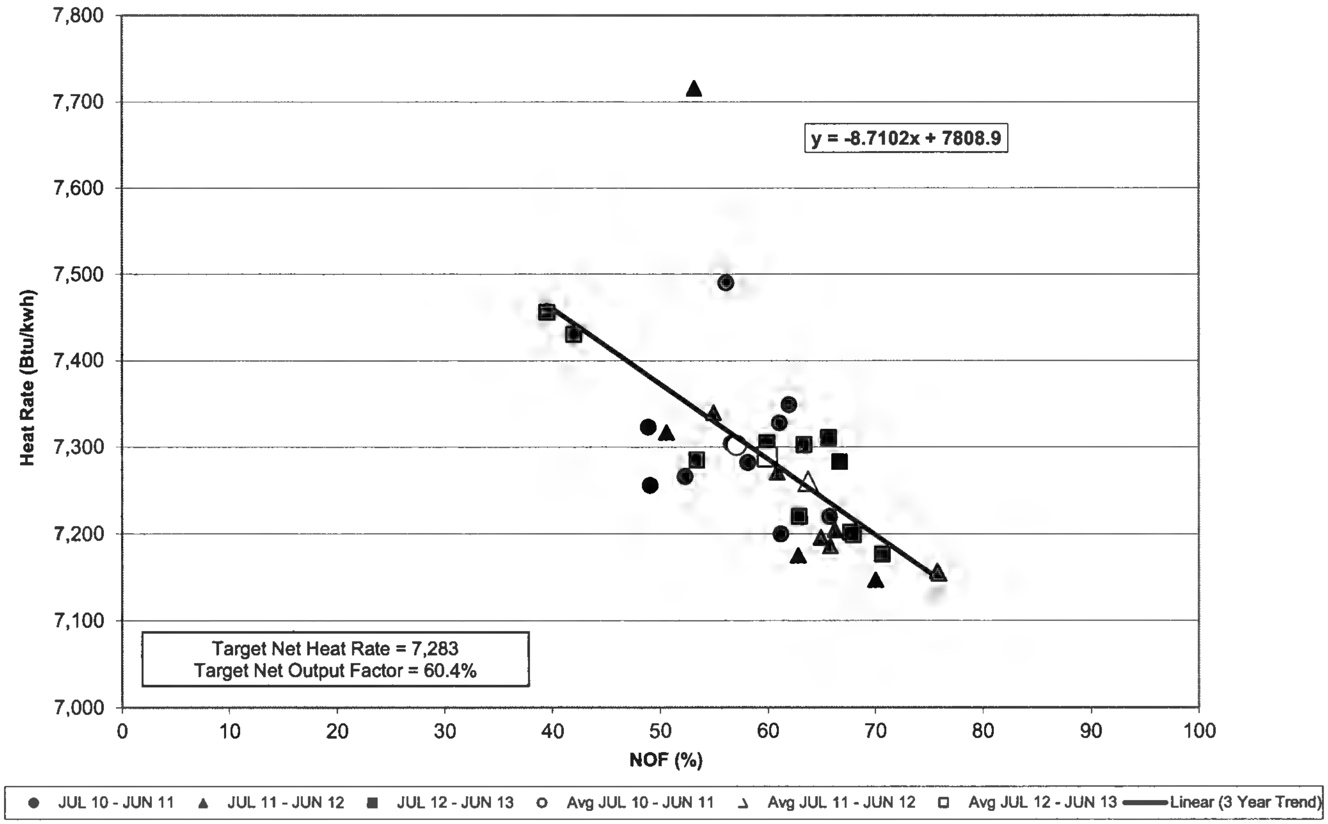


ORIGINAL SHEET NO. 8.401.14E

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



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



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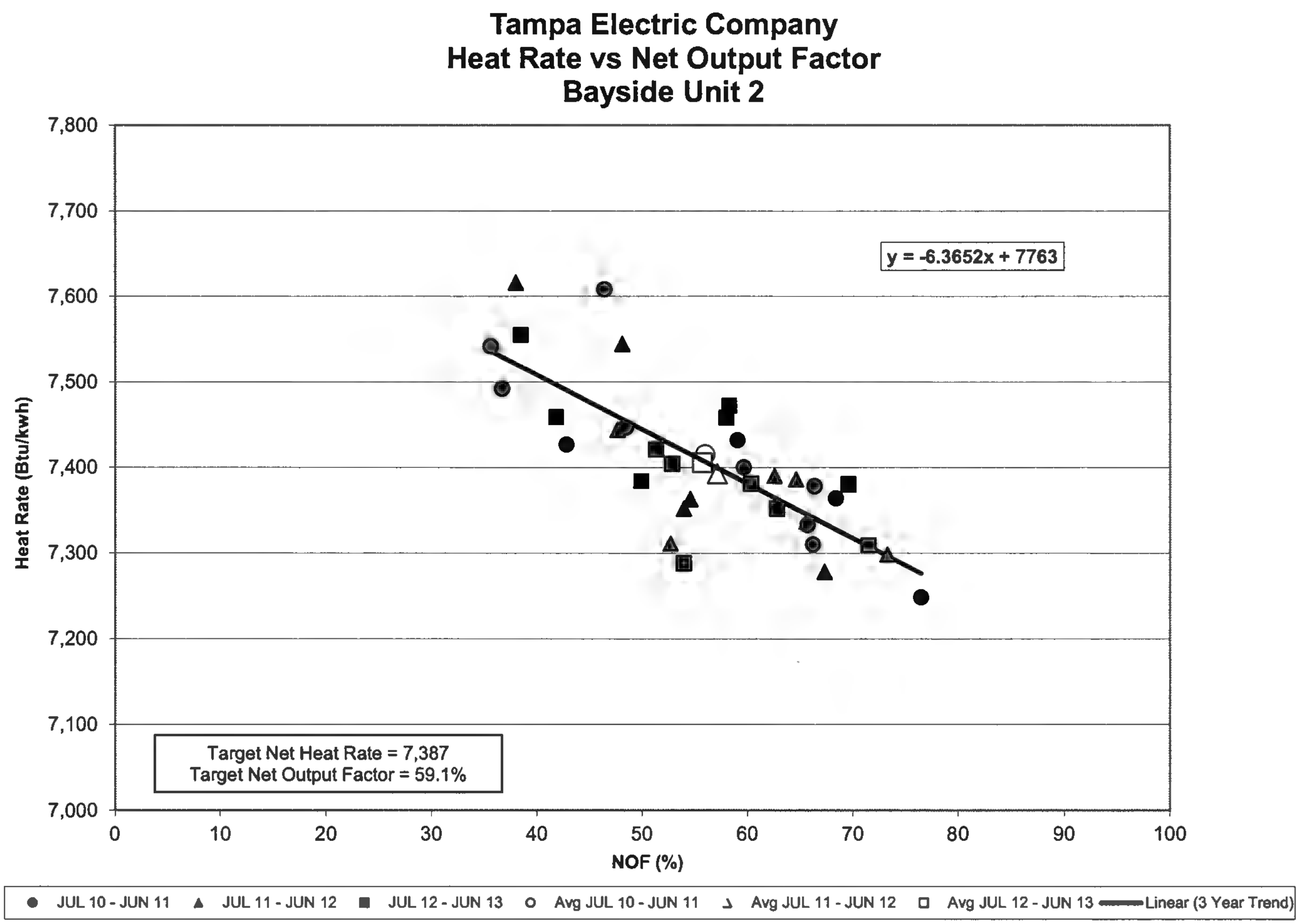

Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -6.3652x + 7763
Target Net Heat Rate = 7,387
Target Net Output Factor = 59.1%
Heat Rate (Btu/kwh)
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
0
10
20
30
40
50
60
70
80
90
100
NOF (%)
JUL 10 - JUN 11
JUL 11 - JUN 12
JUL 12 - JUN 13
Avg JUL 10 - JUN 11
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2014 - DECEMBER 2014

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		443	410
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,670	3,472
	SYSTEM TOTAL	**4,614**	**4,407**
	% OF SYSTEM TOTAL	**79.5%**	**78.8%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2014 - DECEMBER 2014

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		390	365
BIG BEND 4		443	410
	BIG BEND COAL TOTAL	1,660	1,552
BIG BEND CT4		59	58
	BIG BEND CT TOTAL	59	58
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,614**	**4,407**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2014 - DECEMBER 2014

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,301,140	23.07%	23.07%
BAYSIDE	1	3,263,910	17.51%	40.58%
BIG BEND	2	2,484,060	13.33%	53.91%
BIG BEND	3	2,304,460	12.36%	66.27%
BIG BEND	4	2,217,010	11.89%	78.16%
BIG BEND	1	2,014,720	10.81%	88.97%
POLK	1	1,651,170	8.86%	97.83%
POLK	2	136,480	0.73%	98.56%
POLK	3	81,470	0.44%	99.00%
POLK	4	62,790	0.34%	99.34%
POLK	5	37,870	0.20%	99.54%
BIG BEND CT	4	30,170	0.16%	99.70%
BAYSIDE	5	21,850	0.12%	99.82%
BAYSIDE	6	18,330	0.10%	99.92%
BAYSIDE	3	10,750	0.06%	99.97%
BAYSIDE	4	4,920	0.03%	100.00%
TOTAL GENERATION		18,641,100	100.00%	

GENERATION BY COAL UNITS:	10,671,420	MWH	GENERATION BY NATURAL GAS UNITS:	7,969,680 MWH
% GENERATION BY COAL UNIT!	57.25%		% GENERATION BY NATURAL GAS UNITS:	42.75%
GENERATION BY OIL UNITS:	-	MWH	GENERATION BY GPIF UNITS:	18,236,470 MWH
% GENERATION BY OIL UNITS:	0.00%		% GENERATION BY GPIF UNITS:	97.83%

DOCKET NO. 130001-EI
GPIF 2014 PROJECTION FILING
EXHIBIT NO. ____ (BSB-2)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2014 - DECEMBER 2014

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2014 - DECEMBER 2014

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	60.6	23.0	16.4	10,501
Big Bend 2[2]	74.9	6.6	18.6	10,271
Big Bend 3[3]	74.1	6.6	19.4	10,696
Big Bend 4[4]	62.6	18.1	19.3	10,381
Polk 1[5]	84.0	5.2	10.8	10,506
Bayside 1[6]	94.0	4.9	1.1	7,283
Bayside 2[7]	85.8	4.9	9.3	7,387

1 Original Sheet 8.401.14E, Page 14

2 Original Sheet 8.401.14E, Page 15

3 Original Sheet 8.401.14E, Page 16

4 Original Sheet 8.401.14E, Page 17

5 Original Sheet 8.401.14E, Page 18

6 Original Sheet 8.401.14E, Page 19

7 Original Sheet 8.401.14E, Page 20

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2014 THROUGH DECEMBER 2014

TESTIMONY

OF

J. BRENT CALDWELL

FILED: AUGUST 30, 2013

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 of Origination & Market Services.

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long-term fuel origination.

Q. Please state 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. I also sponsor Tampa Electric's 2014 Fuel Procurement and Wholesale Power Purchases Risk Management Plan and Tampa Electric's Natural Gas Hedging Activities submitted on August 2, and August 16, 2013 in this docket.

Q. Have you previously testified before this Commission?

A. Yes. I testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project. I also submitted testimony in Docket Nos. 110001-EI, 120001-EI and 130040-EI.

2014 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2014?

A. In 2014, coal-fired generation is expected to be approximately 62 percent, and natural-gas fired generation is expected to be 38 percent, of total generation. Generation from oil is expected to be less than one percent of the total expected 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. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Similarly, the company maintains multiple delivery paths wherever possible. 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 as the sole 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. Since coal is not a homogenous product, fuel selection is based on these unique 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: long, intermediate, and short. 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 current market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources while still allowing flexibility for the company 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 for 2013.

A. Tampa Electric supplied Big Bend's coal needs through a combination of two "base" coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allowed the supply to adjust for changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2014 delivery?

A. Yes, Tampa Electric has contracted approximately three-fourths of its 2014 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa

Electric anticipates the remaining solid fuel purchases for Big Bend Station and Polk Unit 1 will be procured through spot market purchases during 2013 and 2014.

Coal Transportation

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

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

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

A. 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, 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 2013 and 2014?

A. Yes. Tampa Electric expects to receive approximately two million tons of coal through the Big Bend rail facility during 2014, for use at Big Bend Station.

As part of the CSX transportation agreement, Tampa Electric receives a per ton discount, treated as a reimbursement, for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order. The partial reimbursement expires at the end of 2014 with the expiration of the current agreement.

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 may come through United Bulk Terminal, from other terminals along the Gulf Coast, or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

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 has improved the reliability and cost effectiveness of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives 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 enhances the fuel delivery reliability of the Bayside Power Station, comprised of two large natural gas combine-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 to Polk Station from FGT to support the four natural gas combustion turbines at that station.

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 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 lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"). SESH connects 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 through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric entered any natural gas supply transactions for 2014 delivery?

A. Yes. Approximately two-thirds of the company's expected natural gas requirements for 2014 are under contract. 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. 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 2014 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"), 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.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and 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 2014 projected fuel prices compare to the fuel prices projected for 2013?

A. Fuel prices for coal and natural gas are projected to be slightly higher in 2014 than prices projected for 2013.

The projected higher prices reflect expectations of continuing improvement in domestic and international economies and higher production costs for energy commodities.

Q. What are the market drivers of the expected 2014 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2014 as compared to actual and estimated 2013 costs. An anticipated improvement to the economy and a market adjustment to shale gas production are expected to slightly raise the price in 2014 compared to 2013.

Q. What are the market drivers of the change in the price of coal?

A. The addition of FGD scrubbers on a number of coal plants has made Illinois Basin coal a viable option for those units thus increasing the demand and price for Illinois Basin coal. Additionally, over the past couple of years, coal inventories have declined, and in some areas, production has even been idled. However, with Tampa Electric's existing coal purchase agreements, the impact of coal market price changes is mitigated through 2014.

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

A. Yes. Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 35 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 20 percent. Due to Tampa Electric's generating mix combined with its 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 2, 2013 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2013 and 2014 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2013 natural gas supply needs and a portion of its expected 2014 natural gas supply needs in accordance with its 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 16, 2013.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2013 and 2014 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, 2013 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee.

On April 5, 2013, the company filed its 2012 Natural Gas Risk Management Activities as part of the final true-up process. 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 2013, in this docket on August 16, 2013.

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

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers, but does not guarantee fuel savings.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2014 THROUGH DECEMBER 2014

TESTIMONY

OF

J. BRENT CALDWELL

FILED: AUGUST 30, 2013

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OF

BENJAMIN F. SMITH II

FILED: AUGUST 30, 2013

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 am a registered Professional Engineer within the State of Florida. 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

Energy Products and Structures in the Wholesale Marketing group. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structure, 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 generators.

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 purchased power agreements that 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.

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 2013 wholesale energy 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 seven percent of the expected energy needs for 2013 will be met using purchased power. This purchased power energy includes economy purchases, qualifying facilities, and existing firm purchased power agreements with Pasco Cogen, Calpine, and Southern Power Company. The testimony in previous years describes each existing firm purchased power agreement; however, in summary, all three purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is 121 MW of intermediate capacity and continues through 2018. Both Calpine and Southern Power Company are peaking purchases with capacities of 117 MW and 160 MW, respectively. The Southern Power Company purchase continues through 2015, while the Calpine purchase continues through 2016. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility and were previously approved by the Commission as being cost-effective for Tampa Electric customers.

In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak 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 2013?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2013.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2014 and beyond?

A. In 2014, the Tampa Electric expects purchased power to meet approximately four percent of its energy needs. This energy includes contributions from the previously mentioned firm purchases. In addition, the company will continue to evaluate the short-term purchased power market as part of its purchasing strategy.

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 there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives; however, the company employs a diversified 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 for 2013?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 117 MW purchased from Calpine and 121 MW purchased from Pasco Cogen are reliable, cost-based call options for power. 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 continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short and long-term capacity and energy purchases to augment the company's own generation for the year 2013 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 during major weather-related events. 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 the seller's fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's existing three firm purchased 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. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2013 and 2014.

A. Tampa Electric entered into various non-separated wholesale sales in 2013, and the company anticipates making additional non-separated sales during the balance of 2013 and in 2014. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are 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 2013, Tampa Electric anticipates its gains from non-separated wholesale sales to be $802,676, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $1,366,095. Similarly, in 2014, the company's projected gains from non-separated wholesale sales are $522,912, of which 100 percent would flow back to customers since they are less than the projected three-year rolling average threshold for that year of $650,665.

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. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.