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 31, 2012

HAND DELIVERED

RECEIVED-FPSC
12 AUG 31 PM 2:32
COMMISSION CLERK

Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

REDACTED

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 120001-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 (CA-3) of Carlos Aldazabal.

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,

James D. Beasley

COM 5
AFD 5
APA 1
ECO 1
ENG 1
GCL 1
IDM
TEL
CLK 1-Ctrep

JDB/pp
Enclosures

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

DOCUMENT NUMBER-DATE
05951 AUG 31 ≌
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 120001-EI FILED: August 31, 2012

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, 2012 through December 31, 2012 will be an over-recovery of $69,319,858 (See Exhibit No. ____ (CA-3), Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2013 through December 31, 2013, 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, 2013 through December 31, 2013, produce a fuel and purchased power factor for the new period of 3.719 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. ____ (CA-3), Document No. 2, Schedule E1-E).

3. The company's projected benchmark level for calendar year 2013 for gains on non-separated wholesale energy sales eligible for the shareholder incentive as set forth by Order

No. PSC-00-1744-PAA-EI, in Docket No. 991779 is $1,365,169 as provided in the direct testimony of Tampa Electric witness Carlos Aldazabal.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2012 through December 31, 2012 will be an under-recovery of $6,702,505, as shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 5.

5. The company's projected expenditures for the period January 1, 2013 through December 31, 2013, 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 0.201 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $.73 per billed kW as set forth in Exhibit No. ____ (CA-3), Document No. 1, page 4 of 5.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF penalty of $538,019 for performance experienced during the period January 1, 2011 through December 31, 2011.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2013 through December 31, 2013 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 31st day of August 2012.

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 31st day of August, 2012 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

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

Mr. John T. Burnett
Associate General Counsel
Progress Energy Service Co., LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042

Mr. Paul Lewis, Jr.
Progress Energy Service Co., LLC
106 East College Avenue
Suite 800
Tallahassee, FL 32301-7740

Ms. Vicki Kaufman
Mr. Jon C Moyle
Keefe Anchors Gordon & Moyle, PA
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 618
Tallahassee, FL 32301

Samuel Miller, Capt, USAF
USAF/AFLOA/JAC/ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319

Mr. Tom Geoffroy
Florida Public Utilities Company
P. O. Box 3395
West Palm Beach, FL 33402-3395

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

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

Ms. Susan Ritenour
Secretary and Treasurer
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

ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY AND EXHIBIT

OF

CARLOS ALDAZABAL

FILED: AUGUST 31, 2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. 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 Director, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 17 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager, Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all cost recovery clauses.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2004, and I testified before this Florida Public Service Commission ("FPSC" or "Commission") in Docket Nos. 060001-EI and 080001-EI regarding the appropriateness and prudence of Tampa Electric's recoverable fuel and purchased power costs as well as capacity costs.

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 2013 through December 2013. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2013.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors 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, 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 2013 through December 2013 as well as Schedule H1 for January through December, 2010 through 2013. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 provides the projected monthly Polk 1 Conversion capital costs for the depreciation and return 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. ____ (CA-3), Document No. 1, page 3 of 4. The capacity factors reflect the company's approved rate design from Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009.

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. ____ (CA-3), Document No. 1, Tampa Electric requests recovery of $36,457,223 after jurisdictional separation and prior year true-up, for estimated expenses in 2013.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2013 through December 2013.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.232	
GS and TS Secondary	0.214	
GSD, SBF Standard		
Secondary		0.73
Primary		0.72
Transmission		0.72
IS, IST, SBI		
Primary		0.60
Transmission		0.60
GSD Optional		
Secondary	0.173	
Primary	0.171	
LS1 Secondary	0.060	

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.201 cents per kWh compare to the factor for January 2012 through December 2012?

A. The proposed capacity cost recovery factor is 0.036 cents per kWh (or $0.36 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.237 cents per kWh for the January 2012 through December 2012 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 2013?

A. The appropriate amount for the 2013 period is 3.719 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2013 through December 2013.

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 $538,019, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2012 through December 2012 period. The net true-up amount for this period is an over-recovery of $69,319,858.

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 2013 through December 2013. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

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

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

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

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

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2013 through December 2013.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**	
Secondary	3.719	
Tier I (Up to 1,000 kWh)	3.369	
Tier II (Over 1,000 kWh)	4.369	
Distribution Primary	3.682	
Transmission	3.645	
Lighting Service	3.697	
Distribution Secondary	3.861	(on-peak)
	3.664	(off-peak)
Distribution Primary	3.822	(on-peak)
	3.627	(off-peak)
Transmission	3.784	(on-peak)
	3.591	(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.719 cents per kWh compare to the levelized fuel adjustment factor for the January 2012 through December 2012 period?

A. The proposed fuel charge factor is 0.471 cents per kWh (or $4.71 per 1,000 kWh) lower than the average fuel charge factor of 4.190 cents per kWh for the January 2012 through December 2012 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2013 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events reflected in the 2013 projections: continued downward pressure on natural gas prices due to shale gas production after several years of steady price declines; and, the inclusion of Polk 1 capital conversion costs more than offset by the anticipated fuel savings of that project.

Q. Please describe the results of this natural gas pricing event.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Stations, Tampa Electric increased its reliance on natural gas as a fuel source. The 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 over the period. More recently fuel commodity prices have started to stabilize with an expectation of an economic recovery; however, the increase in shale gas production has kept natural gas storage supply levels high preventing any price increases. 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 2012 and 2013. The foundation for the company's natural gas forecast is based on the average of the New York Mercantile Exchange ("NYMEX") natural gas futures contract closing price published during five consecutive business days of between July 19 and July 25, 2012. Tampa Electric witness J. Brent Caldwell's direct testimony describes existing and forecasted natural gas costs and associated hedge results in more detail.

Q. Please describe the Polk 1 conversion project.

A. Under the Polk 1 conversion project the company is requesting to recover through the fuel adjustment clause the capital costs associated with the conversion of certain equipment at the company's integrated gasification combined cycle Polk Unit 1, because that conversion will enable Tampa electric to significantly reduce the input costs of fossil fuel used to operate Polk 1. Docket No. 120153 was established to allow Staff and interested parties to file discovery and review the anticipated project costs as well as the associated fuel savings of the project. Included in Exhibit No. ____ (CA-3), Document No. 4, are the anticipated depreciation costs and return on the project as well as the anticipated fuel savings. As reflected on line 33 of that document the project is projected to provide $595,258 in net fuel savings in 2013. A Commission agenda on the company's proposed petition is currently scheduled for September 18, 2012.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2013?

A. The company's projected 2013 benchmark is $1,365,169, which is the three-year average of $2,948,964, $902,388 and $244,154 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2010, 2011 and 2012 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2013 from non-separated wholesale sales to exceed its 2013 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2013. Therefore, all sales margins will flow back to customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $4.32 beginning January 2013. These charges are shown in Exhibit No. _____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2013.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2013 - DECEMBER 2013

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2013 THROUGH DECEMBER 2013
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	51.79%	8,476,092	1,868	1.08103	1.05698	8,959,031	2,020	46.71%	56.23%	53.85%
GS, TS	57.57%	1,014,602	201	1.08103	1.05696	1,072,394	218	5.59%	6.07%	5.95%
GSD Optional	3.63%	365,393	55	1.07653	1.05315	384,815	59	2.01%	1.64%	1.73%
GSD, SBF	72.09%	7,266,669	1,096	1.07653	1.05315	7,652,910	1,179	39.91%	32.81%	34.59%
IS,SBI	89.14%	861,507	110	1.03199	1.01859	877,522	114	4.58%	3.17%	3.52%
LS1	935.37%	217,753	3	1.08103	1.05698	230,160	3	1.20%	0.08%	0.36%
TOTAL		18,202,016	3,333			19,176,832	3,593	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2012 projected calendar data.
(2) Projected MWH sales for the period January 2013 thru December 2013.
(3) Based on 12 months average CP at meter.
(4) Based on 2012 projected demand losses.
(5) Based on 2012 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 2013 THROUGH DECEMBER 2013
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,423,510	1,423,510	1,423,510	1,423,510	1,583,510	1,583,510	1,583,510	1,583,510	1,583,510	1,583,510	1,423,510	1,423,510	18,042,120
2	CAPACITY PAYMENTS TO COGENERATORS	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
3	(UNIT POWER CAPACITY REVENUES)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(141,406)	(1,696,872)
4	TOTAL CAPACITY DOLLARS	$2,397,374	$2,397,374	$2,397,374	$2,397,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,397,374	$2,397,374	$29,728,488
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	$2,397,374	$2,397,374	$2,397,374	$2,397,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,557,374	$2,397,374	$2,397,374	$29,728,488
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2012 - DEC. 2012													6,702,505
8	TOTAL													$36,430,993
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$36,457,223

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2013 THROUGH DECEMBER 2013
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	46.71%	56.23%	4,257,291	15,374,923	19,632,214	8,476,092	8,476,092				0.00232
GS, TS	5.59%	6.07%	509,490	1,659,715	2,169,205	1,014,602	1,014,602				0.00214
GSD, SBF											
Secondary						6,036,860	6,036,860			0.73	
Primary						1,223,267	1,211,034			0.72	
Transmission						6,542	6,411			0.72	
GSD, SBF - Standard	39.91%	32.81%	3,637,520	8,971,211	12,608,731	7,266,669	7,254,305	57.61%	17,248,645		
GSD - Optional	2.01%	1.64%	183,198	448,424	631,622						
Secondary						353,947	353,947				0.00173
Primary						11,446	11,332				0.00171
IS, SBI											
Primary						232,660	230,333			0.60	
Transmission						628,847	616,270			0.60	
Total IS, SBI	4.58%	3.17%	417,435	866,770	1,284,205	861,507	846,603	54.82%	2,115,453		
LS1	1.20%	0.08%	109,372	21,874	131,246	217,753	217,753				0.00060
TOTAL	100.00%	100.00%	9,114,306	27,342,917	36,457,223	18,202,016	18,174,634				0.00201

(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 2013 through December 2013.
(7) Projected kWh sales at secondary for the period January 2013 through December 2013.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2013 through December 2013.
(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 2013 THROUGH DECEMBER 2013

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
ORANGE COGEN LP	4/17/1989	12/31/2015	QF
CALPINE	11/1/2011	12/31/2016	LT
PASCO COGEN	1/1/2009	12/31/2018	LT
OLEANDER	1/1/2013	12/31/2015	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT TERM

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	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
TOTAL COGENERATION	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
CALPINE - D	[redacted]												
PASCO COGEN - D													
OLEANDER - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,282,104	1,282,104	1,282,104	1,282,104	1,442,104	1,442,104	1,442,104	1,442,104	1,442,104	1,442,104	1,282,104	1,282,104	16,345,248
TOTAL CAPACITY	**$2,397,374**	**$2,397,374**	**$2,397,374**	**$2,397,374**	**$2,557,374**	**$2,557,374**	**$2,557,374**	**$2,557,374**	**$2,557,374**	**$2,557,374**	**$2,397,374**	**$2,397,374**	**$29,728,488**

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2013 - DECEMBER 2013

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 2013 THROUGH DECEMBER 2013

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	719,428,456	18,584,460	3.87113
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustments to Fuel Cost - Polk 1 Capital Costs	2,571,400	18,584,460 [1]	0.01384
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)**	**721,999,856**	**18,584,460**	**3.88497**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	4,606,910	81,890	5.62573
7.	Energy Cost of Economy Purchases (E9)	15,763,980	450,000	3.50311
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	8,298,210	193,540	4.28759
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**28,669,100**	**725,430**	**3.95201**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,309,890	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	0	0	0.00000
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	4,849,517	150,000	3.23301
14.	Gains on Sales	485,483	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**5,335,000**	**150,000**	**3.55667**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		2,408	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**745,333,956**	**19,157,482**	**3.89056**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,283,885 [1]	33,000	0.00705
22.	T & D Losses	35,889,091 [1]	922,466	0.19717
23.	System MWH Sales	745,333,956	18,202,016	4.09479
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	745,333,956	18,202,016	4.09479
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	745,333,956	18,202,016	4.09479
28.	True-up [2]	(69,319,858)	18,202,016	(0.38084)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	676,014,098	18,202,016	3.71395
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	676,500,828	18,202,016	3.71662
32.	GPIF Adjusted for Taxes [2]	(538,019)	18,202,016	(0.00296)
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	675,962,809	18,202,016	3.71366
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.714**

[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 2013 THROUGH DECEMBER 2013

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2012 - December 2012 (6 months actual, 6 months estimated)	$57,434,679
2.	FINAL TRUE-UP (January 2011 - December 2011) (Per True-Up filed March 1, 2012)	11,885,179
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2013 through December 2013 (Schedule E1, line 28)	$69,319,858
4.	JURISDICTIONAL MWH SALES (Projected January 2013 through December 2013)	18,202,016
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.3808)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2013 through December 2013)	($538,019)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2012 through December 2012)	$69,319,858	
2.	TOTAL SALES (January 2013 through December 2013)	18,202,016	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0030)**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.3808)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	27.91	$33.40
OFF PEAK	72.09	$31.70
	100.00	1.0536

			TOTAL		ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$745,333,956			
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,202,016			
2a	Effective MWH Sales (Jurisd)		18,174,634			
3	Cost Per KWH Sold	(line 1 / line 2)	4.0948			
4	Jurisdictional Loss Factor		1.00000			
5	Jurisdictional Fuel Factor		na			
6	True-Up	(Sch E1 line 28)	($69,319,858)			
7	TOTAL	(line 1 x line 4)+line 6	$676,014,098			
8	Revenue Tax Factor		1.00072			
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.7222			
10	GPIF Factor	(Sch E1-C line 3a)	-0.0030			
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.7192		3.8609	3.6644
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.719		3.861	3.664
13	Hours: ON PEAK			24.94%		
14	OFF PEAK			75.06%		
				100.00%		

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,099,254	16,099,254
Distribution Primary	1,467,373	1,452,699
Transmission	635,389	622,681
Total	18,202,016	18,174,634

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

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)		3.369	4.369
Distribution Secondary	3.719		
Distribution Primary	3.682		
Transmission	3.645		
Lighting Service (1)	3.697		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.861		
Distribution Secondary - Off-Peak	3.664		
Distribution Primary - On-Peak	3.822		
Distribution Primary - Off-Peak	3.627		
Transmission - On-Peak	3.784		
Transmission - Off-Peak	3.591		

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

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

		(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(g)	(h)	(i)	(j)	(k)	(l)	(m) TOTAL
		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	PERIOD
1.	Fuel Cost of System Net Generation	55,223,437	47,431,797	50,894,188	53,761,819	63,351,131	68,765,639	72,067,913	72,565,674	68,703,869	62,474,084	50,776,276	53,412,629	719,428,456
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold (1)	558,620	526,330	603,270	602,170	371,400	415,870	390,180	366,560	330,290	369,420	314,700	486,190	5,335,000
4.	Fuel Cost of Purchased Power	0	73,790	133,150	234,920	393,330	780,060	882,050	949,240	931,280	110,070	80,310	38,710	4,606,910
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	685,660	598,090	696,210	670,380	687,170	738,850	729,760	695,500	713,380	707,020	728,230	647,960	8,298,210
7.	Energy Cost of Economy Purchases	1,682,030	1,594,860	1,808,600	1,756,110	1,118,950	1,189,440	1,156,540	1,075,060	961,530	1,044,930	930,160	1,445,770	15,763,980
8a.	Adj. to Fuel Cost - Polk 1 Capital Costs	0	0	0	0	0	373,847	371,679	369,511	367,343	365,176	363,006	360,838	2,571,400
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**57,032,507**	**49,172,207**	**52,928,878**	**55,821,059**	**65,179,181**	**71,431,966**	**74,817,762**	**75,288,425**	**71,347,112**	**64,331,860**	**52,563,282**	**55,419,717**	**745,333,956**
10.	Jurisdictional MWH Sold	1,456,673	1,310,855	1,274,561	1,315,312	1,453,517	1,706,831	1,778,193	1,762,831	1,614,046	1,600,107	1,374,567	1,354,523	18,202,016
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)	57,032,507	49,172,207	52,928,878	55,821,059	65,179,181	71,431,966	74,817,762	75,288,425	71,347,112	64,331,860	52,563,282	55,419,717	745,333,956
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)	**57,032,507**	**49,172,207**	**52,928,878**	**55,821,059**	**65,179,181**	**71,431,966**	**74,817,762**	**75,288,425**	**71,347,112**	**64,331,860**	**52,563,282**	**55,419,717**	**745,333,956**
15.	Cost Per kWh Sold (Cents/kWh)	3.9153	3.7512	4.1527	4.2439	4.4842	4.1851	4.2075	4.2709	3.9330	4.0205	3.8240	4.0915	4.0948
16.	True-up (Cents/kWh) (2)	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808	-0.3808
17.	Total (Cents/kWh) (Line 15+16)	3.5345	3.3704	3.7719	3.8631	4.1034	3.8043	3.8267	3.8901	3.5522	3.6397	3.4432	3.7107	3.7140
18.	Revanue 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)	3.5370	3.3728	3.7746	3.8659	4.1064	3.8070	3.8295	3.8929	3.5548	3.6423	3.4457	3.7134	3.7167
20.	GPIF Adjusted for Taxes (Cents/kWh) (2)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)	(0.0030)
21.	**TOTAL RECOVERY FACTOR (LINE 19+20)**	**3.5340**	**3.3698**	**3.7716**	**3.8629**	**4.1034**	**3.8040**	**3.8265**	**3.8899**	**3.5518**	**3.6393**	**3.4427**	**3.7104**	**3.7137**
22.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.534**	**3.370**	**3.772**	**3.863**	**4.103**	**3.804**	**3.827**	**3.890**	**3.552**	**3.639**	**3.443**	**3.710**	**3.714**

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

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E3

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	590,190	548,724	614,237	394,659	217,930	45,691
3. COAL	36,983,600	27,012,707	28,386,470	25,245,030	31,832,806	37,219,554
4. NATURAL GAS	17,649,647	19,870,366	21,893,481	28,122,130	31,300,395	31,500,394
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	55,223,437	47,431,797	50,894,188	53,761,819	63,351,131	68,765,639
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	2,580	2,400	2,680	1,710	940	200
10. COAL	1,050,160	742,340	795,700	705,120	906,370	1,045,590
11. NATURAL GAS	381,330	494,850	546,340	660,550	722,530	737,480
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,434,070	1,239,590	1,344,720	1,367,380	1,629,840	1,783,270
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	7,340	9,740	7,470	5,770	5,300	3,090
17. COAL (TON)	451,140	318,540	337,860	303,070	392,210	447,420
18. NATURAL GAS (MCF)	2,798,670	3,537,380	3,936,940	4,861,500	5,372,200	5,493,510
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	26,680	24,620	27,400	17,540	9,670	2,010
23. COAL	10,813,720	7,640,950	8,174,320	7,291,270	9,328,440	10,726,690
24. NATURAL GAS	2,877,040	3,636,480	4,047,210	4,997,670	5,522,640	5,647,370
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	13,717,440	11,302,050	12,248,930	12,306,480	14,860,750	16,376,070
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.18	0.19	0.20	0.13	0.06	0.01
30. COAL	73.23	59.89	59.17	51.56	55.61	58.63
31. NATURAL GAS	26.59	39.92	40.63	48.31	44.33	41.36
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)	80.41	56.34	82.23	68.40	41.12	14.79
37. COAL ($/TON)	81.98	84.80	84.02	83.30	81.16	83.19
38. NATURAL GAS ($/MCF)	6.31	5.62	5.56	5.78	5.83	5.73
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	22.12	22.29	22.42	22.50	22.54	22.73
43. COAL	3.42	3.54	3.47	3.46	3.41	3.47
44. NATURAL GAS	6.13	5.46	5.41	5.63	5.67	5.58
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)	4.03	4.20	4.15	4.37	4.26	4.20
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,341	10,258	10,224	10,257	10,287	10,050
50. COAL	10,297	10,293	10,273	10,340	10,292	10,259
51. NATURAL GAS	7,545	7,349	7,408	7,566	7,643	7,658
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	9,565	9,118	9,109	9,000	9,118	9,183
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	22.88	22.86	22.92	23.08	23.18	22.85
57. COAL	3.52	3.64	3.57	3.58	3.51	3.56
58. NATURAL GAS	4.63	4.02	4.01	4.26	4.33	4.27
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	3.85	3.83	3.78	3.93	3.89	3.86

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

SCHEDULE E3

		Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	15,667	16,975	32,654	0	0	0	2,476,727
3.	COAL	38,742,804	39,093,226	36,783,376	35,382,187	32,064,878	32,467,658	401,214,296
4.	NATURAL GAS	33,309,442	33,455,473	31,887,839	27,091,897	18,711,398	20,944,971	315,737,433
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	TOTAL ($)	72,067,913	72,565,674	68,703,869	62,474,084	50,776,276	53,412,629	719,428,456
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	60	70	120	0	0	0	10,760
10.	COAL	1,087,700	1,095,950	1,026,650	972,160	887,180	884,490	11,199,410
11.	NATURAL GAS	778,580	778,920	737,550	617,670	428,650	489,840	7,374,290
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	TOTAL (MWH)	1,866,340	1,874,940	1,764,320	1,589,830	1,315,830	1,374,330	18,584,460
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	2,860	2,870	2,990	4,520	3,630	4,520	60,100
17.	COAL (TON)	465,200	468,590	439,890	417,250	381,080	379,260	4,801,510
18.	NATURAL GAS (MCF)	5,810,540	5,822,070	5,525,740	4,578,410	3,193,490	3,535,610	54,466,060
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	670	760	1,440	0	0	0	110,790
23.	COAL	11,151,760	11,231,220	10,550,120	10,026,810	9,143,980	9,105,460	115,184,740
24.	NATURAL GAS	5,973,220	5,985,090	5,680,460	4,706,580	3,282,940	3,634,640	55,991,340
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	TOTAL (MMBTU)	17,125,650	17,217,070	16,232,020	14,733,390	12,426,920	12,740,100	171,286,870
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.00	0.00	0.01	0.00	0.00	0.00	0.06
30.	COAL	58.28	58.46	58.19	61.15	67.42	64.36	60.26
31.	NATURAL GAS	41.72	41.54	41.80	38.85	32.58	35.64	39.68
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)	5.48	5.91	10.92	0.00	0.00	0.00	41.21
37.	COAL ($/TON)	83.28	83.43	83.62	84.80	84.14	85.61	83.56
38.	NATURAL GAS ($/MCF)	5.73	5.75	5.77	5.92	5.86	5.92	5.80
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	23.38	22.34	22.68	0.00	0.00	0.00	22.36
43.	COAL	3.47	3.48	3.49	3.53	3.51	3.57	3.48
44.	NATURAL GAS	5.58	5.59	5.61	5.76	5.70	5.76	5.64
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)	4.21	4.21	4.23	4.24	4.09	4.19	4.20
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	11,167	10,857	12,000	0	0	0	10,296
50.	COAL	10,253	10,248	10,276	10,314	10,307	10,295	10,285
51.	NATURAL GAS	7,672	7,684	7,702	7,620	7,659	7,420	7,593
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	TOTAL (BTU/KWH)	9,176	9,183	9,200	9,267	9,444	9,270	9,217
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	26.11	24.25	27.21	0.00	0.00	0.00	23.02
57.	COAL	3.56	3.57	3.58	3.64	3.61	3.67	3.58
58.	NATURAL GAS	4.28	4.30	4.32	4.39	4.37	4.28	4.28
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)	3.86	3.87	3.89	3.93	3.86	3.89	3.87

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	232,800	79.2	85.9	88.2	10,396	COAL	102,120	23,700,157	2,420,260.0	7,951,591	3.42	77.87
2. B.B.#2	395	251,410	85.5	88.0	94.3	10,076	COAL	105,350	24,046,701	2,533,320.0	8,203,095	3.26	77.87
3. B.B.#3	365	203,830	75.1	88.3	83.3	10,280	COAL	89,740	23,349,788	2,095,410.0	6,987,620	3.43	77.87
4. B.B.#4	417	235,610	75.9	86.3	85.3	10,429	COAL	105,230	23,351,516	2,457,280.0	8,244,286	3.50	78.35
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	360,373	-	131.52
5. B.B. COAL	**1,572**	**923,650**	**79.0**	**87.1**	**87.9**	**10,292**		-	-	**9,506,270.0**	**31,746,965**	**3.44**	-
6. POLK #1 GASIFIER	220	126,510	77.3	-	-	10,335	COAL	48,700	26,847,023	1,307,450.0	5,236,635	4.14	107.53
7. POLK #1 CT OIL	235	2,580	1.5	-	-	10,341	LGT OIL	4,600	5,800,000	26,680.0	590,190	22.88	128.30
8. POLK #1 TOTAL	**220**	**129,090**	**78.9**	**87.8**	**90.6**	**10,335**		-	-	**1,334,130.0**	**5,826,825**	**4.51**	-
9. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
12. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15. POLK #4 CT GAS	**183**	**0**	**0.0**	**99.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
16. POLK #5 CT GAS	**183**	**0**	**0.0**	**99.2**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	792	234,470	39.8	97.3	67.1	7,548	GAS	1,721,670	1,028,008	1,769,890.0	10,857,610	4.63	6.31
19. BAYSIDE #2	1,047	146,860	18.9	97.3	67.4	7,539	GAS	1,077,000	1,027,994	1,107,150.0	6,792,037	4.62	6.31
20. BAYSIDE #3	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. BAYSIDE #4	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #5	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #6	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. BAYSIDE TOTAL	**2,083**	**381,330**	**24.6**	**97.4**	**67.2**	**7,545**	**GAS**	**2,798,670**	**1,028,003**	**2,877,040.0**	**17,649,647**	**4.63**	**6.31**
25. B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**99.4**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
28. SYSTEM	**4,682**	**1,434,070**	**41.2**	**93.7**	**81.4**	**9,565**	-	-	-	**13,717,440.0**	**55,223,437**	**3.85**	-

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2013

	(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	395	98,780	37.2	43.0	82.8	10,435	COAL	43,500	23,695,632	1,030,760.0	3,390,321	3.43	77.94
2.	B.B.#2	395	106,200	40.0	44.0	88.2	10,104	COAL	44,630	24,043,693	1,073,070.0	3,478,392	3.28	77.94
3.	B.B.#3	365	193,890	79.0	88.3	87.8	10,252	COAL	85,130	23,350,523	1,987,830.0	6,634,897	3.42	77.94
4.	B.B.#4	417	225,730	80.6	86.3	90.5	10,379	COAL	100,340	23,348,714	2,342,810.0	7,870,876	3.49	78.44
	B.B. IGNITION	-	-	-	-	-	-	LGT OIL	5,490	-	-	726,480	-	132.33
5.	**B.B. COAL**	**1,572**	**624,600**	**59.1**	**65.3**	**88.0**	**10,302**		-	-	**6,434,470.0**	**22,100,966**	**3.54**	-
6.	POLK #1 GASIFIER	220	117,740	79.6	-	-	10,247	COAL	44,940	26,846,462	1,206,480.0	4,911,741	4.17	109.30
7.	POLK #1 CT OIL	235	2,400	1.5	-	-	10,258	LGT OIL	4,250	5,792,941	24,620.0	548,724	22.86	129.11
8.	**POLK #1 TOTAL**	**220**	**120,140**	**81.3**	**87.8**	**93.2**	**10,247**		-	-	**1,231,100.0**	**5,460,465**	**4.55**	-
9.	POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10.	POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11.	**POLK #2 TOTAL**	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
12.	POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13.	POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14.	**POLK #3 TOTAL**	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
15.	**POLK #4 CT GAS**	**183**	**0**	**0.0**	**99.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
16.	**POLK #5 CT GAS**	**183**	**0**	**0.0**	**99.2**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17.	**CITY OF TAMPA GAS**	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18.	BAYSIDE #1	792	310,340	58.3	97.3	77.6	7,355	GAS	2,220,470	1,028,008	2,282,660.0	12,472,947	4.02	5.62
19.	BAYSIDE #2	1,047	184,330	26.2	72.9	80.4	7,333	GAS	1,314,750	1,028,028	1,351,600.0	7,385,286	4.01	5.62
20.	BAYSIDE #3	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21.	BAYSIDE #4	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22.	BAYSIDE #5	61	150	0.4	98.6	49.2	12,000	GAS	1,750	1,028,571	1,800.0	9,830	6.55	5.62
23.	BAYSIDE #6	61	30	0.1	98.6	49.2	14,000	GAS	410	1,024,390	420.0	2,303	7.68	5.62
24.	**BAYSIDE TOTAL**	**2,083**	**494,850**	**35.4**	**85.2**	**78.6**	**7,349**	**GAS**	**3,537,380**	**1,028,015**	**3,636,480.0**	**19,870,366**	**4.02**	**5.62**
25.	B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26.	B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27.	**B.B.C.T.#4 TOTAL**	**61**	**0**	**0.0**	**99.4**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
28.	**SYSTEM**	**4,682**	**1,239,590**	**39.4**	**81.0**	**84.4**	**9,118**	-	-	-	**11,302,050.0**	**47,431,797**	**3.83**	-

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	240,380	81.8	85.9	91.1	10,390	COAL	105,390	23,698,833	2,497,620.0	8,217,926	3.42	77.98
2. B.B.#2	395	251,160	85.5	88.0	94.2	10,077	COAL	105,250	24,046,176	2,530,860.0	8,207,010	3.27	77.98
3. B.B.#3	365	6,120	2.3	21.8	76.2	10,281	COAL	2,690	23,390,335	62,920.0	209,756	3.43	77.98
4. B.B.#4	417	166,770	53.8	47.3	85.1	10,435	COAL	74,520	23,352,254	1,740,210.0	5,861,332	3.51	78.65
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	363,471	-	132.65
5. B.B. COAL	**1,572**	**664,430**	**56.8**	**61.3**	**90.5**	**10,282**		**-**	**-**	**6,831,610.0**	**22,859,495**	**3.44**	**-**
6. POLK #1 GASIFIER	220	131,270	80.2	-	-	10,229	COAL	50,010	26,848,830	1,342,710.0	5,526,975	4.21	110.52
7. POLK #1 CT OIL	235	2,680	1.5	-	-	10,224	LGT OIL	4,730	5,792,812	27,400.0	614,237	22.92	129.86
8. POLK #1 TOTAL	**220**	**133,950**	**81.8**	**87.8**	**94.0**	**10,229**		**-**	**-**	**1,370,110.0**	**6,141,212**	**4.58**	**-**
9. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. POLK #4 CT GAS	**183**	**3,210**	**2.4**	**99.1**	**83.7**	**11,520**	**GAS**	**35,980**	**1,027,793**	**36,980.0**	**200,086**	**6.23**	**5.56**
16. POLK #5 CT GAS	**183**	**550**	**0.4**	**99.2**	**75.1**	**12,527**	**GAS**	**6,710**	**1,026,826**	**6,890.0**	**37,315**	**6.78**	**5.56**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	792	256,040	43.5	75.3	74.0	7,416	GAS	1,847,180	1,028,005	1,898,910.0	10,272,242	4.01	5.56
19. BAYSIDE #2	1,047	286,540	36.8	97.3	80.7	7,344	GAS	2,047,070	1,028,021	2,104,430.0	11,383,838	3.97	5.56
20. BAYSIDE #3	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. BAYSIDE #4	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #5	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #6	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. BAYSIDE TOTAL	**2,083**	**542,580**	**35.0**	**89.1**	**77.4**	**7,378**	**GAS**	**3,894,250**	**1,028,013**	**4,003,340.0**	**21,656,080**	**3.99**	**5.56**
25. B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
28. SYSTEM	**4,682**	**1,344,720**	**38.6**	**81.4**	**85.0**	**9,109**	**-**	**-**	**-**	**12,248,930.0**	**50,894,188**	**3.78**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	221,950	80.1	85.9	89.1	10,438	COAL	97,750	23,700,767	2,316,750.0	7,628,775	3.44	78.04
2. B.B.#2	385	235,120	84.8	88.0	93.5	10,092	COAL	98,690	24,044,381	2,372,940.0	7,702,136	3.28	78.04
3. B.B.#3	365	0	0.0	19.6	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. B.B.#4	407	164,320	56.1	86.3	75.6	10,602	COAL	74,620	23,346,556	1,742,120.0	5,914,159	3.60	79.26
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	364,131	-	132.89
5. B.B. COAL	**1,542**	**621,390**	**56.0**	**70.9**	**86.6**	**10,351**		**-**	**-**	**6,431,810.0**	**21,609,201**	**3.48**	**-**
6. POLK #1 GASIFIER	220	83,730	52.9	-	-	10,265	COAL	32,010	26,849,734	859,460.0	3,635,829	4.34	113.58
7. POLK #1 CT OIL	218	1,710	1.1	-	-	10,257	LGT OIL	3,030	5,788,779	17,540.0	394,659	23.08	130.25
8. POLK #1 TOTAL	**220**	**85,440**	**53.9**	**43.9**	**92.9**	**10,265**		**-**	**-**	**877,000.0**	**4,030,488**	**4.72**	**-**
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. POLK #4 CT GAS	**151**	**2,510**	**2.3**	**99.1**	**83.3**	**12,458**	**GAS**	**30,420**	**1,027,942**	**31,270.0**	**175,969**	**7.01**	**5.78**
16. POLK #5 CT GAS	**151**	**300**	**0.3**	**99.2**	**99.3**	**13,000**	**GAS**	**3,790**	**1,029,024**	**3,900.0**	**21,924**	**7.31**	**5.78**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	216,650	42.9	97.3	83.7	7,565	GAS	1,594,390	1,028,011	1,639,050.0	9,223,006	4.26	5.78
19. BAYSIDE #2	929	441,090	65.9	97.3	83.7	7,534	GAS	3,232,830	1,028,010	3,323,380.0	18,700,826	4.24	5.78
20. BAYSIDE #3	56	0	0.0	75.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. BAYSIDE #4	56	0	0.0	75.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #5	56	0	0.0	98.6	0.0	0	GAS	70	1,000,000	70.0	405	0.00	5.79
23. BAYSIDE #6	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. BAYSIDE TOTAL	**1,854**	**657,740**	**49.3**	**96.0**	**83.7**	**7,545**	**GAS**	**4,827,290**	**1,028,010**	**4,962,500.0**	**27,924,237**	**4.25**	**5.78**
25. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
28. SYSTEM	**4,298**	**1,367,380**	**44.2**	**84.8**	**85.5**	**9,000**	**-**	**-**	**-**	**12,306,480.0**	**53,761,819**	**3.93**	**-**

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	236,090	82.4	85.9	91.8	10,398	COAL	103,580	23,699,942	2,454,840.0	8,072,034	3.42	77.93
2. B.B.#2	385	247,130	86.3	88.0	95.1	10,081	COAL	103,610	24,046,328	2,491,440.0	8,074,371	3.27	77.93
3. B.B.#3	365	140,090	51.6	21.8	84.5	10,280	COAL	61,670	23,351,711	1,440,100.0	4,805,969	3.43	77.93
4. B.B.#4	407	236,840	78.2	86.3	87.9	10,421	COAL	105,700	23,350,615	2,468,160.0	8,287,781	3.50	78.41
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	-	483,813	-	133.28
5. B.B. COAL	**1,542**	**860,150**	**75.0**	**71.4**	**90.3**	**10,294**		**-**	**-**	**8,854,540.0**	**29,723,968**	**3.46**	**-**
6. POLK #1 GASIFIER	220	46,220	28.2	-	-	10,253	COAL	17,650	26,849,858	473,900.0	2,108,838	4.56	119.48
7. POLK #1 CT OIL	218	940	0.6	-	-	10,287	LGT OIL	1,670	5,790,419	9,670.0	217,930	23.18	130.50
8. POLK #1 TOTAL	**220**	**47,160**	**28.8**	**45.3**	**93.2**	**10,254**		**-**	**-**	**483,570.0**	**2,326,768**	**4.93**	**-**
9. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
10. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
11. POLK #2 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
13. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
14. POLK #3 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. POLK #4 CT GAS	**151**	**10,710**	**9.6**	**99.1**	**92.4**	**11,938**	**GAS**	**124,380**	**1,027,979**	**127,860.0**	**724,683**	**6.77**	**5.83**
16. POLK #5 CT GAS	**151**	**5,880**	**5.2**	**99.2**	**81.1**	**12,372**	**GAS**	**70,770**	**1,027,978**	**72,750.0**	**412,332**	**7.01**	**5.83**
17. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BAYSIDE #1	701	241,630	46.3	97.3	85.3	7,551	GAS	1,774,760	1,028,004	1,824,460.0	10,340,399	4.28	5.83
19. BAYSIDE #2	929	463,970	67.1	97.3	84.9	7,528	GAS	3,397,430	1,028,006	3,492,580.0	19,794,665	4.27	5.83
20. BAYSIDE #3	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. BAYSIDE #4	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #5	56	320	0.8	76.3	51.9	14,063	GAS	4,380	1,027,397	4,500.0	25,519	7.97	5.83
23. BAYSIDE #6	56	20	0.0	76.3	17.9	24,500	GAS	480	1,020,833	490.0	2,797	13.99	5.83
24. BAYSIDE TOTAL	**1,854**	**705,940**	**51.2**	**96.1**	**85.0**	**7,539**	**GAS**	**5,177,050**	**1,028,004**	**5,322,030.0**	**30,163,380**	**4.27**	**5.83**
25. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
26. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**77.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
28. SYSTEM	**4,298**	**1,629,840**	**51.0**	**84.8**	**88.0**	**9,118**	**-**	**-**	**-**	**14,860,750.0**	**63,351,131**	**3.89**	**-**

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2013

(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)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. B.B.#1	385	229,160	82.7	85.9	92.0	10,395	COAL	100,510	23,700,826	2,382,170.0	7,822,997	3.41	77.83
2. B.B.#2	385	240,230	86.7	88.0	95.6	10,080	COAL	100,700	24,045,780	2,421,410.0	7,837,785	3.26	77.83
3. B.B.#3	365	204,140	77.7	88.3	86.3	10,274	COAL	89,820	23,350,145	2,097,310.0	6,990,962	3.42	77.83
4. B.B.#4	407	239,970	81.9	86.3	92.1	10,374	COAL	106,610	23,350,342	2,489,380.0	8,348,313	3.48	78.31
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	365,865	-	133.53
5. B.B. COAL	**1,542**	**913,500**	**82.3**	**87.1**	**91.6**	**10,279**		-	-	**9,390,270.0**	**31,365,922**	**3.43**	-
6. POLK #1 GASIFIER	220	132,090	83.4	-	-	10,117	COAL	49,780	26,846,525	1,336,420.0	5,702,563	4.32	114.56
7. POLK #1 CT OIL	218	200	0.1	-	-	10,050	LGT OIL	350	5,742,857	2,010.0	45,691	22.85	130.55
8. POLK SU/SD	218	2,500	1.6	-	-	10,780	GAS	26,220	1,027,841	26,950.0	151,069	6.04	5.76
9. POLK #1 TOTAL	**220**	**134,790**	**85.1**	**87.8**	**97.7**	**10,130**		-	-	**1,365,380.0**	**5,899,323**	**4.38**	-
10. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
11. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
12. POLK #2 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
13. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #3 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
16. POLK #4 CT GAS	**151**	**14,110**	**13.0**	**99.1**	**97.6**	**11,753**	**GAS**	**161,330**	**1,027,955**	**165,840.0**	**929,521**	**6.59**	**5.76**
17. POLK #5 CT GAS	**151**	**7,700**	**7.1**	**99.2**	**92.7**	**11,936**	**GAS**	**89,400**	**1,028,076**	**91,910.0**	**515,088**	**6.69**	**5.76**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	701	252,710	50.1	97.3	87.5	7,529	GAS	1,850,910	1,028,008	1,902,750.0	10,664,222	4.22	5.76
20. BAYSIDE #2	929	459,180	68.6	97.3	87.1	7,502	GAS	3,350,840	1,028,011	3,444,700.0	19,306,234	4.20	5.76
21. BAYSIDE #3	56	60	0.1	98.6	107.1	11,000	GAS	650	1,015,385	660.0	3,745	6.24	5.76
22. BAYSIDE #4	56	10	0.0	98.6	17.9	22,000	GAS	210	1,047,619	220.0	1,210	12.10	5.76
23. BAYSIDE #5	56	800	2.0	98.6	59.5	11,738	GAS	9,140	1,027,352	9,390.0	52,661	6.58	5.76
24. BAYSIDE #6	56	410	1.0	98.6	73.2	12,073	GAS	4,810	1,029,106	4,950.0	27,713	6.76	5.76
25. BAYSIDE TOTAL	**1,854**	**713,170**	**53.4**	**97.4**	**87.2**	**7,519**	**GAS**	**5,216,560**	**1,028,009**	**5,362,670.0**	**30,055,785**	**4.21**	**5.76**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		-	-	**0.0**	**0**	**0.00**	-
29. SYSTEM	**4,298**	**1,783,270**	**57.6**	**93.5**	**90.2**	**9,183**	-	-	-	**16,376,070.0**	**68,765,639**	**3.86**	-

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

SU/SD = START UP/SHUT DOWN

34

Exhibit No._____ (CA-3)
Document No. 2, Page 15 of 30

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	236,160	82.4	85.9	91.8	10,396	COAL	103,590	23,700,164	2,455,100.0	8,072,314	3.42	77.93
2. B.B.#2	385	248,700	86.8	88.0	95.7	10,079	COAL	104,240	24,046,431	2,506,600.0	8,122,966	3.27	77.93
3. B.B.#3	365	212,460	78.2	88.3	86.9	10,271	COAL	93,450	23,350,455	2,182,100.0	7,282,149	3.43	77.93
4. B.B.#4	407	253,390	83.7	86.3	94.0	10,353	COAL	112,350	23,349,711	2,623,340.0	8,805,478	3.48	78.38
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	366,500	-	133.76
5. B.B. COAL	**1,542**	**950,710**	**82.9**	**87.1**	**92.2**	**10,274**		**-**	**-**	**9,767,140.0**	**32,649,407**	**3.43**	**-**
6. POLK #1 GASIFIER	220	136,990	83.7	-	-	10,107	COAL	51,570	26,849,331	1,384,620.0	5,925,565	4.33	114.90
7. POLK #1 CT OIL	218	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	218	2,800	1.7	-	-	10,693	GAS	29,130	1,027,806	29,940.0	167,832	5.99	5.76
9. POLK #1 TOTAL	**220**	**139,790**	**85.4**	**87.8**	**98.1**	**10,119**		**-**	**-**	**1,414,560.0**	**6,093,397**	**4.36**	**-**
10. POLK #2 CT GAS	151	1,120	1.0	-	-	11,768	GAS	12,820	1,028,081	13,180.0	73,862	6.59	5.76
11. POLK #2 CT OIL	159	60	0.1	-	-	11,167	LGT OIL	120	5,583,333	670.0	15,667	26.11	130.56
12. POLK #2 TOTAL	**159**	**1,180**	**1.0**	**98.3**	**92.8**	**11,737**		**-**	**-**	**13,850.0**	**89,529**	**7.59**	**-**
13. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #3 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
16. POLK #4 CT GAS	**151**	**15,150**	**13.5**	**99.1**	**95.8**	**11,757**	**GAS**	**173,270**	**1,027,991**	**178,120.0**	**998,291**	**6.59**	**5.76**
17. POLK #5 CT GAS	**151**	**9,100**	**8.1**	**99.2**	**95.7**	**11,771**	**GAS**	**104,210**	**1,027,924**	**107,120.0**	**600,403**	**6.60**	**5.76**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**- 0**	**0.00**	**0.00**
19. BAYSIDE #1	701	269,190	51.6	97.3	87.9	7,528	GAS	1,971,220	1,028,003	2,026,420.0	11,357,132	4.22	5.76
20. BAYSIDE #2	929	478,890	69.3	97.3	87.1	7,499	GAS	3,493,540	1,028,006	3,591,380.0	20,127,939	4.20	5.76
21. BAYSIDE #3	56	340	0.8	98.6	86.7	11,706	GAS	3,880	1,025,773	3,980.0	22,355	6.58	5.76
22. BAYSIDE #4	56	40	0.1	98.6	71.4	14,000	GAS	550	1,018,182	560.0	3,169	7.92	5.76
23. BAYSIDE #5	56	1,210	2.9	98.6	77.2	11,529	GAS	13,570	1,028,003	13,950.0	78,183	6.46	5.76
24. BAYSIDE #6	56	740	1.8	98.6	73.4	11,581	GAS	8,350	1,026,347	8,570.0	48,108	6.50	5.76
25. BAYSIDE TOTAL	**1,854**	**750,410**	**54.4**	**97.4**	**87.3**	**7,522**	**GAS**	**5,491,110**	**1,028,000**	**5,644,860.0**	**31,636,886**	**4.22**	**5.76**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,298**	**1,866,340**	**58.4**	**93.5**	**90.6**	**9,176**	**-**	**-**	**-**	**17,125,650.0**	**72,067,913**	**3.86**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SU/SD = START UP/SHUT DOWN

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	236,720	82.6	85.9	92.0	10,395	COAL	103,830	23,700,183	2,460,790.0	8,097,033	3.42	77.98
2. B.B.#2	385	249,430	87.1	88.0	96.0	10,078	COAL	104,540	24,045,150	2,513,680.0	8,152,402	3.27	77.98
3. B.B.#3	365	217,810	80.2	88.3	89.1	10,257	COAL	95,680	23,348,871	2,234,020.0	7,461,467	3.43	77.98
4. B.B.#4	407	254,800	84.1	86.3	94.6	10,348	COAL	112,920	23,349,717	2,636,650.0	8,883,439	3.49	78.67
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	367,108	-	133.98
5. B.B. COAL	**1,542**	**958,760**	**83.6**	**87.1**	**93.0**	**10,269**		**-**	**-**	**9,845,140.0**	**32,961,449**	**3.44**	**-**
6. POLK #1 GASIFIER	220	137,190	83.8	-	-	10,103	COAL	51,620	26,851,608	1,386,080.0	5,963,371	4.35	115.52
7. POLK #1 CT OIL	218	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	218	2,800	1.7	-	-	10,704	GAS	29,160	1,027,778	29,970.0	168,406	6.01	5.78
9. POLK #1 TOTAL	**220**	**139,990**	**85.5**	**87.8**	**98.2**	**10,115**		**-**	**-**	**1,416,050.0**	**6,131,777**	**4.38**	**-**
10. POLK #2 CT GAS	151	710	0.6	-	-	11,972	GAS	8,270	1,027,811	8,500.0	47,761	6.73	5.78
11. POLK #2 CT OIL	159	40	0.0	-	-	10,500	LGT OIL	70	6,000,000	420.0	9,140	22.85	130.57
12. POLK #2 TOTAL	**159**	**750**	**0.6**	**98.3**	**94.3**	**11,893**		**-**	**-**	**8,920.0**	**56,901**	**7.59**	**-**
13. POLK #3 CT GAS	151	570	0.5	-	-	12,193	GAS	6,770	1,026,588	6,950.0	39,098	6.86	5.78
14. POLK #3 CT OIL	159	30	0.0	-	-	11,333	LGT OIL	60	5,666,667	340.0	7,835	26.12	130.58
15. POLK #3 TOTAL	**159**	**600**	**0.5**	**98.3**	**94.3**	**12,150**		**-**	**-**	**7,290.0**	**46,933**	**7.82**	**-**
16. POLK #4 CT GAS	**151**	**16,110**	**14.4**	**99.1**	**94.7**	**11,862**	**GAS**	**185,890**	**1,028,027**	**191,100.0**	**1,073,560**	**6.66**	**5.78**
17. POLK #5 CT GAS	**151**	**9,510**	**8.5**	**99.2**	**90.0**	**12,065**	**GAS**	**111,620**	**1,027,952**	**114,740.0**	**644,633**	**6.78**	**5.78**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	701	263,800	50.6	97.3	87.6	7,528	GAS	1,931,790	1,028,000	1,985,880.0	11,156,560	4.23	5.78
20. BAYSIDE #2	929	484,620	70.1	97.3	86.3	7,506	GAS	3,538,360	1,028,007	3,637,460.0	20,434,896	4.22	5.78
21. BAYSIDE #3	56	110	0.3	98.6	49.1	12,818	GAS	1,380	1,021,739	1,410.0	7,970	7.25	5.78
22. BAYSIDE #4	56	0	0.0	98.6	0.0	0	GAS	70	1,000,000	70.0	404	0.00	5.77
23. BAYSIDE #5	56	340	0.8	98.6	40.5	14,471	GAS	4,780	1,029,289	4,920.0	27,606	8.12	5.78
24. BAYSIDE #6	56	350	0.8	98.6	78.1	11,686	GAS	3,980	1,027,638	4,090.0	22,985	6.57	5.78
25. BAYSIDE TOTAL	**1,854**	**749,220**	**54.3**	**97.4**	**86.7**	**7,520**	**GAS**	**5,480,360**	**1,028,004**	**5,633,830.0**	**31,650,421**	**4.22**	**5.78**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,298**	**1,874,940**	**58.6**	**93.5**	**90.7**	**9,183**	**-**	**-**	**-**	**17,217,070.0**	**72,565,674**	**3.87**	**-**

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

SU/SD = START UP/SHUT DOWN

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	228,970	82.6	85.9	91.9	10,397	COAL	100,450	23,699,154	2,380,580.0	7,834,395	3.42	77.99
2. B.B.#2	385	238,920	86.2	88.0	95.0	10,082	COAL	100,170	24,046,421	2,408,730.0	7,812,557	3.27	77.99
3. B.B.#3	365	204,480	77.8	88.3	86.5	10,273	COAL	89,960	23,350,267	2,100,590.0	7,016,249	3.43	77.99
4. B.B.#4	407	222,490	75.9	86.3	85.4	10,455	COAL	99,620	23,351,034	2,326,230.0	7,820,196	3.51	78.50
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	-	367,686	-	134.19
5. B.B. COAL	**1,542**	**894,860**	**80.6**	**87.1**	**89.7**	**10,299**		**-**	**-**	**9,216,130.0**	**30,851,083**	**3.45**	**-**
6. POLK #1 GASIFIER	220	131,790	83.2	-	-	10,122	COAL	49,690	26,846,247	1,333,990.0	5,769,189	4.38	116.10
7. POLK #1 CT OIL	218	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	218	2,690	1.7	-	-	10,743	GAS	28,120	1,027,738	28,900.0	163,104	6.06	5.80
9. POLK #1 TOTAL	**220**	**134,480**	**84.9**	**87.8**	**97.5**	**10,135**		**-**	**-**	**1,362,890.0**	**5,932,293**	**4.41**	**-**
10. POLK #2 CT GAS	151	1,900	1.7	-	-	11,926	GAS	22,040	1,028,131	22,660.0	127,839	6.73	5.80
11. POLK #2 CT OIL	159	100	0.1	-	-	11,400	LGT OIL	200	5,700,000	1,140.0	26,123	26.12	130.62
12. POLK #2 TOTAL	**159**	**2,000**	**1.7**	**98.3**	**89.8**	**11,900**		**-**	**-**	**23,800.0**	**153,962**	**7.70**	**-**
13. POLK #3 CT GAS	151	430	0.4	-	-	14,395	GAS	6,020	1,028,239	6,190.0	34,918	8.12	5.80
14. POLK #3 CT OIL	159	20	0.0	-	-	15,000	LGT OIL	50	6,000,000	300.0	6,531	32.66	130.62
15. POLK #3 TOTAL	**159**	**450**	**0.4**	**98.3**	**56.6**	**14,422**		**-**	**-**	**6,490.0**	**41,449**	**9.21**	**-**
16. POLK #4 CT GAS	**151**	**14,800**	**13.6**	**99.1**	**97.3**	**11,714**	**GAS**	**168,640**	**1,027,989**	**173,360.0**	**978,162**	**6.61**	**5.80**
17. POLK #5 CT GAS	**151**	**11,390**	**10.5**	**99.2**	**93.1**	**11,868**	**GAS**	**131,500**	**1,027,985**	**135,180.0**	**762,739**	**6.70**	**5.80**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	701	249,050	49.3	97.3	86.9	7,537	GAS	1,826,070	1,028,005	1,877,210.0	10,591,752	4.25	5.80
20. BAYSIDE #2	929	456,810	68.3	97.3	86.3	7,510	GAS	3,337,150	1,028,000	3,430,590.0	19,356,467	4.24	5.80
21. BAYSIDE #3	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #4	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #5	56	480	1.2	98.6	57.1	13,271	GAS	6,200	1,027,419	6,370.0	35,962	7.49	5.80
24. BAYSIDE #6	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
25. BAYSIDE TOTAL	**1,854**	**706,340**	**52.9**	**97.4**	**86.4**	**7,524**	**GAS**	**5,169,420**	**1,028,001**	**5,314,170.0**	**29,984,181**	**4.25**	**5.80**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,298**	**1,764,320**	**57.0**	**93.5**	**89.0**	**9,200**	**-**	**-**	**-**	**16,232,020.0**	**68,703,869**	**3.89**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SU/SD = START UP/SHUT DOWN

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	226,760	79.2	85.9	88.2	10,437	COAL	99,860	23,700,481	2,366,730.0	7,799,972	3.44	78.11
2. B.B.#2	385	244,160	85.2	88.0	94.0	10,089	COAL	102,450	24,044,412	2,463,350.0	8,002,274	3.28	78.11
3. B.B.#3	365	154,720	57.0	68.4	81.8	10,299	COAL	68,250	23,348,278	1,593,520.0	5,330,944	3.45	78.11
4. B.B.#4	407	211,890	70.0	86.3	78.6	10,553	COAL	95,770	23,348,335	2,236,070.0	7,531,040	3.55	78.64
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,520	-	-	607,986	-	134.51
5. B.B. COAL	**1,542**	**837,530**	**73.0**	**82.4**	**85.9**	**10,340**		**-**	**-**	**8,659,670.0**	**29,272,216**	**3.50**	**-**
6. POLK #1 GASIFIER	220	134,630	82.3	-	-	10,155	COAL	50,920	26,848,782	1,367,140.0	5,938,593	4.41	116.63
7. POLK #1 CT OIL	218	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	218	2,750	1.7	-	-	10,756	GAS	28,780	1,027,797	29,580.0	171,378	6.23	5.95
9. POLK #1 TOTAL	**220**	**137,380**	**83.9**	**87.8**	**96.4**	**10,167**		**-**	**-**	**1,396,720.0**	**6,109,971**	**4.45**	**-**
10. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
11. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
12. POLK #2 TOTAL	**159**	**0**	**0.0**	**88.8**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
13. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #3 TOTAL	**159**	**0**	**0.0**	**88.8**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
16. POLK #4 CT GAS	**151**	**2,410**	**2.2**	**67.2**	**88.9**	**12,041**	**GAS**	**28,230**	**1,027,984**	**29,020.0**	**168,103**	**6.98**	**5.95**
17. POLK #5 CT GAS	**151**	**2,860**	**2.5**	**86.4**	**86.1**	**12,280**	**GAS**	**34,170**	**1,027,802**	**35,120.0**	**203,474**	**7.11**	**5.95**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	701	209,030	40.1	97.3	82.6	7,579	GAS	1,541,150	1,027,992	1,584,290.0	9,177,158	4.39	5.95
20. BAYSIDE #2	929	400,540	58.0	97.3	83.2	7,558	GAS	2,944,940	1,028,001	3,027,400.0	17,536,373	4.38	5.95
21. BAYSIDE #3	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #4	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #5	56	60	0.1	98.6	53.6	12,667	GAS	740	1,027,027	760.0	4,407	7.35	5.96
24. BAYSIDE #6	56	20	0.0	98.6	35.7	20,500	GAS	400	1,025,000	410.0	2,382	11.91	5.96
25. BAYSIDE TOTAL	**1,854**	**609,650**	**44.2**	**97.4**	**83.0**	**7,566**	**GAS**	**4,487,230**	**1,027,997**	**4,612,860.0**	**26,720,320**	**4.38**	**5.95**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,298**	**1,589,830**	**49.7**	**89.5**	**85.5**	**9,267**	**-**	**-**	**-**	**14,733,390.0**	**62,474,084**	**3.93**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SU/SD = START UP/SHUT DOWN

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	217,990	78.6	85.9	87.5	10,437	COAL	96,000	23,700,208	2,275,220.0	7,495,881	3.44	78.08
2. B.B.#2	385	234,970	84.8	88.0	93.5	10,093	COAL	98,630	24,045,422	2,371,600.0	7,701,237	3.28	78.08
3. B.B.#3	365	193,160	73.5	88.3	81.7	10,306	COAL	85,250	23,351,085	1,990,680.0	6,656,499	3.45	78.08
4. B.B.#4	407	132,890	45.3	86.3	76.5	10,587	COAL	60,250	23,350,871	1,406,890.0	4,754,981	3.58	78.92
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	-	489,145	-	134.75
5. B.B. COAL	**1,542**	**779,010**	**70.2**	**87.1**	**85.5**	**10,326**		**-**	**-**	**8,044,390.0**	**27,097,743**	**3.48**	**-**
6. POLK #1 GASIFIER	220	108,170	68.3	-	-	10,165	COAL	40,950	26,852,015	1,099,590.0	4,818,903	4.45	117.68
7. POLK #1 CT OIL	218	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	218	2,210	1.4	-	-	11,679	GAS	25,100	1,028,287	25,810.0	148,232	6.71	5.91
9. POLK #1 TOTAL	**220**	**110,380**	**69.7**	**73.2**	**95.9**	**10,196**		**-**	**-**	**1,125,400.0**	**4,967,135**	**4.50**	**-**
10. POLK #2 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
11. POLK #2 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
12. POLK #2 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
13. POLK #3 CT GAS	151	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #3 CT OIL	159	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #3 TOTAL	**159**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
16. POLK #4 CT GAS	**151**	**0**	**0.0**	**66.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. POLK #5 CT GAS	**151**	**0**	**0.0**	**99.2**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	701	118,450	23.5	74.6	78.0	7,640	GAS	880,280	1,028,002	904,930.0	5,198,624	4.39	5.91
20. BAYSIDE #2	929	307,980	46.0	97.3	79.0	7,637	GAS	2,287,920	1,028,012	2,352,010.0	13,511,652	4.39	5.91
21. BAYSIDE #3	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #4	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #5	56	10	0.0	98.6	17.9	19,000	GAS	190	1,000,000	190.0	1,122	11.22	5.91
24. BAYSIDE #6	56	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
25. BAYSIDE TOTAL	**1,854**	**426,440**	**31.9**	**88.8**	**78.7**	**7,638**	**GAS**	**3,168,390**	**1,028,008**	**3,257,130.0**	**18,711,398**	**4.39**	**5.91**
26. B.B.C.T.#4 OIL	56	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	56	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,298**	**1,315,830**	**42.5**	**87.8**	**83.9**	**9,444**	**-**	**-**	**-**	**12,426,920.0**	**50,776,276**	**3.86**	**-**

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

SU/SD = START UP/SHUT DOWN

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2013

(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)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	148,880	50.7	58.2	83.2	10,437	COAL	65,570	23,698,490	1,553,910.0	5,114,571	3.44	78.00
2. B.B.#2	395	163,050	55.5	59.6	90.3	10,098	COAL	68,470	24,047,320	1,646,520.0	5,340,776	3.28	78.00
3. B.B.#3	365	207,240	76.3	88.3	84.7	10,272	COAL	91,170	23,349,018	2,128,730.0	7,111,415	3.43	78.00
4. B.B.#4	417	229,610	74.0	58.5	83.2	10,457	COAL	102,830	23,350,190	2,401,100.0	8,103,455	3.53	78.80
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,520	-	-	610,314	-	135.03
5. B.B. COAL	**1,572**	**748,780**	**64.0**	**65.6**	**85.1**	**10,324**		**-**	**-**	**7,730,260.0**	**26,280,531**	**3.51**	**-**
6. POLK #1 GASIFIER	220	135,710	82.9	-	-	10,133	COAL	51,220	26,848,887	1,375,200.0	6,004,451	4.42	117.23
7. POLK #1 CT OIL	235	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
8. POLK SU/SD	235	2,770	1.6	-	-	11,350	GAS	30,570	1,028,459	31,440.0	182,676	6.59	5.98
9. POLK #1 TOTAL	**220**	**138,480**	**84.6**	**87.8**	**97.1**	**10,158**		**-**	**-**	**1,406,640.0**	**6,187,127**	**4.47**	**-**
10. POLK #2 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
11. POLK #2 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
12. POLK #2 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
13. POLK #3 CT GAS	183	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #3 CT OIL	187	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #3 TOTAL	**187**	**0**	**0.0**	**98.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
16. POLK #4 CT GAS	**183**	**0**	**0.0**	**99.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
17. POLK #5 CT GAS	**183**	**0**	**0.0**	**99.2**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. CITY OF TAMPA GAS	**6**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. BAYSIDE #1	792	310,960	52.8	97.3	75.6	7,397	GAS	2,237,540	1,028,008	2,300,210.0	13,370,806	4.30	5.98
20. BAYSIDE #2	1,047	176,060	22.6	75.3	78.1	7,397	GAS	1,266,870	1,027,998	1,302,340.0	7,570,400	4.30	5.98
21. BAYSIDE #3	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. BAYSIDE #4	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
23. BAYSIDE #5	61	50	0.1	98.6	82.0	13,000	GAS	630	1,031,746	650.0	3,765	7.53	5.98
24. BAYSIDE #6	61	0	0.0	98.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
25. BAYSIDE TOTAL	**2,083**	**487,070**	**31.4**	**86.4**	**76.5**	**7,398**	**GAS**	**3,505,040**	**1,028,005**	**3,603,200.0**	**20,944,971**	**4.30**	**5.98**
26. B.B.C.T.#4 OIL	61	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
27. B.B.C.T.#4 GAS	61	0	0.0	-	-	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**99.4**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
29. SYSTEM	**4,682**	**1,374,330**	**39.5**	**81.6**	**82.8**	**9,270**	**-**	**-**	**-**	**12,740,100.0**	**53,412,629**	**3.89**	**-**

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

SU/SD = START UP/SHUT DOWN

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
	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)	7,340	9,740	7,470	5,770	5,300	3,090
16.	UNIT COST ($/BBL)	138.71	138.36	137.54	136.51	137.67	137.22
17.	AMOUNT ($)	1,018,154	1,347,588	1,027,426	787,655	729,645	423,998
18.	BURNED:						
19.	UNITS (BBL)	7,340	9,740	7,470	5,770	5,300	3,090
20.	UNIT COST ($/BBL)	80.41	56.34	82.23	68.40	41.12	14.79
21.	AMOUNT ($)	590,190	548,724	614,237	394,659	217,930	45,691
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	89,664	89,664	89,664	89,664	89,664	89,664
24.	UNIT COST ($/BBL)	129.78	130.59	131.14	131.46	131.77	131.91
25.	AMOUNT ($)	11,636,533	11,708,917	11,758,635	11,787,500	11,815,403	11,827,844
26.	DAYS SUPPLY: NORMAL	545	581	619	655	673	698
27.	DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	405,000	355,000	355,000	340,000	410,000	385,000
30.	UNIT COST ($/TON)	85.95	80.98	80.96	80.98	85.20	80.92
31.	AMOUNT ($)	34,808,403	28,748,901	28,739,286	27,531,867	34,930,735	31,152,692
32.	BURNED:						
33.	UNITS (TONS)	451,140	318,540	337,860	303,070	392,210	447,420
34.	UNIT COST ($/TON)	81.98	84.80	84.02	83.30	81.16	83.19
35.	AMOUNT ($)	36,983,600	27,012,707	28,386,470	25,245,030	31,832,806	37,219,554
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	646,344	682,804	699,944	736,874	754,664	692,244
38.	UNIT COST ($/TON)	83.50	82.82	81.98	81.68	84.67	84.44
39.	AMOUNT ($)	53,971,293	56,550,032	57,381,922	60,188,111	63,900,423	58,452,805
40.	DAYS SUPPLY:	53	63	62	59	53	46
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	2,798,670	3,537,380	3,936,940	4,861,500	5,625,118	5,493,510
43.	UNIT COST ($/MCF)	6.34	5.62	5.55	5.78	5.73	5.77
44.	AMOUNT ($)	17,750,267	19,876,606	21,863,841	28,095,923	32,234,939	31,687,240
45.	BURNED:						
46.	UNITS (MCF)	2,798,670	3,537,380	3,936,940	4,861,500	5,372,200	5,493,510
47.	UNIT COST ($/MCF)	6.31	5.62	5.56	5.78	5.83	5.73
48.	AMOUNT ($)	17,649,647	19,870,366	21,893,481	28,122,130	31,300,395	31,500,394
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	758,755	758,755	758,755	758,755	1,011,673	1,011,673
51.	UNIT COST ($/MCF)	3.69	3.69	3.65	3.62	3.64	3.67
52.	AMOUNT ($)	2,796,456	2,802,696	2,773,056	2,746,848	3,681,392	3,717,168
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 2013 THROUGH DECEMBER 2013

		Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	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)	2,860	2,870	2,990	4,520	3,630	4,520	60,100
16.	UNIT COST ($/BBL)	137.24	137.31	137.36	137.41	137.47	137.52	137.66
17.	AMOUNT ($)	392,501	394,074	410,692	621,079	499,027	621,608	8,273,447
18.	BURNED:							
19.	UNITS (BBL)	2,860	2,870	2,990	4,520	3,630	4,520	60,100
20.	UNIT COST ($/BBL)	5.48	5.91	10.92	0.00	0.00	0.00	41.21
21.	AMOUNT ($)	15,667	16,975	32,654	0	0	0	2,476,727
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	89,664	89,664	89,664	89,664	89,664	89,664	89,664
24.	UNIT COST ($/BBL)	132.03	132.14	132.26	132.40	132.51	132.64	132.64
25.	AMOUNT ($)	11,838,177	11,848,168	11,858,521	11,871,614	11,881,496	11,892,791	11,892,791
26.	DAYS SUPPLY: NORMAL	676	661	634	608	626	606	-
27.	DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	435,000	440,000	440,000	430,000	370,000	360,000	4,725,000
30.	UNIT COST ($/TON)	80.62	80.90	80.83	85.54	82.01	80.96	82.20
31.	AMOUNT ($)	35,071,120	35,595,900	35,563,098	36,783,778	30,344,717	29,147,293	388,417,790
32.	BURNED:							
33.	UNITS (TONS)	465,200	468,590	439,890	417,250	381,080	379,260	4,801,510
34.	UNIT COST ($/TON)	83.28	83.43	83.62	84.80	84.14	85.61	83.56
35.	AMOUNT ($)	38,742,804	39,093,226	36,783,376	35,382,187	32,064,878	32,467,658	401,214,296
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	662,044	633,454	633,564	646,314	635,234	615,974	615,974
38.	UNIT COST ($/TON)	83.71	83.01	82.07	83.99	83.91	82.65	82.65
39.	AMOUNT ($)	55,417,763	52,585,261	51,998,083	54,281,348	53,300,874	50,907,817	50,907,817
40.	DAYS SUPPLY:	44	44	47	50	51	50	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	5,810,540	5,822,070	5,525,740	4,578,410	2,940,572	3,535,610	54,466,060
43.	UNIT COST ($/MCF)	5.77	5.78	5.80	5.96	6.12	6.02	5.83
44.	AMOUNT ($)	33,521,162	33,646,968	32,055,727	27,299,257	17,991,542	21,286,922	317,310,394
45.	BURNED:							
46.	UNITS (MCF)	5,810,540	5,822,070	5,525,740	4,578,410	3,193,490	3,535,610	54,466,060
47.	UNIT COST ($/MCF)	5.73	5.75	5.77	5.92	5.86	5.92	5.80
48.	AMOUNT ($)	33,309,442	33,455,473	31,887,839	27,091,897	18,711,398	20,944,971	315,737,433
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,011,673	1,011,673	1,011,673	1,011,673	758,755	758,755	758,755
51.	UNIT COST ($/MCF)	3.72	3.74	3.75	3.78	3.90	4.11	4.11
52.	AMOUNT ($)	3,761,056	3,784,144	3,788,928	3,824,912	2,956,824	3,116,100	3,116,100
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 2013 THROUGH JUNE 2013

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-13	VARIOUS	JURISD. MKT. BASE	17,590.0	0.0	17,590.0	2.887	3.584	507,786.00	630,380.00	50,834.00
Feb-13	VARIOUS	JURISD. MKT. BASE	16,140.0	0.0	16,140.0	2.964	3.669	478,434.00	592,200.00	47,896.00
Mar-13	VARIOUS	JURISD. MKT. BASE	19,270.0	0.0	19,270.0	2.846	3.539	548,372.00	681,880.00	54,898.00
Apr-13	VARIOUS	JURISD. MKT. BASE	18,160.0	0.0	18,160.0	3.014	3.724	547,373.00	676,250.00	54,797.00
May-13	VARIOUS	JURISD. MKT. BASE	9,670.0	0.0	9,670.0	3.491	4.249	337,603.00	410,870.00	33,797.00
Jun-13	VARIOUS	JURISD. MKT. BASE	10,170.0	0.0	10,170.0	3.717	4.497	378,026.00	457,360.00	37,844.00
Jul-13	VARIOUS	JURISD. MKT. BASE	8,130.0	0.0	8,130.0	4.363	5.207	354,674.00	423,360.00	35,506.00
Aug-13	VARIOUS	JURISD. MKT. BASE	8,130.0	0.0	8,130.0	4.098	4.917	333,203.00	399,750.00	33,357.00
Sep-13	VARIOUS	JURISD. MKT. BASE	8,020.0	0.0	8,020.0	3.744	4.526	300,234.00	362,990.00	30,056.00
Oct-13	VARIOUS	JURISD. MKT. BASE	10,720.0	0.0	10,720.0	3.132	3.854	335,803.00	413,150.00	33,617.00
Nov-13	VARIOUS	JURISD. MKT. BASE	9,480.0	0.0	9,480.0	3.018	3.728	286,062.00	353,390.00	28,638.00
Dec-13	VARIOUS	JURISD. MKT. BASE	14,520.0	0.0	14,520.0	3.044	3.756	441,947.00	545,420.00	44,243.00
TOTAL	VARIOUS	JURISD. MKT. BASE	**150,000.0**	**0.0**	**150,000.0**	**3.233**	**3.965**	**4,849,517.00**	**5,947,000.00**	**485,483.00**

Exhibit No. ____ (CA-3)
Document No. 2, Page 24 of 30

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-13									
	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	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Feb-13									
	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	1,420.0	0.0	0.0	1,420.0	5.196	5.196	73,790.00
	TOTAL		1,420.0	0.0	0.0	1,420.0	5.196	5.196	73,790.00
Mar-13									
	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	2,590.0	0.0	0.0	2,590.0	5.141	5.141	133,150.00
	TOTAL		2,590.0	0.0	0.0	2,590.0	5.141	5.141	133,150.00
Apr-13									
	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	4,430.0	0.0	0.0	4,430.0	5.303	5.303	234,920.00
	TOTAL		4,430.0	0.0	0.0	4,430.0	5.303	5.303	234,920.00
May-13									
	OLEANDER	SCH. D	2,160.0	0.0	0.0	2,160.0	6.470	6.470	139,760.00
	CALPINE	SCH. D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. D	4,750.0	0.0	0.0	4,750.0	5.338	5.338	253,570.00
	TOTAL		6,910.0	0.0	0.0	6,910.0	5.692	5.692	393,330.00
Jun-13									
	OLEANDER	SCH. D	3,290.0	0.0	0.0	3,290.0	6.396	6.396	210,420.00
	CALPINE	SCH. D	520.0	0.0	0.0	520.0	5.887	5.887	30,610.00
	PASCO COGEN	SCH. D	10,300.0	0.0	0.0	10,300.0	5.233	5.233	539,030.00
	TOTAL		14,110.0	0.0	0.0	14,110.0	5.528	5.528	780,060.00

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

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
Jul-13									
	OLEANDER	SCH. D	4,020.0	0.0	0.0	4,020.0	5.879	5.879	236,350.00
	CALPINE	SCH. D	1,130.0	0.0	0.0	1,130.0	7.009	7.009	79,200.00
	PASCO COGEN	SCH. D	10,790.0	0.0	0.0	10,790.0	5.250	5.250	566,500.00
	TOTAL		15,940.0	0.0	0.0	15,940.0	5.534	5.534	882,050.00
Aug-13									
	OLEANDER	SCH. D	6,090.0	0.0	0.0	6,090.0	6.916	6.916	421,210.00
	CALPINE	SCH. D	510.0	0.0	0.0	510.0	7.173	7.173	36,580.00
	PASCO COGEN	SCH. D	9,270.0	0.0	0.0	9,270.0	5.302	5.302	491,450.00
	TOTAL		15,870.0	0.0	0.0	15,870.0	5.981	5.981	949,240.00
Sep-13									
	OLEANDER	SCH. D	5,500.0	0.0	0.0	5,500.0	5.970	5.970	328,370.00
	CALPINE	SCH. D	1,490.0	0.0	0.0	1,490.0	7.215	7.215	107,510.00
	PASCO COGEN	SCH. D	9,430.0	0.0	0.0	9,430.0	5.253	5.253	495,400.00
	TOTAL		16,420.0	0.0	0.0	16,420.0	5.672	5.672	931,280.00
Oct-13									
	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	2,010.0	0.0	0.0	2,010.0	5.476	5.476	110,070.00
	TOTAL		2,010.0	0.0	0.0	2,010.0	5.476	5.476	110,070.00
Nov-13									
	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	1,500.0	0.0	0.0	1,500.0	5.354	5.354	80,310.00
	TOTAL		1,500.0	0.0	0.0	1,500.0	5.354	5.354	80,310.00
Dec-13									
	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	690.0	0.0	0.0	690.0	5.610	5.610	38,710.00
	TOTAL		690.0	0.0	0.0	690.0	5.610	5.610	38,710.00
TOTAL	OLEANDER	SCH. D	21,060.0	0.0	0.0	21,060.0	6.344	6.344	1,336,110.00
Jan-13	CALPINE	SCH. D	3,650.0	0.0	0.0	3,650.0	6.956	6.956	253,900.00
THRU	PASCO COGEN	SCH. D	57,180.0	0.0	0.0	57,180.0	5.276	5.276	3,016,900.00
Dec-13	TOTAL		81,890.0	0.0	0.0	81,890.0	5.626	5.626	4,606,910.00

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E8

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUST-MENT
Jan-13	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.495	3.495	199,240.00
		AS AVAIL.	10,200.0	0.0	0.0	10,200.0	4.769	4.769	486,420.00
	TOTAL		**15,900.0**	**0.0**	**0.0**	**15,900.0**	**4.312**	**4.312**	**685,660.00**
Feb-13	VARIOUS	CO-GEN.							
		FIRM	5,150.0	0.0	0.0	5,150.0	3.501	3.501	180,320.00
		AS AVAIL.	9,370.0	0.0	0.0	9,370.0	4.459	4.459	417,770.00
	TOTAL		**14,520.0**	**0.0**	**0.0**	**14,520.0**	**4.119**	**4.119**	**598,090.00**
Mar-13	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.509	3.509	200,040.00
		AS AVAIL.	10,210.0	0.0	0.0	10,210.0	4.860	4.860	496,170.00
	TOTAL		**15,910.0**	**0.0**	**0.0**	**15,910.0**	**4.376**	**4.376**	**696,210.00**
Apr-13	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.646	3.646	226,420.00
		AS AVAIL.	9,940.0	0.0	0.0	9,940.0	4.466	4.466	443,960.00
	TOTAL		**16,150.0**	**0.0**	**0.0**	**16,150.0**	**4.151**	**4.151**	**670,380.00**
May-13	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.489	3.489	224,020.00
		AS AVAIL.	10,240.0	0.0	0.0	10,240.0	4.523	4.523	463,150.00
	TOTAL		**16,660.0**	**0.0**	**0.0**	**16,660.0**	**4.125**	**4.125**	**687,170.00**
Jun-13	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.474	3.474	215,740.00
		AS AVAIL.	9,910.0	0.0	0.0	9,910.0	5.279	5.279	523,110.00
	TOTAL		**16,120.0**	**0.0**	**0.0**	**16,120.0**	**4.583**	**4.583**	**738,850.00**
Jul-13	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.467	3.467	222,610.00
		AS AVAIL.	10,300.0	0.0	0.0	10,300.0	4.924	4.924	507,150.00
	TOTAL		**16,720.0**	**0.0**	**0.0**	**16,720.0**	**4.365**	**4.365**	**729,760.00**
Aug-13	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.471	3.471	222,860.00
		AS AVAIL.	10,300.0	0.0	0.0	10,300.0	4.589	4.589	472,640.00
	TOTAL		**16,720.0**	**0.0**	**0.0**	**16,720.0**	**4.160**	**4.160**	**695,500.00**
Sep-13	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.512	3.512	218,100.00
		AS AVAIL.	9,880.0	0.0	0.0	9,880.0	5.013	5.013	495,280.00
	TOTAL		**16,090.0**	**0.0**	**0.0**	**16,090.0**	**4.434**	**4.434**	**713,380.00**
Oct-13	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.548	3.548	227,800.00
		AS AVAIL.	10,370.0	0.0	0.0	10,370.0	4.621	4.621	479,220.00
	TOTAL		**16,790.0**	**0.0**	**0.0**	**16,790.0**	**4.211**	**4.211**	**707,020.00**
Nov-13	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.682	3.682	228,650.00
		AS AVAIL.	9,820.0	0.0	0.0	9,820.0	5.087	5.087	499,580.00
	TOTAL		**16,030.0**	**0.0**	**0.0**	**16,030.0**	**4.543**	**4.543**	**728,230.00**
Dec-13	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.528	3.528	201,070.00
		AS AVAIL.	10,230.0	0.0	0.0	10,230.0	4.368	4.368	446,890.00
	TOTAL		**15,930.0**	**0.0**	**0.0**	**15,930.0**	**4.068**	**4.068**	**647,960.00**
TOTAL	VARIOUS	CO-GEN.							
Jan-13		FIRM	72,770.0	0.0	0.0	72,770.0	3.527	3.527	2,566,870.00
THRU		AS AVAIL.	120,770.0	0.0	0.0	120,770.0	4.746	4.746	5,731,340.00
Dec-13	TOTAL		**193,540.0**	**0.0**	**0.0**	**193,540.0**	**4.288**	**4.288**	**8,298,210.00**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

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-13	VARIOUS	ECONOMY	53,210.0	0.0	53,210.0	3.161	1,682,030.00	3.161	1,682,030.00	0.00
Feb-13	VARIOUS	ECONOMY	48,190.0	0.0	48,190.0	3.310	1,594,860.00	3.310	1,594,860.00	0.00
Mar-13	VARIOUS	ECONOMY	57,610.0	0.0	57,610.0	3.139	1,808,600.00	3.139	1,808,600.00	0.00
Apr-13	VARIOUS	ECONOMY	53,890.0	0.0	53,890.0	3.259	1,756,110.00	3.259	1,756,110.00	0.00
May-13	VARIOUS	ECONOMY	30,130.0	0.0	30,130.0	3.714	1,118,950.00	3.714	1,118,950.00	0.00
Jun-13	VARIOUS	ECONOMY	29,970.0	0.0	29,970.0	3.969	1,189,440.00	3.969	1,189,440.00	0.00
Jul-13	VARIOUS	ECONOMY	24,790.0	0.0	24,790.0	4.665	1,156,540.00	4.665	1,156,540.00	0.00
Aug-13	VARIOUS	ECONOMY	24,010.0	0.0	24,010.0	4.478	1,075,060.00	4.478	1,075,060.00	0.00
Sep-13	VARIOUS	ECONOMY	24,690.0	0.0	24,690.0	3.894	961,530.00	3.894	961,530.00	0.00
Oct-13	VARIOUS	ECONOMY	31,510.0	0.0	31,510.0	3.316	1,044,930.00	3.316	1,044,930.00	0.00
Nov-13	VARIOUS	ECONOMY	28,450.0	0.0	28,450.0	3.269	930,160.00	3.269	930,160.00	0.00
Dec-13	VARIOUS	ECONOMY	43,550.0	0.0	43,550.0	3.320	1,445,770.00	3.320	1,445,770.00	0.00
TOTAL	VARIOUS	ECONOMY	450,000.0	0.0	450,000.0	3.503	15,763,980.00	3.503	15,763,980.00	0.00

SCHEDULE E10

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

	Current Jan 12 - Dec 12	Projected Jan 13 - Dec 13	Difference $	Difference %
Base Rate Revenue	55.45	55.45	0.00	0%
Fuel Recovery Revenue	38.40	33.69	(4.71)	-12%
Conservation Revenue	3.02	2.98	(0.04)	-1%
Capacity Revenue	2.76	2.32	(0.44)	-16%
Environmental Revenue	4.60	5.58	0.98	21%
Florida Gross Receipts Tax Revenue	2.67	2.56	(0.11)	-4%
TOTAL REVENUE	**$106.90**	**$102.58**	**($4.32)**	**-4%**

SCHEDULE H1

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

	ACTUAL 2010	ACTUAL 2011	ACT/EST 2012	EST 2013	DIFFERENCE (%) 2011-2010	2012-2011	2013-2012
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	28,030	0	0	0	-100.0%	0.0%	0.0%
2 LIGHT OIL [1]	7,840,460	2,915,586	6,083,056	2,476,727	-62.8%	108.6%	-59.3%
3 COAL	333,636,297	386,430,361	382,082,691	401,214,296	15.8%	-1.1%	5.0%
4 NATURAL GAS	424,142,038	348,457,572	325,450,365	315,737,433	-17.8%	-6.6%	-3.0%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**765,646,825**	**737,803,519**	**713,616,112**	**719,428,456**	**-3.6%**	**-3.3%**	**0.8%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	49,477	13,423	27,112	10,760	-72.9%	102.0%	-60.3%
10 COAL	10,612,934	10,888,182	10,513,856	11,199,410	2.6%	-3.4%	6.5%
11 NATURAL GAS	8,374,745	7,392,465	7,880,507	7,374,290	-11.7%	6.6%	-6.4%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,037,156**	**18,294,070**	**18,421,475**	**18,584,460**	**-3.9%**	**0.7%**	**0.9%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	84,364	27,473	77,186	60,100	-67.4%	181.0%	-22.1%
17 COAL (TON)	4,442,745	4,763,638	4,536,380	4,801,510	7.2%	-4.8%	5.8%
18 NATURAL GAS (MCF)	61,925,208	55,514,960	58,857,173	54,466,060	-10.4%	8.0%	-7.5%
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]	488,733	146,019	280,356	110,790	-70.1%	92.0%	-60.5%
23 COAL	107,891,545	114,391,211	108,595,219	115,184,740	8.0%	-5.1%	6.1%
24 NATURAL GAS	63,015,339	56,296,514	59,085,550	55,991,340	-10.7%	5.0%	-5.2%
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)	**171,395,617**	**170,833,745**	**167,961,125**	**171,286,870**	**-0.3%**	**-1.7%**	**2.0%**
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]	0.26	0.07	0.15	0.06	-73.1%	114.3%	-60.0%
30 COAL	55.75	59.52	57.07	60.26	6.8%	-4.1%	5.6%
31 NATURAL GAS	43.99	40.41	42.78	39.68	-8.1%	5.9%	-7.2%
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]	92.94	106.13	78.81	41.21	14.2%	-25.7%	-47.7%
37 COAL ($/TON)	75.10	81.12	84.23	83.56	8.0%	3.8%	-0.8%
38 NATURAL GAS ($/MCF)	6.85	6.28	5.53	5.80	-8.3%	-11.9%	4.9%
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]	16.04	19.97	21.70	22.36	24.5%	8.7%	3.0%
43 COAL	3.09	3.38	3.52	3.48	9.4%	4.1%	-1.1%
44 NATURAL GAS	6.73	6.19	5.51	5.64	-8.0%	-11.0%	2.4%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**4.47**	**4.32**	**4.25**	**4.20**	**-3.4%**	**-1.6%**	**-1.2%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	9,878	10,878	10,341	10,296	10.1%	-4.9%	-0.4%
50 COAL	10,166	10,506	10,329	10,285	3.3%	-1.7%	-0.4%
51 NATURAL GAS	7,524	7,615	7,498	7,593	1.2%	-1.5%	1.3%
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)	9,003	9,338	9,118	9,217	3.7%	-2.4%	1.1%
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]	15.85	21.72	22.44	23.02	37.0%	3.3%	2.6%
57 COAL	3.14	3.55	3.63	3.58	13.1%	2.3%	-1.4%
58 NATURAL GAS	5.06	4.71	4.13	4.28	-6.9%	-12.3%	3.6%
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)	4.02	4.03	3.87	3.87	0.2%	-4.0%	0.0%

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

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2013 - DECEMBER 2013

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2013 through December 2013

	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	5,487,853	3.719	204,093,259	3.369	184,885,773
TIER II (Over 1,000) kWh	2,954,998	3.719	109,896,370	4.369	129,103,856
Total	8,442,851		313,989,629		313,989,629

Exhibit No.____ (CA-3)
Document No. 3, Page 1 of 1

EXHIBIT TO THE TESTIMONY OF

CARLOS ALDAZABAL

DOCUMENT NO. 4

PROJECTED POLK 1 CAPITAL COSTS

JANUARY 2013 - DECEMBER 2013

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY, 2013 THROUGH JUNE, 2013

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	TOTAL
1	BEGINNING BALANCE	$ -	$ -	$ -	$ -	$ -	$ 14,690,000	$ -
2	ADD INVESTMENT	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	-	-	-	-	-	14,690,000	-
5								
6								
7	AVERAGE BALANCE	-	-	-	-	-	14,690,000	
8	DEPRECIATION RATE	1.666670%	1.666670%	1.666670%	1.666670%	1.666670%	1.666670%	
9	DEPRECIATION EXPENSE	-	-	-	-	-	244,834	244,834
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	-	-	-	-	-	-
12	ENDING BALANCE DEPRECIATION	-	-	-	-	-	244,834	244,834
13								
14								
15	ENDING NET INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ 14,445,166	$ (244,834)
16								
17								
18	AVERAGE INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ 14,567,583	
19	ALLOWED EQUITY RETURN	.40281%	.40281%	.40281%	.40281%	.40281%	.40281%	
20	EQUITY COMPONENT AFTER-TAX	-	-	-	-	-	58,679	58,679
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	-	-	-	-	-	95,529	95,529
23								
24	ALLOWED DEBT RETURN	.22985%	.22985%	.22985%	.22985%	.22985%	.22985%	
25	DEBT COMPONENT	-	-	-	-	-	33,484	33,484
26								
27	TOTAL RETURN REQUIREMENTS	-	-	-	-	-	129,013	129,013
28								
29	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ -	$ -	$ -	$ 373,847	$ 373,847
30								
31	ESTIMATED FUEL SAVINGS	$0	$0	$0	$0	$0	$428,158	428,158
32	TOTAL DEPRECIATION & RETURN	-	-	-	-	-	373,847	373,847
33	NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ -	$ -	$ -	$ 54,311	$ 54,311
34								

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL MAY SR. RATE OF 7.59% (EQUITY 4.8348% , DEBT 2.7582%). THE EQUITY COMPONENT IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 080317-EI.
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%

Computation of Savings

	compute sav	compute sav	compute sav	compute sav	compute sav	compute sav
A4,clmn L / K,#2	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.22732
A4,clmn L / K, GS	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.05606
#2 less GS	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.17126
Gen. Cost Anal. Rept - Generat	0	0	0	0	0	2,500
Mult. by 1000.	0	0	0	0	0	2,500,000
= Fuel Savings	$0	$0	$0	$0	$0	$428,158

D:\caldazab\gasconvr\Polk 1 Capital Doc 4.xls
FIVEYEAR
8/24/2012 9:37 AM

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JULY, 2013 THROUGH DECEMBER, 2013

		JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 14,690,000	$ 14,690,000	$ 14,690,000	$ 14,690,000	$ 14,690,000	$ 14,690,000	$ 14,690,000
2	ADD INVESTMENT	-	-					-
3	LESS RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	14,690,000	14,690,000	14,690,000	14,690,000	14,690,000	14,690,000	14,690,000
5								
6								
7	AVERAGE BALANCE	14,690,000	14,690,000	14,690,000	14,690,000	14,690,000	14,690,000	
8	DEPRECIATION RATE	1.666670%	1.666670%	1.666670%	1.666670%	1.666670%	1.666670%	
9	DEPRECIATION EXPENSE	244,834	244,834	244,834	244,834	244,834	244,834	1,469,004
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	244,834	489,668	734,502	979,336	1,224,170	1,469,004	244,834
12	ENDING BALANCE DEPRECIATION	489,668	734,502	979,336	1,224,170	1,469,004	1,713,838	1,713,838
13								
14								
15	ENDING NET INVESTMENT	$ 14,200,332	$ 13,955,498	$ 13,710,664	$ 13,465,830	$ 13,220,996	$ 12,976,162	$ 12,976,162
16								
17								
18	AVERAGE INVESTMENT	$ 14,322,749	$ 14,077,915	$ 13,833,081	$ 13,588,247	$ 13,343,413	$ 13,098,579	
19	ALLOWED EQUITY RETURN	.40281%	.40281%	.40281%	.40281%	.40281%	.40281%	
20	EQUITY COMPONENT AFTER-TAX	57,693	56,707	55,721	54,735	53,748	52,762	331,366
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	93,924	92,319	90,714	89,109	87,502	85,897	539,465
23								
24	ALLOWED DEBT RETURN	.22985%	.22985%	.22985%	.22985%	.22985%	.22985%	
25	DEBT COMPONENT	32,921	32,358	31,795	31,233	30,670	30,107	189,084
26								
27	TOTAL RETURN REQUIREMENTS	126,845	124,677	122,509	120,342	118,172	116,004	728,549
28								
29	TOTAL DEPRECIATION & RETURN	$ 371,679	$ 369,511	$ 367,343	$ 365,176	$ 363,006	$ 360,838	$ 2,197,553
30								
31	ESTIMATED FUEL SAVINGS	$497,783	$451,997	$464,595	$470,833	$379,495	$473,798	2,738,500
32	TOTAL DEPRECIATION & RETURN	371,679	369,511	367,343	365,176	363,006	360,838	2,197,553
33	NET BENEFIT (COST) TO RATEPAYER	$ 126,104	$ 82,486	$ 97,252	$ 105,657	$ 16,489	$ 112,960	$ 540,947
34								

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL MAY SR. RATE OF 7.59% (EQUITY 4.8348% , DEBT 2.7582%). THE EQUITY COMPONENT IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 080317-EI.
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%

Computation of Savings

	compute sav	compute sav	compute sav	compute sav	compute sav	compute sav
A4,clmn m,#2	$0.23384	$0.21762	$0.22915	$0.22915	$0.22915	$0.22915
A4,clmn m,GS	$0.05606	$0.05619	$0.05644	$0.05794	$0.05743	$0.05810
#2 less GS	$0.17778	$0.16143	$0.17271	$0.17121	$0.17172	$0.17105
Gen. Cost Anal. Rept - Generat	2,800	2,800	2,690	2,750	2,210	2,770
Mult. by 1000.	2,800,000	2,800,000	2,690,000	2,750,000	2,210,000	2,770,000
=Savings	$497,783	$451,997	$464,595	$470,833	$379,495	$473,798

D:\caldazab\gasconvr\Polk 1 Capital Doc 4.xls
FIVEYEAR
8/24/2012 9:37 AM

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: AUGUST 31, 2012

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 1993 as a Co-op Student. Upon graduation, I continued my career 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, instrumentation and controls, performance planning and asset management. I was promoted to Manager, Operations Planning in 2008. As of 2012, I am the Manager of Compliance and Performance responsible for NERC compliance standards, unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents 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 2013 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 outage from Bayside Unit 1 was identified as an outlying outage; therefore, the associated forced outage hours were removed from the study.

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 2013 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 2013 period, the projected EUOF for Bayside Unit 1 is 1.0 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit

1 equals 94.1 percent or:

$$100\% - (1.0\% + 4.9\%) = 94.1\%$$

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

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

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

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

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80 \; (1.0\%) + 0.95 \; (4.9\%)] = 94.5\%$$

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,

$$EAF_{MIN} = 1 - [1.40 \ (1.0\%) + 1.10 \ (4.9\%)] = 93.2\%$$

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 2013 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2013; 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 9, 2013 to March 17, 2013 and November 16, 2013 to November 24, 2013. There are 432 planned outage hours scheduled for the 2013 period, and a total of 8760 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 6.6 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 21.1 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 9.6 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 5.5 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 2012, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in a EUOF of 1.0 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

$$EUOF = \frac{(0 + 84)}{8,760} \times 100\% = 1.0\%$$

Relative to Bayside Unit 1, the EUOF of 1.0 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 29.2 percent. The unit will have a planned outage in 2013, and the POF is

6.6 percent. Therefore, the target equivalent availability for this unit is 64.2 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.7 percent. The unit will have a planned outage in 2013, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.8 percent.

Big Bend Unit 3

The projected EUOF for this unit is 18.1 percent. The unit will have a planned outage in 2013, and the POF is 21.1 percent. Therefore, the target equivalent availability for this unit is 60.8 percent.

Big Bend Unit 4

The projected EUOF for this unit is 9.8 percent. The unit will have a planned outage in 2013, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 83.6 percent.

Polk Unit 1

The projected EUOF for this unit is 15.3 percent. The unit will have a planned outage in 2013, and the POF is 9.6 percent. Therefore, the target equivalent availability for this unit is 75.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.0 percent. The unit will have a planned outage in 2013, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 94.1 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.3 percent. The unit will have a planned outage in 2013, and the POF is 5.5 percent. Therefore, the target equivalent availability for this unit is 93.2 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 73.5 percent is shown on Page 5 of Document No. 1. This target is greater than the 2009 and 2010 January through December actual performances and the three year period average.

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 November, 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 November, 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 2013 period.

A. The heat rate target for Big Bend Unit 1 is 10,530

Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±653 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,199 Btu/Net kWh with a range of ±213 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,614 Btu/Net kWh, with a range of ±388 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,536 Btu/Net kWh with a range of ±412 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,437 Btu/Net kWh with a range of ±605 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,177 Btu/Net kWh with a range of ±150 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,325 Btu/Net kWh with a range of ±129 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 $746,179,030 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 $23,316,906 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 8.8 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 7,027 average net operating heat rate, fuel savings would equal $2,051,933 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 $23,316,906. 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 2013 is $2,010,138,931. This produces the maximum allowed jurisdictional incentive of $8,215,862 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.

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):

$$
\begin{aligned}
GPIP: = (\ & 0.1046\ EAP_{BB1} + 0.0269\ EAP_{BB2} \\
& + 0.0133\ EAP_{BB3} + 0.0686\ EAP_{BB4} \\
& + 0.0063\ EAP_{PK1} + 0.0005\ EAP_{BAY1} \\
& + 0.0199\ EAP_{BAY2} + 0.1782\ HRP_{BB1} \\
& + 0.0598\ HRP_{BB2} + 0.1075\ HRP_{BB3} \\
& + 0.1121\ HRP_{BB4} + 0.1391\ HRP_{PK1} \\
& + 0.0880\ HRP_{BAY1} + 0.0750\ HRP_{BAY2})
\end{aligned}
$$

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 2013 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 2013 - DECEMBER 2013

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2013 - DECEMBER 2013
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2013 - DECEMBER 2013

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	23,316.9	8,215.9
+9	20,985.2	7,394.3
+8	18,653.5	6,572.7
+7	16,321.8	5,751.1
+6	13,990.1	4,929.5
+5	11,658.5	4,107.9
+4	9,326.8	3,286.3
+3	6,995.1	2,464.8
+2	4,663.4	1,643.2
+1	2,331.7	821.6
0	0.0	0.0
-1	(2,499.9)	(821.6)
-2	(4,999.8)	(1,643.2)
-3	(7,499.7)	(2,464.8)
-4	(9,999.6)	(3,286.3)
-5	(12,499.5)	(4,107.9)
-6	(14,999.4)	(4,929.5)
-7	(17,499.3)	(5,751.1)
-8	(19,999.2)	(6,572.7)
-9	(22,499.1)	(7,394.3)
-10	(24,999.0)	(8,215.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2013 - DECEMBER 2013

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,983,321,000	
Line 2	Month of January	2013	$	1,929,433,000	
Line 3	Month of February	2013	$	1,947,521,434	
Line 4	Month of March	2013	$	1,965,779,448	
Line 5	Month of April	2013	$	2,001,750,182	
Line 6	Month of May	2013	$	2,020,516,590	
Line 7	Month of June	2013	$	2,039,458,933	
Line 8	Month of July	2013	$	1,984,899,375	
Line 9	Month of August	2013	$	2,003,507,807	
Line 10	Month of September	2013	$	2,022,290,693	
Line 11	Month of October	2013	$	2,058,417,909	
Line 12	Month of November	2013	$	2,077,715,576	
Line 13	Month of December	2013	$	2,097,194,160	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,010,138,931	
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)		$	8,215,862	
Line 18	Jurisdictional Sales			18,202,016	MWH
Line 19	Total Sales			18,202,016	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)**		**$**	**8,215,862**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2013 - DECEMBER 2013

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	10.46%	64.2	70.4	51.9	2,439.8	(1,203.1)
BIG BEND 2	2.69%	74.8	78.8	66.7	626.9	(557.3)
BIG BEND 3	1.33%	60.8	65.5	51.4	310.8	(2,550.5)
BIG BEND 4	6.86%	83.6	85.9	79.1	1,599.9	(1,511.6)
POLK 1	0.63%	75.1	78.7	68.1	147.7	(269.7)
BAYSIDE 1	0.05%	94.1	94.5	93.2	12.6	(1,124.3)
BAYSIDE 2	1.99%	93.2	93.8	92.2	463.7	(66.9)
GPIF SYSTEM	**24.02%**					

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	17.82%	10,530	85.1	9,876	11,183	4,155.7	(4,155.7)
BIG BEND 2	5.98%	10,199	87.9	9,986	10,412	1,394.7	(1,394.7)
BIG BEND 3	10.75%	10,614	84.2	10,226	11,001	2,505.8	(2,505.8)
BIG BEND 4	11.21%	10,536	83.6	10,124	10,947	2,614.9	(2,614.9)
POLK 1	13.91%	10,437	95.3	9,832	11,042	3,243.0	(3,243.0)
BAYSIDE 1	8.80%	7,177	83.4	7,027	7,327	2,051.9	(2,051.9)
BAYSIDE 2	7.50%	7,325	83.1	7,196	7,454	1,749.5	(1,749.5)
GPIF SYSTEM	**75.98%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 13 - DEC 13			ACTUAL PERFORMANCE JAN 11 - DEC 11			ACTUAL PERFORMANCE JAN 10 - DEC 10			ACTUAL PERFORMANCE JAN 09 - DEC 09		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	10.46%	43.6%	6.6	29.2	31.3	5.8	13.5	14.4	24.5	15.1	19.9	14.0	30.3	35.3
BIG BEND 2	2.69%	11.2%	6.6	18.7	20.0	17.1	25.4	30.6	5.5	26.1	27.6	26.5	36.7	49.9
BIG BEND 3	1.33%	5.5%	21.1	18.1	23.0	8.6	17.9	19.5	8.4	11.9	13.1	5.0	16.2	17.0
BIG BEND 4	6.86%	28.6%	6.6	9.8	10.5	9.4	15.1	16.7	19.3	14.2	17.5	1.9	18.6	19.0
POLK 1	0.63%	2.6%	9.6	15.3	16.9	4.4	17.3	18.5	4.8	5.2	5.7	14.1	9.4	12.7
BAYSIDE 1	0.05%	0.2%	4.9	1.0	1.0	21.2	1.3	2.0	5.0	1.1	1.1	5.6	1.3	1.4
BAYSIDE 2	1.99%	8.3%	5.5	1.3	1.3	3.2	4.6	4.8	8.7	1.8	1.9	6.8	1.3	1.4
GPIF SYSTEM	**24.02%**	**100.0%**	**7.4**	**19.1**	**20.7**	**8.0**	**14.9**	**16.4**	**18.1**	**14.5**	**17.8**	**10.8**	**23.9**	**27.8**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**73.5**			**77.1**			**67.4**			**65.3**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
12.3	**17.7**	**20.7**	**69.9**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 13 - DEC 13	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 11 - DEC 11	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 10 - DEC 10	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 09 - DEC 09
BIG BEND 1	17.82%	23.5%	10,530	10,718	10,287	10,582
BIG BEND 2	5.98%	7.9%	10,199	10,290	10,175	10,222
BIG BEND 3	10.75%	14.1%	10,614	10,529	10,761	10,611
BIG BEND 4	11.21%	14.8%	10,536	10,476	10,513	10,699
POLK 1	13.91%	18.3%	10,437	10,840	10,360	9,759
BAYSIDE 1	8.80%	11.6%	7,177	7,147	7,152	7,174
BAYSIDE 2	7.50%		7,325	7,290	7,307	7,288
GPIF SYSTEM	**75.98%**	**90.1%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**10,065**	**10,177**	**10,001**	**9,969**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2013 - DECEMBER 2013
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	746,179.0	743,739.3	2,439.8	10.46%
EA_2 BIG BEND 2	746,179.0	745,552.1	626.9	2.69%
EA_3 BIG BEND 3	746,179.0	745,868.3	310.8	1.33%
EA_4 BIG BEND 4	746,179.0	744,579.2	1,599.9	6.86%
EA_7 POLK 1	746,179.0	746,031.4	147.7	0.63%
EA_8 BAYSIDE 1	746,179.0	746,166.4	12.6	0.05%
EA_9 BAYSIDE 2	746,179.0	745,715.3	463.7	1.99%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	746,179.0	742,023.3	4,155.7	17.82%
AHR_2 BIG BEND 2	746,179.0	744,784.3	1,394.7	5.98%
AHR_3 BIG BEND 3	746,179.0	743,673.2	2,505.8	10.75%
AHR_4 BIG BEND 4	746,179.0	743,564.1	2,614.9	11.21%
AHR_7 POLK 1	746,179.0	742,936.0	3,243.0	13.91%
AHR_8 BAYSIDE 1	746,179.0	744,127.1	2,051.9	8.80%
AHR_9 BAYSIDE 2	746,179.0	744,429.5	1,749.5	7.50%
TOTAL SAVINGS			**23,316.9**	**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 2013 - DECEMBER 2013

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,439.8	70.4	+10	4,155.7	9,876
+9	2,195.8	69.8	+9	3,740.2	9,934
+8	1,951.8	69.1	+8	3,324.6	9,992
+7	1,707.8	68.5	+7	2,909.0	10,050
+6	1,463.9	67.9	+6	2,493.4	10,108
+5	1,219.9	67.3	+5	2,077.9	10,166
+4	975.9	66.7	+4	1,662.3	10,223
+3	731.9	66.1	+3	1,246.7	10,281
+2	488.0	65.4	+2	831.1	10,339
+1	244.0	64.8	+1	415.6	10,397
					10,455
0	0.0	64.2	0	0.0	10,530
					10,605
-1	(120.3)	63.0	-1	(415.6)	10,662
-2	(240.6)	61.7	-2	(831.1)	10,720
-3	(360.9)	60.5	-3	(1,246.7)	10,778
-4	(481.3)	59.3	-4	(1,662.3)	10,836
-5	(601.6)	58.0	-5	(2,077.9)	10,894
-6	(721.9)	56.8	-6	(2,493.4)	10,952
-7	(842.2)	55.6	-7	(2,909.0)	11,009
-8	(962.5)	54.3	-8	(3,324.6)	11,067
-9	(1,082.8)	53.1	-9	(3,740.2)	11,125
-10	(1,203.1)	51.9	-10	(4,155.7)	11,183
	Weighting Factor =	10 46%		Weighting Factor =	17 82%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	626.9	78.8	+10	1,394.7	9,986
+9	564.2	78.4	+9	1,255.2	10,000
+8	501.5	78.0	+8	1,115.7	10,014
+7	438.8	77.6	+7	976.3	10,028
+6	376.1	77.2	+6	836.8	10,041
+5	313.4	76.8	+5	697.3	10,055
+4	250.8	76.4	+4	557.9	10,069
+3	188.1	76.0	+3	418.4	10,083
+2	125.4	75.6	+2	278.9	10,097
+1	62.7	75.2	+1	139.5	10,110
					10,124
0	0.0	74.8	0	0.0	10,199
					10,274
-1	(55.7)	74.0	-1	(139.5)	10,288
-2	(111.5)	73.1	-2	(278.9)	10,302
-3	(167.2)	72.3	-3	(418.4)	10,315
-4	(222.9)	71.5	-4	(557.9)	10,329
-5	(278.6)	70.7	-5	(697.3)	10,343
-6	(334.4)	69.9	-6	(836.8)	10,357
-7	(390.1)	69.1	-7	(976.3)	10,370
-8	(445.8)	68.3	-8	(1,115.7)	10,384
-9	(501.5)	67.5	-9	(1,255.2)	10,398
-10	(557.3)	66.7	-10	(1,394.7)	10,412
	Weighting Factor =	2.69%		Weighting Factor =	5.98%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	310.8	65.5	+10	2,505.8	10,226
+9	279.7	65.0	+9	2,255.2	10,257
+8	248.6	64.5	+8	2,004.6	10,289
+7	217.5	64.1	+7	1,754.0	10,320
+6	186.5	63.6	+6	1,503.5	10,351
+5	155.4	63.1	+5	1,252.9	10,383
+4	124.3	62.7	+4	1,002.3	10,414
+3	93.2	62.2	+3	751.7	10,445
+2	62.2	61.7	+2	501.2	10,476
+1	31.1	61.3	+1	250.6	10,508
					10,539
0	0.0	60.8	0	0.0	10,614
					10,689
-1	(255.0)	59.8	-1	(250.6)	10,720
-2	(510.1)	58.9	-2	(501.2)	10,751
-3	(765.1)	58.0	-3	(751.7)	10,783
-4	(1,020.2)	57.0	-4	(1,002.3)	10,814
-5	(1,275.2)	56.1	-5	(1,252.9)	10,845
-6	(1,530.3)	55.2	-6	(1,503.5)	10,876
-7	(1,785.3)	54.2	-7	(1,754.0)	10,908
-8	(2,040.4)	53.3	-8	(2,004.6)	10,939
-9	(2,295.4)	52.4	-9	(2,255.2)	10,970
-10	(2,550.5)	51.4	-10	(2,505.8)	11,001
	Weighting Factor =	1.33%		Weighting Factor =	10.75%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,599.9	85.9	+10	2,614.9	10,124
+9	1,439.9	85.7	+9	2,353.4	10,157
+8	1,279.9	85.5	+8	2,092.0	10,191
+7	1,119.9	85.2	+7	1,830.5	10,225
+6	959.9	85.0	+6	1,569.0	10,258
+5	799.9	84.8	+5	1,307.5	10,292
+4	640.0	84.6	+4	1,046.0	10,326
+3	480.0	84.3	+3	784.5	10,360
+2	320.0	84.1	+2	523.0	10,393
+1	160.0	83.9	+1	261.5	10,427
					10,461
0	0.0	83.6	0	0.0	10,536
					10,611
-1	(151.2)	83.2	-1	(261.5)	10,644
-2	(302.3)	82.7	-2	(523.0)	10,678
-3	(453.5)	82.3	-3	(784.5)	10,712
-4	(604.7)	81.8	-4	(1,046.0)	10,745
-5	(755.8)	81.4	-5	(1,307.5)	10,779
-6	(907.0)	80.9	-6	(1,569.0)	10,813
-7	(1,058.1)	80.4	-7	(1,830.5)	10,846
-8	(1,209.3)	80.0	-8	(2,092.0)	10,880
-9	(1,360.5)	79.5	-9	(2,353.4)	10,914
-10	(1,511.6)	79.1	-10	(2,614.9)	10,947
	Weighting Factor =	6.86%		Weighting Factor =	11.21%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	147.7	78.7	+10	3,243.0	9,832
+9	132.9	78.3	+9	2,918.7	9,885
+8	118.1	78.0	+8	2,594.4	9,938
+7	103.4	77.6	+7	2,270.1	9,991
+6	88.6	77.2	+6	1,945.8	10,044
+5	73.8	76.9	+5	1,621.5	10,097
+4	59.1	76.5	+4	1,297.2	10,150
+3	44.3	76.2	+3	972.9	10,203
+2	29.5	75.8	+2	648.6	10,256
+1	14.8	75.5	+1	324.3	10,309
					10,362
0	0.0	75.1	0	0.0	10,437
					10,512
-1	(27.0)	74.4	-1	(324.3)	10,565
-2	(53.9)	73.7	-2	(648.6)	10,618
-3	(80.9)	73.0	-3	(972.9)	10,671
-4	(107.9)	72.3	-4	(1,297.2)	10,724
-5	(134.8)	71.6	-5	(1,621.5)	10,777
-6	(161.8)	70.9	-6	(1,945.8)	10,830
-7	(188.8)	70.2	-7	(2,270.1)	10,883
-8	(215.7)	69.5	-8	(2,594.4)	10,936
-9	(242.7)	68.8	-9	(2,918.7)	10,989
-10	(269.7)	68.1	-10	(3,243.0)	11,042
	Weighting Factor =	0.63%		Weighting Factor =	13.91%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	12.6	94.5	+10	2,051.9	7,027
+9	11.3	94.5	+9	1,846.7	7,034
+8	10.1	94.5	+8	1,641.5	7,042
+7	8.8	94.4	+7	1,436.4	7,049
+6	7.6	94.4	+6	1,231.2	7,057
+5	6.3	94.3	+5	1,026.0	7,064
+4	5.0	94.3	+4	820.8	7,072
+3	3.8	94.2	+3	615.6	7,079
+2	2.5	94.2	+2	410.4	7,087
+1	1.3	94.2	+1	205.2	7,094
					7,102
0	0.0	94.1	0	0.0	7,177
					7,252
-1	(112.4)	94.0	-1	(205.2)	7,259
-2	(224.9)	93.9	-2	(410.4)	7,267
-3	(337.3)	93.8	-3	(615.6)	7,274
-4	(449.7)	93.8	-4	(820.8)	7,282
-5	(562.2)	93.7	-5	(1,026.0)	7,289
-6	(674.6)	93.6	-6	(1,231.2)	7,297
-7	(787.0)	93.5	-7	(1,436.4)	7,304
-8	(899.4)	93.4	-8	(1,641.5)	7,312
-9	(1,011.9)	93.3	-9	(1,846.7)	7,319
-10	(1,124.3)	93.2	-10	(2,051.9)	7,327

Weighting Factor = 0.05% Weighting Factor = 8.80%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2013 - DECEMBER 2013

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	463.7	93.8	+10	1,749.5	7,196
+9	417.3	93.7	+9	1,574.6	7,201
+8	371.0	93.7	+8	1,399.6	7,207
+7	324.6	93.6	+7	1,224.7	7,212
+6	278.2	93.6	+6	1,049.7	7,218
+5	231.8	93.5	+5	874.8	7,223
+4	185.5	93.5	+4	699.8	7,228
+3	139.1	93.4	+3	524.9	7,234
+2	92.7	93.4	+2	349.9	7,239
+1	46.4	93.3	+1	175.0	7,244
					7,250
0	0.0	93.2	0	0.0	7,325
					7,400
-1	(6.7)	93.1	-1	(175.0)	7,405
-2	(13.4)	93.0	-2	(349.9)	7,411
-3	(20.1)	92.9	-3	(524.9)	7,416
-4	(26.8)	92.8	-4	(699.8)	7,421
-5	(33.5)	92.7	-5	(874.8)	7,427
-6	(40.1)	92.6	-6	(1,049.7)	7,432
-7	(46.8)	92.5	-7	(1,224.7)	7,437
-8	(53.5)	92.4	-8	(1,399.6)	7,443
-9	(60.2)	92.3	-9	(1,574.6)	7,448
-10	(66.9)	92.2	-10	(1,749.5)	7,454
	Weighting Factor =	1.99%		Weighting Factor =	7.50%

33

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BIG BEND 1	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	68 7	34 4	68.7	68 7	68 7	68 7	68.7	68.7	68 7	68 7	68 7	46 6	64.2
2. POF	0 0	50.0	0 0	0 0	0 0	0 0	0.0	0 0	0 0	0.0	0.0	32.3	6.6
3 EUOF	31.3	15 6	31.3	31.3	31 3	31 3	31 3	31 3	31.3	31 3	31 3	21.2	29.2
4. EUOR	31 3	31 3	31 3	31 3	31 3	31.3	31 3	31 3	31 3	31 3	31 3	31 3	31.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	564	255	564	546	564	546	564	564	546	564	546	382	6,205
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	180	417	179	174	180	174	180	180	174	180	175	362	2,555
9. POH	0	336	0	0	0	0	0	0	0	0	0	240	576
10 EFOH	222	100	222	215	222	215	222	222	215	222	215	150	2,442
11 EMOH	11	5	11	10	11	10	11	11	10	11	10	7	118
12 OPER BTU (GBTU)	1,961	877	2,013	1,876	1,974	1,897	2,000	2,006	1,929	1,935	1,829	1,294	21,595
13 NET GEN (MWH)	185,890	83,000	191,380	178,130	187,720	180,310	190,470	191,130	183,710	183,640	173,170	122,300	2,050,850
14. ANOHR (Btu/kwh)	10,550	10,562	10,520	10,534	10,514	10,522	10,498	10,495	10,502	10,536	10,562	10,578	10,530
15. NOF (%)	83.4	82 4	85 9	84 7	86 5	85.8	87 7	88 0	87 4	84.6	82.4	81 1	85.1
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388

17 ANOHR EQUATION ANOHR = NOF(-12 004) + 11,551

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BIG BEND 2	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	80.0	40 0	80 0	80 0	80 0	80 0	80 0	80 0	80 0	80.0	80 0	54 2	74 8
2 POF	0 0	50.0	0 0	0.0	0 0	0 0	0.0	0 0	0 0	0 0	0.0	32 3	6 6
3 EUOF	20 0	10 0	20 0	20 0	20 0	20 0	20.0	20.0	20 0	20.0	20.0	13.5	18 7
4 EUOR	20.0	20 0	20 0	20 0	20 0	20 0	20 0	20 0	20 0	20 0	20 0	20 0	20 0
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6 SH	664	300	664	642	664	642	664	664	642	664	642	450	7,302
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	80	372	79	78	80	78	80	80	78	80	79	294	1,458
9. POH	0	336	0	0	0	0	0	0	0	0	0	240	576
10. EFOH	120	54	120	116	120	116	120	120	116	120	117	82	1,324
11 EMOH	28	13	28	27	28	27	28	28	27	28	27	19	311
12. OPER BTU (GBTU)	2,339	1,000	2,344	2,210	2,326	2,253	2,329	2,330	2,240	2,285	2,192	1,560	25,412
13. NET GEN (MWH)	229,250	97,390	229,790	216,680	228,480	221,330	228,770	228,850	219,910	223,940	214,670	152,560	2,491,620
14 ANOHR (Btu/kwh)	10,204	10,264	10,202	10,201	10,182	10,180	10,181	10,180	10,187	10,202	10,211	10,222	10,199
15. NOF (%)	87 4	82 2	87.6	87.7	89 4	89 5	89 5	89 5	89 0	87 6	86.9	85.8	87 9
16 NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17 ANOHR EQUATION	ANOHR = NOF(		-11 395	) +	11,200								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BIG BEND 3	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	77.0	77 0	2.5	0.0	52.2	77 0	77 0	77 0	77 0	59 6	77 0	77 0	60 8
2 POF	0 0	0 0	96 8	100.0	32 3	0 0	0.0	0 0	0 0	22 6	0.0	0.0	21 1
3. EUOF	23.0	23 0	0.7	0 0	15 6	23 0	23 0	23 0	23 0	17 8	23 0	23.0	18 1
4 EUOR	23.0	23 0	23 0	0.0	23 0	23 0	23 0	23 0	23 0	23 0	23 0	23 0	23 0
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	601	543	20	0	407	582	601	601	582	466	582	601	5,586
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	143	129	723	720	337	138	143	143	138	278	139	143	3,174
9 POH	0	0	719	720	240	0	0	0	0	168	0	0	1,847
10 EFOH	156	141	5	0	106	151	156	156	151	121	151	156	1,451
11 EMOH	15	13	0	0	10	14	15	15	14	11	14	15	138
12 OPER BTU (GBTU)	1,956	1,824	27	0	1,308	1,930	1,994	2,022	1,920	1,465	1,833	1,933	18,217
13 NET GEN (MWH)	184,190	172,900	2,280	0	122,830	182,510	188,520	191,720	181,340	137,050	171,460	181,550	1,716,350
14 ANOHR (Btu/kwh)	10,618	10,548	11,762	0	10,646	10,576	10,576	10,544	10,588	10,692	10,689	10,645	10,614
15 NOF (%)	84.0	87 2	31 2	0 0	82 7	85.9	85 9	87.4	85 4	80 6	80 7	82.8	84 2
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365

17 ANOHR EQUATION ANOHR = NOF(-21 678) + 12,439

35

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BIG BEND 4	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	89.5	89.5	63.5	74.6	89.5	89.5	89.5	89.5	89.5	89.5	59.7	89.5	83.6
2 POF	0.0	0.0	29.1	16.7	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3 EUOF	10.5	10.5	7.4	8.7	10.5	10.5	10.5	10.5	10.5	10.5	7.0	10.5	9.8
4 EUOR	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
5 PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	719	649	510	580	719	696	719	719	696	719	464	719	7,909
7 RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	25	23	233	140	25	24	25	25	24	25	257	25	851
9 POH	0	0	216	120	0	0	0	0	0	0	240	0	576
10. EFOH	64	58	45	52	64	62	64	64	62	64	41	64	705
11 EMOH	14	12	10	11	14	13	14	14	13	14	9	14	152
12 OPER BTU (GBTU)	2,580	2,419	1,859	1,862	2,659	2,653	2,721	2,740	2,490	2,391	1,514	2,680	28,593
13. NET GEN (MWH)	243,520	230,420	176,060	172,470	254,340	255,840	261,880	264,150	236,160	223,110	140,730	255,250	2,713,930
14 ANOHR (Btu/kwh)	10,595	10,498	10,556	10,795	10,455	10,371	10,392	10,372	10,542	10,717	10,760	10,499	10,536
15 NOF (%)	81.2	85.1	82.8	73.1	86.9	90.3	89.5	90.3	83.4	76.2	74.5	85.1	83.6
16 NPC (MW)	417	417	417	407	407	407	407	407	407	407	407	417	410

17 ANOHR EQUATION ANOHR = NOF(-24.581) + 12,591

36

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
POLK 1	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	83.1	83.1	83.1	55.4	29.5	83.1	83.1	83.1	83.1	83.1	69.2	83.1	75.1
2 POF	0.0	0.0	0.0	33.3	64.5	0.0	0.0	0.0	0.0	0.0	16.8	0.0	9.6
3 EUOF	16.9	16.9	16.9	11.3	6.0	16.9	16.9	16.9	16.9	16.9	14.1	16.9	15.3
4. EUOR	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
5 PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6 SH	634	573	634	409	225	613	634	634	613	634	511	634	6,748
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8 UH	110	99	109	311	519	107	110	110	107	110	210	110	2,012
9 POH	0	0	0	240	480	0	0	0	0	0	121	0	841
10 EFOH	113	102	113	73	40	109	113	113	109	113	91	113	1,200
11 EMOH	13	12	13	8	5	12	13	13	12	13	10	13	137
12 OPER BTU (GBTU)	1,396	1,259	1,388	898	494	1,336	1,381	1,381	1,337	1,385	1,117	1,382	14,764
13 NET GEN (MWH)	126,420	117,240	132,250	83,730	46,160	130,900	135,550	135,730	130,330	133,770	107,390	135,120	1,414,590
14. ANOHR (Btu/kwh)	11,044	10,735	10,498	10,728	10,702	10,205	10,190	10,173	10,260	10,356	10,406	10,230	10,437
15 NOF (%)	90.6	93.0	94.8	93.1	93.3	97.1	97.2	97.3	96.6	95.9	95.5	96.9	95.3
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17 ANOHR EQUATION	ANOHR = NOF(	-130.472	) +		22,869								

37

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BAYSIDE 1	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	99.0	99.0	70.2	99.0	99.0	99.0	99.0	99.0	99.0	99.0	69.3	99.0	94.1
2. POF	0.0	0.0	29.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	4.9
3. EUOF	1.0	1.0	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.7	1.0	1.0
4. EUOR	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
5 PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	493	536	502	375	435	445	466	457	443	382	258	575	5,366
7 RSH	244	129	19	338	302	268	270	280	269	354	242	161	2,877
8 UH	8	7	221	7	8	7	8	8	7	8	221	8	516
9 POH	0	0	216	0	0	0	0	0	0	0	216	0	432
10 EFOH	0	0	0	0	0	0	0	0	0	0	0	0	0
11. EMOH	8	7	5	7	8	7	8	8	7	8	5	8	84
12. OPER BTU (GBTU)	2,028	2,433	2,235	1,601	1,897	1,969	2,079	2,023	1,970	1,625	1,067	2,561	23,480
13 NET GEN (MWH)	276,820	336,750	308,390	223,680	266,080	276,900	292,690	284,550	277,190	226,860	148,310	353,490	3,271,710
14. ANOHR (Btu/kwh)	7,327	7,226	7,247	7,155	7,129	7,111	7,102	7,111	7,107	7,162	7,192	7,246	7,177
15 NOF (%)	70.9	79.3	77.5	85.2	87.3	88.8	89.6	88.9	89.2	84.6	82.1	77.6	83.4
16 NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17 ANOHR EQUATION	ANOHR = NOF(	-12.033	) +		8,180								

38

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2013 - DECEMBER 2013

PLANT/UNIT	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	MONTH OF	PERIOD
BAYSIDE 2	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1 EAF (%)	98 7	66.9	95 5	98.7	98 7	98 7	98 7	98 7	98 7	98.7	92.1	73 2	93 2
2 POF	0.0	32 1	3 2	0 0	0 0	0.0	0 0	0 0	0 0	0.0	6.7	25 8	5 5
3 EUOF	1.3	0.9	1 3	1 3	1.3	1 3	1 3	1 3	1 3	1 3	1 3	1 0	1 3
4. EUOR	1 3	1.3	1 3	1 3	1 3	1 3	1 3	1.3	1 3	1 3	1.3	1.3	1 3
5 PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	242	232	347	622	628	611	654	668	618	558	472	198	5,850
7. RSH	492	218	363	88	106	99	80	66	93	176	192	347	2,319
8 UH	10	222	34	10	10	10	10	10	10	10	57	199	592
9 POH	0	216	24	0	0	0	0	0	0	0	48	192	480
10 EFOH	4	2	3	3	4	3	4	4	3	4	3	3	40
11. EMOH	6	4	6	6	6	6	6	6	6	6	6	5	71
12. OPER BTU (GBTU)	1,381	1,469	2,198	3,587	3,676	3,604	3,860	3,906	3,647	3,238	2,625	1,185	34,453
13. NET GEN (MWH)	186,270	200,430	299,930	490,940	504,030	494,620	529,700	535,430	500,480	443,510	357,600	160,690	4,703,630
14. ANOHR (Btu/kwh)	7,413	7,331	7,328	7,307	7,294	7,287	7,287	7,294	7,286	7,301	7,339	7,375	7,325
15 NOF (%)	73.6	82.4	82.7	84 9	86 4	87 1	87.2	86 3	87.2	85 6	81.5	77 7	83 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(-9 350) + 8,101

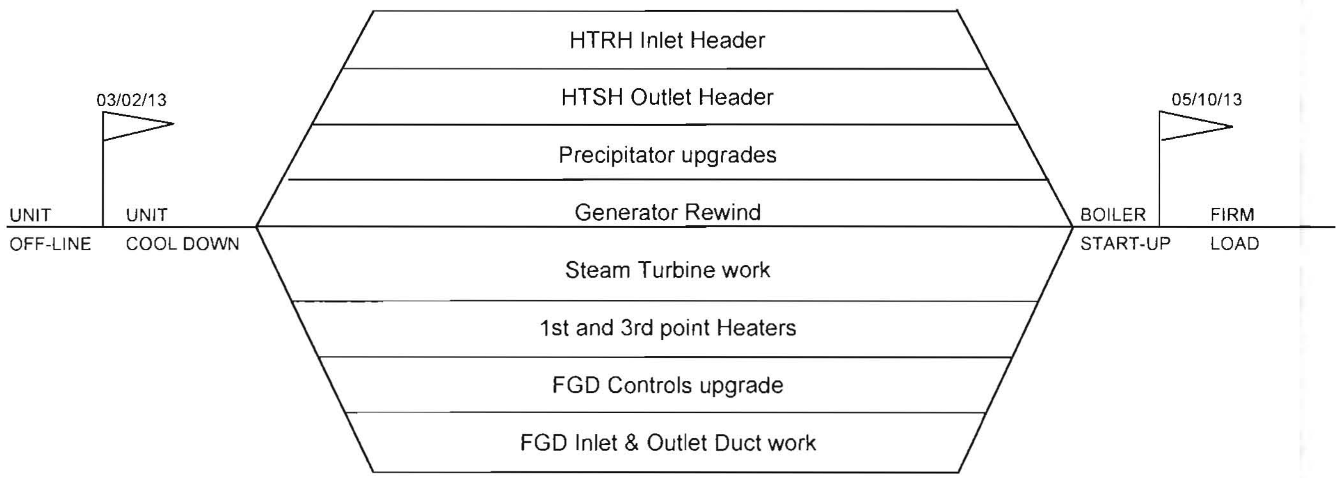
39

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2013 - DECEMBER 2013

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Feb 02	-	Feb 15	Fuel System Cleanup and FGD/SCR work
		Dec 08	-	Dec 17	Fuel System Cleanup
	BIG BEND 2	Feb 03	-	Feb 16	Fuel System Cleanup
		Dec 09	-	Dec 18	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 3	Mar 02	-	May 10	Generator Rewind, Precipitator upgrades, HTSH Outlet Header, HTRH Inlet Header, Steam Turbine work, 1st and 3rd point Heaters, Furnace Floor Refractory, Slag Tank Necks, FGD Controls upgrade, FGD Inlet & Outlet Duct work
		Oct 05	-	Oct 11	Fuel System Cleanup
	BIG BEND 4	Mar 23	-	Apr 05	Fuel System Cleanup and FGD/SCR work
		Nov 02	-	Nov 11	Fuel System Cleanup
+	POLK 1	Apr 21	-	May 20	CT and Gasifier Inspection, Replace MAC Motor, Replace Gox Motor and Compressor Wheel, Replace ASU Dgan Motor, Natural Gas S/U Fuel Conversion, Replace Catalyst and clean towers, Aux Boiler Natural Gas Conversion, Geho Pump Inspection
		Nov 03	-	Nov 07	Gasifier Outage
	BAYSIDE 1	Mar 09	-	Mar 17	Fuel System Cleanup
		Nov 16	-	Nov 24	Fuel System Cleanup
	BAYSIDE 2	Feb 20	-	Mar 01	Fuel System Cleanup
		Nov 29	-	Dec 08	Fuel System Cleanup

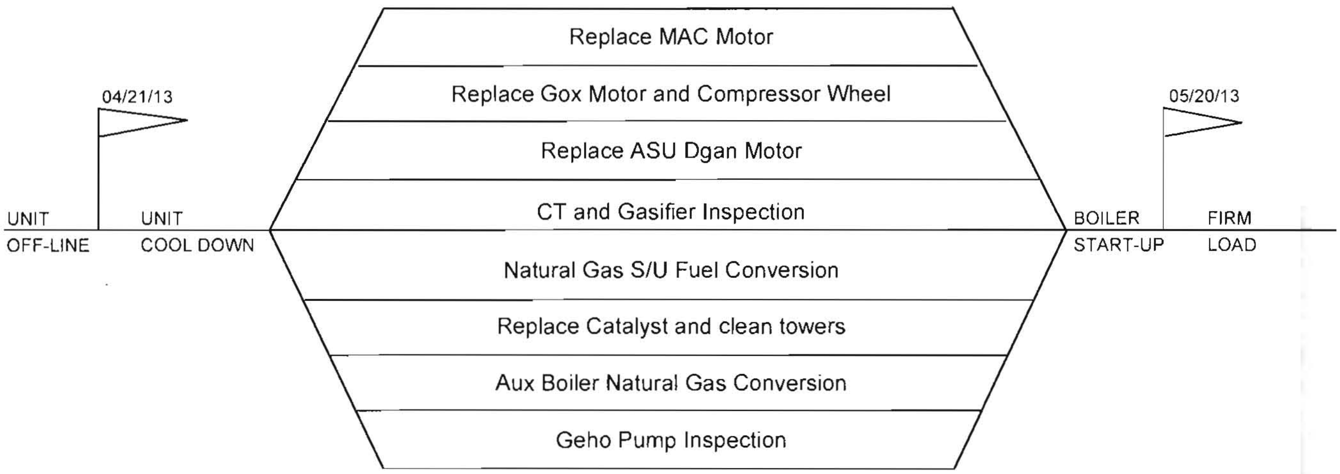
\+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2013 - DECEMBER 2013

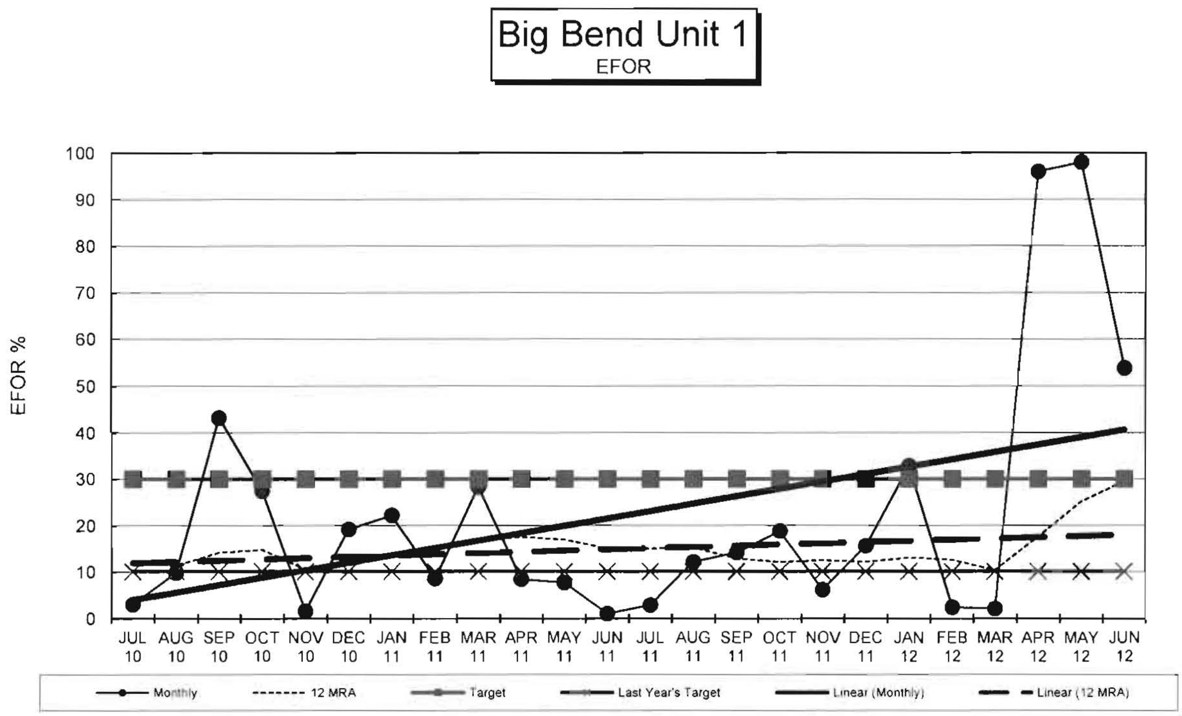


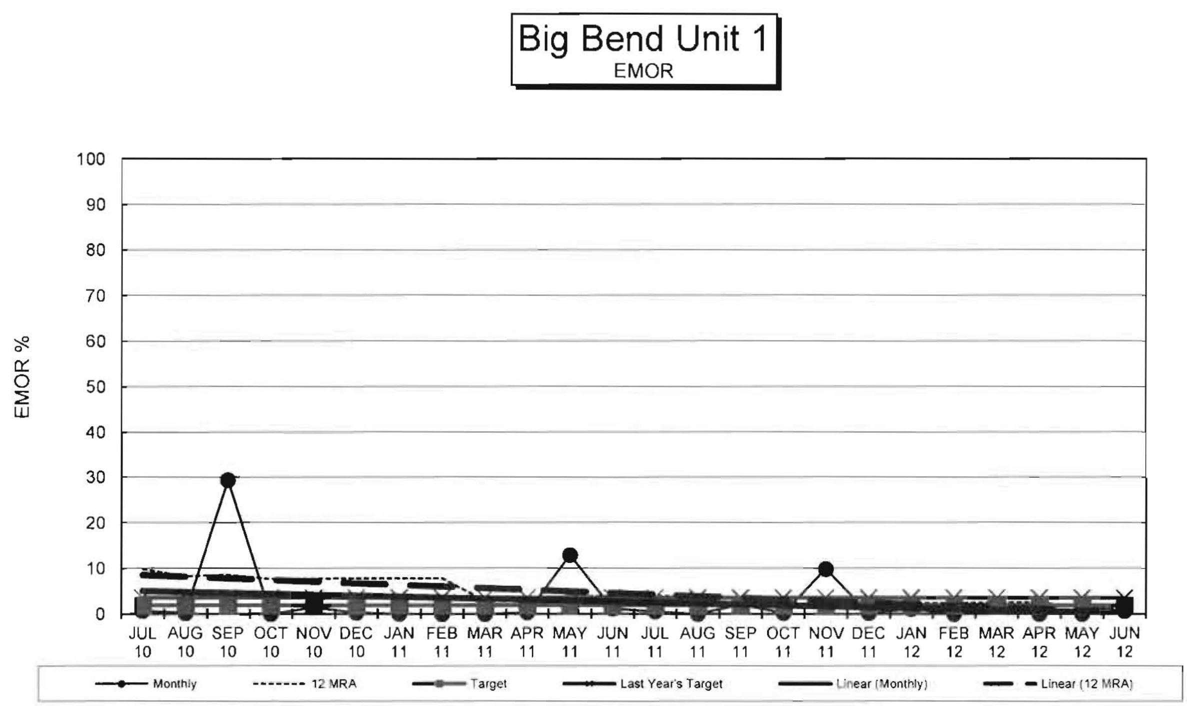
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 3
PLANNED OUTAGE 2013
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2013 - DECEMBER 2013



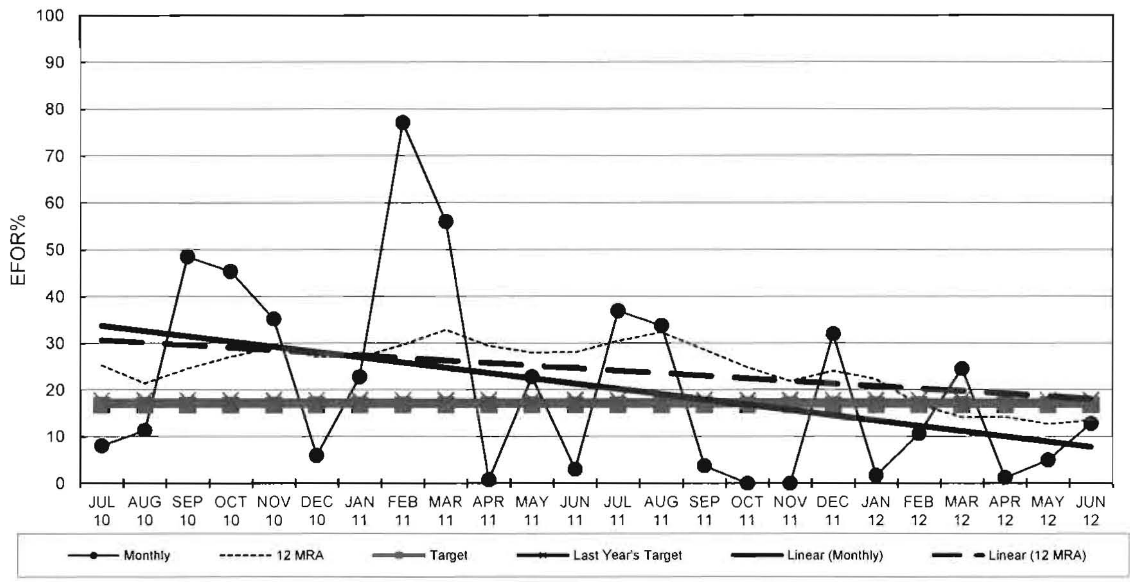
TAMPA ELECTRIC COMPANY
POLK UNIT 1
PLANNED OUTAGE 2013
PROJECTED CPM


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

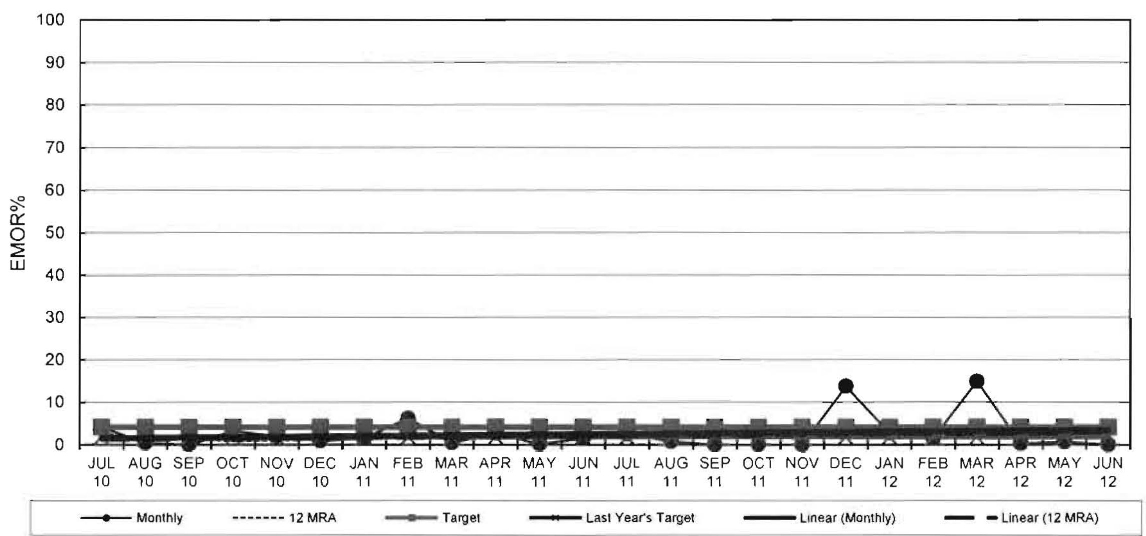

Big Bend Unit 1
EMOR
EMOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

T/

Big Bend Unit 2
EFOR

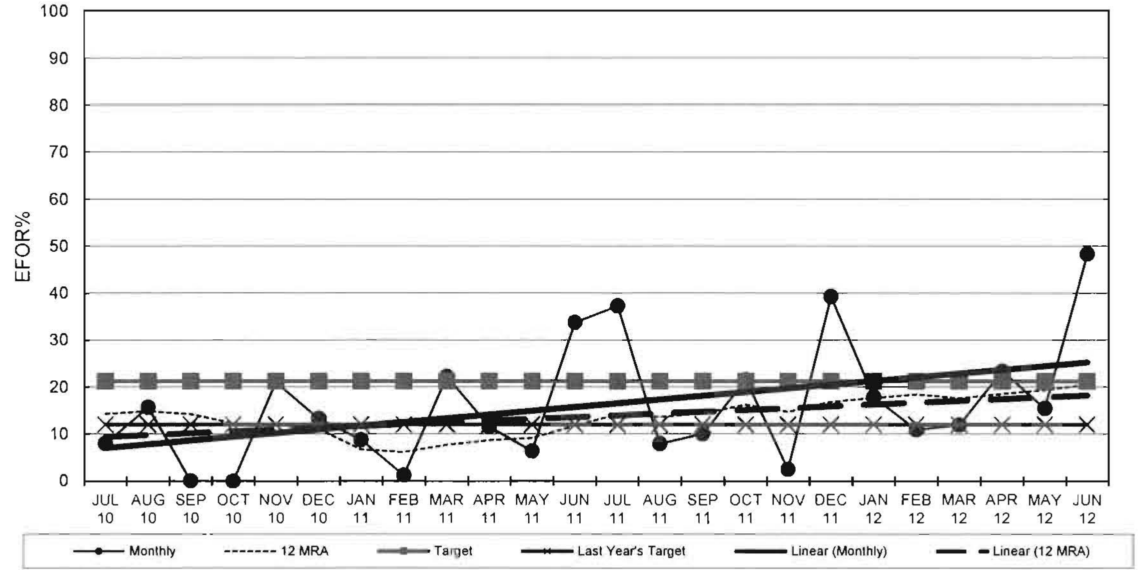


Big Bend Unit 2
EMOR

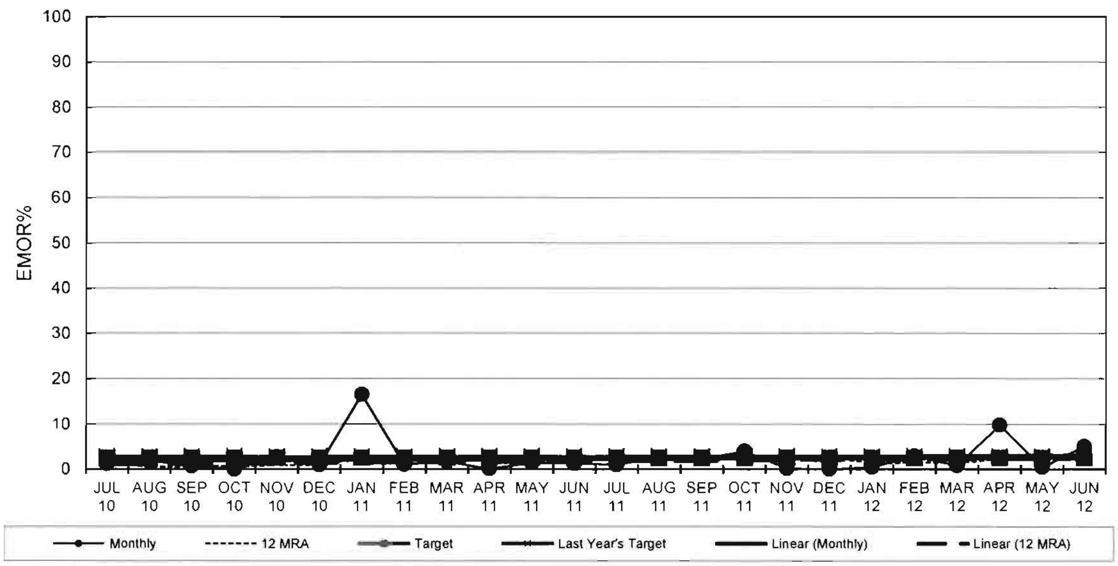


T/

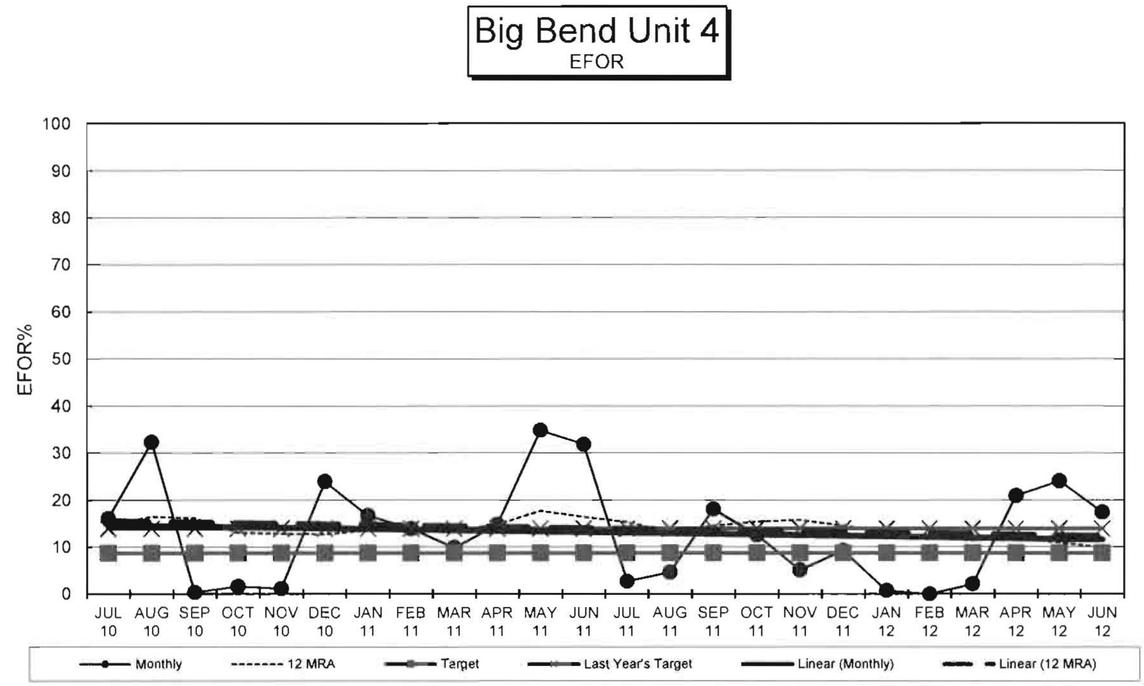
Big Bend Unit 3
EFOR

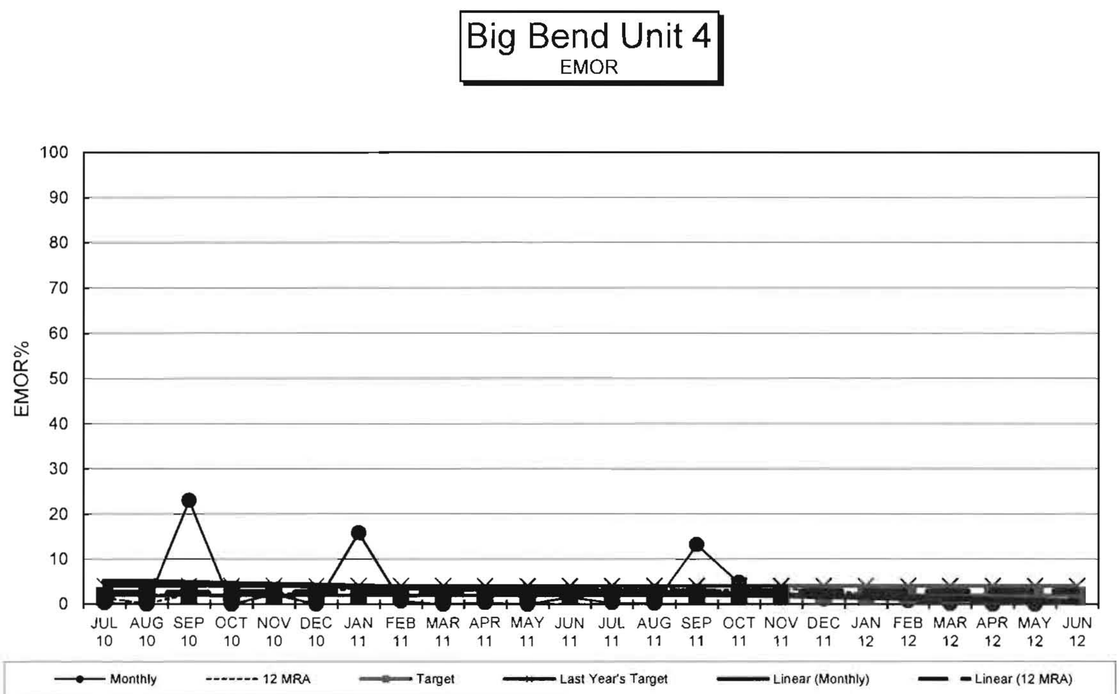


Big Bend Unit 3
EMOR

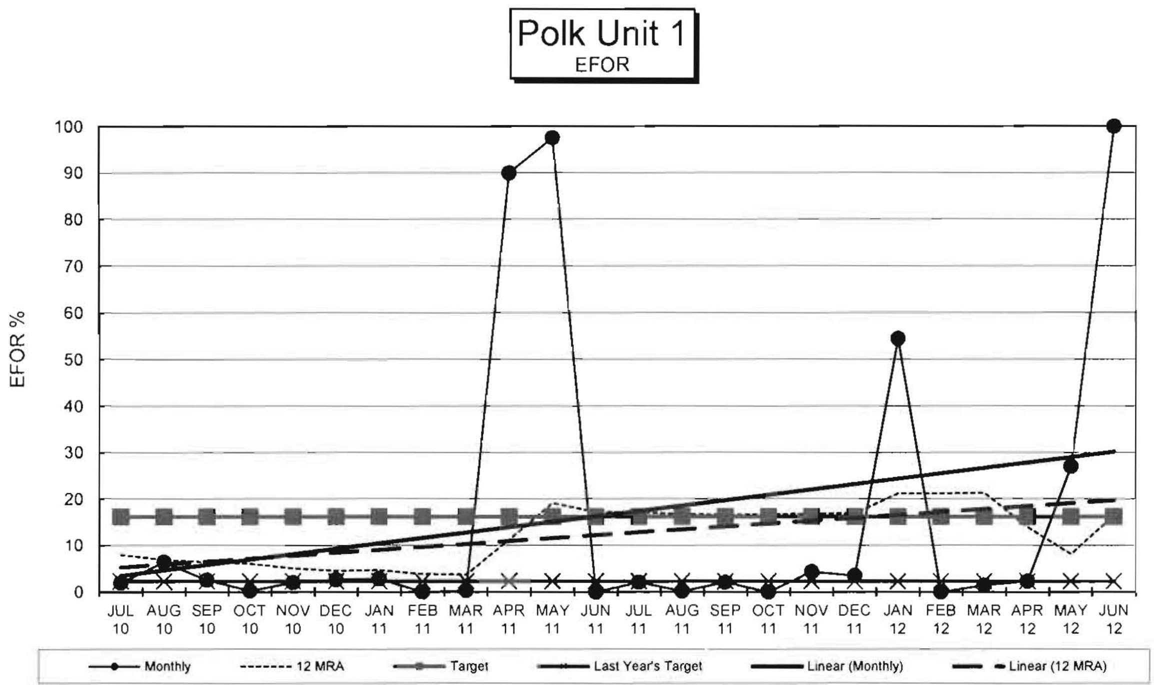


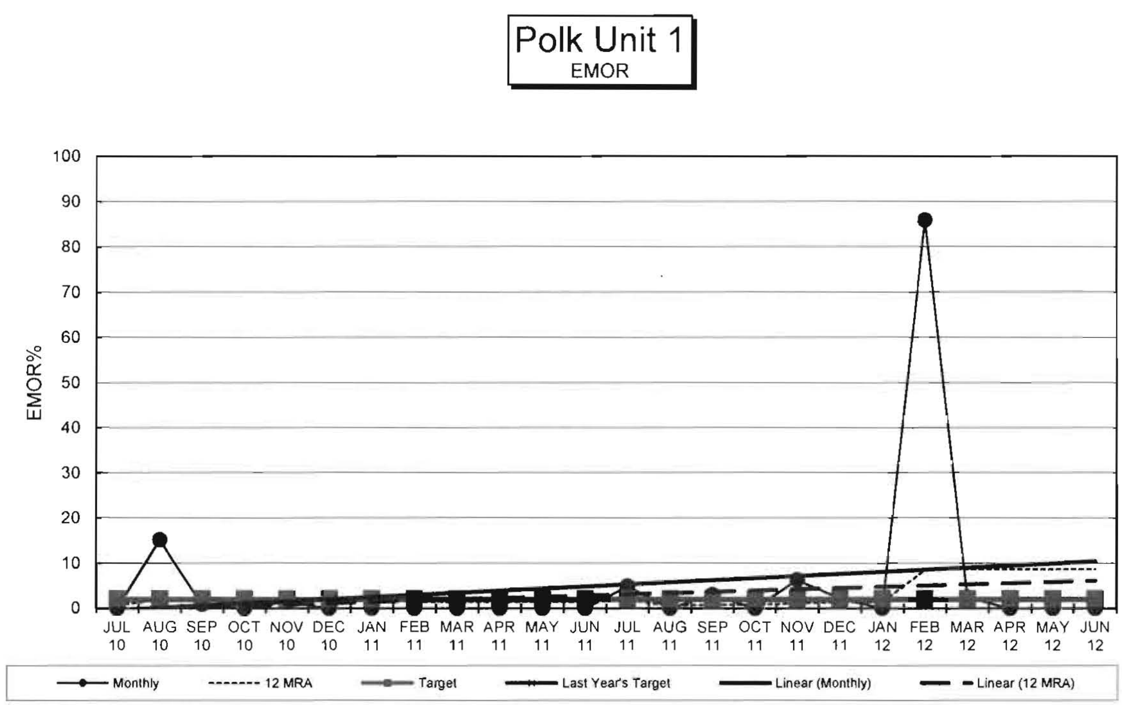
T/


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

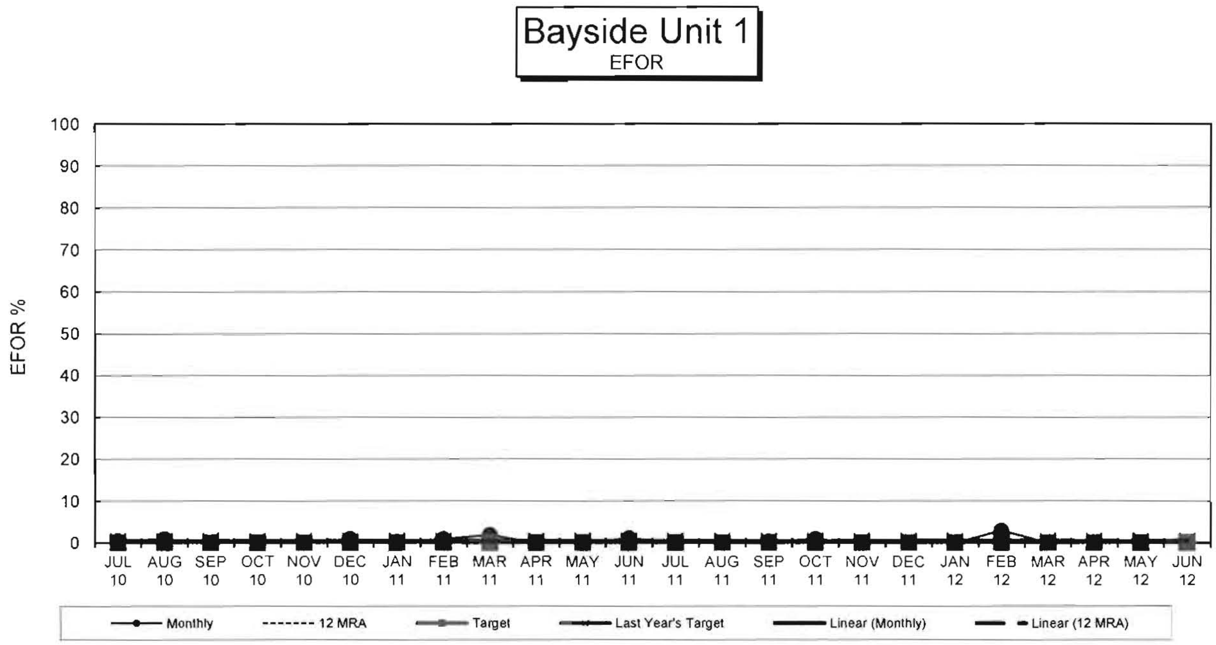

Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

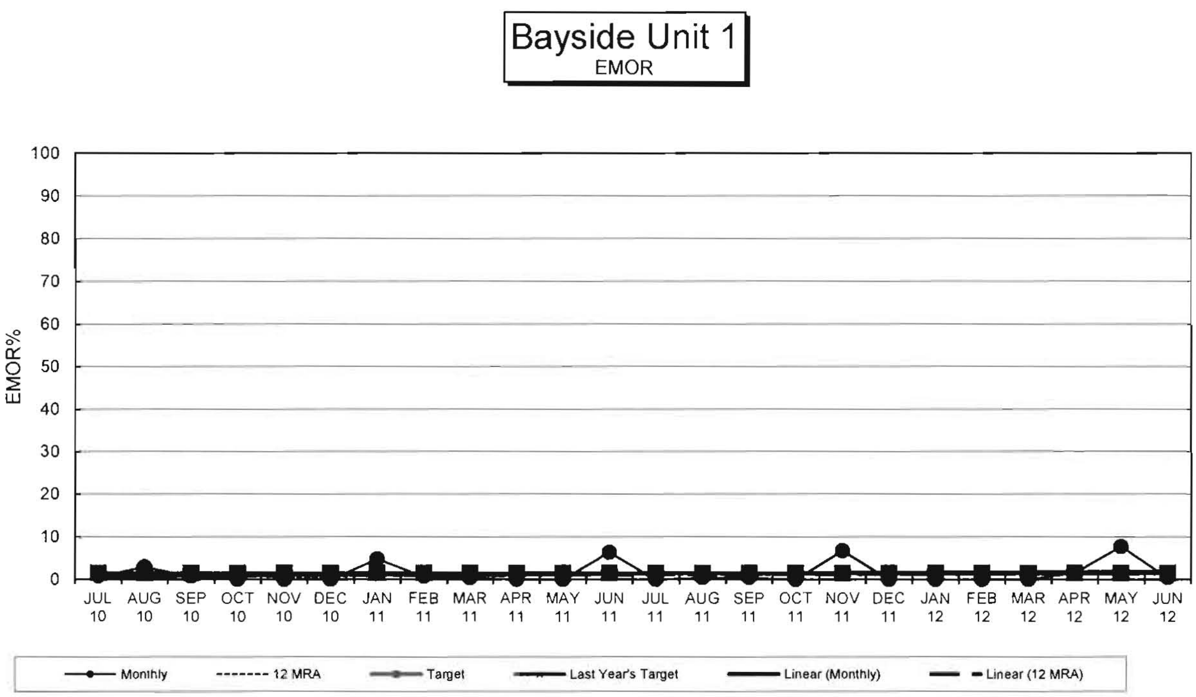
T/


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

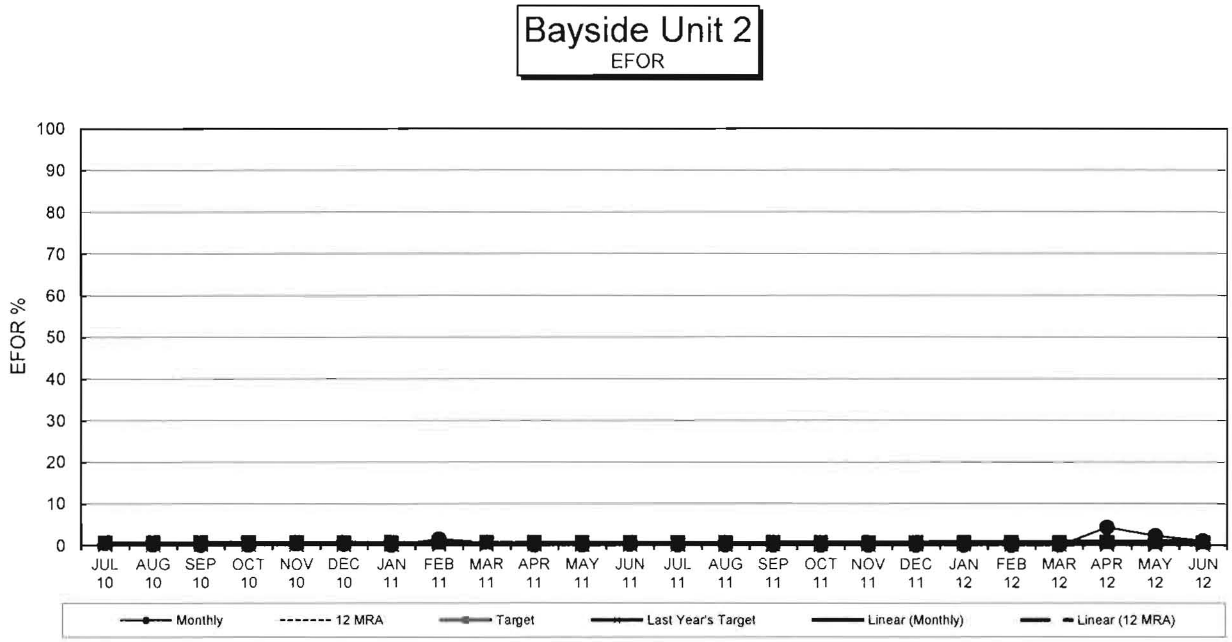

Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

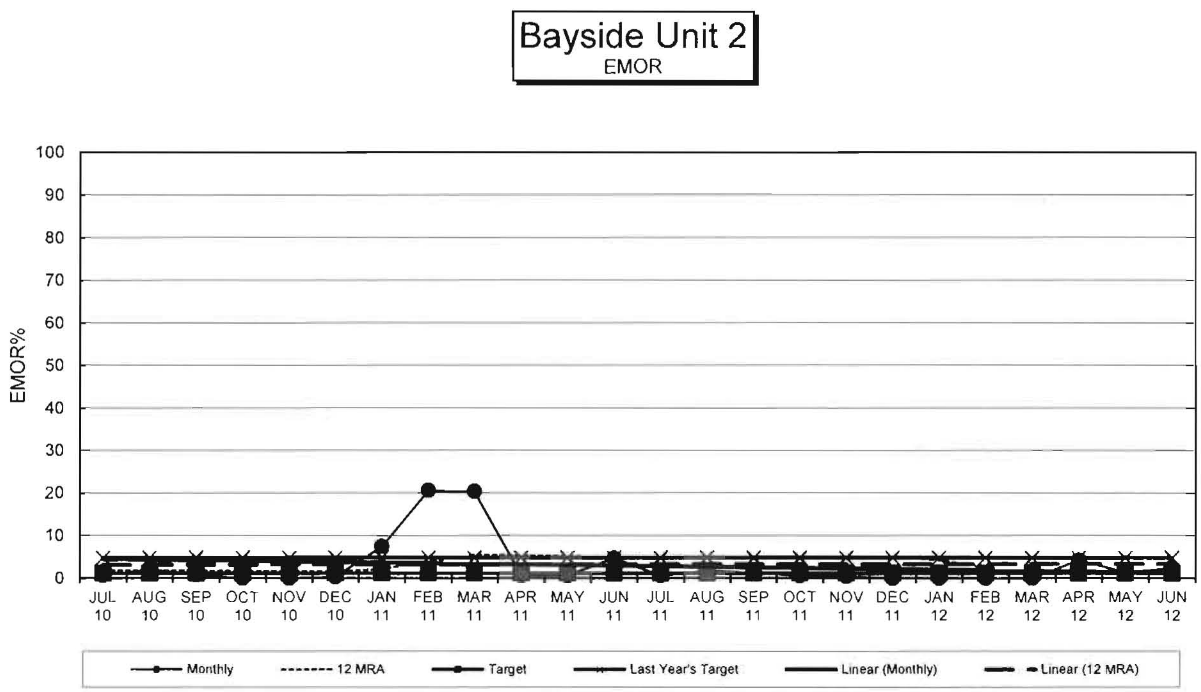
T/


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

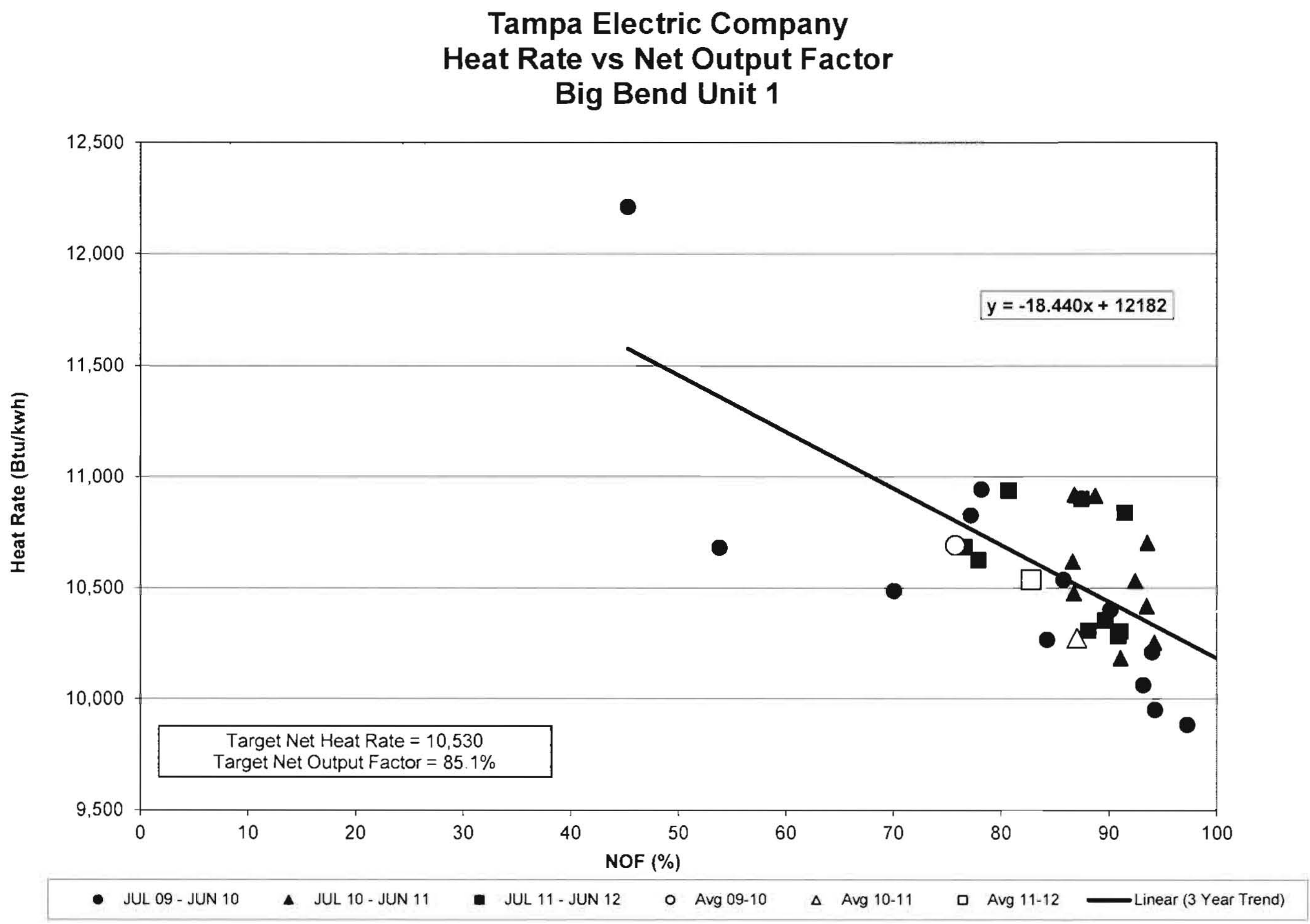

Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

T/

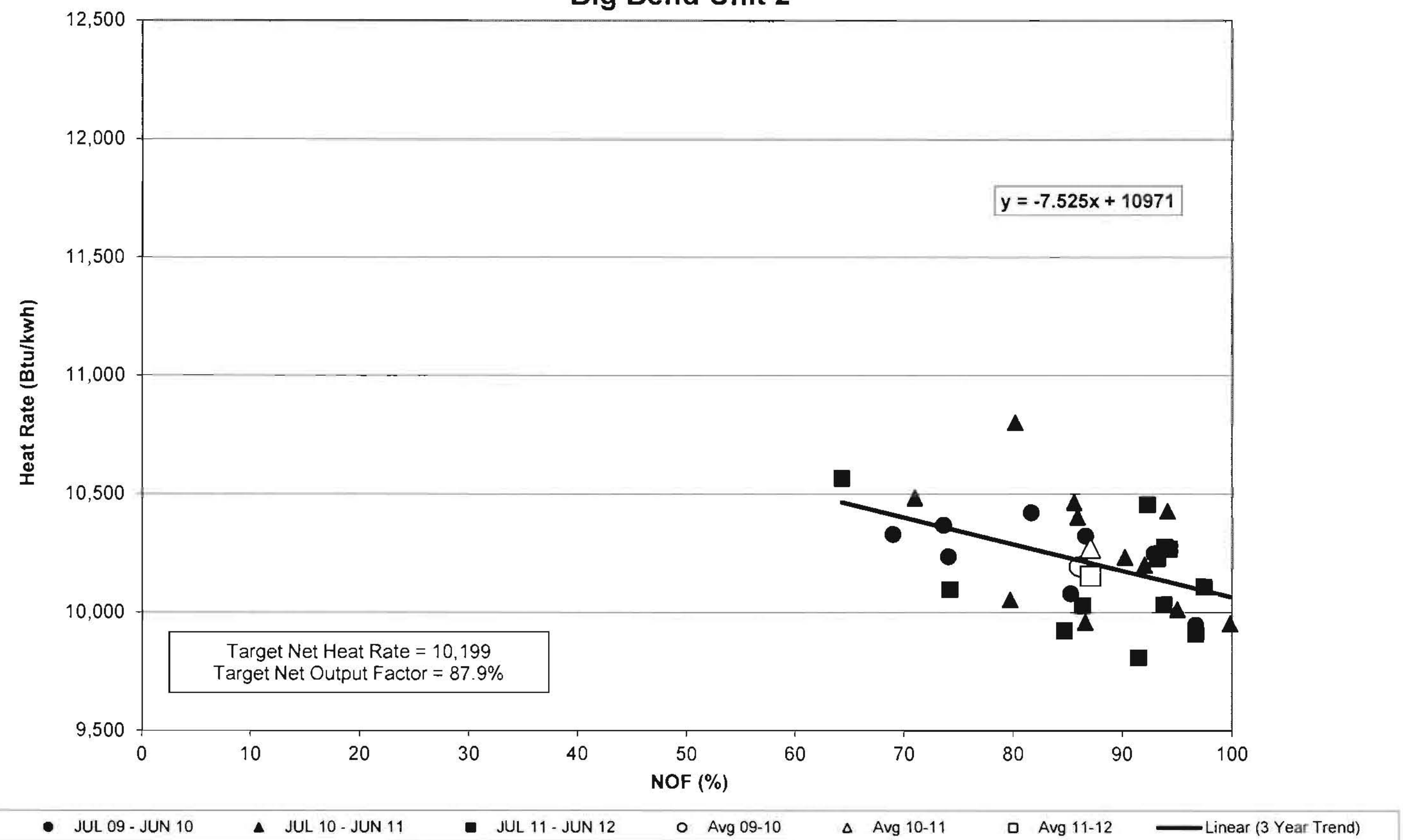

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

TAMPA ELECTRIC COMPANY

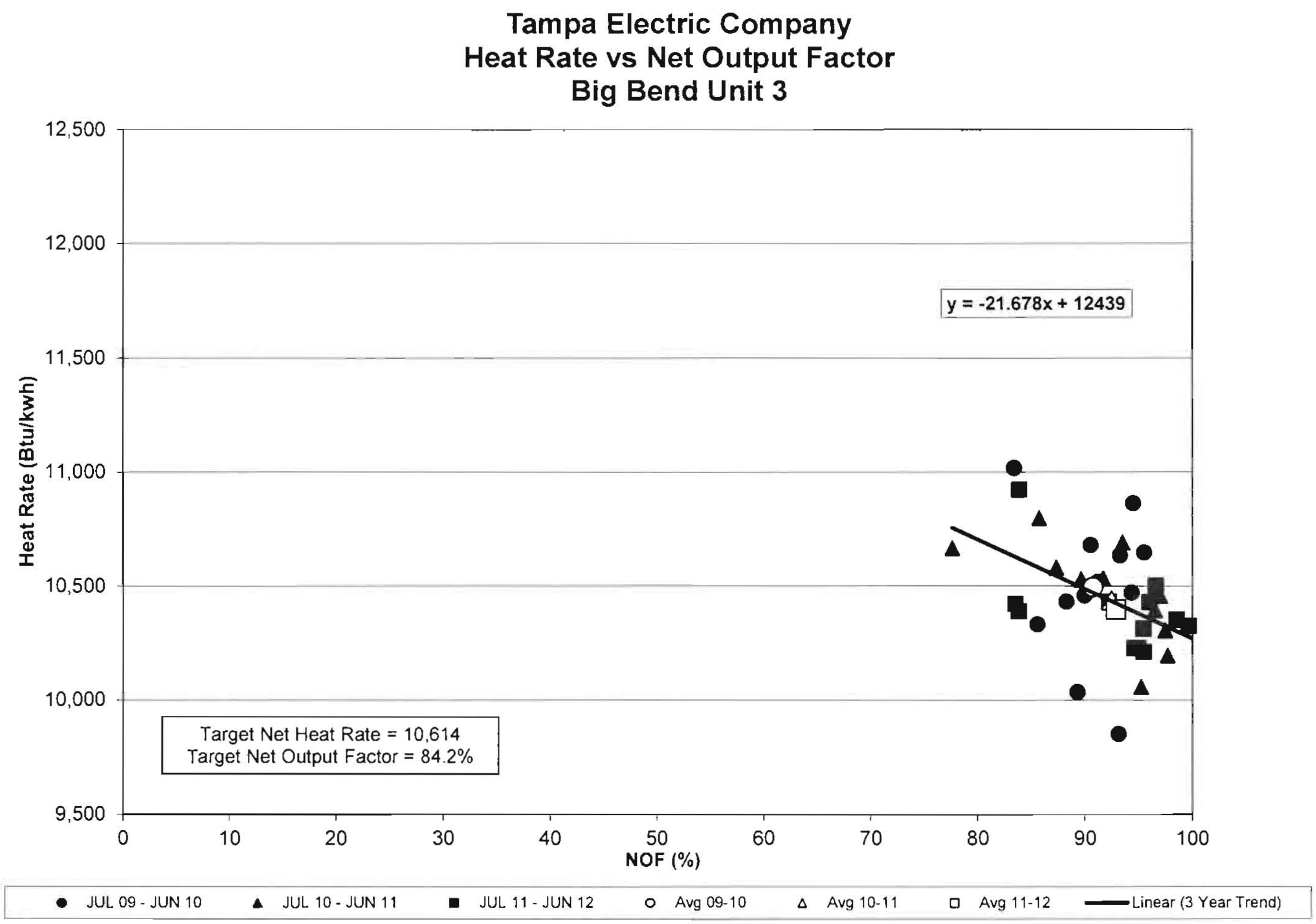


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



51

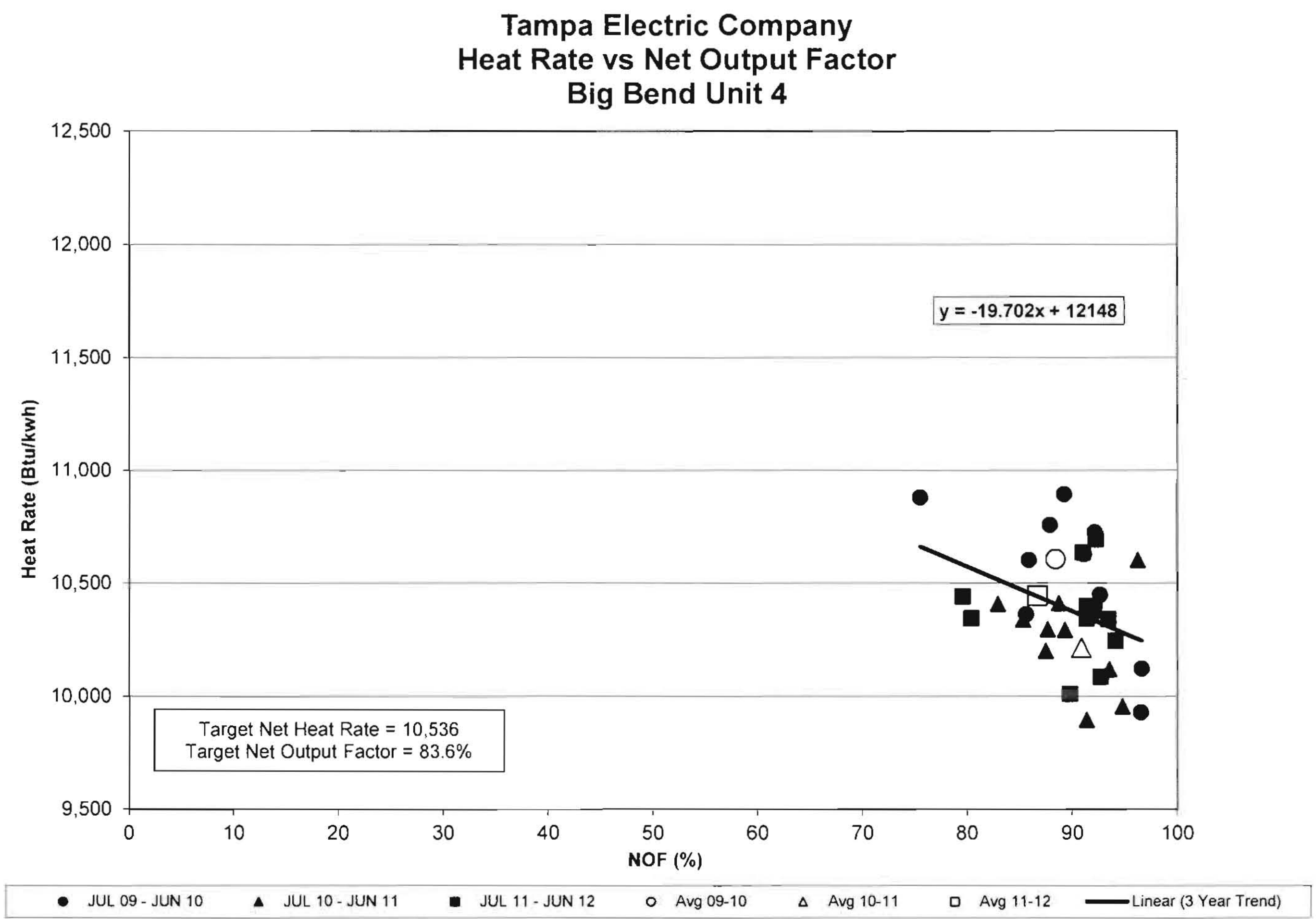
TAMPA ELECTRIC COMPANY



52

ORIGINAL SHEET NO. 8.401.13E
PAGE 33 OF 40

TAMPA ELECTRIC COMPANY

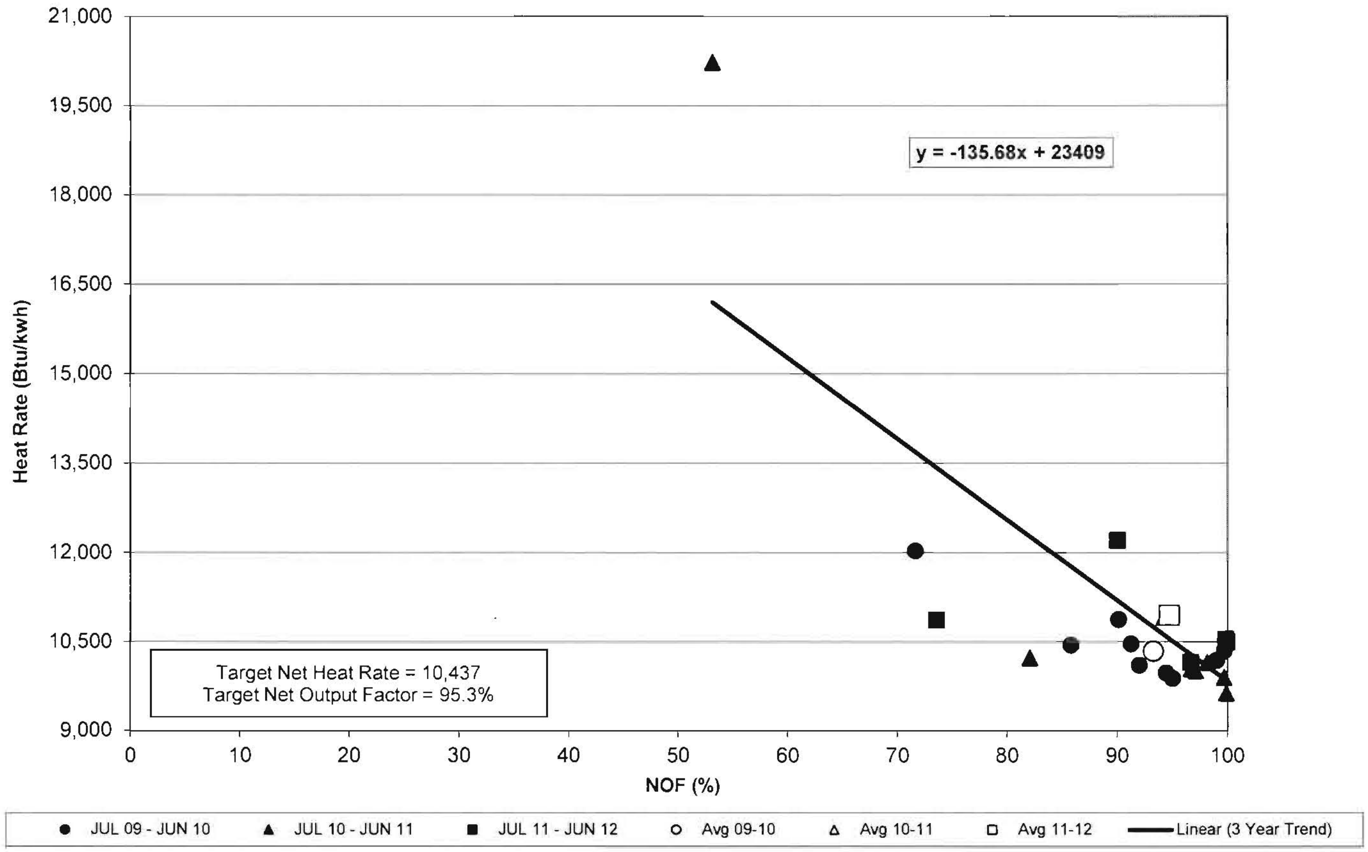


53

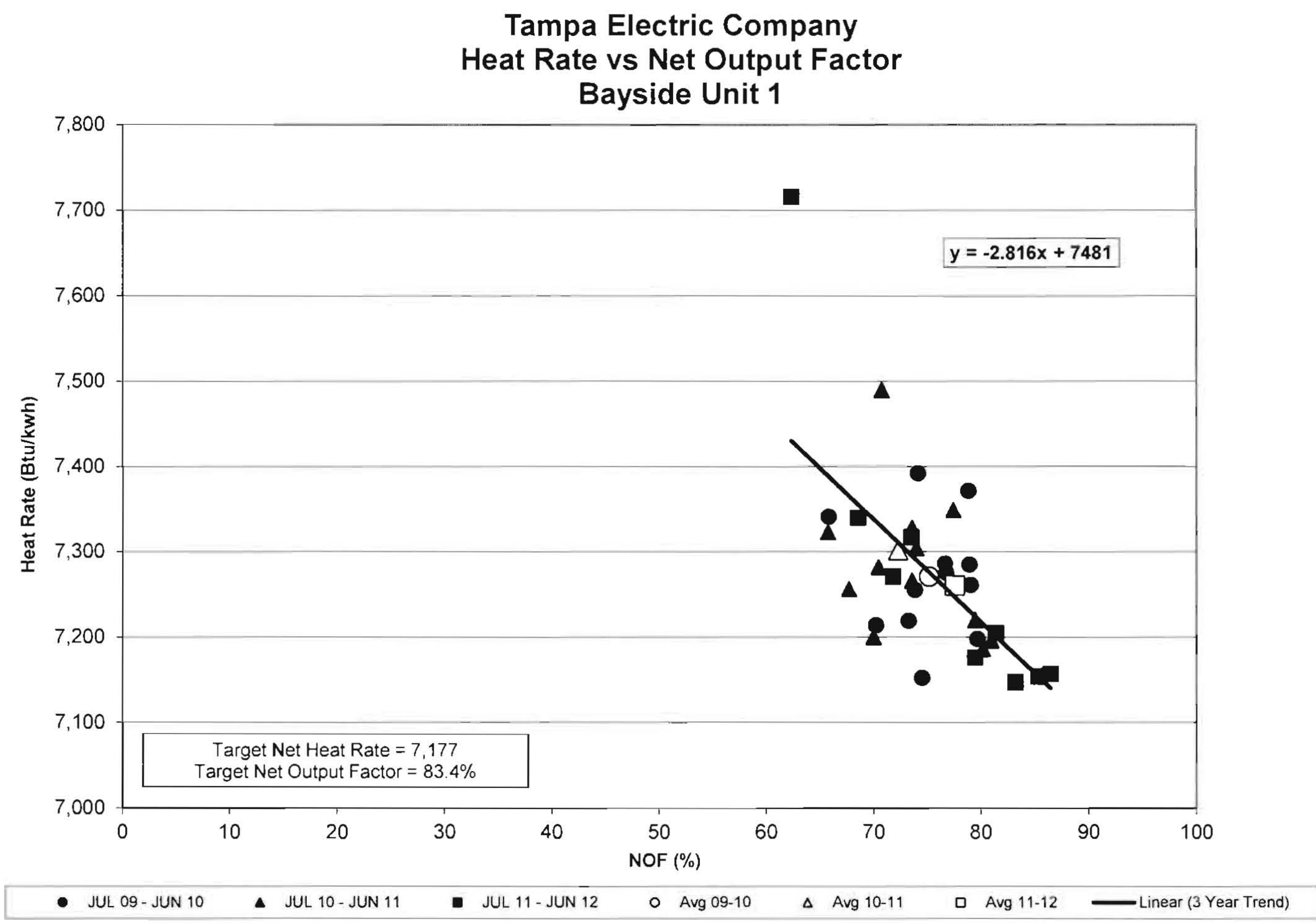
ORIGINAL SHEET NO. 8.401.13E

54

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



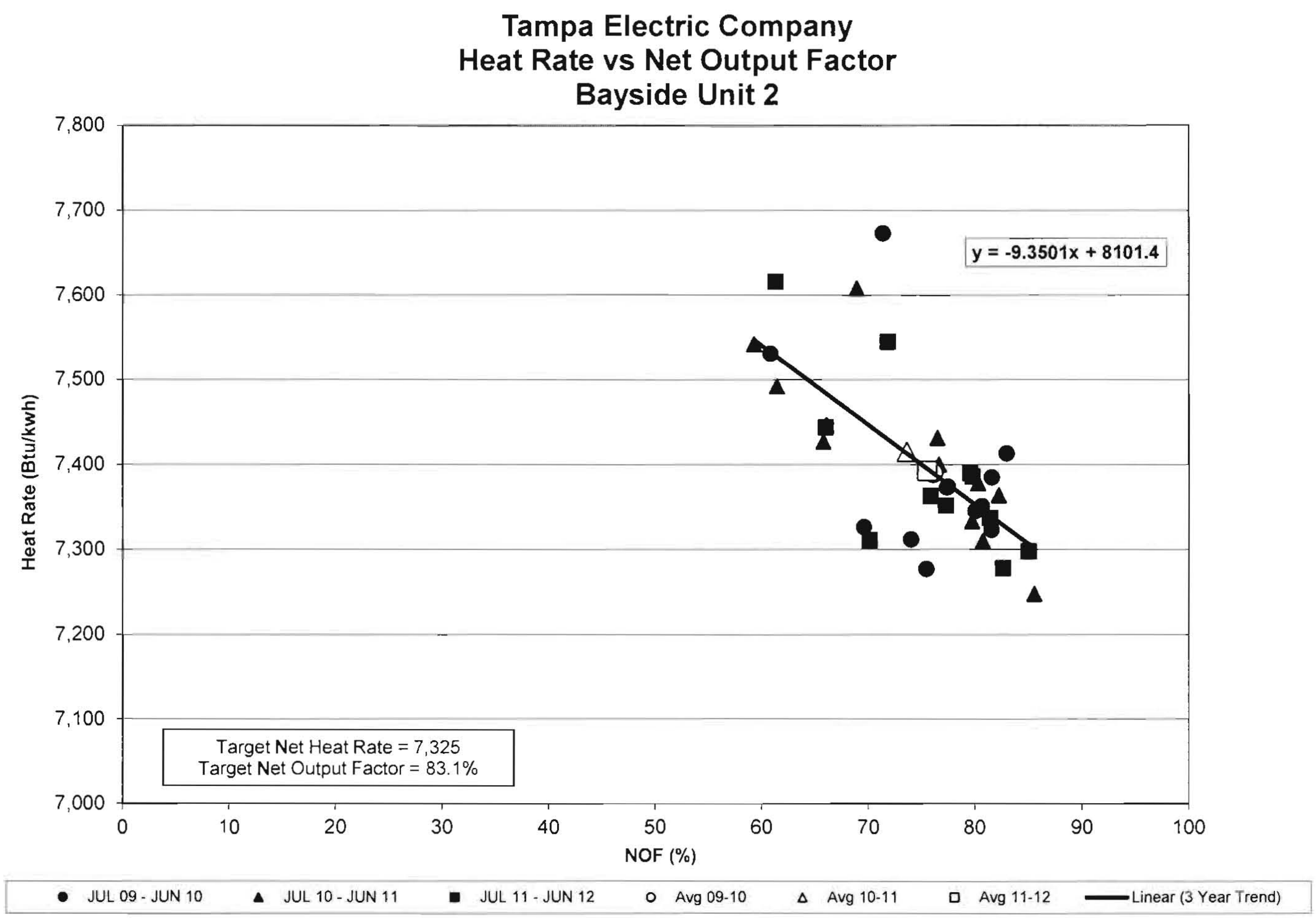
TAMPA ELECTRIC COMPANY



55

ORIGINAL SHEET NO. 8.401.13E
PAGE 36 OF 40

TAMPA ELECTRIC COMPANY



56

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2013 - DECEMBER 2013

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 2013 - DECEMBER 2013

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 2013 - DECEMBER 2013

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,703,630	25.35%	25.35%
BAYSIDE	1	3,271,710	17.63%	42.99%
BIG BEND	4	2,713,930	14.63%	57.62%
BIG BEND	2	2,491,620	13.43%	71.05%
BIG BEND	1	2,050,850	11.05%	82.10%
BIG BEND	3	1,716,350	9.25%	91.35%
POLK	1	1,414,590	7.62%	98.98%
POLK	4	113,980	0.61%	99.59%
POLK	5	62,070	0.33%	99.92%
BAYSIDE	5	6,660	0.04%	99.96%
POLK	2	3,240	0.02%	99.98%
BAYSIDE	6	2,210	0.01%	99.99%
BAYSIDE	3	1,110	0.01%	100.00%
POLK	3	600	0.00%	100.00%
BAYSIDE	4	250	0.00%	100.00%
BIG BEND CT	4	-	0.00%	100.00%
TOTAL GENERATION		18,552,800	100.00%	

GENERATION BY COAL UNITS:	10,387,340 MWH	GENERATION BY NATURAL GAS UNITS:	8,165,460 MWH
% GENERATION BY COAL UNITS	55.99%	% GENERATION BY NATURAL GAS UNITS:	44.01%
GENERATION BY OIL UNITS:	- MWH	GENERATION BY GPIF UNITS:	18,362,680 MWH
% GENERATION BY OIL UNITS:	0.00%	% GENERATION BY GPIF UNITS:	98.98%

DOCKET NO. 120001-EI
GPIF 2013 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 2013 - DECEMBER 2013

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2013 - DECEMBER 2013

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	64.2	6.6	29.2	10,530
Big Bend 2[2]	74.8	6.6	18.7	10,199
Big Bend 3[3]	60.8	21.1	18.1	10,614
Big Bend 4[4]	83.6	6.6	9.8	10,536
Polk 1[5]	75.1	9.6	15.3	10,437
Bayside 1[6]	94.1	4.9	1.0	7,177
Bayside 2[7]	93.2	5.5	1.3	7,325

1 Original Sheet 8.401.13E, Page 14

2 Original Sheet 8.401.13E, Page 15

3 Original Sheet 8.401.13E, Page 16

4 Original Sheet 8.401.13E, Page 17

5 Original Sheet 8.401.13E, Page 18

6 Original Sheet 8.401.13E, Page 19

7 Original Sheet 8.401.13E, Page 20

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY

OF

J. BRENT CALDWELL

FILED: AUGUST 31, 2012

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 2013 Fuel Procurement and Wholesale Power Purchases Risk Management Plan and Hedging Report submitted on August 1, and August 15, 2012 in this docket.

Q. Have you previously submitted testimony to this Commission?

A. Yes. I have filed testimony before this Commission in this docket since 2011.

2013 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2013?

A. In 2013, coal-fired generation is expected to be approximately 60 percent and natural-gas fired generation

40 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 location from which its supply is sourced. Similarly, the company attempts to maintain multiple delivery paths wherever possible. Tampa Electric believes that increasing the number of fuel supply options provides increased reliability and lower costs for 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 combine cycle Unit One at Polk Station. The coal-fired units at Big Bend Station are all fully scrubbed for sulfur-dioxide and nitrogen-oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit One 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 cost, 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. This allows for stable supply of reliable sources while still providing flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2012.

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 2013 delivery?

A. Yes, Tampa Electric has contracted approximately two-thirds of its 2013 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 the balance of 2012 and in 2013.

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 flexibility 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. How was Tampa Electric impacted by the severe drought conditions in the Ohio River Valley?

A. There has been some media attention to the recent drought that has plagued the central U.S. and navigation along the Mississippi River system. Tampa Electric, to date, has not encountered any difficulties in transporting its coal. Although, there have been some delays in transit times and reductions in barge tow sizes, Tampa Electric has sufficient inventory at its plants and terminal facilities and does not anticipate any adverse inventory impacts. Tampa Electric and its ratepayers continue to enjoy the benefits of bi-modal transportation in terms of increased reliability and fuel diversity.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2012 and 2013?

A. Yes. Tampa Electric expects to receive over 1.7 million tons of coal in 2013 for use at Big Bend through the Big Bend rail facility.

As part of the CSX transportation agreement, Tampa Electric receives a per ton 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.

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 2013 delivery?

A. Yes, by the end of October 2012, over two-thirds of the company's expected natural gas requirements will be under contract.

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 2013 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 2013 projected fuel prices compare to the fuel prices projected for 2012?

A. Fuel prices are projected to be lower in 2013 than prices projected for 2012. However, natural gas prices are projected to be higher in 2013 than actual natural gas prices in 2012. Natural gas prices in 2012 were particularly low due to the extremely mild winter of 2012, the continuing stagnation of the economy, and abundant shale gas production.

Q. What are the market drivers of the expected 2013 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2013 as compared to actual and estimated 2012 costs. An anticipated improvement to the economy, a return to more normal winter weather pattern in 2012 and 2013, and market adjustment to shale gas production is expected to slightly raise the price in 2013 compared to 2012.

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

A. International demand for coal and petroleum coke has increased the price of coal for several years, and particularly in early 2012 for Illinois Basin coal as it found ways to be exported to Europe, South Africa and India. Additionally, the addition of FGD scrubbers on a number of coal plants has made the lower cost Illinois Basin coal viable in those units thus increasing the demand and price for Illinois Basin coal. Conversely, low natural gas prices caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. These changes are expected to cap the price of Illinois Basin coal in 2013 at a level similar to the price in 2012. And, with the contract pricing of Tampa Electric's base agreements, most of the impact of coal market price changes should be 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 fuel prices were 35 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 35 percent lower for both natural gas and No. 2 oil. Due to Tampa Electric's generating mix as well as its Commission approved hedging strategy the impact the fuel cost 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 Risk Management plan filed August 1, 2012 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2012 and 2013 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2012 natural gas supply needs and a portion of its expected 2013 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 the company's approved Fuel Procurement and Wholesale Power Purchases Risk Management Plan. The current market position for natural gas hedges was provided in the company's Hedging Information Report submitted on August 15, 2012.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2012 and 2013 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 described in detail in Tampa Electric's Fuel Procurement and Wholesale Power Purchases Risk Management Plan filed August 1, 2012.

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

A. Tampa Electric projects the quantity or 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, 2012 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 2, 2012, the company filed its 2011 hedging results as part of the final true-up process. Additionally, Commission Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information 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 Hedging Information Report showing the results of its prudent hedging activities from January through July 2012 in this docket on August 15, 2012.

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. 120001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: AUGUST 31, 2012

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 contract structure and help evaluate the processes used to value wholesale power opportunities. 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 purchased power needs 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 there is a purchased power need, 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 2012 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 2012 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, RRI Energy Services (formerly known as Reliant), Pasco Cogen, qualifying facilities, and a new Calpine purchase. The RRI Energy Services purchase ended as of June 2012, and the Hardee Power Partners purchase continues through December 2012.

With the exception of the Calpine purchase, the testimony in previous years describes each existing firm purchased power agreement, which were subsequently approved by the Commission as being cost-effective for Tampa Electric customers. The current Calpine purchase, further described herein, results from the company's May 2011 solicitation for proposals. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility.

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 2012?

A. Yes. As mentioned in my testimony submitted in 2011, Tampa Electric issued a solicitation for proposals (*i.e.*, request to purchase power) to the marketplace in May 2011. The purpose of the solicitation was to evaluate firm power purchase options capable of filling the company's 2013-2015 reserve margin needs, as shown in the company's 2011 Ten Year Site Plan. From this process, the company signed two new purchased power agreements--one with Calpine for 117 MW that began November 2011, and one with Southern Power Company for 160 MW that will begin January 2013.

The Calpine purchase is a natural gas peaking product and is the same 117 MW Auburndale resource that served customers during the 2011 summer season. Although the company's solicitation was for proposals beginning in 2013, Calpine proposed a low price option that began in 2011 and continues through 2016. An economic analysis of the earlier start date proposal showed $16.1 million of benefits to customers. This economic benefit, combined with the product also being available to provide coverage for unplanned unit outages and incremental peak demand needs, resulted in the November 2011 start date being in the best interest for Tampa Electric customers.

The Southern Power Company purchase is a 160 MW natural gas peaking product from their Oleander generating facility in Brevard County, Florida. The purchase begins January 2013, continues through 2015, and provides $16.6 million of benefits to customers. The purchase also contains an option to extend it for a period of two years (*i.e.*, 2016-2017). In addition to the economic benefits, both the Southern Power Company and Calpine purchases provide customers with additional supply protection for unplanned unit outages; market price volatility protection, because its energy price is based on a contracted heat rate; and fuel supply certainty, because of their dual fuel capability.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2013 and beyond?

A. In 2013, 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, 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 2012?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 117 MW Calpine purchase and the 121 MW purchase 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 in 2012. 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 2012 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, most of the company's purchased power products, such as the RRI Energy Services and Pasco Cogen purchases, 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 2012 and 2013.

A. Tampa Electric entered into various non-separated wholesale sales in 2012, and the company anticipates making additional non-separated sales during the balance of 2012 and in 2013. 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 2012, Tampa Electric anticipates its gains from non-separated wholesale sales to be $244,154, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $2,461,614. Similarly, in 2013, the company's projected gains from non-separated wholesale sales are $485,483, of which 100 percent would flow back to customers since they are less than the projected 2013 three-year rolling average threshold of $1,365,169.

The company also entered into a separated sale transaction with Florida Power & Light for calendar year 2012. This firm sale commits capacity that is a different amount each month, and that monthly amount varies within the range of 25 to 125 MW. In accordance with the Commission's March 11, 1997 Order, No.

PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, Tampa Electric separates the capacity associated with this sale from the retail jurisdiction in its monthly surveillance reporting and credits system average fuel to the fuel clause for all energy served under the sale.

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.