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August 22, 2014

VIA: ELECTRONIC FILING

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

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 140001-EI

Dear Ms. Stauffer:

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

1. Petition of Tampa Electric Company.

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

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

4. Prepared Direct Testimony of J. Brent Caldwell.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition and Testimonies, filed on behalf of Tampa Electric Company, has been furnished by hand delivery (*) or electronic mail on this 22nd day of August 2014, to the following:

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ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 140001-EI FILED: August 22, 2014

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, 2014 through December 31, 2014 will be an over-recovery of $13,386,207 (See Exhibit No. ____ (PAR-3), Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2015 through December 31, 2015, 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, 2015 through December 31, 2015, produce a fuel and purchased power factor for the new period of 3.874 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. ____ (PAR-3), Document No. 2, Schedule E1-E).

3. The company's projected benchmark level for calendar year 2015 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 $1,403,580 as provided in the direct testimony of Tampa Electric witness Penelope Rusk.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2014 through December 31, 2014 will be an under-recovery of $33,526, as shown in Exhibit No. ____ (PAR-3), Document No. 1, page 2 of 4.

5. The company's projected expenditures for the period January 1, 2015 through December 31, 2015, when adjusted for the true-up under-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of 0.172 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.63 per billed kW as set forth in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF reward of $1,689,728 for performance experienced during the period January 1, 2013 through December 31, 2013.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2015 through December 31, 2015 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 22nd day of August 2014.

Respectfully submitted,

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Ausley & McMullen
Post Office Box 391
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by hand delivery (*) or electronic mail on this 22nd day of August 2014, to the following:

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ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2015 THROUGH DECEMBER 2015

TESTIMONY AND EXHIBIT

OF

PENELOPE A. RUSK

FILED: AUGUST 22, 2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

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

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2015 through December 2015. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2015.

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

A. Yes. Exhibit No. ____ (PAR-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2015 through December 2015 as well as Schedule H1 for January through December, 2012 through 2015. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and related fuel savings for the company’s projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

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

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

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (PAR-3), Document No. 1, Tampa Electric requests recovery of $31,972,087 after jurisdictional separation and prior year true-up, for estimated expenses in 2015.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2015 through December 2015.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.204	
GS and TS Secondary	0.183	
GSD, SBF Standard Secondary		0.63

Primary		0.62
Transmission		0.62
IS, IST, SBI		
Primary		0.41
Transmission		0.40
GSD Optional		
Secondary	0.147	
Primary	0.146	
LS1 Secondary	0.025	

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

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.172 cents per kWh compare to the factor for January 2014 through December 2014?

A. The proposed capacity cost recovery factor is the same as the average capacity cost recovery factor of 0.172 cents per kWh for the January 2014 through December 2014 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 2015?

A. The appropriate amount for the 2015 period is 3.874 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (PAR-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2015 through December 2015.

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

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,689,728, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2014 through December 2014 period. The net true-up amount for this period is an over-recovery of $13,386,207.

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 2015 through

December 2015. The schedule also presents Tampa Electric’s levelized fuel cost factors at each metering voltage level.

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

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

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

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

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2015 through December 2015.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	3.874
Tier I (Up to 1,000 kWh)	3.559
Tier II (Over 1,000 kWh)	4.559
Distribution Primary	3.835
Transmission	3.797
Lighting Service	3.830
Distribution Secondary	4.114 (on-peak)
	3.772 (off-peak)
Distribution Primary	4.073 (on-peak)
	3.734 (off-peak)
Transmission	4.032 (on-peak)
	3.697 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.874 cents per kWh compare to the levelized fuel adjustment factor for the January 2014 through December 2014 period?

A. The proposed fuel charge factor is 0.036 cents per kWh (or $0.36 per 1,000 kWh) lower than the average fuel charge factor of 3.910 cents per kWh for the January 2014 through December 2014 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2015 fuel and purchased power and capacity cost recovery projections?

A. Yes. There is one significant event reflected in the 2015 projections: the inclusion of Big Bend Units 1-4 Igniters Conversion capital costs, which is more than offset by the anticipated fuel savings of the project. The Commission approved the recovery of the estimated depreciation and return costs for the Big Bend conversion project in FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014. The costs are shown in Document No. 4 of my exhibit, and described below.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project costs for the period January 2015 through December 2015?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $4,114,495. This is shown in Exhibit No. _____ (PAR-3), Document No. 4.

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project fuel savings for the period January 2015 through December 2015?

A. The estimated fuel savings for the period January 2015 through December 2015 are $5,950,084, which exceeds the estimated capital costs by $1,835,588, as shown in Exhibit No. _____ (PAR-3), Document No. 4.

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

A. Yes. The January 2015 through December 2015 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customer, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2015 through December 2015?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $3,310,090. This is shown in Document No. 4 of my exhibit.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project fuel savings for the period January 2015 through December 2015?

A. The estimated fuel savings for the period January 2015 through December 2015 are $3,639,503, which exceeds the estimated capital costs by $329,413. This information is also presented in Document No. 4 of my exhibit.

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

A. Yes. The January 2015 through December 2015 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customer, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

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

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

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric’s projected wholesale incentive benchmark for 2015?

A. The company’s projected 2015 benchmark is $1,403,580, which is the three-year average of $246,932, $894,045 and $3,069,762 in gains on the company’s non-separated wholesale sales, excluding emergency sales, for 2012, 2013 and 2014 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2015 from non-separated wholesale sales to exceed its 2015 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2015. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $1.22 beginning January 2015, when compared to the January 2014 through October 2014 charges. These charges are shown in Exhibit No. ____ (PAR-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2015.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2015 - DECEMBER 2015

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	54.04%	8,713,087	1,841	1.07665	1.05525	9,194,470	1,982	46.92%	56.36%	55.64%
GS, TS	60.65%	1,047,683	197	1.07665	1.05523	1,105,551	212	5.64%	6.03%	6.00%
GSD Optional	3.58%	357,148	53	1.07236	1.05157	375,566	57	1.92%	1.62%	1.64%
GSD, SBF	73.67%	7,345,405	1,085	1.07236	1.05157	7,724,211	1,164	39.41%	33.11%	33.59%
IS,SBI	113.14%	949,661	96	1.02745	1.01946	968,139	98	4.94%	2.79%	2.96%
LS1	808.37%	217,416	3	1.07665	1.05525	229,428	3	1.17%	0.09%	0.17%
TOTAL		18,630,400	3,275			19,597,365	3,516	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2014 projected calendar data.
(2) Projected MWH sales for the period January 2015 thru December 2015.
(3) Based on 12 months average CP at meter.
(4) Based on 2014 projected demand losses.
(5) Based on 2014 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	1,517,620	18,211,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
3	(UNIT POWER CAPACITY REVENUES)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,765)	(119,757)	(1,437,172)
4	TOTAL CAPACITY DOLLARS	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,633	$31,915,558
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,625	$2,659,625	$2,659,635	$2,659,625	$2,659,635	$2,659,633	$31,915,558
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2014 - DEC. 2014													33,526
8	TOTAL													$31,949,084
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,972,087

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2015 THROUGH DECEMBER 2015
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	46.92%	56.36%	1,153,601	16,633,771	17,787,372	8,713,087	8,713,087				0.00204
GS, CS	5.64%	6.03%	138,668	1,779,660	1,918,328	1,047,683	1,047,683				0.00183
GSD, SBF											
Secondary						6,038,291	6,038,291			0.63	
Primary						1,299,355	1,286,361			0.62	
Transmission						7,759	7,604			0.62	
GSD, SBF - Standard	39.41%	33.11%	968,955	9,771,898	10,740,853	7,345,405	7,332,256	58.57%	17,148,546		
GSD - Optional	1.92%	1.62%	47,206	478,118	525,324						
Secondary						342,215	342,215				0.00147
Primary						14,933	14,784				0.00146
IS, SBI											
Primary						254,684	252,137			0.41	
Transmission						694,977	681,077			0.40	
Total IS, SBI	4.94%	2.79%	121,457	823,425	944,882	949,661	933,214	55.82%	2,290,004		
LS1	1.17%	0.09%	28,766	26,562	55,328	217,416	217,416				0.00025
TOTAL	100.00%	100.00%	2,458,653	29,513,434	31,972,087	18,630,400	18,600,655				0.00172

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * 0.0769 * Col (1).
(4) Total capacity costs * 0.9231 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2015 through December 2015.
(7) Projected kWh sales at secondary for the period January 2015 through December 2015.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2015 through December 2015.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

REDACTED

TAMPA ELECTRIC COMPANY

CAPACITY COSTS

ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E12

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

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
PASCO COGEN	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
OLEANDER	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
SEMINOLE ELECTRIC	1.4	1.4	1.5	1.8	1.3	1.4	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
TOTAL COGENERATION	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	1,261,770	1,261,780	1,261,770	1,261,780	1,261,770	15,141,290
CALPINE - D	[redacted]												
PASCO COGEN - D													
OLEANDER - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,855	1,397,863	16,774,268
TOTAL CAPACITY	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,625**	**$2,659,635**	**$2,659,625**	**$2,659,635**	**$2,659,633**	**$31,915,558**

DOCKET NO. 140001-EI
EXHIBIT NO. _____ (PAR-3)
DOCUMENT NO. 1, PAGE 4 OF 4

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2015 - DECEMBER 2015

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	698,913,664	18,831,670	3.71137
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Big Bend Units 1-4 Igniters Conversion Project	3,310,090	18,831,670 [1]	0.01758
4b.	Polk 1 Conversion Depreciation & ROI	4,114,495	18,831,670 [1]	0.02185
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**706,338,249**	**18,831,670**	**3.75080**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	6,810,170	154,460	4.40902
7.	Energy Cost of Economy Purchases (E9)	16,990,090	509,460	3.33492
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	8,238,900	256,140	3.21656
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**32,039,160**	**920,060**	**3.48229**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,751,730	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	321,850	10,330	3.11568
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,644,499	178,480	3.16254
14.	Gains on Sales	581,933	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**6,548,282**	**188,810**	**3.46819**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		3,197	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**731,829,127**	**19,559,723**	**3.74151**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,230,208 [1]	32,880	0.00660
22.	T & D Losses	33,540,507 [1]	896,443	0.18003
23.	System MWH Sales	731,829,127	18,630,400	3.92815
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	731,829,127	18,630,400	3.92815
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	731,829,127	18,630,400	3.92815
28.	True-up [2]	(13,386,207)	18,630,400	(0.07185)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	718,442,920	18,630,400	3.85629
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	718,960,199	18,630,400	3.85907
32.	GPIF Adjusted for Taxes [2]	1,689,728	18,630,400	0.00907
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	720,649,927	18,630,400	3.86814
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.868**

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

TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2014 - December 2014 (6 months actual, 6 months estimated)	($10,166,001)
2.	FINAL TRUE-UP (January 2013 - December 2013) (Per True-Up filed March 3, 2014)	23,552,208
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2015 through December 2015 (Schedule E1, line 28)	$13,386,207
4.	JURISDICTIONAL MWH SALES (Projected January 2015 through December 2015)	18,630,400
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0719)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2015 through December 2015)	$1,689,728	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2014 through December 2014)	$13,386,207	
2.	TOTAL SALES (January 2015 through December 2015)	18,630,400	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0091**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0719)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.01	$32.37
OFF PEAK	69.99	$29.68
	100.00	1.0906

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$731,829,127		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,630,400		
2a	Effective MWH Sales (Jurisd)		18,600,655		
3	Cost Per KWH Sold	(line 1 / line 2)	3.9281		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($13,386,207)		
7	TOTAL	(line 1 x line 4)+line 6	$718,442,920		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.8652		
10	GPIF Factor	(Sch E1-C line 3a)	0.0091		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.8743	4.1135	3.7717
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.874	4.114	3.772

13	Hours: ON PEAK	25.01%
14	OFF PEAK	74.99%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,358,692	16,358,692
Distribution Primary	1,568,972	1,553,282
Transmission	702,736	688,681
Total	18,630,400	18,600,655

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.874	4.114	3.772
Distribution Primary	3.835	4.073	3.734
Transmission	3.797	4.032	3.697
RS 1st Tier	3.559		
RS 2nd Tier	4.559		
Lighting	3.830		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		3.559	4.559
Distribution Secondary	3.874		
Distribution Primary	3.835		
Transmission	3.797		
Lighting Service (1)	3.830		
TIME-OF-USE			
Distribution Secondary - On-Peak	4.114		
Distribution Secondary - Off-Peak	3.772		
Distribution Primary - On-Peak	4.073		
Distribution Primary - Off-Peak	3.734		
Transmission - On-Peak	4.032		
Transmission - Off-Peak	3.697		

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

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	(a) Jan-15	(b) Feb-15	(c) Mar-15	(d) Apr-15	(e) May-15	(f) ESTIMATED Jun-15	(g) Jul-15	(h) Aug-15	(i) Sep-15	(j) Oct-15	(k) Nov-15	(l) Dec-15	(m) TOTAL PERIOD
1. Fuel Cost of System Net Generation	54,277,329	48,284,354	51,702,083	54,615,201	62,932,967	66,631,475	68,738,093	69,019,911	64,016,194	57,959,486	48,824,166	51,912,405	698,913,664
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	521,643	727,839	775,317	789,700	663,497	491,251	526,973	152,799	75,512	235,080	1,133,837	454,834	6,548,282
4. Fuel Cost of Purchased Power	8,860	132,500	263,610	426,840	697,470	564,370	631,130	1,106,720	1,256,320	1,196,990	309,560	215,800	6,810,170
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	664,130	585,300	568,030	731,910	758,720	569,650	667,160	759,940	822,540	756,620	639,940	714,960	8,238,900
7. Energy Cost of Economy Purchases	1,017,820	1,048,640	1,112,500	1,050,600	1,584,350	1,678,360	1,695,010	1,725,610	2,195,180	1,831,370	978,410	1,072,240	16,990,090
8. Big Bend Units 1-4 Igniters Conversion Project	0	0	33,035	225,368	318,929	394,762	392,682	390,603	388,523	386,443	384,363	395,382	3,310,090
9. Polk 1 Conversion Depreciation & ROI	354,126	352,080	350,036	347,990	345,943	343,897	341,851	339,806	337,761	335,714	333,668	331,623	4,114,495
10. TOTAL FUEL & NET POWER TRANSACTIONS	**55,800,622**	**49,675,035**	**53,253,977**	**56,608,209**	**65,974,882**	**69,691,263**	**71,938,953**	**73,189,791**	**68,941,006**	**62,231,543**	**50,336,270**	**54,187,576**	**731,829,127**
11. Jurisdictional MWH Sold	1,460,709	1,327,839	1,307,319	1,375,861	1,504,829	1,754,329	1,814,047	1,805,882	1,862,609	1,649,232	1,398,249	1,369,495	18,630,400
12. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	55,800,622	49,675,035	53,253,977	56,608,209	65,974,882	69,691,263	71,938,953	73,189,791	68,941,006	62,231,543	50,336,270	54,187,576	731,829,127
14. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**55,800,622**	**49,675,035**	**53,253,977**	**56,608,209**	**65,974,882**	**69,691,263**	**71,938,953**	**73,189,791**	**68,941,006**	**62,231,543**	**50,336,270**	**54,187,576**	**731,829,127**
16. Cost Per kWh Sold (Cents/kWh)	3.8201	3.7410	4.0735	4.1144	4.3842	3.9725	3.9657	4.0529	3.7013	3.7734	3.6000	3.9568	3.9281
17. True-up (Cents/kWh) (2)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)	(0.0719)
18. Total (Cents/kWh) (Line 16+17)	3.7482	3.6691	4.0016	4.0425	4.3123	3.9006	3.8938	3.9810	3.6294	3.7015	3.5281	3.8849	3.8562
19. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
20. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.7509	3.6717	4.0045	4.0454	4.3154	3.9034	3.8966	3.9839	3.6320	3.7042	3.5306	3.8877	3.8590
21. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**3.7600**	**3.6808**	**4.0136**	**4.0545**	**4.3245**	**3.9125**	**3.9057**	**3.9930**	**3.6411**	**3.7133**	**3.5397**	**3.8968**	**3.8681**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.760**	**3.681**	**4.014**	**4.055**	**4.325**	**3.913**	**3.906**	**3.993**	**3.641**	**3.713**	**3.540**	**3.897**	**3.868**

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

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

SCHEDULE E3

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	12,871	12,871	10,488	5,721	12,871	12,871
3. COAL	38,661,568	31,408,363	31,000,156	31,499,413	33,195,265	36,519,675
4. NATURAL GAS	15,602,890	16,863,120	20,691,439	23,110,067	29,724,831	30,098,929
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**54,277,329**	**48,284,354**	**51,702,083**	**54,615,201**	**62,932,967**	**66,631,475**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	50	50	50	10	50	50
10. COAL	1,112,580	916,860	905,060	921,320	984,550	1,097,650
11. NATURAL GAS	309,360	364,930	472,990	529,960	709,930	717,580
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,421,990**	**1,281,840**	**1,378,100**	**1,451,290**	**1,694,530**	**1,815,280**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	1,940	2,830	1,920	1,520	1,510	620
17. COAL (TON)	486,010	398,200	398,730	409,260	432,630	480,700
18. NATURAL GAS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,266,450	5,372,220
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	550	530	480	200	600	630
23. COAL	11,316,900	9,301,200	9,212,920	9,404,330	10,060,890	11,193,900
24. NATURAL GAS	2,292,410	2,672,450	3,501,010	3,987,940	5,398,660	5,508,930
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,609,860**	**11,974,180**	**12,714,410**	**13,392,470**	**15,460,150**	**16,703,460**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00
30. COAL	78.24	71.53	65.68	63.48	58.10	60.47
31. NATURAL GAS	21.76	28.47	34.32	36.52	41.90	39.53
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	6.63	4.55	5.46	3.76	8.52	20.76
37. COAL ($/TON)	79.55	78.88	77.75	76.97	76.73	75.97
38. NATURAL GAS ($/MCF)	6.99	6.48	6.06	5.94	5.64	5.60
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.40	24.28	21.85	28.61	21.45	20.43
43. COAL	3.42	3.38	3.36	3.35	3.30	3.26
44. NATURAL GAS	6.81	6.31	5.91	5.79	5.51	5.46
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.99**	**4.03**	**4.07**	**4.08**	**4.07**	**3.99**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,000	10,600	9,600	20,000	12,000	12,600
50. COAL	10,172	10,145	10,179	10,207	10,219	10,198
51. NATURAL GAS	7,410	7,323	7,402	7,525	7,604	7,677
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,571**	**9,341**	**9,226**	**9,228**	**9,124**	**9,202**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	25.74	25.74	20.98	57.21	25.74	25.74
57. COAL	3.47	3.43	3.43	3.42	3.37	3.33
58. NATURAL GAS	5.04	4.62	4.37	4.36	4.19	4.19
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.82**	**3.77**	**3.75**	**3.76**	**3.71**	**3.67**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

SCHEDULE E3

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	10,488	10,488	12,871	10,488	10,488	12,871	135,387
3.	COAL	37,466,150	35,217,466	28,714,269	27,220,227	31,731,776	34,370,993	397,005,321
4.	NATURAL GAS	31,261,455	33,791,957	35,289,054	30,728,771	17,081,902	17,528,541	301,772,956
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**68,738,093**	**69,019,911**	**64,016,194**	**57,959,486**	**48,824,166**	**51,912,405**	**698,913,664**
	SYSTEM NET GENERATION (MWH)							
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	50	50	50	50	50	50	560
10.	COAL	1,133,800	1,059,460	866,580	822,050	947,010	1,030,580	11,797,500
11.	NATURAL GAS	737,250	820,750	865,120	745,760	379,970	380,010	7,033,610
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**1,871,100**	**1,880,260**	**1,731,750**	**1,567,860**	**1,327,030**	**1,410,640**	**18,831,670**
	UNITS OF FUEL BURNED							
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	600	600	100	80	80	100	11,900
17.	COAL (TON)	496,540	464,500	381,340	362,230	416,530	448,890	5,175,560
18.	NATURAL GAS (MCF)	5,566,610	6,166,160	6,543,190	5,624,300	2,806,550	2,801,060	52,285,140
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)							
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	480	480	630	480	500	550	6,110
23.	COAL	11,558,520	10,806,170	8,856,790	8,405,290	9,698,720	10,498,820	120,314,450
24.	NATURAL GAS	5,712,400	6,326,150	6,716,300	5,758,400	2,865,810	2,856,080	53,596,540
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,271,400**	**17,132,800**	**15,573,720**	**14,164,170**	**12,565,030**	**13,355,450**	**173,917,100**
	GENERATION MIX (% MWH)							
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30.	COAL	60.60	56.35	50.04	52.43	71.37	73.06	62.65
31.	NATURAL GAS	39.40	43.65	49.96	47.57	28.63	26.94	37.35
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
	FUEL COST PER UNIT							
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	17.48	17.48	128.71	131.10	131.10	128.71	11.38
37.	COAL ($/TON)	75.45	75.82	75.30	75.15	76.18	76.57	76.71
38.	NATURAL GAS ($/MCF)	5.62	5.48	5.39	5.46	6.09	6.26	5.77
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)							
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	21.85	21.85	20.43	21.85	20.98	23.40	22.16
43.	COAL	3.24	3.26	3.24	3.24	3.27	3.27	3.30
44.	NATURAL GAS	5.47	5.34	5.25	5.34	5.96	6.14	5.63
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.98**	**4.03**	**4.11**	**4.09**	**3.89**	**3.89**	**4.02**
	BTU BURNED PER KWH (BTU/KWH)							
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	9,600	9,600	12,600	9,600	10,000	11,000	10,911
50.	COAL	10,194	10,200	10,220	10,225	10,241	10,187	10,198
51.	NATURAL GAS	7,748	7,708	7,763	7,722	7,542	7,516	7,620
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,231**	**9,112**	**8,993**	**9,034**	**9,469**	**9,468**	**9,235**
	GENERATED FUEL COST PER KWH (CENTS/KWH)							
55.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56.	LIGHT OIL	20.98	20.98	25.74	20.98	20.98	25.74	24.18
57.	COAL	3.30	3.32	3.31	3.31	3.35	3.34	3.37
58.	NATURAL GAS	4.24	4.12	4.08	4.12	4.50	4.61	4.29
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**3.67**	**3.67**	**3.70**	**3.70**	**3.68**	**3.68**	**3.71**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	237,300	80.7	85.1	92.3	10,026	COAL	101,350	23,474,494	2,379,140.0	7,927,767	3.34	78.22
2. B.B.#2	395	236,280	80.4	84.8	90.2	10,227	COAL	102,930	23,476,635	2,416,450.0	8,051,363	3.41	78.22
3. B.B.#3	400	233,190	78.4	83.2	90.1	10,389	COAL	107,040	22,633,221	2,422,660.0	8,372,850	3.59	78.22
4. B.B.#4	417	270,980	87.3	88.1	97.6	10,059	COAL	123,410	22,088,323	2,725,920.0	9,653,342	3.56	78.22
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,840	-	10,710.0	255,609	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,607**	**977,750**	**81.8**	**85.3**	**92.6**	**10,170**	**-**	**-**	**-**	**-**	**34,260,931**	**3.50**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.7	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
10. B.B.C.T.#4 TOTAL	**61**	**10**	**0.0**	**98.2**	**2.7**	**11,000**	**-**	**-**	**-**	**110.0**	**3,338**	**33.38**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**977,760**	**78.8**	**85.8**	**92.6**	**10,170**	**-**	**-**	**-**	**9,944,280.0**	**34,264,269**	**3.50**	**-**
12. POLK #1 GASIFIER	220	134,830	82.4	-	97.1	10,181	COAL	51,280	26,769,306	1,372,730.0	4,400,637	3.26	85.82
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	3,500	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**134,830**	**82.4**	**81.5**	**97.1**	**10,181**	**-**	**-**	**-**	**1,372,730.0**	**4,400,637**	**3.26**	**-**
15. POLK #2 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
16. POLK #2 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**20**	**0.0**	**97.7**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,767**	**23.84**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**97.7**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**134,870**	**19.0**	**56.4**	**95.9**	**10,181**	**-**	**-**	**-**	**1,373,170.0**	**4,410,170**	**3.27**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	161,060	27.3	91.5	36.7	7,361	GAS	1,153,300	1,028,007	1,185,600.0	8,069,640	5.01	7.00
26. BAYSIDE #2	1,047	148,240	19.0	93.2	20.6	7,462	GAS	1,076,000	1,028,020	1,106,150.0	7,528,772	5.08	7.00
27. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
28. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. BAYSIDE #5	61	60	0.1	98.6	98.4	11,000	GAS	640	1,031,250	660.0	4,478	7.46	7.00
30. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BAYSIDE TOTAL	**2,083**	**309,360**	**20.0**	**84.5**	**26.7**	**7,410**	**GAS**	**2,229,940**	**1,028,014**	**2,292,410.0**	**15,602,890**	**5.04**	**7.00**
32. SYSTEM	**4,703**	**1,421,990**	**40.6**	**79.3**	**60.4**	**9,571**	**-**	**-**	**-**	**13,609,860.0**	**54,277,329**	**3.82**	**-**

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

[1] As burned fuel cost system total includes ignition.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Units burned are ignition associated with Polk #1 Gasifier.

DOCKET NO. 140001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 10 OF 31

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	220,270	83.0	85.1	94.8	10,011	COAL	93,940	23,472,961	2,205,050.0	7,243,410	3.29	77.11
2. B.B.#2	395	217,720	82.0	84.8	92.0	10,211	COAL	94,700	23,475,290	2,223,110.0	7,302,007	3.35	77.11
3. B.B.#3	400	112,260	41.8	46.0	86.6	10,431	COAL	51,740	22,631,620	1,170,960.0	3,989,500	3.55	77.11
4. B.B.#4	417	244,770	87.3	88.1	97.5	10,061	COAL	111,480	22,090,151	2,462,610.0	8,595,866	3.51	77.11
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,730	-	15,860.0	379,246	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
7. B.B. COAL	**1,607**	**795,020**	**73.6**	**76.1**	**93.6**	**10,140**	**-**	**-**	**-**	**-**	**27,510,029**	**3.46**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.7	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	470	1.1	-	70.0	10,936	GAS	5,000	1,028,000	5,140.0	32,434	6.90	6.49
10. B.B.C.T.#4 TOTAL	**61**	**480**	**1.2**	**98.2**	**46.3**	**10,938**	**-**	**-**	**-**	**5,250.0**	**35,772**	**7.45**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**795,500**	**71.0**	**76.9**	**93.5**	**10,141**	**-**	**-**	**-**	**8,066,980.0**	**27,545,801**	**3.46**	**-**
12. POLK #1 GASIFIER	220	121,840	82.4	-	97.2	10,173	COAL	46,340	26,747,303	1,239,470.0	3,898,334	3.20	84.12
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**121,840**	**82.4**	**58.2**	**97.2**	**10,173**	**-**	**-**	**-**	**1,239,470.0**	**3,898,334**	**3.20**	**-**
15. POLK #2 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
16. POLK #2 CT OIL	187	20	0.0	-	2.7	10,500	LGT OIL	40	5,250,000	210.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**20**	**0.0**	**83.8**	**2.7**	**10,500**	**-**	**-**	**-**	**210.0**	**4,767**	**23.84**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.7	10,500	LGT OIL	40	5,250,000	210.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**83.8**	**2.7**	**10,500**	**-**	**-**	**-**	**210.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**121,880**	**19.1**	**45.7**	**96.0**	**10,173**	**-**	**-**	**-**	**1,239,890.0**	**3,907,867**	**3.21**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	162,160	30.5	55.6	52.4	7,267	GAS	1,146,250	1,027,996	1,178,340.0	7,435,395	4.59	6.49
26. BAYSIDE #2	1,047	199,020	28.3	79.9	31.8	7,307	GAS	1,414,640	1,028,014	1,454,270.0	9,176,364	4.61	6.49
27. BAYSIDE #3	61	790	1.9	98.6	99.6	10,418	GAS	8,010	1,027,466	8,230.0	51,959	6.58	6.49
28. BAYSIDE #4	61	620	1.5	98.6	84.7	10,839	GAS	6,540	1,027,523	6,720.0	42,423	6.84	6.49
29. BAYSIDE #5	61	950	2.3	98.6	91.6	10,589	GAS	9,780	1,028,630	10,060.0	63,440	6.68	6.49
30. BAYSIDE #6	61	920	2.2	98.6	94.3	10,533	GAS	9,420	1,028,662	9,690.0	61,105	6.64	6.49
31. BAYSIDE TOTAL	**2,083**	**364,460**	**26.0**	**72.8**	**38.8**	**7,319**	**GAS**	**2,594,640**	**1,028,008**	**2,667,310.0**	**16,830,686**	**4.62**	**6.49**
32. SYSTEM	**4,703**	**1,281,840**	**40.6**	**68.8**	**66.9**	**9,341**	**-**	**-**	**-**	**11,974,180.0**	**48,284,354**	**3.77**	**-**

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

[1] As burned fuel cost system total includes ignition.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Units burned are ignition associated with Polk #1 Gasifier.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	243,350	82.8	85.1	94.6	10,010	COAL	103,780	23,472,731	2,436,000.0	7,957,092	3.27	76.67
2. B.B.#2	395	241,320	82.1	84.8	92.1	10,205	COAL	104,910	23,474,311	2,462,690.0	8,043,732	3.33	76.67
3. B.B.#3	400	243,120	81.7	85.9	91.0	10,379	COAL	111,490	22,633,061	2,523,360.0	8,548,238	3.52	76.67
4. B.B.#4	417	146,800	47.3	48.3	96.4	10,074	COAL	66,950	22,088,424	1,478,820.0	5,133,235	3.50	76.67
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,840	-	10,710.0	255,609	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	30,439	-	6.08
7. B.B. COAL	**1,607**	**874,590**	**73.2**	**75.7**	**93.2**	**10,177**	**-**	**-**	**-**	**-**	**29,968,345**	**3.43**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	3.3	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	280	0.6	-	91.8	10,643	GAS	2,900	1,027,586	2,980.0	17,619	6.29	6.08
10. B.B.C.T.#4 TOTAL	**61**	**290**	**0.6**	**98.2**	**47.5**	**10,621**	**-**	**-**	**-**	**3,080.0**	**20,957**	**7.23**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**874,880**	**70.5**	**76.5**	**93.2**	**10,177**	**-**	**-**	**-**	**8,903,950.0**	**29,989,302**	**3.43**	**-**
12. POLK #1 GASIFIER	220	30,470	18.6	-	96.9	10,241	COAL	11,600	26,900,862	312,050.0	1,031,811	3.39	88.95
13. POLK #1 CT GAS (4)	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**30,470**	**18.6**	**26.3**	**96.9**	**10,241**	**-**	**-**	**-**	**312,050.0**	**1,031,811**	**3.39**	**-**
15. POLK #2 CT GAS	183	11,180	8.2	-	92.6	10,513	GAS	114,330	1,027,989	117,530.0	694,618	6.21	6.08
16. POLK #2 CT OIL	187	20	0.0	-	2.7	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**183**	**11,200**	**8.2**	**22.1**	**87.3**	**10,511**	**-**	**-**	**-**	**117,720.0**	**698,193**	**6.23**	**-**
18. POLK #3 CT GAS	183	1,870	1.4	-	92.7	10,465	GAS	19,040	1,027,836	19,570.0	115,678	6.19	6.08
19. POLK #3 CT OIL	187	20	0.0	-	2.7	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**183**	**1,890**	**1.4**	**22.1**	**68.3**	**10,455**	**-**	**-**	**-**	**19,760.0**	**119,253**	**6.31**	**-**
21. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
22. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**952**	**43,560**	**6.1**	**14.6**	**92.6**	**10,320**	**-**	**-**	**-**	**449,530.0**	**1,849,257**	**4.25**	**-**
24. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	290,960	49.4	91.5	54.5	7,238	GAS	2,048,630	1,028,004	2,106,000.0	12,446,554	4.28	6.08
26. BAYSIDE #2	1,047	161,610	20.7	69.1	30.3	7,297	GAS	1,147,100	1,027,984	1,179,200.0	6,969,263	4.31	6.08
27. BAYSIDE #3	61	1,800	4.0	82.7	84.3	10,772	GAS	18,870	1,027,557	19,390.0	114,646	6.37	6.08
28. BAYSIDE #4	61	280	0.6	70.0	91.8	10,821	GAS	2,950	1,027,119	3,030.0	17,923	6.40	6.08
29. BAYSIDE #5	61	2,270	5.0	70.0	93.0	10,604	GAS	23,420	1,027,754	24,070.0	142,289	6.27	6.08
30. BAYSIDE #6	61	2,740	6.0	98.6	88.1	10,672	GAS	28,450	1,027,768	29,240.0	172,849	6.31	6.08
31. BAYSIDE TOTAL	**2,083**	**459,660**	**29.7**	**79.0**	**42.7**	**7,312**	**GAS**	**3,269,420**	**1,027,990**	**3,360,930.0**	**19,863,524**	**4.32**	**6.08**
32. SYSTEM	**4,703**	**1,378,100**	**39.4**	**65.0**	**66.8**	**9,226**	**-**	**-**	**-**	**12,714,410.0**	**51,702,083**	**3.75**	**-**

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

[1] As burned fuel cost system total includes ignition.
[3] City of Tampa on long term reserve standby.
[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Units burned are ignition associated with Polk #1 Gasifier.

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	186,590	67.3	68.1	96.2	10,094	COAL	80,240	23,471,461	1,883,350.0	6,090,552	3.26	75.90
2. B.B.#2	385	194,890	70.3	70.6	94.6	10,212	COAL	84,770	23,477,527	1,990,190.0	6,434,399	3.30	75.90
3. B.B.#3	395	243,480	85.6	85.9	95.3	10,368	COAL	111,530	22,634,538	2,524,430.0	8,465,588	3.48	75.90
4. B.B.#4	407	257,090	87.7	88.1	98.1	10,119	COAL	117,780	22,087,112	2,601,420.0	8,939,996	3.48	75.90
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,480	-	8,580.0	205,599	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	5,000	-	5,140.0	29,786	-	5.96
7. B.B. COAL	**1,572**	**882,050**	**77.9**	**78.4**	**96.1**	**10,203**	**-**	**-**	**-**	**-**	**30,165,920**	**3.42**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	4.5	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	620	1.5	-	100.6	10,677	GAS	6,440	1,027,950	6,620.0	38,365	6.19	5.96
10. B.B.C.T.#4 TOTAL	**56**	**630**	**1.6**	**81.8**	**75.0**	**10,667**	**-**	**-**	**-**	**6,720.0**	**41,703**	**6.62**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**882,680**	**75.3**	**78.5**	**96.1**	**10,203**	**-**	**-**	**-**	**9,006,110.0**	**30,207,623**	**3.42**	**-**
12. POLK #1 GASIFIER	220	39,270	24.8	-	97.0	10,312	COAL	14,940	27,104,418	404,940.0	1,333,493	3.40	89.26
13. POLK #1 CT GAS	218	1,540	1.0	-	88.3	7,929	GAS	17,720	689,052	12,210.0	70,772	4.60	3.99
14. POLK #1 TOTAL	**220**	**40,810**	**25.8**	**81.5**	**96.7**	**10,222**	**-**	**-**	**-**	**417,150.0**	**1,404,265**	**3.44**	**-**
15. POLK #2 CT GAS	151	5,380	4.9	-	93.8	10,857	GAS	56,820	1,027,983	58,410.0	338,491	6.29	5.96
16. POLK #2 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	10	5,000,000	50.0	1,192	0.00	119.20
17. POLK #2 TOTAL	**151**	**5,380**	**4.9**	**97.7**	**91.2**	**10,866**	**-**	**-**	**-**	**58,460.0**	**339,683**	**6.31**	**-**
18. POLK #3 CT GAS	151	3,180	2.9	-	95.4	10,814	GAS	33,450	1,028,102	34,390.0	199,270	6.27	5.96
19. POLK #3 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	10	5,000,000	50.0	1,191	0.00	119.10
20. POLK #3 TOTAL	**151**	**3,180**	**2.9**	**97.7**	**91.1**	**10,830**	**-**	**-**	**-**	**34,440.0**	**200,461**	**6.30**	**-**
21. POLK #4 CT GAS	**151**	**5,320**	**4.9**	**98.6**	**95.5**	**10,878**	**GAS**	**56,300**	**1,027,886**	**57,870.0**	**335,393**	**6.30**	**5.96**
22. POLK #5 CT GAS	**151**	**2,810**	**2.6**	**98.6**	**97.9**	**10,769**	**GAS**	**29,440**	**1,027,853**	**30,260.0**	**175,381**	**6.24**	**5.96**
23. POLK STATION TOTAL	**824**	**57,500**	**9.7**	**93.7**	**95.7**	**10,403**	**-**	**-**	**-**	**598,180.0**	**2,455,183**	**4.27**	**-**
24. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	149,690	29.7	91.5	49.7	7,365	GAS	1,072,410	1,028,012	1,102,450.0	6,388,611	4.27	5.96
26. BAYSIDE #2	929	354,880	53.1	93.2	57.4	7,369	GAS	2,543,850	1,028,001	2,615,080.0	15,154,342	4.27	5.96
27. BAYSIDE #3	56	1,650	4.1	98.6	95.0	10,788	GAS	17,310	1,028,307	17,800.0	103,120	6.25	5.96
28. BAYSIDE #4	56	900	2.2	98.6	84.6	11,033	GAS	9,660	1,027,950	9,930.0	57,547	6.39	5.96
29. BAYSIDE #5	56	2,120	5.3	98.6	94.6	10,811	GAS	22,300	1,027,803	22,920.0	132,847	6.27	5.96
30. BAYSIDE #6	56	1,870	4.6	69.0	98.2	10,695	GAS	19,460	1,027,749	20,000.0	115,928	6.20	5.96
31. BAYSIDE TOTAL	**1,854**	**511,110**	**38.3**	**92.3**	**55.2**	**7,412**	**GAS**	**3,684,990**	**1,028,003**	**3,788,180.0**	**21,952,395**	**4.30**	**5.96**
32. SYSTEM	**4,306**	**1,451,290**	**46.8**	**87.4**	**76.2**	**9,228**	**-**	**-**	**-**	**13,392,470.0**	**54,615,201**	**3.76**	**-**

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

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	175,080	61.1	63.1	94.2	10,114	COAL	75,450	23,470,113	1,770,820.0	5,673,948	3.24	75.20
2. B.B.#2	385	165,570	57.8	60.1	91.3	10,257	COAL	72,330	23,478,363	1,698,190.0	5,439,319	3.29	75.20
3. B.B.#3	395	243,410	82.8	85.9	92.2	10,403	COAL	111,880	22,633,625	2,532,250.0	8,413,534	3.46	75.20
4. B.B.#4	407	265,570	87.7	88.1	98.0	10,120	COAL	121,670	22,088,025	2,687,450.0	9,149,751	3.45	75.20
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,410	-	8,150.0	195,875	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	12,510	-	12,860.0	70,808	-	5.66
7. B.B. COAL	**1,572**	**849,630**	**72.6**	**74.6**	**94.2**	**10,226**	**-**	**-**	**-**	**-**	**28,943,235**	**3.41**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	12,000	LGT OIL	20	6,000,000	120.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,060	2.5	-	99.6	11,000	GAS	11,340	1,028,219	11,660.0	64,186	6.06	5.66
10. B.B.C.T.#4 TOTAL	**56**	**1,070**	**2.6**	**98.2**	**76.4**	**11,009**	**-**	**-**	**-**	**11,780.0**	**67,524**	**6.31**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**850,700**	**70.2**	**75.4**	**94.1**	**10,227**	**-**	**-**	**-**	**8,700,490.0**	**29,010,759**	**3.41**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,748,148	1,372,180.0	4,252,030	3.15	82.89
13. POLK #1 CT GAS	218	5,300	3.3	-	86.8	8,025	GAS	43,700	973,227	42,530.0	234,160	4.42	5.36
14. POLK #1 TOTAL	**220**	**140,220**	**85.7**	**81.5**	**96.8**	**10,089**	**-**	**-**	**-**	**1,414,710.0**	**4,486,190**	**3.20**	**-**
15. POLK #2 CT GAS	151	18,100	16.1	-	93.6	10,905	GAS	192,010	1,027,967	197,380.0	1,086,804	6.00	5.66
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**18,120**	**16.1**	**97.7**	**90.0**	**10,906**	**-**	**-**	**-**	**197,620.0**	**1,091,571**	**6.02**	**-**
18. POLK #3 CT GAS	151	8,810	7.8	-	95.4	10,831	GAS	92,810	1,028,122	95,420.0	525,317	5.96	5.66
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,000	LGT OIL	40	6,000,000	240.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**8,830**	**7.8**	**97.7**	**88.0**	**10,834**	**-**	**-**	**-**	**95,660.0**	**530,083**	**6.00**	**-**
21. POLK #4 CT GAS	**151**	**6,690**	**6.0**	**98.6**	**94.5**	**10,865**	**GAS**	**70,710**	**1,028,002**	**72,690.0**	**400,228**	**5.98**	**5.66**
22. POLK #5 CT GAS	**151**	**4,190**	**3.7**	**98.6**	**92.5**	**10,900**	**GAS**	**44,420**	**1,028,140**	**45,670.0**	**251,423**	**6.00**	**5.66**
23. POLK STATION TOTAL	**824**	**178,050**	**29.0**	**93.7**	**95.4**	**10,258**	**-**	**-**	**-**	**1,826,350.0**	**6,759,495**	**3.80**	**-**
24. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	244,410	46.9	91.5	56.2	7,366	GAS	1,751,320	1,028,002	1,800,360.0	9,912,711	4.06	5.66
26. BAYSIDE #2	929	408,550	59.1	93.2	64.0	7,332	GAS	2,914,020	1,027,996	2,995,600.0	16,493,752	4.04	5.66
27. BAYSIDE #3	56	3,140	7.5	98.6	100.1	10,707	GAS	32,700	1,028,135	33,620.0	185,086	5.89	5.66
28. BAYSIDE #4	56	1,790	4.3	98.6	99.9	10,760	GAS	18,740	1,027,748	19,260.0	106,071	5.93	5.66
29. BAYSIDE #5	56	4,310	10.3	98.6	100.0	10,703	GAS	44,880	1,027,852	46,130.0	254,027	5.89	5.66
30. BAYSIDE #6	56	3,580	8.6	98.6	99.9	10,709	GAS	37,290	1,028,158	38,340.0	211,066	5.90	5.66
31. BAYSIDE TOTAL	**1,854**	**665,780**	**48.3**	**93.2**	**61.3**	**7,410**	**GAS**	**4,798,950**	**1,027,998**	**4,933,310.0**	**27,162,713**	**4.08**	**5.66**
32. SYSTEM	**4,306**	**1,694,530**	**52.9**	**86.6**	**77.9**	**9,124**	**-**	**-**	**-**	**15,460,150.0**	**62,932,967**	**3.71**	**-**

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

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

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 14 OF 31

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	234,290	84.5	85.1	96.6	10,087	COAL	100,670	23,474,719	2,363,200.0	7,536,258	3.22	74.86
2. B.B.#2	385	233,590	84.3	84.8	94.5	10,213	COAL	101,620	23,476,678	2,385,700.0	7,607,375	3.26	74.86
3. B.B.#3	395	242,120	85.1	85.9	94.7	10,374	COAL	110,980	22,632,997	2,511,810.0	8,308,074	3.43	74.86
4. B.B.#4	407	257,080	87.7	88.1	98.1	10,119	COAL	117,770	22,088,308	2,601,340.0	8,816,370	3.43	74.86
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	42,125	-	5.62
7. B.B. COAL	**1,572**	**967,080**	**85.4**	**86.0**	**96.0**	**10,198**	**-**	**-**	**-**	**-**	**32,382,439**	**3.35**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	13,000	LGT OIL	20	6,500,000	130.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,160	2.9	-	98.6	10,948	GAS	12,360	1,027,508	12,700.0	69,422	5.98	5.62
10. B.B.C.T.#4 TOTAL	**56**	**1,170**	**2.9**	**98.2**	**77.4**	**10,966**	**-**	**-**	**-**	**12,830.0**	**72,760**	**6.22**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**968,250**	**82.6**	**86.4**	**96.0**	**10,199**	**-**	**-**	**-**	**9,874,880.0**	**32,455,199**	**3.35**	**-**
12. POLK #1 GASIFIER	220	130,570	82.4	-	97.1	10,200	COAL	49,660	26,819,372	1,331,850.0	4,137,236	3.17	83.31
13. POLK #1 CT GAS	218	3,500	2.2	-	73.0	8,346	GAS	34,260	852,598	29,210.0	159,625	4.56	4.66
14. POLK #1 TOTAL	**220**	**134,070**	**84.6**	**81.5**	**96.3**	**10,152**	**-**	**-**	**-**	**1,361,060.0**	**4,296,861**	**3.20**	**-**
15. POLK #2 CT GAS	151	18,270	16.8	-	96.8	10,790	GAS	191,770	1,028,002	197,140.0	1,077,105	5.90	5.62
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**18,290**	**16.8**	**97.7**	**93.0**	**10,792**	**-**	**-**	**-**	**197,390.0**	**1,081,872**	**5.92**	**-**
18. POLK #3 CT GAS	151	16,110	14.8	-	96.7	10,790	GAS	169,080	1,028,034	173,820.0	949,662	5.89	5.62
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**16,130**	**14.8**	**97.7**	**92.4**	**10,792**	**-**	**-**	**-**	**174,070.0**	**954,428**	**5.92**	**-**
21. POLK #4 CT GAS	**151**	**12,900**	**11.9**	**98.6**	**98.5**	**10,765**	**GAS**	**135,080**	**1,028,057**	**138,870.0**	**758,696**	**5.88**	**5.62**
22. POLK #5 CT GAS	**151**	**8,820**	**8.1**	**98.6**	**99.0**	**10,749**	**GAS**	**92,230**	**1,027,974**	**94,810.0**	**518,023**	**5.87**	**5.62**
23. POLK STATION TOTAL	**824**	**190,210**	**32.1**	**93.7**	**95.9**	**10,337**	**-**	**-**	**-**	**1,966,200.0**	**7,609,880**	**4.00**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	238,140	47.2	91.5	53.4	7,369	GAS	1,706,990	1,028,003	1,754,790.0	9,587,558	4.03	5.62
26. BAYSIDE #2	929	405,830	60.7	93.2	65.7	7,316	GAS	2,888,050	1,027,998	2,968,910.0	16,221,152	4.00	5.62
27. BAYSIDE #3	56	2,690	6.7	98.6	94.2	10,836	GAS	28,350	1,028,219	29,150.0	159,232	5.92	5.62
28. BAYSIDE #4	56	2,000	5.0	98.6	94.0	10,885	GAS	21,180	1,027,856	21,770.0	118,961	5.95	5.62
29. BAYSIDE #5	56	4,950	12.3	98.6	98.2	10,725	GAS	51,650	1,027,880	53,090.0	290,100	5.86	5.62
30. BAYSIDE #6	56	3,210	8.0	98.6	97.2	10,801	GAS	33,720	1,028,173	34,670.0	189,393	5.90	5.62
31. BAYSIDE TOTAL	**1,854**	**656,820**	**49.2**	**93.2**	**61.0**	**7,403**	**GAS**	**4,729,940**	**1,028,000**	**4,862,380.0**	**26,566,396**	**4.04**	**5.62**
32. SYSTEM	**4,306**	**1,815,280**	**58.6**	**90.7**	**79.5**	**9,202**	**-**	**-**	**-**	**16,703,460.0**	**66,631,475**	**3.67**	**-**

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

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	241,400	84.3	85.1	96.3	10,089	COAL	103,760	23,472,726	2,435,530.0	7,712,993	3.20	74.33
2. B.B.#2	385	241,270	84.2	84.8	94.5	10,213	COAL	104,960	23,475,419	2,463,980.0	7,802,196	3.23	74.33
3. B.B.#3	395	250,300	85.2	85.9	94.9	10,373	COAL	114,710	22,633,162	2,596,250.0	8,526,962	3.41	74.33
4. B.B.#4	407	265,910	87.8	88.1	98.1	10,118	COAL	121,810	22,088,416	2,690,590.0	9,054,755	3.41	74.34
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	42,194	-	5.63
7. B.B. COAL	**1,572**	**998,880**	**85.4**	**86.0**	**96.0**	**10,198**	**-**	**-**	**-**	**-**	**33,211,337**	**3.32**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.6	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,150	2.8	-	93.3	11,296	GAS	12,640	1,027,690	12,990.0	71,110	6.18	5.63
10. B.B.C.T.#4 TOTAL	**56**	**1,160**	**2.8**	**98.2**	**71.4**	**11,284**	**-**	**-**	**-**	**13,090.0**	**74,448**	**6.42**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**1,000,040**	**82.6**	**86.4**	**95.9**	**10,199**	**-**	**-**	**-**	**10,199,440.0**	**33,285,785**	**3.33**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,254,813	3.15	82.94
13. POLK #1 CT GAS	218	3,390	2.1	-	74.0	8,115	GAS	29,090	945,686	27,510.0	150,547	4.44	5.18
14. POLK #1 TOTAL	**220**	**138,310**	**84.5**	**81.5**	**96.5**	**10,120**	**-**	**-**	**-**	**1,399,680.0**	**4,405,360**	**3.19**	**-**
15. POLK #2 CT GAS	151	28,120	25.0	-	95.5	10,836	GAS	296,420	1,027,967	304,710.0	1,667,606	5.93	5.63
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**28,140**	**25.0**	**97.7**	**93.5**	**10,835**	**-**	**-**	**-**	**304,900.0**	**1,671,181**	**5.94**	**-**
18. POLK #3 CT GAS	151	20,870	18.5	-	96.4	10,812	GAS	219,500	1,028,018	225,650.0	1,234,868	5.92	5.63
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**20,890**	**18.5**	**97.7**	**93.7**	**10,811**	**-**	**-**	**-**	**225,840.0**	**1,238,443**	**5.93**	**-**
21. POLK #4 CT GAS	**151**	**15,320**	**13.7**	**98.6**	**97.8**	**10,790**	**GAS**	**160,800**	**1,028,047**	**165,310.0**	**904,632**	**5.90**	**5.63**
22. POLK #5 CT GAS	**151**	**4,490**	**4.0**	**98.6**	**99.1**	**10,808**	**GAS**	**47,200**	**1,028,178**	**48,530.0**	**265,539**	**5.91**	**5.63**
23. POLK STATION TOTAL	**824**	**207,150**	**33.8**	**93.7**	**95.9**	**10,351**	**-**	**-**	**-**	**2,144,260.0**	**8,485,155**	**4.10**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	251,690	48.3	91.5	56.0	7,380	GAS	1,806,770	1,028,011	1,857,380.0	10,164,567	4.04	5.63
26. BAYSIDE #2	929	397,670	57.5	93.2	62.3	7,325	GAS	2,833,600	1,028,003	2,912,950.0	15,941,329	4.01	5.63
27. BAYSIDE #3	56	3,490	8.4	98.6	97.4	10,834	GAS	36,780	1,028,004	37,810.0	206,918	5.93	5.63
28. BAYSIDE #4	56	2,570	6.2	98.6	95.6	10,938	GAS	27,350	1,027,788	28,110.0	153,866	5.99	5.63
29. BAYSIDE #5	56	4,700	11.3	98.6	98.7	10,753	GAS	49,160	1,028,072	50,540.0	276,565	5.88	5.63
30. BAYSIDE #6	56	3,790	9.1	98.6	98.1	10,794	GAS	39,800	1,027,889	40,910.0	223,908	5.91	5.63
31. BAYSIDE TOTAL	**1,854**	**663,910**	**48.1**	**93.2**	**60.2**	**7,422**	**GAS**	**4,793,460**	**1,028,005**	**4,927,700.0**	**26,967,153**	**4.06**	**5.63**
32. SYSTEM	**4,306**	**1,871,100**	**58.4**	**90.7**	**79.3**	**9,231**	**-**	**-**	**-**	**17,271,400.0**	**68,738,093**	**3.67**	**-**

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

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

DOCKET NO. 140001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 16 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	164,840	57.5	57.6	97.1	10,083	COAL	70,810	23,473,379	1,662,150.0	5,286,000	3.21	74.65
2. B.B.#2	385	242,810	84.8	84.8	95.1	10,206	COAL	105,560	23,476,127	2,478,140.0	7,880,104	3.25	74.65
3. B.B.#3	395	252,160	85.8	85.9	95.6	10,365	COAL	115,480	22,632,144	2,613,560.0	8,620,636	3.42	74.65
4. B.B.#4	407	264,730	87.4	88.1	97.7	10,124	COAL	121,350	22,086,115	2,680,150.0	9,058,828	3.42	74.65
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	520	-	3,000.0	72,237	-	138.92
6. B.B. IGNITION	-	-	-	-	-	-	GAS	10,010	-	10,290.0	54,967	-	5.49
7. B.B. COAL	**1,572**	**924,540**	**79.0**	**79.3**	**96.3**	**10,204**	**-**	**-**	**-**	**-**	**30,972,772**	**3.35**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,180	2.8	-	100.3	10,780	GAS	12,370	1,028,294	12,720.0	67,926	5.76	5.49
10. B.B.C.T.#4 TOTAL	**56**	**1,190**	**2.9**	**98.2**	**78.7**	**10,773**	**-**	**-**	**-**	**12,820.0**	**71,264**	**5.99**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**925,730**	**76.4**	**79.9**	**96.3**	**10,205**	**-**	**-**	**-**	**9,446,820.0**	**31,044,036**	**3.35**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,244,694	3.15	82.74
13. POLK #1 CT GAS	218	6,770	4.2	-	86.3	8,092	GAS	55,620	984,898	54,780.0	292,627	4.32	5.26
14. POLK #1 TOTAL	**220**	**141,690**	**86.6**	**81.5**	**96.6**	**10,071**	**-**	**-**	**-**	**1,426,950.0**	**4,537,321**	**3.20**	**-**
15. POLK #2 CT GAS	151	31,710	28.2	-	95.0	10,847	GAS	334,590	1,028,004	343,960.0	1,837,306	5.79	5.49
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**31,730**	**28.2**	**97.7**	**93.3**	**10,846**	**-**	**-**	**-**	**344,150.0**	**1,840,881**	**5.80**	**-**
18. POLK #3 CT GAS	151	21,470	19.1	-	95.1	10,838	GAS	226,350	1,028,010	232,690.0	1,242,937	5.79	5.49
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**21,490**	**19.1**	**97.7**	**92.6**	**10,837**	**-**	**-**	**-**	**232,880.0**	**1,246,512**	**5.80**	**-**
21. POLK #4 CT GAS	**151**	**14,800**	**13.2**	**98.6**	**99.3**	**10,739**	**GAS**	**154,590**	**1,028,074**	**158,930.0**	**848,887**	**5.74**	**5.49**
22. POLK #5 CT GAS	**151**	**4,200**	**3.7**	**98.6**	**99.3**	**10,743**	**GAS**	**43,890**	**1,028,025**	**45,120.0**	**241,009**	**5.74**	**5.49**
23. POLK STATION TOTAL	**824**	**213,910**	**34.9**	**93.7**	**95.9**	**10,322**	**-**	**-**	**-**	**2,208,030.0**	**8,714,610**	**4.07**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	282,360	54.1	91.5	58.9	7,336	GAS	2,014,940	1,028,006	2,071,370.0	11,064,472	3.92	5.49
26. BAYSIDE #2	929	439,720	63.6	93.2	68.9	7,295	GAS	3,120,590	1,028,001	3,207,970.0	17,135,835	3.90	5.49
27. BAYSIDE #3	56	4,700	11.3	98.6	99.9	10,706	GAS	48,950	1,027,988	50,320.0	268,795	5.72	5.49
28. BAYSIDE #4	56	3,140	7.5	98.6	100.1	10,748	GAS	32,830	1,028,023	33,750.0	180,277	5.74	5.49
29. BAYSIDE #5	56	5,880	14.1	98.6	100.0	10,709	GAS	61,260	1,027,914	62,970.0	336,392	5.72	5.49
30. BAYSIDE #6	56	4,820	11.6	98.6	100.1	10,699	GAS	50,170	1,027,905	51,570.0	275,494	5.72	5.49
31. BAYSIDE TOTAL	**1,854**	**740,620**	**53.7**	**93.2**	**65.2**	**7,396**	**GAS**	**5,328,740**	**1,028,001**	**5,477,950.0**	**29,261,265**	**3.95**	**5.49**
32. SYSTEM	**4,306**	**1,880,260**	**58.7**	**88.3**	**81.0**	**9,112**	**-**	**-**	**-**	**17,132,800.0**	**69,019,911**	**3.67**	**-**

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

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

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DOCKET NO. 140001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 17 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [(2)]	(L) AS BURNED FUEL COST ($) [(1)]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	234,950	84.8	84.8	95.1	10,207	COAL	102,160	23,474,941	2,398,200.0	7,567,027	3.22	74.07
3. B.B.#3	395	243,970	85.8	85.9	95.5	10,366	COAL	111,740	22,632,182	2,528,920.0	8,276,622	3.39	74.07
4. B.B.#4	407	257,090	87.7	88.1	98.1	10,119	COAL	117,780	22,087,112	2,601,420.0	8,724,007	3.39	74.07
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	7,500	-	7,710.0	40,510	-	5.40
7. B.B. COAL	**1,572**	**736,010**	**65.0**	**65.2**	**96.2**	**10,229**	**-**	**-**	**-**	**-**	**24,608,166**	**3.34**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	2.6	13,000	LGT OIL	20	6,500,000	130.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	1,720	4.3	-	99.1	10,820	GAS	18,100	1,028,177	18,610.0	97,765	5.68	5.40
10. B.B.C.T.#4 TOTAL	**56**	**1,730**	**4.3**	**98.2**	**81.3**	**10,832**	**-**	**-**	**-**	**18,740.0**	**101,103**	**5.84**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**737,740**	**62.9**	**66.3**	**96.2**	**10,230**	**-**	**-**	**-**	**7,547,280.0**	**24,709,269**	**3.35**	**-**
12. POLK #1 GASIFIER	220	130,570	82.4	-	97.1	10,173	COAL	49,660	26,746,879	1,328,250.0	4,106,103	3.14	82.68
13. POLK #1 CT GAS	218	5,460	3.5	-	73.7	8,148	GAS	45,610	975,444	44,490.0	233,771	4.28	5.13
14. POLK #1 TOTAL	**220**	**136,030**	**85.9**	**81.5**	**95.9**	**10,091**	**-**	**-**	**-**	**1,372,740.0**	**4,339,874**	**3.19**	**-**
15. POLK #2 CT GAS	151	32,080	29.5	-	97.0	10,786	GAS	336,590	1,027,987	346,010.0	1,818,045	5.67	5.40
16. POLK #2 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**151**	**32,100**	**29.5**	**97.7**	**94.8**	**10,787**	**-**	**-**	**-**	**346,260.0**	**1,822,812**	**5.68**	**-**
18. POLK #3 CT GAS	151	27,760	25.5	-	97.5	10,765	GAS	290,700	1,028,001	298,840.0	1,570,177	5.66	5.40
19. POLK #3 CT OIL	159	20	0.0	-	2.5	12,500	LGT OIL	40	6,250,000	250.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**151**	**27,780**	**25.5**	**97.7**	**94.9**	**10,766**	**-**	**-**	**-**	**299,090.0**	**1,574,943**	**5.67**	**-**
21. POLK #4 CT GAS	**151**	**23,640**	**21.8**	**98.6**	**98.1**	**10,771**	**GAS**	**247,690**	**1,028,019**	**254,630.0**	**1,337,864**	**5.66**	**5.40**
22. POLK #5 CT GAS	**151**	**14,320**	**13.2**	**98.6**	**98.8**	**10,755**	**GAS**	**149,810**	**1,028,036**	**154,010.0**	**809,178**	**5.65**	**5.40**
23. POLK STATION TOTAL	**824**	**233,870**	**39.4**	**93.7**	**96.0**	**10,376**	**-**	**-**	**-**	**2,426,730.0**	**9,884,671**	**4.23**	**-**
24. CITY OF TAMPA GAS [(3)]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	282,530	56.0	91.5	61.0	7,314	GAS	2,010,160	1,027,998	2,066,440.0	10,857,605	3.84	5.40
26. BAYSIDE #2	929	460,020	68.8	93.2	74.5	7,270	GAS	3,253,150	1,028,004	3,344,250.0	17,571,446	3.82	5.40
27. BAYSIDE #3	56	3,790	9.4	98.6	99.5	10,752	GAS	39,640	1,028,002	40,750.0	214,110	5.65	5.40
28. BAYSIDE #4	56	2,730	6.8	98.6	99.5	10,751	GAS	28,550	1,028,021	29,350.0	154,209	5.65	5.40
29. BAYSIDE #5	56	6,310	15.6	98.6	99.7	10,729	GAS	65,860	1,027,938	67,700.0	355,734	5.64	5.40
30. BAYSIDE #6	56	4,760	11.8	98.6	100.0	10,761	GAS	49,830	1,027,895	51,220.0	269,150	5.65	5.40
31. BAYSIDE TOTAL	**1,854**	**760,140**	**56.9**	**93.2**	**69.2**	**7,367**	**GAS**	**5,447,190**	**1,028,000**	**5,599,710.0**	**29,422,254**	**3.87**	**5.40**
32. SYSTEM	**4,306**	**1,731,750**	**55.9**	**83.1**	**82.1**	**8,993**	**-**	**-**	**-**	**15,573,720.0**	**64,016,194**	**3.70**	**-**

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

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

DOCKET NO. 140001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 18 OF 31

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	6,050	2.1	2.7	74.8	10,486	COAL	2,700	23,496,296	63,440.0	198,601	3.28	73.56
2. B.B.#2	385	163,020	56.9	57.4	94.3	10,217	COAL	70,950	23,475,969	1,665,620.0	5,218,747	3.20	73.56
3. B.B.#3	395	252,150	85.8	85.9	95.6	10,365	COAL	115,470	22,633,325	2,613,470.0	8,493,428	3.37	73.56
4. B.B.#4	407	265,910	87.8	88.1	98.1	10,118	COAL	121,810	22,088,416	2,690,590.0	8,959,758	3.37	73.56
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	20,440	-	21,010.0	112,130	-	5.49
7. B.B. COAL	**1,572**	**687,130**	**58.8**	**59.1**	**96.0**	**10,236**	**-**	**-**	**-**	**-**	**22,982,664**	**3.34**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	4.5	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	2,920	7.0	-	94.8	10,863	GAS	30,860	1,027,868	31,720.0	169,291	5.80	5.49
10. B.B.C.T.#4 TOTAL	**56**	**2,930**	**7.0**	**98.2**	**88.7**	**10,860**	**-**	**-**	**-**	**31,820.0**	**172,629**	**5.89**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**690,060**	**57.0**	**60.5**	**96.0**	**10,238**	**-**	**-**	**-**	**7,064,940.0**	**23,155,293**	**3.36**	**-**
12. POLK #1 GASIFIER	220	134,920	82.4	-	97.2	10,170	COAL	51,300	26,747,953	1,372,170.0	4,237,563	3.14	82.60
13. POLK #1 CT GAS	218	3,390	2.1	-	86.4	7,944	GAS	28,520	944,250	26,930.0	143,673	4.24	5.04
14. POLK #1 TOTAL	**220**	**138,310**	**84.5**	**81.5**	**96.9**	**10,116**	**-**	**-**	**-**	**1,399,100.0**	**4,381,236**	**3.17**	**-**
15. POLK #2 CT GAS	151	25,040	22.3	-	97.0	10,785	GAS	262,690	1,028,018	270,050.0	1,441,060	5.76	5.49
16. POLK #2 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**25,060**	**22.3**	**97.7**	**94.7**	**10,784**	**-**	**-**	**-**	**270,240.0**	**1,444,635**	**5.76**	**-**
18. POLK #3 CT GAS	151	18,080	16.0	-	97.0	10,769	GAS	189,400	1,028,036	194,710.0	1,039,007	5.75	5.49
19. POLK #3 CT OIL	159	20	0.0	-	3.1	9,500	LGT OIL	30	6,333,333	190.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**18,100**	**16.1**	**97.7**	**93.9**	**10,768**	**-**	**-**	**-**	**194,900.0**	**1,042,582**	**5.76**	**-**
21. POLK #4 CT GAS	**151**	**12,140**	**10.8**	**98.6**	**99.5**	**10,715**	**GAS**	**126,540**	**1,027,975**	**130,080.0**	**694,171**	**5.72**	**5.49**
22. POLK #5 CT GAS	**151**	**10,670**	**9.5**	**98.6**	**99.5**	**10,698**	**GAS**	**111,040**	**1,028,008**	**114,150.0**	**609,141**	**5.71**	**5.49**
23. POLK STATION TOTAL	**824**	**204,280**	**33.3**	**93.7**	**96.6**	**10,321**	**-**	**-**	**-**	**2,108,470.0**	**8,171,765**	**4.00**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	231,490	44.4	91.5	54.7	7,326	GAS	1,649,650	1,028,006	1,695,850.0	9,049,620	3.91	5.49
26. BAYSIDE #2	929	423,080	61.2	93.2	66.3	7,304	GAS	3,005,950	1,027,998	3,090,110.0	16,489,985	3.90	5.49
27. BAYSIDE #3	56	4,450	10.7	85.9	95.7	10,822	GAS	46,850	1,027,962	48,160.0	257,009	5.78	5.49
28. BAYSIDE #4	56	3,890	9.3	98.6	95.2	10,892	GAS	41,210	1,028,149	42,370.0	226,069	5.81	5.49
29. BAYSIDE #5	56	6,280	15.1	98.6	95.8	10,780	GAS	65,860	1,027,938	67,700.0	361,294	5.75	5.49
30. BAYSIDE #6	56	4,330	10.4	85.9	99.1	10,755	GAS	45,290	1,028,262	46,570.0	248,451	5.74	5.49
31. BAYSIDE TOTAL	**1,854**	**673,520**	**48.8**	**92.4**	**62.3**	**7,410**	**GAS**	**4,854,810**	**1,028,003**	**4,990,760.0**	**26,632,428**	**3.95**	**5.49**
32. SYSTEM	**4,306**	**1,567,860**	**48.9**	**80.6**	**77.9**	**9,034**	**-**	**-**	**-**	**14,164,170.0**	**57,959,486**	**3.70**	**-**

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

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	223,040	80.5	85.1	92.0	10,144	COAL	96,390	23,472,767	2,262,540.0	7,242,384	3.25	75.14
2. B.B.#2	385	218,400	78.8	84.8	88.4	10,312	COAL	95,930	23,475,972	2,252,050.0	7,207,823	3.30	75.14
3. B.B.#3	395	140,360	49.4	57.3	82.4	10,534	COAL	65,330	22,632,481	1,478,580.0	4,908,651	3.50	75.14
4. B.B.#4	407	256,630	87.6	88.1	97.9	10,118	COAL	117,560	22,086,424	2,596,480.0	8,833,018	3.44	75.14
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	12,930	-	13,290.0	79,228	-	6.13
7. B.B. COAL	**1,572**	**838,430**	**74.1**	**78.8**	**90.9**	**10,245**	**-**	**-**	**-**	**-**	**28,271,104**	**3.37**	**-**
8. B.B.C.T.#4 OIL	56	10	0.0	-	3.6	10,000	LGT OIL	20	5,000,000	100.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	56	60	0.1	-	107.1	10,833	GAS	630	1,031,746	650.0	3,860	6.43	6.13
10. B.B.C.T.#4 TOTAL	**56**	**70**	**0.2**	**98.2**	**20.8**	**10,714**	**-**	**-**	**-**	**750.0**	**7,198**	**10.28**	**-**
11. BIG BEND STATION TOTAL	**1,628**	**838,500**	**71.5**	**79.5**	**90.9**	**10,245**	**-**	**-**	**-**	**8,590,400.0**	**28,278,302**	**3.37**	**-**
12. POLK #1 GASIFIER	220	108,580	68.5	-	97.0	10,214	COAL	41,320	26,840,997	1,109,070.0	3,460,672	3.19	83.75
13. POLK #1 CT GAS	218	10,100	6.4	-	82.7	8,049	GAS	84,930	957,141	81,290.0	484,618	4.80	5.71
14. POLK #1 TOTAL	**220**	**118,680**	**74.9**	**67.9**	**95.6**	**10,030**	**-**	**-**	**-**	**1,190,360.0**	**3,945,290**	**3.32**	**-**
15. POLK #2 CT GAS	151	5,350	4.9	-	90.8	10,987	GAS	57,180	1,027,982	58,780.0	350,367	6.55	6.13
16. POLK #2 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
17. POLK #2 TOTAL	**151**	**5,370**	**4.9**	**97.7**	**82.3**	**10,983**	**-**	**-**	**-**	**58,980.0**	**353,942**	**6.59**	**-**
18. POLK #3 CT GAS	151	2,550	2.3	-	93.5	10,886	GAS	27,000	1,028,148	27,760.0	165,440	6.49	6.13
19. POLK #3 CT OIL	159	20	0.0	-	3.1	10,000	LGT OIL	30	6,666,667	200.0	3,575	17.88	119.17
20. POLK #3 TOTAL	**151**	**2,570**	**2.4**	**97.7**	**76.4**	**10,879**	**-**	**-**	**-**	**27,960.0**	**169,015**	**6.58**	**-**
21. POLK #4 CT GAS	**151**	**300**	**0.3**	**98.6**	**99.6**	**10,933**	**GAS**	**3,190**	**1,028,213**	**3,280.0**	**19,546**	**6.52**	**6.13**
22. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. POLK STATION TOTAL	**824**	**126,920**	**21.4**	**72.0**	**94.5**	**10,090**	**-**	**-**	**-**	**1,280,580.0**	**4,487,793**	**3.54**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	701	172,000	34.1	82.3	46.4	7,487	GAS	1,252,730	1,027,987	1,287,790.0	7,676,004	4.46	6.13
26. BAYSIDE #2	929	187,660	28.1	43.5	53.6	7,378	GAS	1,346,780	1,028,008	1,384,500.0	8,252,288	4.40	6.13
27. BAYSIDE #3	56	500	1.2	98.6	99.2	11,140	GAS	5,420	1,027,675	5,570.0	33,211	6.64	6.13
28. BAYSIDE #4	56	110	0.3	98.6	98.2	11,364	GAS	1,220	1,024,590	1,250.0	7,475	6.80	6.13
29. BAYSIDE #5	56	780	1.9	98.6	99.5	11,256	GAS	8,540	1,028,103	8,780.0	52,328	6.71	6.13
30. BAYSIDE #6	56	560	1.4	98.6	100.0	11,000	GAS	6,000	1,026,667	6,160.0	36,765	6.57	6.13
31. BAYSIDE TOTAL	**1,854**	**361,610**	**27.1**	**64.8**	**50.0**	**7,450**	**GAS**	**2,620,690**	**1,027,993**	**2,694,050.0**	**16,058,071**	**4.44**	**6.13**
32. SYSTEM	**4,306**	**1,327,030**	**42.8**	**71.7**	**74.6**	**9,469**	**-**	**-**	**-**	**12,565,030.0**	**48,824,166**	**3.68**	**-**

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

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

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 20 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2015

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	239,420	81.5	85.1	93.1	10,026	COAL	102,260	23,473,206	2,400,370.0	7,716,288	3.22	75.46
2. B.B.#2	395	235,840	80.3	84.8	90.1	10,235	COAL	102,810	23,477,677	2,413,740.0	7,757,790	3.29	75.46
3. B.B.#3	400	240,110	80.7	85.9	89.9	10,392	COAL	110,240	22,633,618	2,495,130.0	8,318,440	3.46	75.46
4. B.B.#4	417	180,320	58.1	59.7	95.9	10,080	COAL	82,280	22,090,423	1,817,600.0	6,208,644	3.44	75.46
5. B.B. IGNITION	-	-	-	-	-	-	LGT OIL	0	-	0.0	0	-	0.00
6. B.B. IGNITION	-	-	-	-	-	-	GAS	20,450	-	21,020.0	129,022	-	6.31
7. B.B. COAL	**1,607**	**895,690**	**74.9**	**78.6**	**91.9**	**10,190**	**-**	**-**	**-**	**-**	**30,130,184**	**3.36**	**-**
8. B.B.C.T.#4 OIL	61	10	0.0	-	2.0	11,000	LGT OIL	20	5,500,000	110.0	3,338	33.38	166.90
9. B.B.C.T.#4 GAS	61	120	0.3	-	65.6	11,750	GAS	1,370	1,029,197	1,410.0	8,643	7.20	6.31
10. B.B.C.T.#4 TOTAL	**61**	**130**	**0.3**	**98.2**	**19.4**	**11,692**	**-**	**-**	**-**	**1,520.0**	**11,981**	**9.22**	**-**
11. BIG BEND STATION TOTAL	**1,668**	**895,820**	**72.2**	**79.3**	**91.9**	**10,190**	**-**	**-**	**-**	**9,128,360.0**	**30,142,165**	**3.36**	**-**
12. POLK #1 GASIFIER	220	134,890	82.4	-	97.2	10,171	COAL	51,300	26,744,250	1,371,980.0	4,240,809	3.14	82.67
13. POLK #1 CT GAS [4]	205	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
14. POLK #1 TOTAL	**220**	**134,890**	**82.4**	**81.5**	**97.2**	**10,171**	**-**	**-**	**-**	**1,371,980.0**	**4,240,809**	**3.14**	**-**
15. POLK #2 CT GAS	183	7,950	5.8	-	90.5	10,560	GAS	81,660	1,028,043	83,950.0	515,204	6.48	6.31
16. POLK #2 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,767	23.84	119.18
17. POLK #2 TOTAL	**183**	**7,970**	**5.9**	**88.3**	**82.0**	**10,561**	**-**	**-**	**-**	**84,170.0**	**519,971**	**6.52**	**-**
18. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
19. POLK #3 CT OIL	187	20	0.0	-	2.1	11,000	LGT OIL	40	5,500,000	220.0	4,766	23.83	119.15
20. POLK #3 TOTAL	**183**	**20**	**0.0**	**88.3**	**2.1**	**11,000**	**-**	**-**	**-**	**220.0**	**4,766**	**23.83**	**-**
21. POLK #4 CT GAS	**183**	**5,580**	**4.1**	**89.1**	**92.6**	**10,507**	**GAS**	**57,030**	**1,028,055**	**58,630.0**	**359,810**	**6.45**	**6.31**
22. POLK #5 CT GAS	**183**	**320**	**0.2**	**92.2**	**87.4**	**10,500**	**GAS**	**3,270**	**1,027,523**	**3,360.0**	**20,631**	**6.45**	**6.31**
23. POLK STATION TOTAL	**952**	**148,780**	**21.0**	**87.6**	**95.5**	**10,205**	**-**	**-**	**-**	**1,518,360.0**	**5,145,987**	**3.46**	**-**
24. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. BAYSIDE #1	792	153,120	26.0	67.9	45.3	7,400	GAS	1,102,150	1,028,009	1,133,020.0	6,953,612	4.54	6.31
26. BAYSIDE #2	1,047	209,600	26.9	93.2	29.1	7,348	GAS	1,498,210	1,028,007	1,540,170.0	9,452,408	4.51	6.31
27. BAYSIDE #3	61	550	1.2	98.6	90.2	10,600	GAS	5,680	1,026,408	5,830.0	35,836	6.52	6.31
28. BAYSIDE #4	61	320	0.7	98.6	87.4	10,594	GAS	3,300	1,027,273	3,390.0	20,820	6.51	6.31
29. BAYSIDE #5	61	1,590	3.5	98.6	96.5	10,686	GAS	16,530	1,027,828	16,990.0	104,290	6.56	6.31
30. BAYSIDE #6	61	860	1.9	98.6	82.9	10,849	GAS	9,080	1,027,533	9,330.0	57,287	6.66	6.31
31. BAYSIDE TOTAL	**2,083**	**366,040**	**23.6**	**84.2**	**34.5**	**7,400**	**GAS**	**2,634,950**	**1,028,001**	**2,708,730.0**	**16,624,253**	**4.54**	**6.31**
32. SYSTEM	**4,703**	**1,410,640**	**40.3**	**83.2**	**64.4**	**9,468**	**-**	**-**	**-**	**13,355,450.0**	**51,912,405**	**3.68**	**-**

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

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] Units burned are ignition associated with Polk #1 Gasifier.

DOCKET NO. 140001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 21 OF 31

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0
18. BURNED:						
19. UNITS (BBL)	1,940	2,830	1,920	1,520	1,510	620
20. UNIT COST ($/BBL)	6.63	4.55	5.46	3.76	8.52	20.76
21. AMOUNT ($)	12,871	12,871	10,488	5,721	12,871	12,871
22. ENDING INVENTORY:						
23. UNITS (BBL)	63,434	60,604	58,684	57,164	55,654	55,034
24. UNIT COST ($/BBL)	130.10	129.71	129.43	129.19	128.95	128.87
25. AMOUNT ($)	8,252,700	7,861,142	7,595,605	7,384,844	7,176,659	7,092,110
26. DAYS SUPPLY: NORMAL	1,946	1,843	1,775	3,867	5,029	7,688
27. DAYS SUPPLY: EMERGENCY	9	9	8	8	8	8
COAL						
28. PURCHASES:						
29. UNITS (TONS)	449,082	389,999	429,082	374,999	469,082	493,082
30. UNIT COST ($/TON)	75.68	75.02	75.19	74.67	75.35	74.39
31. AMOUNT ($)	33,985,185	29,257,489	32,264,783	27,999,684	35,346,459	36,681,971
32. BURNED:						
33. UNITS (TONS)	486,010	398,200	398,730	409,260	432,630	480,700
34. UNIT COST ($/TON)	79.55	78.88	77.75	76.97	76.73	75.97
35. AMOUNT ($)	38,661,568	31,408,363	31,000,156	31,499,413	33,195,265	36,519,675
36. ENDING INVENTORY:						
37. UNITS (TONS)	578,442	570,241	600,593	566,332	602,784	615,166
38. UNIT COST ($/TON)	76.40	74.63	73.66	72.70	72.53	71.76
39. AMOUNT ($)	44,195,308	42,555,656	44,236,849	41,173,907	43,719,834	44,144,655
40. DAYS SUPPLY:	107	30	26	39	39	39
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,558,279	5,372,220
43. UNIT COST ($/MCF)	7.02	6.48	6.06	5.90	5.57	5.62
44. AMOUNT ($)	15,684,980	16,866,534	20,673,034	22,962,243	30,944,627	30,211,055
45. BURNED:						
46. UNITS (MCF)	2,233,440	2,601,970	3,413,030	3,890,160	5,266,450	5,372,220
47. UNIT COST ($/MCF)	6.99	6.48	6.06	5.94	5.64	5.60
48. AMOUNT ($)	15,602,890	16,863,120	20,691,439	23,110,067	29,724,831	30,098,929
49. ENDING INVENTORY:						
50. UNITS (MCF)	875,486	875,486	875,486	875,486	1,167,315	1,167,315
51. UNIT COST ($/MCF)	4.27	4.26	4.18	3.94	3.93	3.96
52. AMOUNT ($)	3,737,700	3,726,000	3,663,000	3,450,600	4,586,400	4,623,600
53. DAYS SUPPLY:	6	6	5	6	8	8
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

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

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	0	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0	0
18.	BURNED:							
19.	UNITS (BBL)	600	600	100	80	80	100	11,900
20.	UNIT COST ($/BBL)	17.48	17.48	128.71	131.10	131.10	128.71	11.38
21.	AMOUNT ($)	10,488	10,488	12,871	10,488	10,488	12,871	135,387
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	54,434	53,834	53,734	53,654	53,574	53,474	53,474
24.	UNIT COST ($/BBL)	128.78	128.69	128.70	128.70	128.71	128.72	128.72
25.	AMOUNT ($)	7,009,944	6,927,778	6,915,466	6,905,537	6,895,610	6,883,298	6,883,298
26.	DAYS SUPPLY: NORMAL	9,487	12,470	18,553	18,526	18,498	18,464	-
27.	DAYS SUPPLY: EMERGENCY	8	8	8	8	8	8	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	472,082	458,082	416,082	383,082	362,082	407,098	5,103,834
30.	UNIT COST ($/TON)	73.50	75.18	75.43	75.99	75.33	75.87	75.10
31.	AMOUNT ($)	34,695,876	34,437,295	31,383,234	29,109,574	27,273,836	30,887,725	383,323,111
32.	BURNED:							
33.	UNITS (TONS)	496,540	464,500	381,340	362,230	416,530	448,890	5,175,560
34.	UNIT COST ($/TON)	75.45	75.82	75.30	75.15	76.18	76.57	76.71
35.	AMOUNT ($)	37,466,150	35,217,466	28,714,269	27,220,227	31,731,776	34,370,993	397,005,321
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	590,708	584,290	619,032	639,884	585,436	543,644	543,644
38.	UNIT COST ($/TON)	70.52	70.40	71.03	72.12	71.60	71.18	71.18
39.	AMOUNT ($)	41,656,032	41,132,972	43,971,644	46,147,015	41,919,699	38,695,520	38,695,520
40.	DAYS SUPPLY:	40	44	49	48	41	38	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	5,566,610	6,166,160	6,543,190	5,429,748	2,563,359	2,801,060	52,139,226
43.	UNIT COST ($/MCF)	5.63	5.49	5.40	5.54	6.35	6.35	5.79
44.	AMOUNT ($)	31,355,157	33,868,119	35,321,749	30,095,683	16,270,414	17,796,013	302,049,608
45.	BURNED:							
46.	UNITS (MCF)	5,566,610	6,166,160	6,543,190	5,624,300	2,806,550	2,801,060	52,285,140
47.	UNIT COST ($/MCF)	5.62	5.48	5.39	5.46	6.09	6.26	5.77
48.	AMOUNT ($)	31,261,455	33,791,957	35,289,054	30,728,771	17,081,902	17,528,541	301,772,956
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,167,315	1,167,315	1,167,315	972,763	729,572	729,572	729,572
51.	UNIT COST ($/MCF)	3.99	4.00	3.98	4.00	4.06	4.23	4.23
52.	AMOUNT ($)	4,662,000	4,670,400	4,650,000	3,892,000	2,965,500	3,089,250	3,089,250
53.	DAYS SUPPLY:	8	8	8	7	5	5	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

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

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

SCHEDULE E6

(1) 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-15	SEMINOLE	JURISD.	SCH. - D	810.0	0.0	810.0	2.917	3.107	23,630.00	25,163.00	1,533.00
	VARIOUS	JURISD.	MKT. BASE	15,310.0	0.0	15,310.0	2.948	3.243	451,300.32	496,480.00	45,179.68
	TOTAL			**16,120.0**	**0.0**	**16,120.0**	**2.946**	**3.236**	**474,930.32**	**521,643.00**	**46,712.68**
Feb-15	SEMINOLE	JURISD.	SCH. - D	670.0	0.0	670.0	3.034	3.231	20,330.00	21,649.00	1,319.00
	VARIOUS	JURISD.	MKT. BASE	21,460.0	0.0	21,460.0	2.991	3.291	641,926.71	706,190.00	64,263.29
	TOTAL			**22,130.0**	**0.0**	**22,130.0**	**2.993**	**3.289**	**662,256.71**	**727,839.00**	**65,582.29**
Mar-15	SEMINOLE	JURISD.	SCH. - D	880.0	0.0	880.0	3.078	3.278	27,090.00	28,847.00	1,757.00
	VARIOUS	JURISD.	MKT. BASE	20,490.0	0.0	20,490.0	3.312	3.643	678,541.23	746,470.00	67,928.77
	TOTAL			**21,370.0**	**0.0**	**21,370.0**	**3.302**	**3.628**	**705,631.23**	**775,317.00**	**69,685.77**
Apr-15	SEMINOLE	JURISD.	SCH. - D	1,090.0	0.0	1,090.0	2.970	3.162	32,370.00	34,470.00	2,100.00
	VARIOUS	JURISD.	MKT. BASE	23,590.0	0.0	23,590.0	2.910	3.201	686,504.07	755,230.00	68,725.93
	TOTAL			**24,680.0**	**0.0**	**24,680.0**	**2.913**	**3.200**	**718,874.07**	**789,700.00**	**70,825.93**
May-15	SEMINOLE	JURISD.	SCH. - D	920.0	0.0	920.0	3.061	3.259	28,160.00	29,987.00	1,827.00
	VARIOUS	JURISD.	MKT. BASE	15,350.0	0.0	15,350.0	3.752	4.127	575,860.59	633,510.00	57,649.41
	TOTAL			**16,270.0**	**0.0**	**16,270.0**	**3.712**	**4.078**	**604,020.59**	**663,497.00**	**59,476.41**
Jun-15	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	3.055	3.253	30,240.00	32,201.00	1,961.00
	VARIOUS	JURISD.	MKT. BASE	13,320.0	0.0	13,320.0	3.133	3.446	417,276.45	459,050.00	41,773.55
	TOTAL			**14,310.0**	**0.0**	**14,310.0**	**3.127**	**3.433**	**447,516.45**	**491,251.00**	**43,734.55**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jul-15	SEMINOLE JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.134	3.337	31,650.00	33,703.00	2,053.00
	VARIOUS JURISD.	MKT. BASE	13,950.0	0.0	13,950.0	3.214	3.536	448,382.43	493,270.00	44,887.57
	TOTAL		**14,960.0**	**0.0**	**14,960.0**	**3.209**	**3.523**	**480,032.43**	**526,973.00**	**46,940.57**
Aug-15	SEMINOLE JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.360	3.578	33,600.00	35,779.00	2,179.00
	VARIOUS JURISD.	MKT. BASE	3,770.0	0.0	3,770.0	2.822	3.104	106,371.18	117,020.00	10,648.82
	TOTAL		**4,770.0**	**0.0**	**4,770.0**	**2.934**	**3.203**	**139,971.18**	**152,799.00**	**12,827.82**
Sep-15	SEMINOLE JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.272	3.484	32,720.00	34,842.00	2,122.00
	VARIOUS JURISD.	MKT. BASE	1,310.0	0.0	1,310.0	2.822	3.105	36,969.03	40,670.00	3,700.97
	TOTAL		**2,310.0**	**0.0**	**2,310.0**	**3.017**	**3.269**	**69,689.03**	**75,512.00**	**5,822.97**
Oct-15	SEMINOLE JURISD.	SCH. - D	730.0	0.0	730.0	3.400	3.621	24,820.00	26,430.00	1,610.00
	VARIOUS JURISD.	MKT. BASE	6,660.0	0.0	6,660.0	2.848	3.133	189,662.85	208,650.00	18,987.15
	TOTAL		**7,390.0**	**0.0**	**7,390.0**	**2.902**	**3.181**	**214,482.85**	**235,080.00**	**20,597.15**
Nov-15	SEMINOLE JURISD.	SCH. - D	650.0	0.0	650.0	3.006	3.201	19,540.00	20,807.00	1,267.00
	VARIOUS JURISD.	MKT. BASE	30,060.0	0.0	30,060.0	3.366	3.703	1,011,744.27	1,113,030.00	101,285.73
	TOTAL		**30,710.0**	**0.0**	**30,710.0**	**3.358**	**3.692**	**1,031,284.27**	**1,133,837.00**	**102,552.73**
Dec-15	SEMINOLE JURISD.	SCH. - D	580.0	0.0	580.0	3.052	3.250	17,700.00	18,848.00	1,148.00
	VARIOUS JURISD.	MKT. BASE	13,210.0	0.0	13,210.0	3.028	3.331	399,960.00	440,000.00	36,026.00
	TOTAL		**13,790.0**	**0.0**	**13,790.0**	**3.029**	**3.327**	**417,660.00**	**458,848.00**	**37,174.00**
TOTAL	SEMINOLE JURISD.	SCH. - D	10,330.0	0.0	10,330.0	3.116	3.318	321,850.00	342,726.00	20,876.00
	VARIOUS JURISD.	MKT. BASE	178,480.0	0.0	178,480.0	3.163	3.479	5,644,499.13	6,209,570.00	561,056.87
	TOTAL		**188,810.0**	**0.0**	**188,810.0**	**3.160**	**3.470**	**5,966,349.13**	**6,552,296.00**	**581,932.87**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH JUNE 2015

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	TOTAL $
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	FOR FUEL
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	ADJUSTMENT
Jan-15									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	200.0	0.0	0.0	200.0	4.430	4.430	8,860.00
	TOTAL		**200.0**	**0.0**	**0.0**	**200.0**	**4.430**	**4.430**	**8,860.00**
Feb-15									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	3,140.0	0.0	0.0	3,140.0	4.220	4.220	132,500.00
	TOTAL		**3,140.0**	**0.0**	**0.0**	**3,140.0**	**4.220**	**4.220**	**132,500.00**
Mar-15									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	6,490.0	0.0	0.0	6,490.0	4.062	4.062	263,610.00
	TOTAL		**6,490.0**	**0.0**	**0.0**	**6,490.0**	**4.062**	**4.062**	**263,610.00**
Apr-15									
	OLEANDER	SCH. - D	1,570.0	0.0	0.0	1,570.0	5.252	5.252	82,450.00
	CALPINE	SCH. - D	1,150.0	0.0	0.0	1,150.0	6.369	6.369	73,240.00
	PASCO COGEN	SCH. - D	6,840.0	0.0	0.0	6,840.0	3.964	3.964	271,150.00
	TOTAL		**9,560.0**	**0.0**	**0.0**	**9,560.0**	**4.465**	**4.465**	**426,840.00**
May-15									
	OLEANDER	SCH. - D	1,410.0	0.0	0.0	1,410.0	5.279	5.279	74,430.00
	CALPINE	SCH. - D	1,150.0	0.0	0.0	1,150.0	6.312	6.312	72,590.00
	PASCO COGEN	SCH. - D	13,930.0	0.0	0.0	13,930.0	3.952	3.952	550,450.00
	TOTAL		**16,490.0**	**0.0**	**0.0**	**16,490.0**	**4.230**	**4.230**	**697,470.00**
Jun-15									
	OLEANDER	SCH. - D	530.0	0.0	0.0	530.0	8.404	8.404	44,540.00
	CALPINE	SCH. - D	330.0	0.0	0.0	330.0	8.079	8.079	26,660.00
	PASCO COGEN	SCH. - D	12,470.0	0.0	0.0	12,470.0	3.955	3.955	493,170.00
	TOTAL		**13,330.0**	**0.0**	**0.0**	**13,330.0**	**4.234**	**4.234**	**564,370.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2015 THROUGH DECEMBER 2015

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-15									
	OLEANDER	SCH. - D	310.0	0.0	0.0	310.0	6.471	6.471	20,060.00
	CALPINE	SCH. - D	530.0	0.0	0.0	530.0	7.170	7.170	38,000.00
	PASCO COGEN	SCH. - D	14,340.0	0.0	0.0	14,340.0	3.996	3.996	573,070.00
	TOTAL		**15,180.0**	**0.0**	**0.0**	**15,180.0**	**4.158**	**4.158**	**631,130.00**
Aug-15									
	OLEANDER	SCH. - D	3,070.0	0.0	0.0	3,070.0	6.730	6.730	206,620.00
	CALPINE	SCH. - D	2,020.0	0.0	0.0	2,020.0	6.617	6.617	133,660.00
	PASCO COGEN	SCH. - D	19,290.0	0.0	0.0	19,290.0	3.973	3.973	766,440.00
	TOTAL		**24,380.0**	**0.0**	**0.0**	**24,380.0**	**4.539**	**4.539**	**1,106,720.00**
Sep-15									
	OLEANDER	SCH. - D	4,370.0	0.0	0.0	4,370.0	5.519	5.519	241,160.00
	CALPINE	SCH. - D	3,190.0	0.0	0.0	3,190.0	6.220	6.220	198,420.00
	PASCO COGEN	SCH. - D	20,690.0	0.0	0.0	20,690.0	3.948	3.948	816,740.00
	TOTAL		**28,250.0**	**0.0**	**0.0**	**28,250.0**	**4.447**	**4.447**	**1,256,320.00**
Oct-15									
	OLEANDER	SCH. - D	6,060.0	0.0	0.0	6,060.0	5.964	5.964	361,440.00
	CALPINE	SCH. - D	4,190.0	0.0	0.0	4,190.0	6.432	6.432	269,480.00
	PASCO COGEN	SCH. - D	14,280.0	0.0	0.0	14,280.0	3.964	3.964	566,070.00
	TOTAL		**24,530.0**	**0.0**	**0.0**	**24,530.0**	**4.880**	**4.880**	**1,196,990.00**
Nov-15									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	7,640.0	0.0	0.0	7,640.0	4.052	4.052	309,560.00
	TOTAL		**7,640.0**	**0.0**	**0.0**	**7,640.0**	**4.052**	**4.052**	**309,560.00**
Dec-15									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	5,270.0	0.0	0.0	5,270.0	4.095	4.095	215,800.00
	TOTAL		**5,270.0**	**0.0**	**0.0**	**5,270.0**	**4.095**	**4.095**	**215,800.00**
TOTAL	OLEANDER	SCH. - D	17,320.0	0.0	0.0	17,320.0	5.951	5.951	1,030,700.00
Jan-15	CALPINE	SCH. - D	12,560.0	0.0	0.0	12,560.0	6.465	6.465	812,050.00
THRU	PASCO COGEN	SCH. - D	124,580.0	0.0	0.0	124,580.0	3.987	3.987	4,967,420.00
Dec-15	**TOTAL**		**154,460.0**	**0.0**	**0.0**	**154,460.0**	**4.409**	**4.409**	**6,810,170.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

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-15	**VARIOUS**	**CO-GEN.**							
		FIRM	5,700.0	0.0	0.0	5,700.0	2.959	2.959	168,670.00
		AS AVAIL.	15,370.0	0.0	0.0	15,370.0	3.224	3.224	495,460.00
	TOTAL		**21,070.0**	**0.0**	**0.0**	**21,070.0**	**3.152**	**3.152**	**664,130.00**
Feb-15	**VARIOUS**	**CO-GEN.**							
		FIRM	5,150.0	0.0	0.0	5,150.0	2.677	2.677	137,870.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	2.940	2.940	447,430.00
	TOTAL		**20,370.0**	**0.0**	**0.0**	**20,370.0**	**2.873**	**2.873**	**585,300.00**
Mar-15	**VARIOUS**	**CO-GEN.**							
		FIRM	5,700.0	0.0	0.0	5,700.0	2.492	2.492	142,030.00
		AS AVAIL.	15,320.0	0.0	0.0	15,320.0	2.781	2.781	426,000.00
	TOTAL		**21,020.0**	**0.0**	**0.0**	**21,020.0**	**2.702**	**2.702**	**568,030.00**
Apr-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.229	3.229	200,520.00
		AS AVAIL.	15,320.0	0.0	0.0	15,320.0	3.469	3.469	531,390.00
	TOTAL		**21,530.0**	**0.0**	**0.0**	**21,530.0**	**3.399**	**3.399**	**731,910.00**
May-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.343	3.343	214,650.00
		AS AVAIL.	15,170.0	0.0	0.0	15,170.0	3.586	3.586	544,070.00
	TOTAL		**21,590.0**	**0.0**	**0.0**	**21,590.0**	**3.514**	**3.514**	**758,720.00**
Jun-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,210.0	0.0	0.0	6,210.0	2.433	2.433	151,090.00
		AS AVAIL.	15,360.0	0.0	0.0	15,360.0	2.725	2.725	418,560.00
	TOTAL		**21,570.0**	**0.0**	**0.0**	**21,570.0**	**2.641**	**2.641**	**569,650.00**
Jul-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,420.0	0.0	0.0	6,420.0	2.918	2.918	187,310.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	3.153	3.153	479,850.00
	TOTAL		**21,640.0**	**0.0**	**0.0**	**21,640.0**	**3.083**	**3.083**	**667,160.00**
Aug-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.319	3.319	213,110.00
		AS AVAIL.	15,260.0	0.0	0.0	15,260.0	3.583	3.583	546,830.00
	TOTAL		**21,680.0**	**0.0**	**0.0**	**21,680.0**	**3.505**	**3.505**	**759,940.00**
Sep-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.307	3.307	205,360.00
		AS AVAIL.	15,340.0	0.0	0.0	15,340.0	4.023	4.023	617,180.00
	TOTAL		**21,550.0**	**0.0**	**0.0**	**21,550.0**	**3.817**	**3.817**	**822,540.00**
Oct-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.294	3.294	211,500.00
		AS AVAIL.	15,310.0	0.0	0.0	15,310.0	3.561	3.561	545,120.00
	TOTAL		**21,730.0**	**0.0**	**0.0**	**21,730.0**	**3.482**	**3.482**	**756,620.00**
Nov-15	**VARIOUS**	**CO-GEN.**							
		FIRM	6,210.0	0.0	0.0	6,210.0	2.809	2.809	174,440.00
		AS AVAIL.	15,220.0	0.0	0.0	15,220.0	3.058	3.058	465,500.00
	TOTAL		**21,430.0**	**0.0**	**0.0**	**21,430.0**	**2.986**	**2.986**	**639,940.00**
Dec-15	**VARIOUS**	**CO-GEN.**							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.220	3.220	183,560.00
		AS AVAIL.	15,260.0	0.0	0.0	15,260.0	3.482	3.482	531,400.00
	TOTAL		**20,960.0**	**0.0**	**0.0**	**20,960.0**	**3.411**	**3.411**	**714,960.00**
TOTAL	**VARIOUS**	**CO-GEN.**							
Jan-14		FIRM	72,770.0	0.0	0.0	72,770.0	3.010	3.010	2,190,110.00
THRU		AS AVAIL.	183,370.0	0.0	0.0	183,370.0	3.299	3.299	6,048,790.00
Dec-14	**TOTAL**		**256,140.0**	**0.0**	**0.0**	**256,140.0**	**3.217**	**3.217**	**8,238,900.00**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
Jan-15	VARIOUS	ECONOMY	35,870.0	0.0	35,870.0	2.838	1,017,820.00	5.444	1,952,880.00	935,060.00
Feb-15	VARIOUS	ECONOMY	34,940.0	0.0	34,940.0	3.001	1,048,640.00	4.896	1,710,630.00	661,990.00
Mar-15	VARIOUS	ECONOMY	35,020.0	0.0	35,020.0	3.177	1,112,500.00	5.005	1,752,600.00	640,100.00
Apr-15	VARIOUS	ECONOMY	35,320.0	0.0	35,320.0	2.975	1,050,600.00	5.194	1,834,410.00	783,810.00
May-15	VARIOUS	ECONOMY	44,600.0	0.0	44,600.0	3.552	1,584,350.00	5.827	2,598,650.00	1,014,300.00
Jun-15	VARIOUS	ECONOMY	51,190.0	0.0	51,190.0	3.279	1,678,360.00	5.491	2,810,650.00	1,132,290.00
Jul-15	VARIOUS	ECONOMY	51,150.0	0.0	51,150.0	3.314	1,695,010.00	5.599	2,863,830.00	1,168,820.00
Aug-15	VARIOUS	ECONOMY	47,210.0	0.0	47,210.0	3.655	1,725,610.00	5.694	2,688,040.00	962,430.00
Sep-15	VARIOUS	ECONOMY	57,800.0	0.0	57,800.0	3.798	2,195,180.00	5.820	3,363,990.00	1,168,810.00
Oct-15	VARIOUS	ECONOMY	47,520.0	0.0	47,520.0	3.854	1,831,370.00	5.501	2,614,210.00	782,840.00
Nov-15	VARIOUS	ECONOMY	32,670.0	0.0	32,670.0	2.995	978,410.00	5.417	1,769,740.00	791,330.00
Dec-15	VARIOUS	ECONOMY	36,170.0	0.0	36,170.0	2.964	1,072,240.00	4.985	1,803,023.00	730,783.00
TOTAL	VARIOUS	ECONOMY	**509,460.0**	**0.0**	**509,460.0**	**3.335**	**16,990,090.00**	**5.449**	**27,762,653.00**	**10,772,563.00**

SCHEDULE E10

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

	Current	Step Increase	Difference		Projected	Difference	
	Jan 14 - Oct 14	Nov 14 - Dec 14	$	%	Jan 15 - Oct 15	$	%
Base Rate Revenue *	60.98	61.50	0.52	0.9%	61.50	0.00	0.0%
Fuel Recovery Revenue	36.09	36.09	0.00	0.0%	35.59	(0.50)	-1.4%
Conservation Revenue	2.95	2.95	0.00	0.0%	2.47	(0.48)	-16.3%
Capacity Revenue	2.02	2.02	0.00	0.0%	2.04	0.02	1.0%
Environmental Revenue	4.83	4.83	0.00	0.0%	4.08	(0.75)	-15.5%
Florida Gross Receipts Tax Revenue	2.74	2.75	0.01	0.4%	2.71	(0.04)	-1.5%
TOTAL REVENUE	**$109.61**	**$110.14**	**$0.53**	**0.5%**	**$108.39**	**($1.75)**	**-1.6%**

*** Base rate change effective November 1, 2014.**

SCHEDULE H1

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

	ACTUAL 2012	ACTUAL 2013	ACT/EST 2014	EST 2015	DIFFERENCE (%) 2013-2012	2014-2013	2015-2014
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	4,902,843	2,070,617	71,032	135,387	-57.8%	-96.6%	90.6%
3 COAL	395,142,292	380,570,736	406,849,497	397,005,321	-3.7%	6.9%	-2.4%
4 NATURAL GAS	305,701,892	300,114,267	308,644,366	301,772,956	-1.8%	2.8%	-2.2%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**705,747,027**	**682,755,620**	**715,564,895**	**698,913,664**	**-3.3%**	**4.8%**	**-2.3%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	20,242	8,475	300	560	-58.1%	-96.5%	86.7%
10 COAL	10,690,533	10,821,031	11,585,990	11,797,500	1.2%	7.1%	1.8%
11 NATURAL GAS	7,567,891	7,601,115	7,130,215	7,033,610	0.4%	-6.2%	-1.4%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**18,278,666**	**18,430,621**	**18,716,505**	**18,831,670**	**0.8%**	**1.6%**	**0.6%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	40,791	16,398	18,730	11,900	-59.8%	14.2%	-36.5%
17 COAL (TON)	4,671,399	4,702,698	5,051,883	5,175,560	0.7%	7.4%	2.4%
18 NATURAL GAS (MCF)	56,591,885	56,560,899	52,832,364	52,285,140	-0.1%	-6.6%	-1.0%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL [1]	208,086	83,760	3,210	6,110	-59.7%	-96.2%	90.3%
23 COAL	112,307,550	113,471,450	119,403,945	120,314,450	1.0%	5.2%	0.8%
24 NATURAL GAS	57,395,050	57,416,563	54,047,903	53,596,540	0.0%	-5.9%	-0.8%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**169,910,686**	**170,971,773**	**173,455,058**	**173,917,100**	**0.6%**	**1.5%**	**0.3%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL [1]	0.11	0.05	0.00	0.00	-54.5%	-100.0%	0.0%
30 COAL	58.49	58.71	61.90	62.65	0.4%	5.4%	1.2%
31 NATURAL GAS	41.40	41.24	38.10	37.35	-0.4%	-7.6%	-2.0%
32 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	120.19	126.27	3.79	11.38	5.1%	-97.0%	200.3%
37 COAL ($/TON)	84.59	80.93	80.53	76.71	-4.3%	-0.5%	-4.7%
38 NATURAL GAS ($/MCF)	5.40	5.31	5.84	5.77	-1.7%	10.0%	-1.2%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL [1]	23.56	24.72	22.13	22.16	4.9%	-10.5%	0.1%
43 COAL	3.52	3.35	3.41	3.30	-4.8%	1.8%	-3.2%
44 NATURAL GAS	5.33	5.23	5.71	5.63	-1.9%	9.2%	-1.4%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**4.15**	**3.99**	**4.13**	**4.02**	**-3.9%**	**3.5%**	**-2.7%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	10,280	9,883	10,700	10,911	-3.9%	8.3%	2.0%
50 COAL	10,505	10,486	10,306	10,198	-0.2%	-1.7%	-1.0%
51 NATURAL GAS	7,584	7,554	7,580	7,620	-0.4%	0.3%	0.5%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	**9,296**	**9,277**	**9,267**	**9,235**	**-0.2%**	**-0.1%**	**-0.3%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL [1]	24.22	24.43	23.68	24.18	0.9%	-3.1%	2.1%
57 COAL	3.70	3.52	3.51	3.37	-4.9%	-0.3%	-4.0%
58 NATURAL GAS	4.04	3.95	4.33	4.29	-2.2%	9.6%	-0.9%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	**3.86**	**3.70**	**3.82**	**3.71**	**-4.1%**	**3.2%**	**-2.9%**

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

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE
JANUARY 2015 - DECEMBER 2015

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2015 through December 2015

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	3,198,584	3.874	123,913,152	3.559	113,837,612
TIER II (Over 1,000) kWh	1,470,882	3.874	56,981,961	4.559	67,057,501
Total	4,669,466		180,895,113		180,895,113

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2015 - DECEMBER 2015

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951
2	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951
5														
6														
7	AVERAGE BALANCE	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	16,143,951	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	4,836,498	5,105,723	5,374,948	5,644,173	5,913,398	6,182,623	6,451,848	6,721,073	6,990,298	7,259,523	7,528,748	7,797,974	4,836,498
12	ENDING BALANCE DEPRECIATION	5,105,723	5,374,948	5,644,173	5,913,398	6,182,623	6,451,848	6,721,073	6,990,298	7,259,523	7,528,748	7,797,974	8,067,199	8,067,199
13														
14														
15	ENDING NET INVESTMENT	11,038,228	10,769,003	10,499,778	10,230,553	9,961,328	9,692,102	9,422,877	9,153,652	8,884,427	8,615,202	8,345,977	8,076,752	8,076,752
16														
17														
18	AVERAGE INVESTMENT	$ 11,172,840	$ 10,903,615	$ 10,634,390	$ 10,365,165	$ 10,095,940	$ 9,826,715	$ 9,557,490	$ 9,288,265	$ 9,019,040	$ 8,749,815	$ 8,480,590	$ 8,211,365	
19	ALLOWED EQUITY RETURN	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	
20	EQUITY COMPONENT AFTER-TAX	40,412	39,438	38,465	37,491	36,517	35,543	34,569	33,596	32,622	31,648	30,674	29,701	420,676
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	65,960	64,371	62,783	61,193	59,603	58,013	56,424	54,835	53,246	51,656	50,066	48,478	686,628
23														
24	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	
25	DEBT COMPONENT	$ 18,941	$ 18,484	$ 18,028	$ 17,572	$ 17,115	$ 16,659	16,202	15,746	15,290	14,833	14,377	13,920	197,167
26														
27	TOTAL RETURN REQUIREMENTS	$ 84,901	$ 82,855	$ 80,811	$ 78,765	$ 76,718	$ 74,672	72,626	70,581	68,536	66,489	64,443	62,398	883,795
28														
29	TOTAL DEPRECIATION & RETURN	$ 354,126	$ 352,080	$ 350,036	$ 347,990	$ 345,943	$ 343,897	341,851	339,806	337,761	335,714	333,668	331,623	4,114,495
30														
31	ESTIMATED FUEL SAVINGS	$0	$0	$0	$20,944	$1,029,260	$674,800	$455,616	$918,012	$1,067,976	$462,396	$1,321,080	$0	$5,950,084
32	TOTAL DEPRECIATION & RETURN	$ 354,126	$ 352,080	$ 350,036	$ 347,990	$ 345,943	$ 343,897	$ 341,851	$ 339,806	$ 337,761	$ 335,714	$ 333,668	$ 331,623	4,114,495
33	NET BENEFIT (COST) TO RATEPAYER	($354,126)	($352,080)	($350,036)	($327,046)	$683,317	$330,903	$113,765	$578,206	$730,215	$126,682	$987,412	($331,623)	$1,835,588

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.1187% (EQUITY 7.0844% , DEBT 2.0343%).
36 THE RATES ARE FROM THE MAY 2014 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%.
38 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

DOCKET NO. 140001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 4, PAGE 1 OF 3

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS

SCHEDULE OF DEPRECIATION AND RETURN

FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ -	$ -	$ -	$ 8,694,457	$ 12,627,359	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568	$ 16,422,568
2	ADD INVESTMENT	-	-	8,694,457	3,932,902	3,795,209	-	$ -	-	-	-	-	$ 3,447,732	19,870,300
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	-	-	8,694,457	12,627,359	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	19,870,300	19,870,300
5														
6	AVERAGE BALANCE	-	-	-	8,694,457	12,627,359	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	16,422,568	
7	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
8	DEPRECIATION EXPENSE	-	-	-	144,908	210,456	273,709	273,709	273,709	273,709	273,709	273,709	273,709	2,271,330
9	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
10	BEGINNING BALANCE DEPRECIATION	-	-	-	-	144,908	355,364	629,073	902,783	1,176,492	1,450,201	1,723,911	1,997,620	-
11	ENDING BALANCE DEPRECIATION	-	-	-	144,908	355,364	629,073	902,783	1,176,492	1,450,201	1,723,911	1,997,620	2,271,330	2,271,330
12														
13	ENDING NET INVESTMENT	-	-	8,694,457	12,482,451	16,067,204	15,793,495	15,519,785	15,246,076	14,972,367	14,698,657	14,424,948	17,598,970	
14														
15	AVERAGE INVESTMENT	$ -	$ -	$ 4,347,229	$ 10,588,454	$ 14,274,828	$ 15,930,350	$ 15,656,640	$ 15,382,931	$ 15,109,221	$ 14,835,512	$ 14,561,802	$ 16,011,959	
16	ALLOWED EQUITY RETURN	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	
17	EQUITY COMPONENT AFTER-TAX	-	-	15,724	38,298	51,632	57,620	56,630	55,640	54,650	53,660	52,670	57,915	494,439
18	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
19	EQUITY COMPONENT PRE-TAX	-	-	25,665	62,510	84,274	94,047	92,431	90,816	89,200	87,584	85,968	94,529	807,024
20														
21	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	
22	DEBT COMPONENT	$ -	$ -	$ 7,370	$ 17,950	$ 24,199	$ 27,006	$ 26,542	$ 26,078	$ 25,614	$ 25,150	$ 24,686	$ 27,144	$ 231,739
23														
24	TOTAL RETURN REQUIREMENTS	$ -	$ -	$ 33,035	$ 80,460	$ 108,473	$ 121,053	$ 118,973	$ 116,894	$ 114,814	$ 112,734	$ 110,654	$ 121,673	$ 1,038,763
25														
26	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ 33,035	$ 225,368	$ 318,929	$ 394,762	$ 392,682	$ 390,603	$ 388,523	$ 386,443	$ 384,363	$ 395,382	$ 3,310,090
27														
28	ESTIMATED FUEL SAVINGS	$ -	$ -	$ 204,769	$ 205,004	$ 407,735	$ 405,018	$ 302,181	$ 301,197	$ 401,370	$ 300,313	$ 708,156	$ 403,760	$ 3,639,503
29	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ 33,035	$ 225,368	$ 318,929	$ 394,762	$ 392,682	$ 390,603	$ 388,523	$ 386,443	$ 384,363	$ 395,382	$ 3,310,090
30	CURRENT PERIOD NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ 171,734	$ (20,364)	$ 88,806	$ 10,256	$ (90,501)	$ (89,406)	$ 12,847	$ (86,130)	$ 323,793	$ 8,378	$ 329,413

31 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD

32 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.1187% (EQUITY 7.0844% , DEBT 2.0343%).

33 THE RATES ARE FROM THE MAY 2014 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
for Cost Recovery Clauses

January to December 2015 Estimated Period

	(1) Jurisdictional Rate Base Actual May 2014 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,429,551	35.37%	5.55%	1.96%
Short Term Debt	25,222	0.62%	0.61%	0.00%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	107,785	2.67%	2.25%	0.06%
Common Equity	1,707,776	42.26%	10.25%	4.33%
Deferred ITC - Weighted Cost	8,027	0.20%	8.05%	0.02%
Accumulated Deferred Income Taxes & Zero Cost ITCs	763,143	18.88%	0.00%	0.00%
Total	$ 4,041,504	100.00%		6.37%

ITC split between Debt and Equity:

Long Term Debt	$ 1,429,551	Long Term Debt	45.20%
Short Term Debt	25,222	Short Term Debt	0.80%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,707,776	Equity - Common	54.00%
Total	$ 3,162,549	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0161% * 46.00%	0.0074%
Equity = .0161% * 54.00%	0.0087%
Weighted Cost	0.0161%

Total Equity Cost Rate:		**Monthly Rate:**
Preferred Stock	0.0000%	
Common Equity	4.3317%	
Deferred ITC - Weighted Cost	0.0087%	
	4.3404%	0.36170%
Times Tax Multiplier	1.632200	
Total Equity Component	7.0844%	

Total Debt Cost Rate:		**Monthly Rate:**
Long Term Debt	1.9630%	
Short Term Debt	0.0038%	
Customer Deposits	0.0601%	
Deferred ITC - Weighted Cost	0.0074%	
Total Debt Component	2.0343%	0.16953%
Total Weighted Cost:	9.1187%	

Notes:

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

TECO

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2015 THROUGH DECEMBER 2015

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: AUGUST 22, 2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

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

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

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit No. ____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2015 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. The methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. Big Bend Unit 3, Big Bend Unit 4 and Bayside Unit 1 outages were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

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 2015 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 2015 period, the projected EUOF for Bayside Unit 1 is 5.2 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit 1 equals 89.9 percent or:

$$100\% - (5.2\% + 4.9\%) = 89.9\%$$

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

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

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

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

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

$$EAF_{MAX} = 1 - [0.80\ (5.2\%) + 0.95\ (4.9\%)] = 91.2\%$$

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,

$$EAF_{MIN} = 1 - [1.40\ (5.2\%) + 1.10\ (4.9\%)] = 87.3\%$$

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 2015 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2015; 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 February 16, 2015 to February 24, 2015 and November 30, 2015 to December 8, 2015. There are 432 planned outage hours scheduled for the 2015 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 4.9 percent or:

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

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 23.0 percent. Big Bend Unit 2 has a POF of 6.6

percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 13.7 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 6.0 percent.

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

A. Projected factors are based upon historical unit performance. For each unit the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 5.2 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

$$EUOF = \frac{(84 + 372)}{8,760} \times 100\% = 5.2\%$$

Relative to Bayside Unit 1, the EUOF of 5.2 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 15.8 percent. The unit will have two planned outages in 2015, and the POF is 23.0 percent. Therefore, the target equivalent availability for this unit is 61.2 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.2 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 75.2 percent.

Big Bend Unit 3

The projected EUOF for this unit is 14.2 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 79.2 percent.

Big Bend Unit 4

The projected EUOF for this unit is 13.1 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 80.3 percent.

Polk Unit 1

The projected EUOF for this unit is 9.2 percent. The unit will have two planned outages in 2015, and the POF is 13.7 percent. Therefore, the target equivalent availability for this unit is 77.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 5.2 percent. The unit will have two planned outages in 2015, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 89.9 percent.

Bayside Unit 2

The projected EUOF for this unit is 7.4 percent. The unit will have two planned outages in 2015, and the POF is 6.0 percent. Therefore, the target equivalent availability for this unit is 86.6 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 78.1 percent is shown on Page 5 of Document No. 1. This target is similar to last year’s January through December actual performance.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 19 of Document No. 1. Except for the months of February, November, and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of February, November, and December, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

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

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 2015 period.

A. The heat rate target for Big Bend Unit 1 is 10,563 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±194 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,379 Btu/Net kWh with a range of ±230 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,495 Btu/Net kWh, with a range of ±169 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,416 Btu/Net kWh with a range of ±171 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,552 Btu/Net kWh with a range of ±532 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,414 Btu/Net kWh with a range of ±92 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,447 Btu/Net kWh with a range of ±95 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 $596,119,836 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 $15,405,074 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 6.02 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 7,322 average net operating heat rate, fuel savings would equal $928,043 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 $15,405,074. 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 2015 is $2,200,493,028. This produces the maximum allowed jurisdictional incentive of $8,993,880 shown on line 21.

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

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $7,702,537.

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):

$$
\begin{aligned}
GPIP: = (0.0778\ EAP_{BB1} &+ 0.0204\ EAP_{BB2} \\
+ 0.0149\ EAP_{BB3} &+ 0.0413\ EAP_{BB4} \\
+ 0.0060\ EAP_{PK1} &+ 0.0339\ EAP_{BAY1}
\end{aligned}
$$

$$+ 0.1011\ EAP_{BAY2} + 0.0843\ HRP_{BB1}$$
$$+ 0.1129\ HRP_{BB2} + 0.0897\ HRP_{BB3}$$
$$+ 0.0886\ HRP_{BB4} + 0.1665\ HRP_{PK1}$$
$$+ 0.0602\ HRP_{BAY1} + 0.1024\ HRP_{BAY2})$$

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 2015 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 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2015 - DECEMBER 2015
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2015 - DECEMBER 2015

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	15,405.1	7,702.5
+9	13,864.6	6,932.3
+8	12,324.1	6,162.0
+7	10,783.6	5,391.8
+6	9,243.0	4,621.5
+5	7,702.5	3,851.3
+4	6,162.0	3,081.0
+3	4,621.5	2,310.8
+2	3,081.0	1,540.5
+1	1,540.5	770.3
0	0.0	0.0
-1	(1,456.1)	(770.3)
-2	(2,912.1)	(1,540.5)
-3	(4,368.2)	(2,310.8)
-4	(5,824.2)	(3,081.0)
-5	(7,280.3)	(3,851.3)
-6	(8,736.3)	(4,621.5)
-7	(10,192.4)	(5,391.8)
-8	(11,648.4)	(6,162.0)
-9	(13,104.5)	(6,932.3)
-10	(14,560.5)	(7,702.5)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2015 - DECEMBER 2015

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,168,605,000	
Line 2	Month of January	2015	$	2,115,059,000	
Line 3	Month of February	2015	$	2,134,887,678	
Line 4	Month of March	2015	$	2,154,902,250	
Line 5	Month of April	2015	$	2,188,807,209	
Line 6	Month of May	2015	$	2,209,327,276	
Line 7	Month of June	2015	$	2,230,039,719	
Line 8	Month of July	2015	$	2,175,808,872	
Line 9	Month of August	2015	$	2,196,207,081	
Line 10	Month of September	2015	$	2,216,796,522	
Line 11	Month of October	2015	$	2,250,822,187	
Line 12	Month of November	2015	$	2,271,923,645	
Line 13	Month of December	2015	$	2,293,222,929	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,200,493,028	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.17%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	8,993,880	
Line 18	Jurisdictional Sales			18,630,400	MWH
Line 19	Total Sales			18,630,400	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**8,993,880**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2015 - DECEMBER 2015

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	7.78%	61.2	65.5	52.6	1,197.9	(284.9)
BIG BEND 2	2.04%	75.2	79.2	67.3	314.8	(548.1)
BIG BEND 3	1.49%	79.2	82.4	72.9	229.3	(572.6)
BIG BEND 4	4.13%	80.3	83.2	74.4	635.7	(1,103.8)
POLK 1	0.60%	77.1	79.6	72.0	91.9	(222.1)
BAYSIDE 1	3.39%	89.9	91.2	87.3	522.4	(908.6)
BAYSIDE 2	10.11%	86.6	88.4	83.0	1,556.9	(64.2)
GPIF SYSTEM	**29.53%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	8.43%	10,563	94.8	10,368	10,757	1,299.3	(1,299.3)
BIG BEND 2	11.29%	10,379	92.7	10,149	10,609	1,739.7	(1,739.7)
BIG BEND 3	8.97%	10,495	92.5	10,326	10,664	1,382.3	(1,382.3)
BIG BEND 4	8.86%	10,416	97.6	10,245	10,587	1,365.4	(1,365.4)
POLK 1	16.65%	10,552	96.6	10,020	11,085	2,564.5	(2,564.5)
BAYSIDE 1	6.02%	7,414	52.3	7,322	7,505	928.0	(928.0)
BAYSIDE 2	10.24%	7,447	51.7	7,351	7,542	1,576.8	(1,576.8)
GPIF SYSTEM	**70.47%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 15 - DEC 15			ACTUAL PERFORMANCE JAN 13 - DEC 13			ACTUAL PERFORMANCE JAN 12 - DEC 12			ACTUAL PERFORMANCE JAN 11 - DEC 11		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	7.78%	26.3%	23.0	15.8	20.5	10.8	17.6	19.8	6.8	26.2	28.3	5.8	13.5	14.4
BIG BEND 2	2.04%	6.9%	6.6	18.2	19.5	6.1	18.3	19.5	4	17.9	18.7	17.1	25.4	30.6
BIG BEND 3	1.49%	5.0%	6.6	14.2	15.2	25.0	8.5	11.3	2.8	25	25.7	8.6	17.9	19.5
BIG BEND 4	4.13%	14.0%	6.6	13.1	14.1	4.8	17.6	18.5	8.2	16.2	17.6	9.4	15.1	16.7
POLK 1	0.60%	2.0%	13.7	9.2	10.7	15.3	6.7	8.8	12.7	17.3	21.0	4.4	17.3	17.6
BAYSIDE 1	3.39%	11.5%	4.9	5.2	5.5	3.8	7.5	8.7	1.9	3.0	2.0	21.0	3.3	2.0
BAYSIDE 2	10.11%	34.2%	6.0	7.4	7.9	4.1	12.2	13.1	16.5	7.5	2.9	3.7	7.4	3.2
GPIF SYSTEM	**29.53%**	**100.0%**	**10.7**	**11.3**	**13.0**	**7.3**	**14.0**	**15.4**	**9.5**	**14.9**	**14.2**	**8.2**	**11.6**	**10.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**78.1**			**78.7**			**75.6**			**80.2**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
8.3	**13.5**	**13.5**	**78.2**

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AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 13 - DEC 13	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 11 - DEC 11
BIG BEND 1	8.43%	12.0%	10,563	10,546	10,485	10,719
BIG BEND 2	11.29%	16.0%	10,379	10,303	10,362	10,254
BIG BEND 3	8.97%	12.7%	10,495	10,516	10,468	10,346
BIG BEND 4	8.86%	12.6%	10,416	10,445	10,427	10,310
POLK 1	16.65%	23.6%	10,552	10,465	10,503	10,364
BAYSIDE 1	6.02%	8.5%	7,414	7,403	7,382	7,348
BAYSIDE 2	10.24%	14.5%	7,447	7,464	7,401	7,409
GPIF SYSTEM	**70.47%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,782**	**9,755**	**9,747**	**9,693**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2015 - DECEMBER 2015
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	596,119.8	594,921.9	1,197.9	7.78%
EA_2 BIG BEND 2	596,119.8	595,805.1	314.8	2.04%
EA_3 BIG BEND 3	596,119.8	595,890.5	229.3	1.49%
EA_4 BIG BEND 4	596,119.8	595,484.2	635.7	4.13%
EA_5 POLK 1	596,119.8	596,028.0	91.9	0.60%
EA_6 BAYSIDE 1	596,119.8	595,597.4	522.4	3.39%
EA_7 BAYSIDE 2	596,119.8	594,562.9	1,556.9	10.11%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	596,119.8	594,820.5	1,299.3	8.43%
AHR_2 BIG BEND 2	596,119.8	594,380.1	1,739.7	11.29%
AHR_3 BIG BEND 3	596,119.8	594,737.5	1,382.3	8.97%
AHR_4 BIG BEND 4	596,119.8	594,754.4	1,365.4	8.86%
AHR_5 POLK 1	596,119.8	593,555.3	2,564.5	16.65%
AHR_6 BAYSIDE 1	596,119.8	595,191.8	928.0	6.02%
AHR_7 BAYSIDE 2	596,119.8	594,543.0	1,576.8	10.24%
TOTAL SAVINGS			**15,405.1**	**100.00%**

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

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,197.9	65.5	+10	1,299.3	10,368
+9	1,078.1	65.1	+9	1,169.4	10,380
+8	958.3	64.7	+8	1,039.5	10,392
+7	838.6	64.2	+7	909.5	10,404
+6	718.8	63.8	+6	779.6	10,416
+5	599.0	63.4	+5	649.7	10,428
+4	479.2	62.9	+4	519.7	10,440
+3	359.4	62.5	+3	389.8	10,452
+2	239.6	62.1	+2	259.9	10,464
+1	119.8	61.6	+1	129.9	10,476
					10,488
0	0.0	61.2	0	0.0	10,563
					10,638
-1	(28.5)	60.4	-1	(129.9)	10,649
-2	(57.0)	59.5	-2	(259.9)	10,661
-3	(85.5)	58.6	-3	(389.8)	10,673
-4	(114.0)	57.8	-4	(519.7)	10,685
-5	(142.4)	56.9	-5	(649.7)	10,697
-6	(170.9)	56.0	-6	(779.6)	10,709
-7	(199.4)	55.2	-7	(909.5)	10,721
-8	(227.9)	54.3	-8	(1,039.5)	10,733
-9	(256.4)	53.5	-9	(1,169.4)	10,745
-10	(284.9)	52.6	-10	(1,299.3)	10,757
	Weighting Factor =	7.78%		Weighting Factor =	8.43%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	314.8	79.2	+10	1,739.7	10,149
+9	283.3	78.8	+9	1,565.7	10,165
+8	251.8	78.4	+8	1,391.8	10,180
+7	220.3	78.0	+7	1,217.8	10,195
+6	188.9	77.6	+6	1,043.8	10,211
+5	157.4	77.2	+5	869.9	10,226
+4	125.9	76.8	+4	695.9	10,242
+3	94.4	76.4	+3	521.9	10,257
+2	63.0	76.0	+2	347.9	10,273
+1	31.5	75.6	+1	174.0	10,288
					10,304
0	0.0	75.2	0	0.0	10,379
					10,454
-1	(54.8)	74.4	-1	(174.0)	10,469
-2	(109.6)	73.6	-2	(347.9)	10,485
-3	(164.4)	72.8	-3	(521.9)	10,500
-4	(219.2)	72.0	-4	(695.9)	10,516
-5	(274.0)	71.2	-5	(869.9)	10,531
-6	(328.9)	70.4	-6	(1,043.8)	10,547
-7	(383.7)	69.6	-7	(1,217.8)	10,562
-8	(438.5)	68.8	-8	(1,391.8)	10,578
-9	(493.3)	68.1	-9	(1,565.7)	10,593
-10	(548.1)	67.3	-10	(1,739.7)	10,609
	Weighting Factor =	2.04%		Weighting Factor =	11.29%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	229.3	82.4	+10	1,382.3	10,326
+9	206.4	82.1	+9	1,244.1	10,336
+8	183.5	81.8	+8	1,105.9	10,345
+7	160.5	81.5	+7	967.6	10,355
+6	137.6	81.1	+6	829.4	10,364
+5	114.7	80.8	+5	691.2	10,373
+4	91.7	80.5	+4	552.9	10,383
+3	68.8	80.2	+3	414.7	10,392
+2	45.9	79.9	+2	276.5	10,402
+1	22.9	79.6	+1	138.2	10,411
					10,420
0	0.0	79.2	0	0.0	10,495
					10,570
-1	(57.3)	78.6	-1	(138.2)	10,580
-2	(114.5)	78.0	-2	(276.5)	10,589
-3	(171.8)	77.3	-3	(414.7)	10,599
-4	(229.1)	76.7	-4	(552.9)	10,608
-5	(286.3)	76.1	-5	(691.2)	10,617
-6	(343.6)	75.4	-6	(829.4)	10,627
-7	(400.8)	74.8	-7	(967.6)	10,636
-8	(458.1)	74.2	-8	(1,105.9)	10,646
-9	(515.4)	73.5	-9	(1,244.1)	10,655
-10	(572.6)	72.9	-10	(1,382.3)	10,664

Weighting Factor = 1.49%

Weighting Factor = 8.97%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	635.7	83.2	+10	1,365.4	10,245
+9	572.1	83.0	+9	1,228.9	10,254
+8	508.5	82.7	+8	1,092.3	10,264
+7	445.0	82.4	+7	955.8	10,274
+6	381.4	82.1	+6	819.2	10,283
+5	317.8	81.8	+5	682.7	10,293
+4	254.3	81.5	+4	546.2	10,302
+3	190.7	81.2	+3	409.6	10,312
+2	127.1	80.9	+2	273.1	10,322
+1	63.6	80.6	+1	136.5	10,331
					10,341
0	0.0	80.3	0	0.0	10,416
					10,491
-1	(110.4)	79.7	-1	(136.5)	10,501
-2	(220.8)	79.1	-2	(273.1)	10,510
-3	(331.1)	78.5	-3	(409.6)	10,520
-4	(441.5)	77.9	-4	(546.2)	10,529
-5	(551.9)	77.3	-5	(682.7)	10,539
-6	(662.3)	76.8	-6	(819.2)	10,549
-7	(772.7)	76.2	-7	(955.8)	10,558
-8	(883.0)	75.6	-8	(1,092.3)	10,568
-9	(993.4)	75.0	-9	(1,228.9)	10,578
-10	(1,103.8)	74.4	-10	(1,365.4)	10,587
	Weighting Factor =	4.13%		Weighting Factor =	8.86%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	91.9	79.6	+10	2,564.5	10,020
+9	82.7	79.4	+9	2,308.1	10,065
+8	73.5	79.1	+8	2,051.6	10,111
+7	64.3	78.9	+7	1,795.2	10,157
+6	55.1	78.6	+6	1,538.7	10,203
+5	45.9	78.4	+5	1,282.3	10,248
+4	36.7	78.1	+4	1,025.8	10,294
+3	27.6	77.8	+3	769.4	10,340
+2	18.4	77.6	+2	512.9	10,386
+1	9.2	77.3	+1	256.5	10,431
					10,477
0	0.0	77.1	0	0.0	10,552
					10,627
-1	(22.2)	76.6	-1	(256.5)	10,673
-2	(44.4)	76.1	-2	(512.9)	10,719
-3	(66.6)	75.6	-3	(769.4)	10,764
-4	(88.9)	75.1	-4	(1,025.8)	10,810
-5	(111.1)	74.6	-5	(1,282.3)	10,856
-6	(133.3)	74.1	-6	(1,538.7)	10,902
-7	(155.5)	73.5	-7	(1,795.2)	10,947
-8	(177.7)	73.0	-8	(2,051.6)	10,993
-9	(199.9)	72.5	-9	(2,308.1)	11,039
-10	(222.1)	72.0	-10	(2,564.5)	11,085
	Weighting Factor =	0.60%		Weighting Factor =	16.65%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	522.4	91.2	+10	928.0	7,322
+9	470.2	91.0	+9	835.2	7,324
+8	417.9	90.9	+8	742.4	7,326
+7	365.7	90.8	+7	649.6	7,327
+6	313.5	90.6	+6	556.8	7,329
+5	261.2	90.5	+5	464.0	7,331
+4	209.0	90.4	+4	371.2	7,332
+3	156.7	90.2	+3	278.4	7,334
+2	104.5	90.1	+2	185.6	7,336
+1	52.2	90.0	+1	92.8	7,337
					7,339
0	0.0	89.9	0	0.0	7,414
					7,489
-1	(90.9)	89.6	-1	(92.8)	7,491
-2	(181.7)	89.3	-2	(185.6)	7,492
-3	(272.6)	89.1	-3	(278.4)	7,494
-4	(363.4)	88.8	-4	(371.2)	7,496
-5	(454.3)	88.6	-5	(464.0)	7,497
-6	(545.2)	88.3	-6	(556.8)	7,499
-7	(636.0)	88.1	-7	(649.6)	7,501
-8	(726.9)	87.8	-8	(742.4)	7,502
-9	(817.7)	87.5	-9	(835.2)	7,504
-10	(908.6)	87.3	-10	(928.0)	7,505
	Weighting Factor =	3.39%		Weighting Factor =	6.02%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2015 - DECEMBER 2015

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,556.9	88.4	+10	1,576.8	7,351
+9	1,401.3	88.2	+9	1,419.1	7,354
+8	1,245.6	88.0	+8	1,261.4	7,356
+7	1,089.9	87.8	+7	1,103.8	7,358
+6	934.2	87.7	+6	946.1	7,360
+5	778.5	87.5	+5	788.4	7,362
+4	622.8	87.3	+4	630.7	7,364
+3	467.1	87.1	+3	473.0	7,366
+2	311.4	86.9	+2	315.4	7,368
+1	155.7	86.8	+1	157.7	7,370
					7,372
0	0.0	86.6	0	0.0	7,447
					7,522
-1	(6.4)	86.2	-1	(157.7)	7,524
-2	(12.8)	85.9	-2	(315.4)	7,526
-3	(19.3)	85.5	-3	(473.0)	7,528
-4	(25.7)	85.2	-4	(630.7)	7,530
-5	(32.1)	84.8	-5	(788.4)	7,532
-6	(38.5)	84.5	-6	(946.1)	7,534
-7	(45.0)	84.1	-7	(1,103.8)	7,536
-8	(51.4)	83.8	-8	(1,261.4)	7,538
-9	(57.8)	83.4	-9	(1,419.1)	7,540
-10	(64.2)	83.0	-10	(1,576.8)	7,542

Weighting Factor = 10.11%

Weighting Factor = 10.24%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	79.5	79.5	79.5	63.6	59.0	79.5	79.5	53.9	0.0	2.6	79.5	79.5	61.2
2. POF	0.0	0.0	0.0	20.0	25.8	0.0	0.0	32.3	100.0	96.8	0.0	0.0	23.0
3. EUOF	20.5	20.5	20.5	16.4	15.2	20.5	20.5	13.9	0.0	0.7	20.5	20.5	15.8
4. EUOR	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	0.0	20.5	20.5	20.5	20.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	651	588	651	504	483	630	651	441	0	21	630	651	5,901
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	93	84	92	216	261	90	93	303	720	723	91	93	2,859
9. POH	0	0	0	144	192	0	0	240	720	720	0	0	2,016
10. EFOH	137	124	137	106	102	132	137	93	0	4	133	137	1,240
11. EMOH	16	14	16	12	12	15	16	11	0	1	15	16	141
12. OPER BTU (GBTU)	2,505	2,327	2,570	1,971	1,849	2,476	2,551	1,742	0	64	2,354	2,528	22,938
13. NET GEN (MWH)	237,300	220,270	243,350	186,590	175,080	234,290	241,400	164,840	0	6,050	223,040	239,420	2,171,630
14. ANOHR (Btu/kwh)	10,557	10,563	10,562	10,566	10,561	10,567	10,566	10,568	0	10,516	10,556	10,559	10,563
15. NOF (%)	92.3	94.8	94.6	96.2	94.2	96.6	96.3	97.1	0.0	74.8	92.0	93.1	94.8
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		2.316	) +	10,343								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	80.5	80.5	80.5	67.1	57.1	80.5	80.5	80.5	80.5	54.5	80.5	80.5	75.2
2. POF	0.0	0.0	0.0	16.7	29.0	0.0	0.0	0.0	0.0	32.3	0.0	0.0	6.6
3. EUOF	19.5	19.5	19.5	16.3	13.8	19.5	19.5	19.5	19.5	13.2	19.5	19.5	18.2
4. EUOR	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	663	599	663	535	471	642	663	663	642	449	642	663	7,295
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	81	73	80	185	273	78	81	81	78	295	79	81	1,465
9. POH	0	0	0	120	216	0	0	0	0	240	0	0	576
10. EFOH	112	101	112	90	79	108	112	112	108	76	108	112	1,231
11. EMOH	33	30	33	27	24	32	33	33	32	22	32	33	365
12. OPER BTU (GBTU)	2,456	2,261	2,505	2,020	1,720	2,422	2,501	2,516	2,435	1,690	2,273	2,452	27,251
13. NET GEN (MWH)	236,280	217,720	241,320	194,890	165,570	233,590	241,270	242,810	234,950	163,020	218,400	235,840	2,625,660
14. ANOHR (Btu/kwh)	10,395	10,383	10,382	10,366	10,388	10,367	10,367	10,363	10,363	10,368	10,407	10,396	10,379
15. NOF (%)	90.2	92.0	92.1	94.6	91.3	94.5	94.5	95.1	95.1	94.3	88.4	90.1	92.7
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		-6.562	) +	10,987								

DOCKET NO. 140001-EI
GPIF 2015 PROJECTION FILING
EXHIBIT NO. ___ (BSB-2)
DOCUMENT NO. 1, PAGE 15 OF 40

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	82.1	45.4	84.8	84.8	84.8	84.8	84.8	84.8	84.8	84.8	56.6	84.8	79.2
2. POF	3.2	46.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	14.7	8.1	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	10.1	15.2	14.2
4. EUOR	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	647	324	668	647	668	647	668	668	647	668	431	668	7,351
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	97	348	75	73	76	73	76	76	73	76	290	76	1,409
9. POH	24	312	0	0	0	0	0	0	0	0	240	0	576
10. EFOH	84	42	87	84	87	84	87	87	84	87	56	87	955
11. EMOH	25	13	26	25	26	25	26	26	25	26	17	26	288
12. OPER BTU (GBTU)	2,459	1,191	2,559	2,542	2,556	2,530	2,615	2,631	2,546	2,631	1,501	2,533	28,302
13. NET GEN (MWH)	233,190	112,260	243,120	243,480	243,410	242,120	250,300	252,160	243,970	252,150	140,360	240,110	2,696,630
14. ANOHR (Btu/kwh)	10,543	10,613	10,526	10,439	10,500	10,450	10,448	10,433	10,435	10,433	10,697	10,548	10,495
15. NOF (%)	90.1	86.6	91.0	95.3	92.2	94.7	94.9	95.6	95.5	95.6	82.4	89.9	92.5
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397

17. ANOHR EQUATION ANOHR = NOF(-20.119) + 12,356

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	85.9	85.9	47.1	85.9	85.9	85.9	85.9	85.9	85.9	85.9	85.9	58.2	80.3
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	14.1	14.1	7.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	9.5	13.1
4. EUOR	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	666	602	365	644	666	644	666	666	644	666	644	451	7,324
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	78	70	378	76	78	76	78	78	76	78	77	293	1,436
9. POH	0	0	336	0	0	0	0	0	0	0	0	240	576
10. EFOH	77	70	42	75	77	75	77	77	75	77	75	52	847
11. EMOH	28	25	15	27	28	27	28	28	27	28	27	19	303
12. OPER BTU (GBTU)	2,823	2,550	1,529	2,678	2,766	2,678	2,770	2,757	2,678	2,770	2,673	1,878	30,549
13. NET GEN (MWH)	270,980	244,770	146,800	257,090	265,570	257,080	265,910	264,730	257,090	265,910	256,630	180,320	2,932,880
14. ANOHR (Btu/kwh)	10,416	10,416	10,417	10,415	10,416	10,415	10,415	10,416	10,415	10,415	10,416	10,418	10,416
15. NOF (%)	97.6	97.5	96.4	98.1	98.0	98.1	98.1	97.7	98.1	98.1	97.9	95.9	97.6
16. NPC (MW)	417	417	417	407	407	407	407	407	407	407	407	417	410
17. ANOHR EQUATION	ANOHR = NOF(		-0.940	) +	10,508								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	89.3	89.3	20.1	26.8	89.3	89.3	89.3	89.3	89.3	89.3	74.5	89.3	77.1
2. POF	0.0	0.0	77.5	70.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	13.7
3. EUOF	10.7	10.7	2.4	3.2	10.7	10.7	10.7	10.7	10.7	10.7	8.9	10.7	9.2
4. EUOR	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	631	570	143	192	659	633	652	667	645	649	565	631	6,637
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	113	102	600	528	85	87	92	77	75	95	156	113	2,123
9. POH	0	0	576	504	0	0	0	0	0	0	120	0	1,200
10. EFOH	61	55	14	18	61	59	61	61	59	61	49	61	619
11. EMOH	19	17	4	5	19	18	19	19	18	19	15	19	188
12. OPER BTU (GBTU)	1,419	1,282	321	431	1,479	1,417	1,460	1,495	1,440	1,458	1,258	1,420	14,880
13. NET GEN (MWH)	134,830	121,840	30,470	40,810	140,220	134,070	138,310	141,690	136,030	138,310	118,680	134,890	1,410,150
14. ANOHR (Btu/kwh)	10,526	10,524	10,539	10,550	10,545	10,566	10,559	10,553	10,586	10,538	10,604	10,524	10,552
15. NOF (%)	97.1	97.2	96.9	96.6	96.7	96.3	96.4	96.6	95.9	96.9	95.5	97.2	96.6
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(		-47.266	) +	15,117								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	94.5	64.1	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	91.4	70.1	89.9
2. POF	0.0	32.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	25.8	4.9
3. EUOF	5.5	3.7	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.3	4.1	5.2
4. EUOR	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	554	391	674	430	620	636	641	684	661	604	529	427	6,851
7. RSH	149	40	28	251	83	45	62	19	20	99	130	95	1,021
8. UH	41	241	41	39	41	39	41	41	39	41	62	222	888
9. POH	0	216	0	0	0	0	0	0	0	0	24	192	432
10. EFOH	8	5	8	7	8	7	8	8	7	8	7	6	84
11. EMOH	33	20	33	32	33	32	33	33	32	33	31	25	372
12. OPER BTU (GBTU)	1,226	1,202	2,149	1,115	1,800	1,762	1,854	2,070	2,063	1,709	1,288	1,149	19,422
13. NET GEN (MWH)	161,060	162,160	290,960	149,690	244,410	238,140	251,690	282,360	282,530	231,490	172,000	153,120	2,619,610
14. ANOHR (Btu/kwh)	7,614	7,413	7,386	7,448	7,363	7,400	7,366	7,329	7,303	7,383	7,490	7,504	7,414
15. NOF (%)	36.7	52.4	54.5	49.7	56.2	53.4	56.0	58.9	61.0	54.7	46.4	45.3	52.3
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-12.819	) +	8,084								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1. EAF (%)	92.1	88.9	68.3	92.1	92.1	92.1	92.1	92.1	92.1	92.1	52.3	92.1	86.6
2. POF	0.0	3.6	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.3	0.0	6.0
3. EUOF	7.9	7.6	5.8	7.9	7.9	7.9	7.9	7.9	7.9	7.9	4.5	7.9	7.4
4. EUOR	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	686	597	508	664	686	664	686	686	664	686	377	686	7,586
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	58	75	235	57	58	57	58	58	57	58	344	58	1,174
9. POH	0	24	192	0	0	0	0	0	0	0	312	0	528
10. EFOH	26	23	19	25	26	25	26	26	25	26	14	26	291
11. EMOH	32	28	24	31	32	31	32	32	31	32	18	32	355
12. OPER BTU (GBTU)	1,136	1,510	1,228	2,628	3,007	2,982	2,931	3,221	3,351	3,107	1,395	1,594	28,267
13. NET GEN (MWH)	148,240	199,020	161,610	354,880	408,550	405,830	397,670	439,720	460,020	423,080	187,660	209,600	3,795,880
14. ANOHR (Btu/kwh)	7,666	7,587	7,597	7,405	7,359	7,347	7,371	7,324	7,285	7,343	7,433	7,605	7,447
15. NOF (%)	20.7	31.8	30.4	57.6	64.1	65.8	62.4	69.0	74.6	66.4	53.6	29.2	51.7
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968

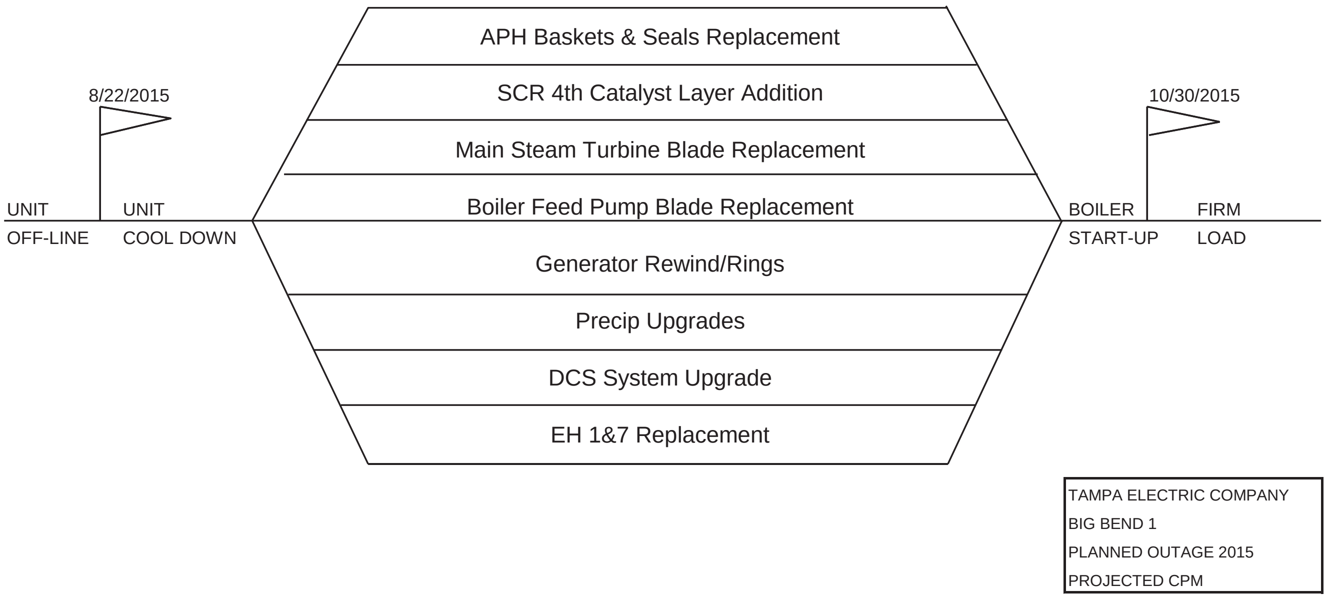
17. ANOHR EQUATION   ANOHR = NOF(-7.052) + 7,811

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2015 - DECEMBER 2015

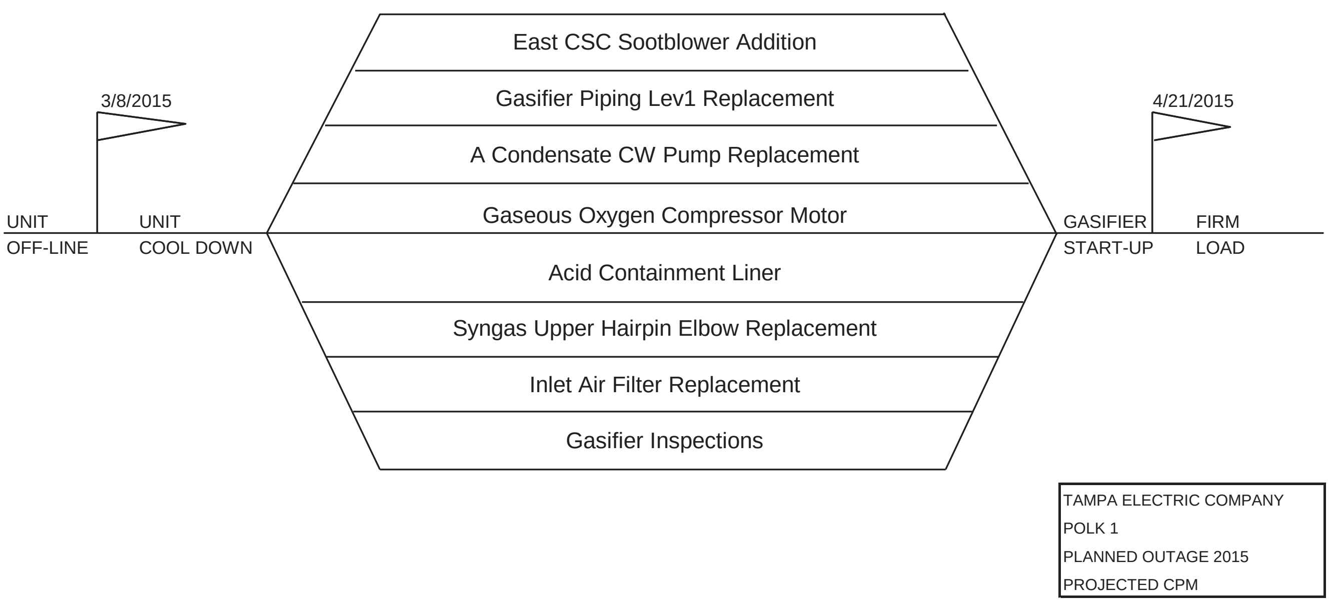
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Apr 25	-	May 09	Fuel System Cleanup and FGD/SCR work
		Aug 22	-	Oct 30	APH Baskets & Seals Replacement, BFP Turbine Blade Repl, DCS Syst Soft-Hardware Upgrades, EH1&7 Repl, Generator Rewind/Rings, Main Steam Turbine Blade Replac, Precip Upgrades, SCR 4th Catalyst Layer Addition
	BIG BEND 2	Apr 26	-	May 09	Fuel System Cleanup and FGD/SCR work
		Oct 17	-	Oct 26	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Jan 31	-	Feb 13	Fuel System Cleanup and FGD/SCR work
		Nov 02	-	Nov 11	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Mar 14	-	Mar 27	Fuel System Cleanup and FGD/SCR work
		Dec 05	-	Dec 14	Fuel System Cleanup and FGD/SCR work
+	POLK 1	Mar 08	-	Apr 21	Gaseous Oxygen Compressor Mtr, Acid Containment Liner, East CSC Sootblower Addition, A Condensate CW Pump Repl, Syngas Upper Hairpin Elbow R, Gasifier Piping Lev1 replace, Inlet Air Filter Replacement
		Nov 01	-	Nov 05	Gasifier Outage
	BAYSIDE 1	Feb 16	-	Feb 24	Fuel System Cleanup
		Nov 30	-	Dec 08	Fuel System Cleanup
	BAYSIDE 2	Feb 28	-	Mar 08	Fuel System Cleanup
		Nov 10	-	Nov 22	Fuel System Cleanup

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

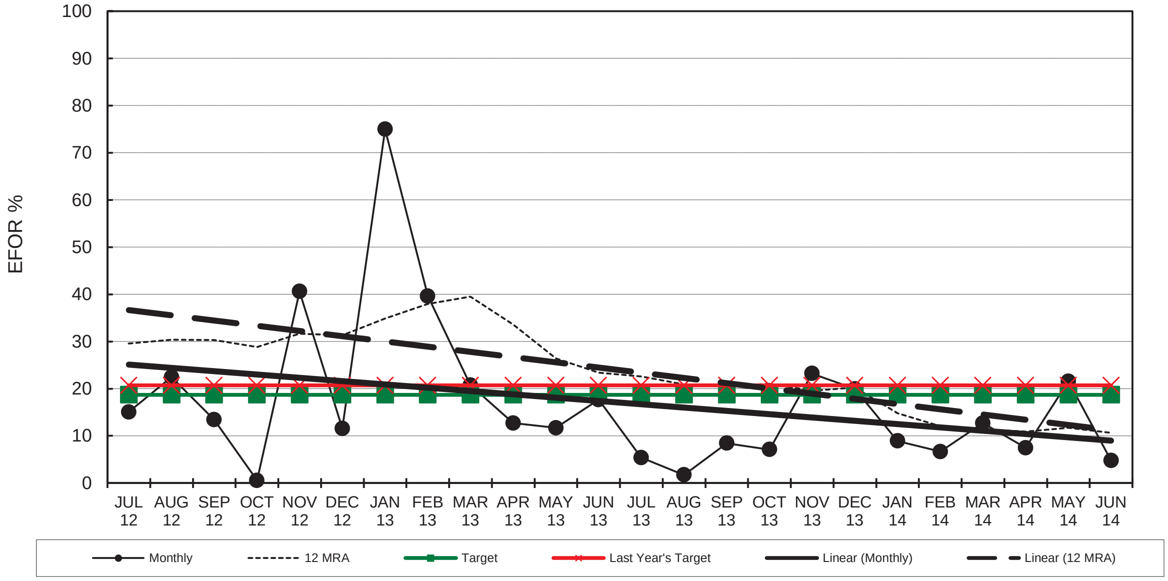
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2015 - DECEMBER 2015



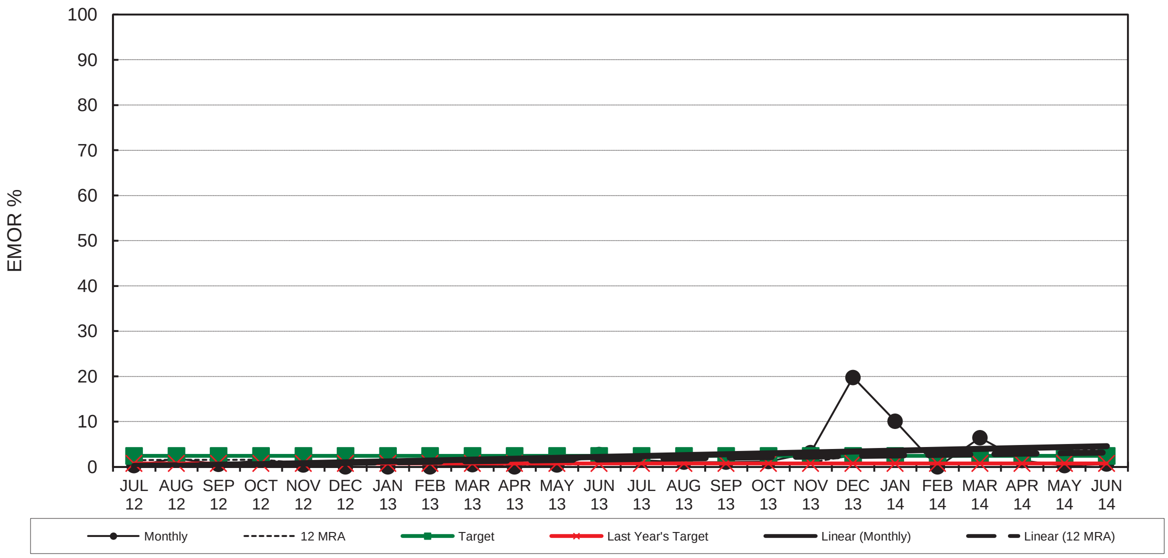
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2015 - DECEMBER 2015

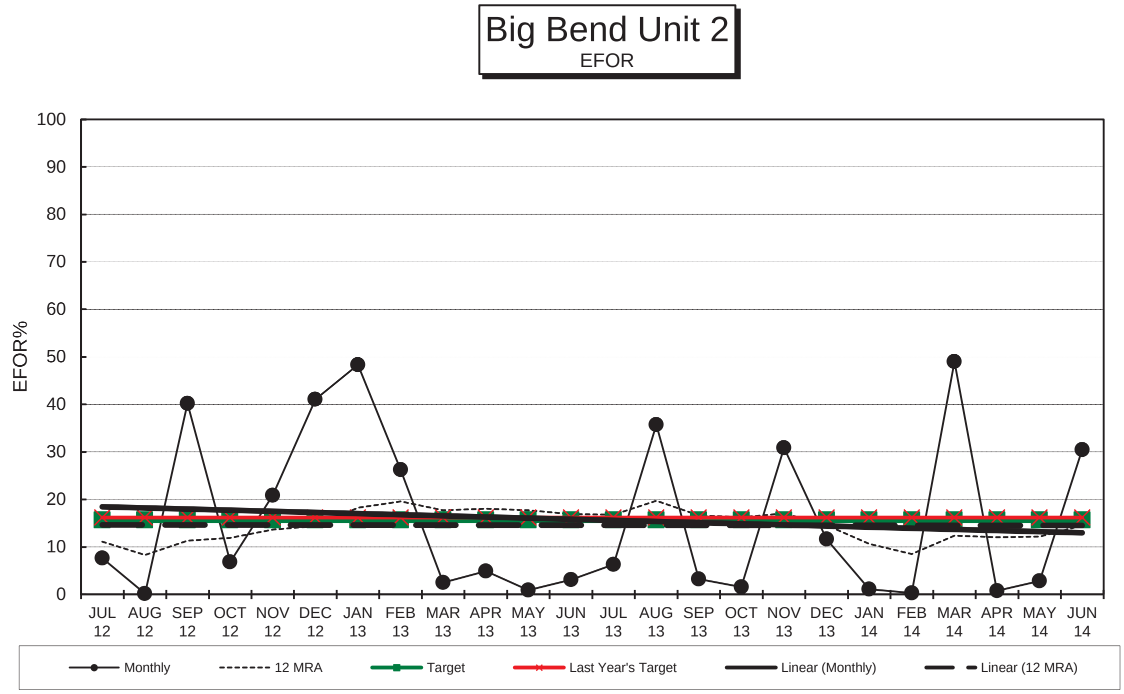


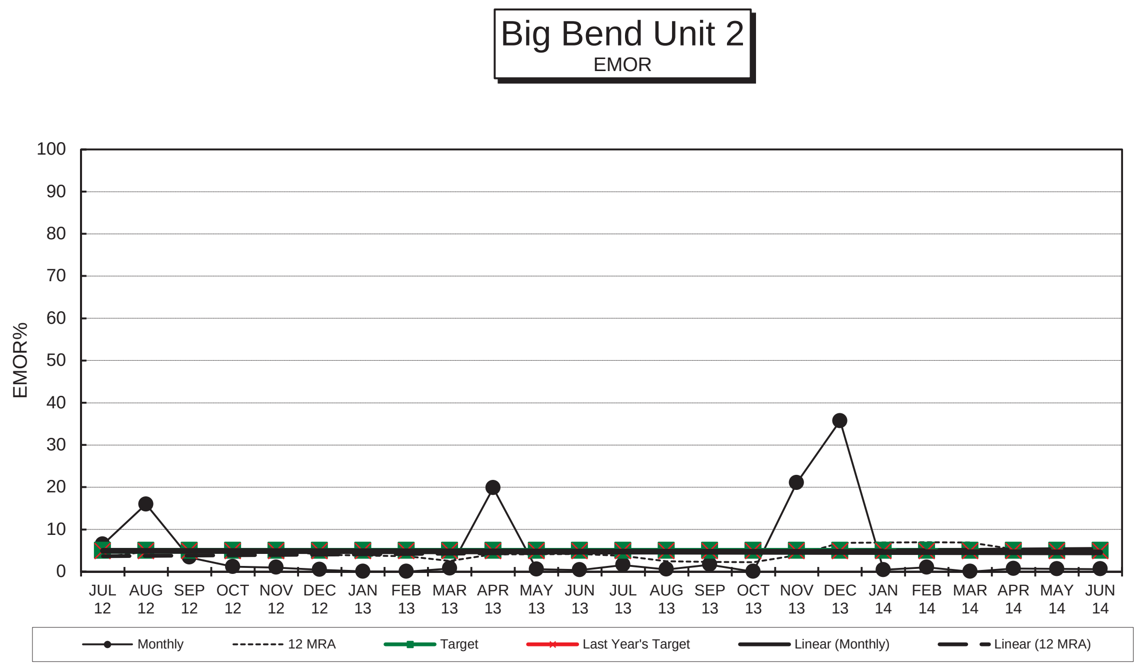
Big Bend Unit 1
EFOR



Big Bend Unit 1
EMOR




Big Bend Unit 2
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EMOR
EMOR%
100
90
80
70
60
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10
0
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AUG 12
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OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
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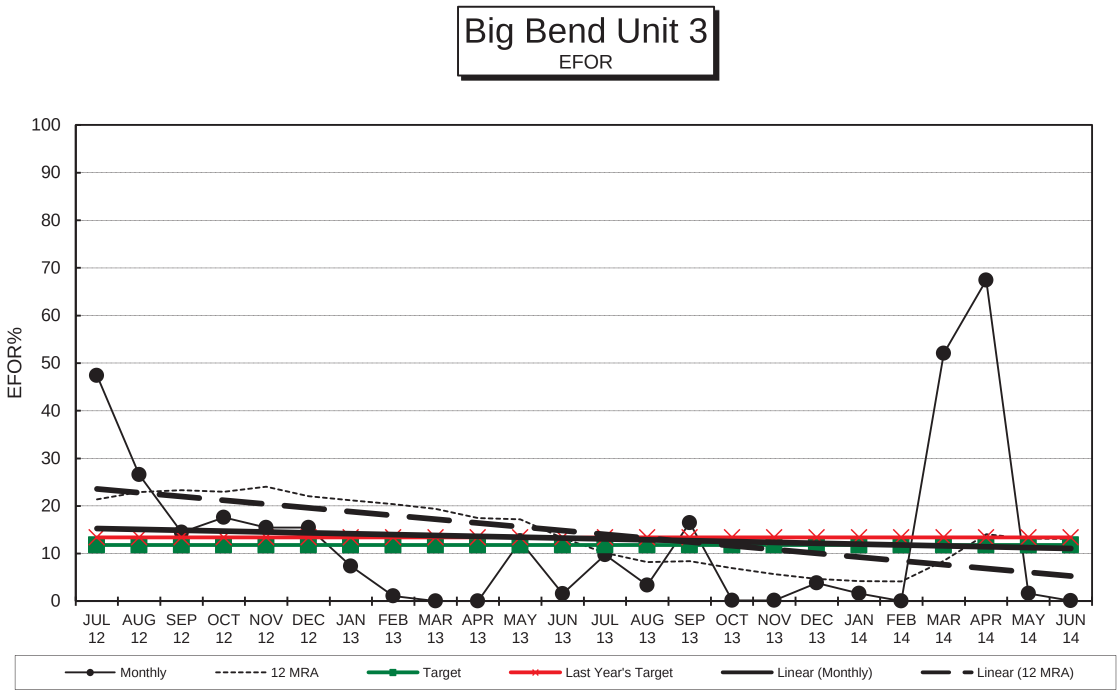
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
EFOR
EFOR%
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80
70
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40
30
20
10
0
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AUG 12
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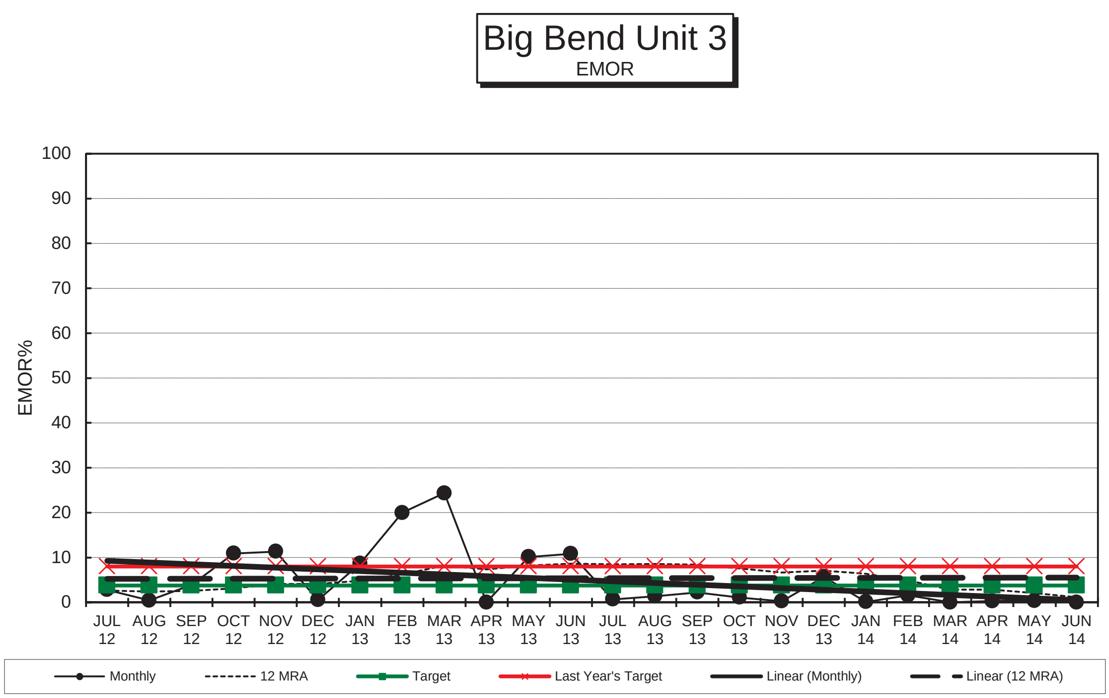
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
EMOR
EMOR%
100
90
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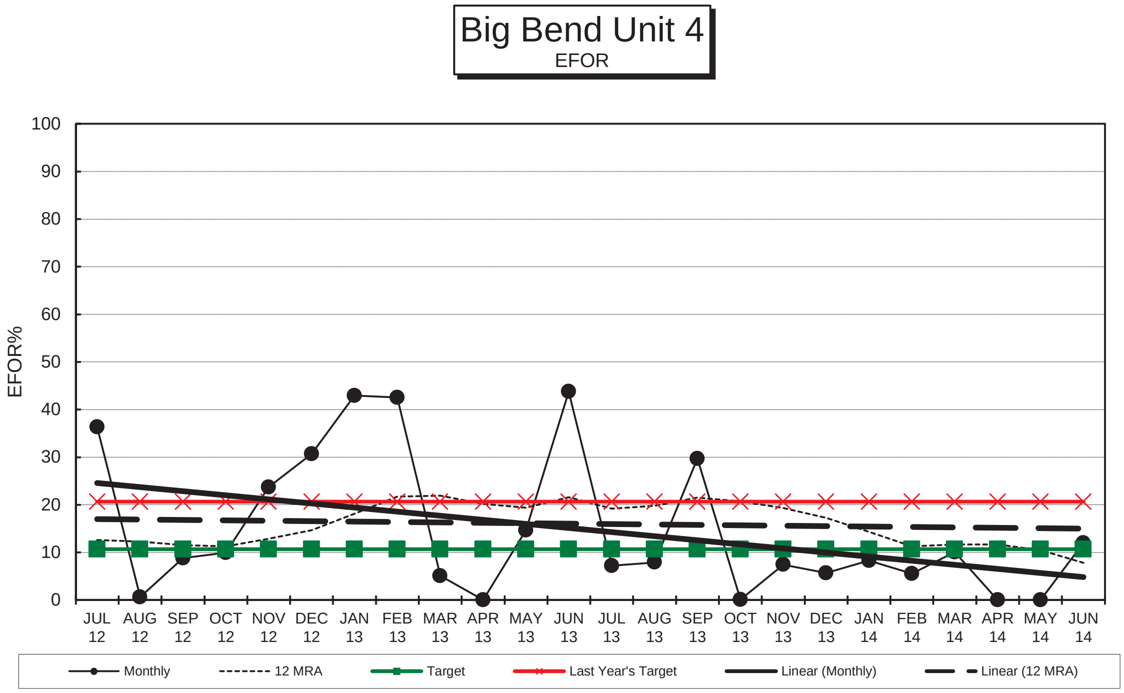
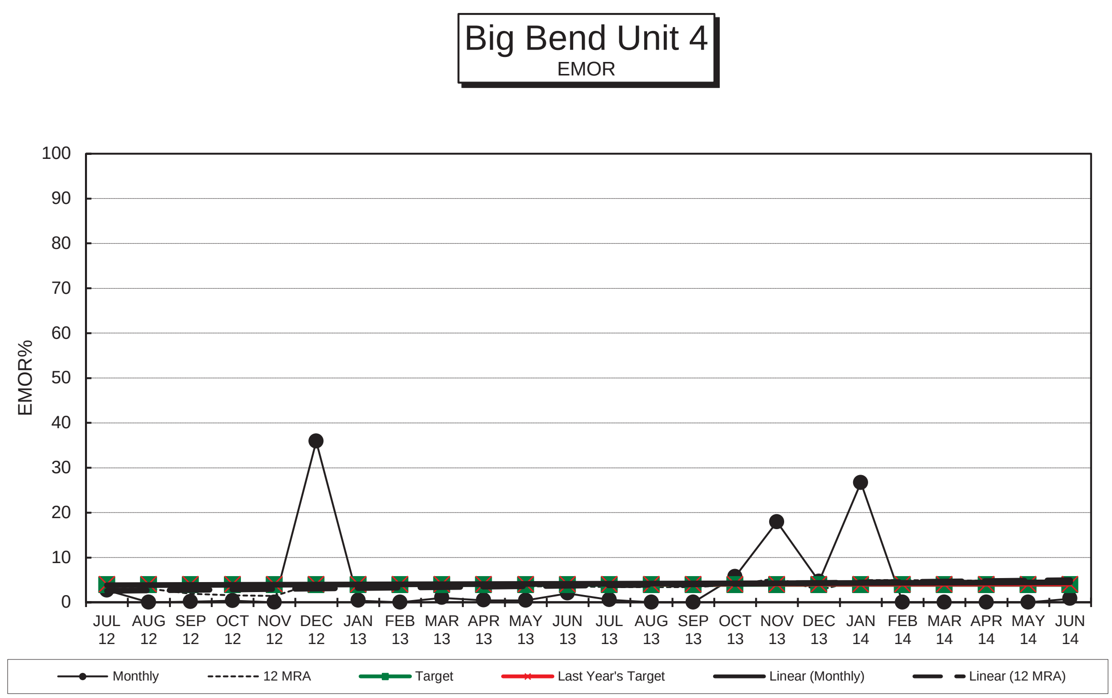
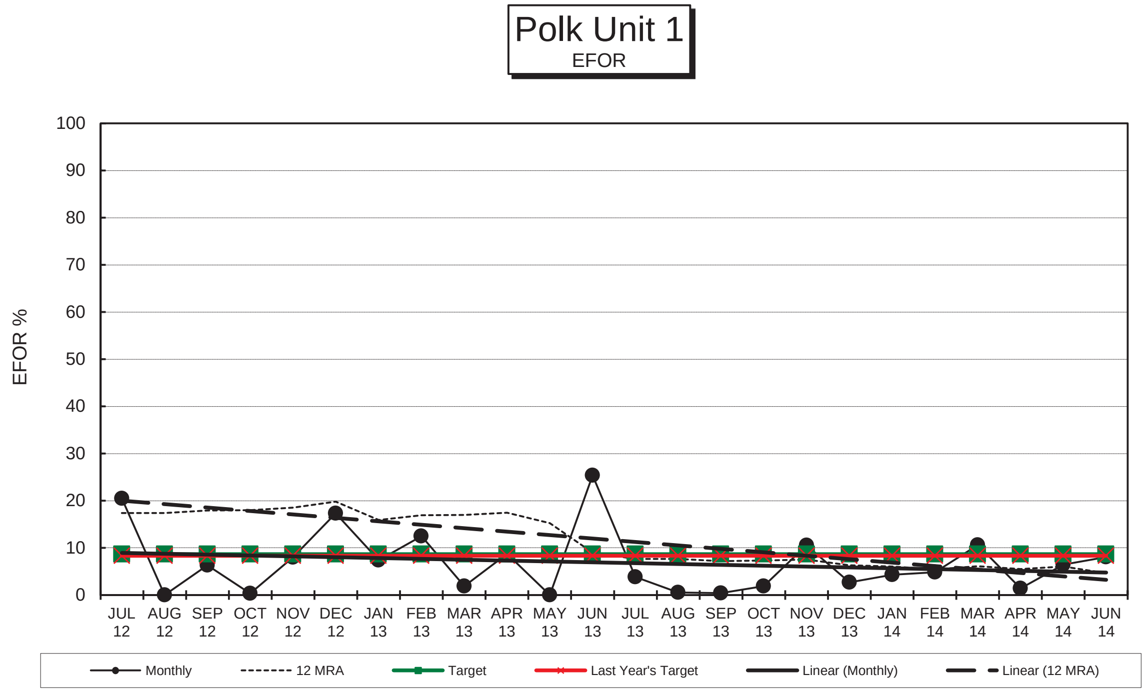
70
60
50
40
30
20
10
0
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EFOR
EFOR%
JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13 JUL 13 AUG 13 SEP 13 OCT 13 NOV 13 DEC 13 JAN 14 FEB 14 MAR 14 APR 14 MAY 14 JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13 JUL 13 AUG 13 SEP 13 OCT 13 NOV 13 DEC 13 JAN 14 FEB 14 MAR 14 APR 14 MAY 14 JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
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20
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JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
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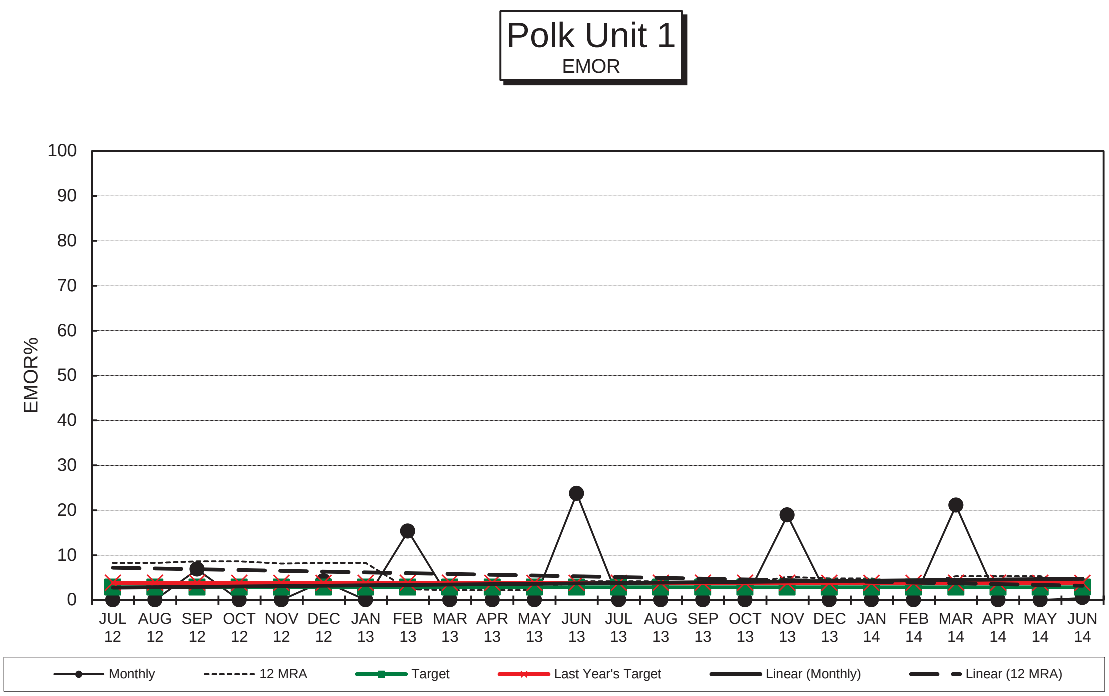
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
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OCT 12
NOV 12
DEC 12
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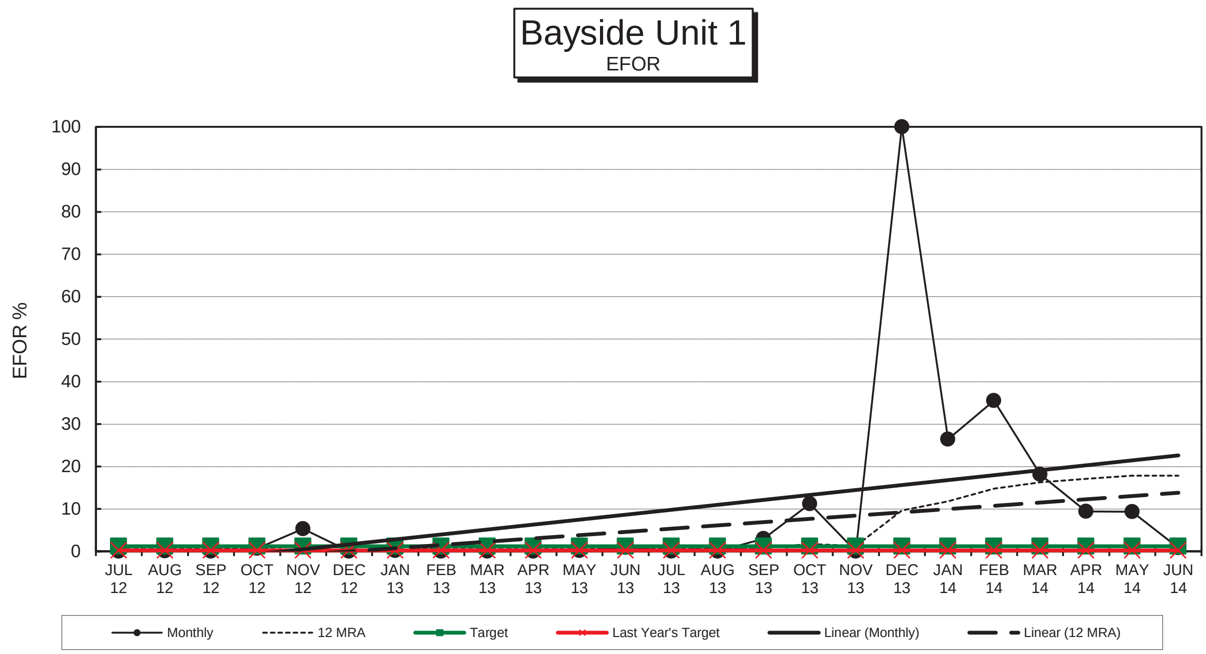
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
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EFOR %
100
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80
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60
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JUL 12
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NOV 12
DEC 12
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DEC 13
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APR 14
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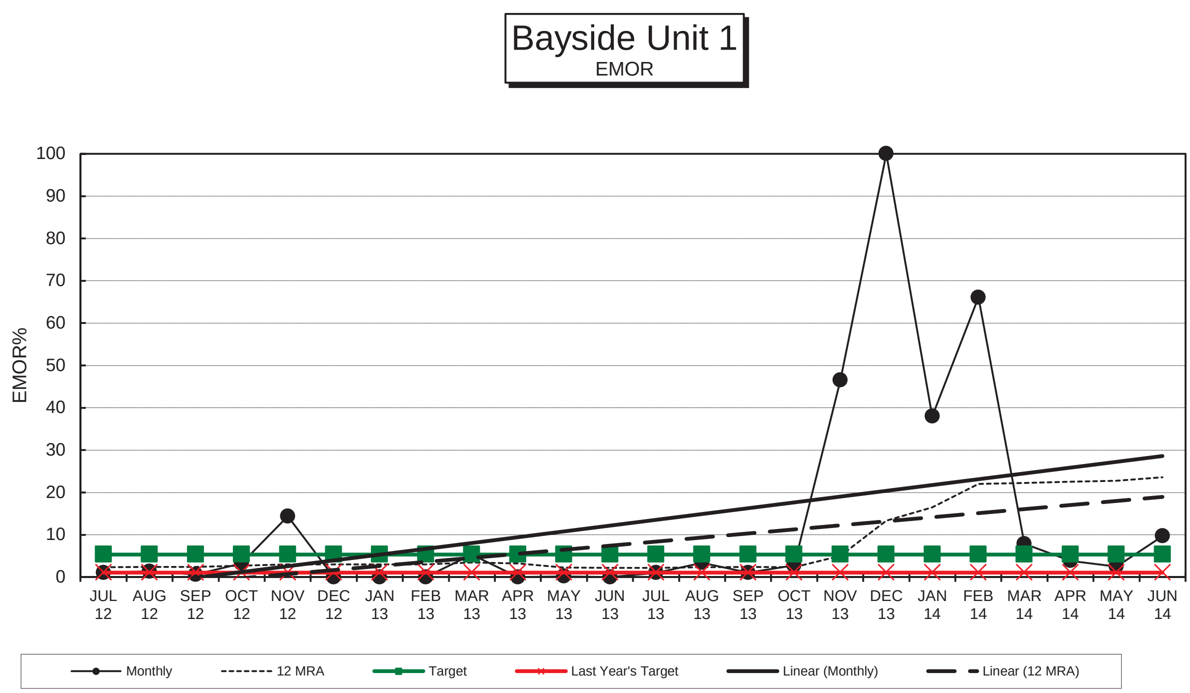
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
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AUG 12
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NOV 12
DEC 12
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APR 13
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AUG 13
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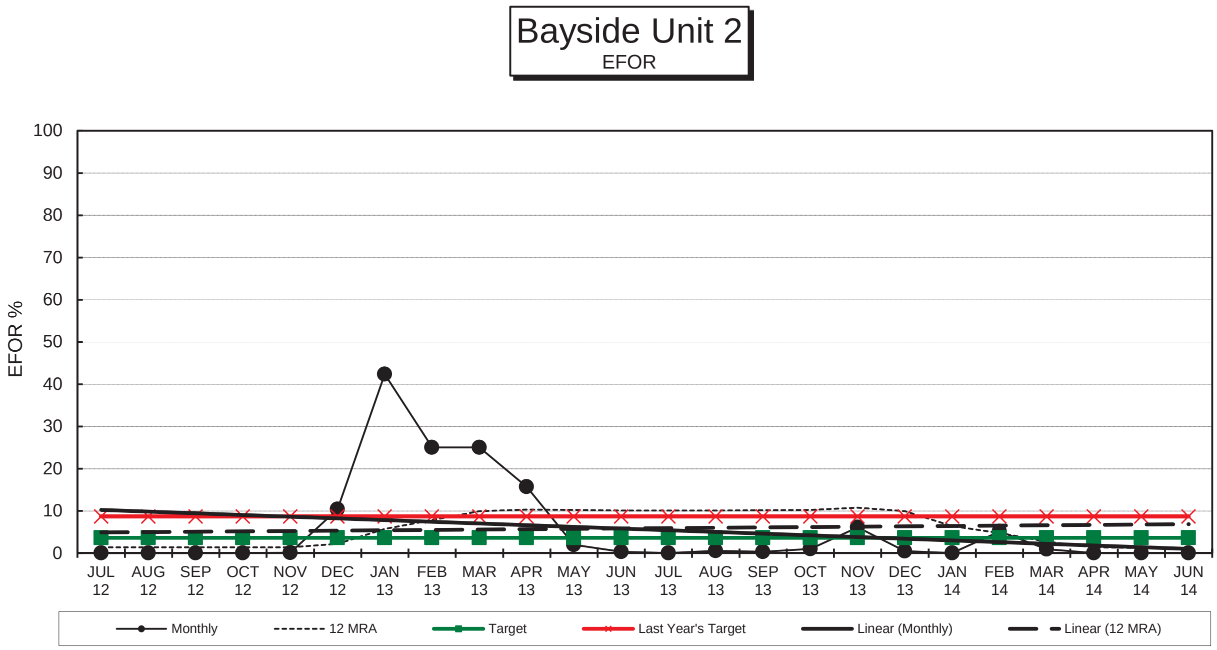
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
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EFOR %
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OCT 12
NOV 12
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JAN 14
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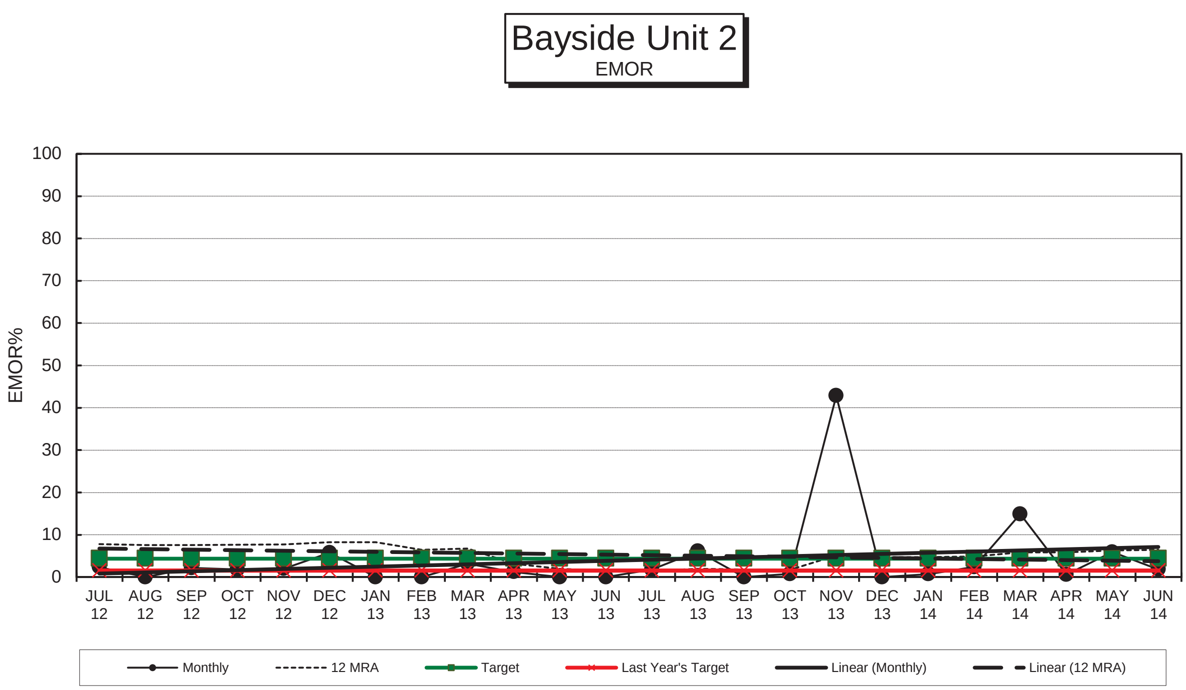
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
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EMOR%
100
90
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OCT 12
NOV 12
DEC 12
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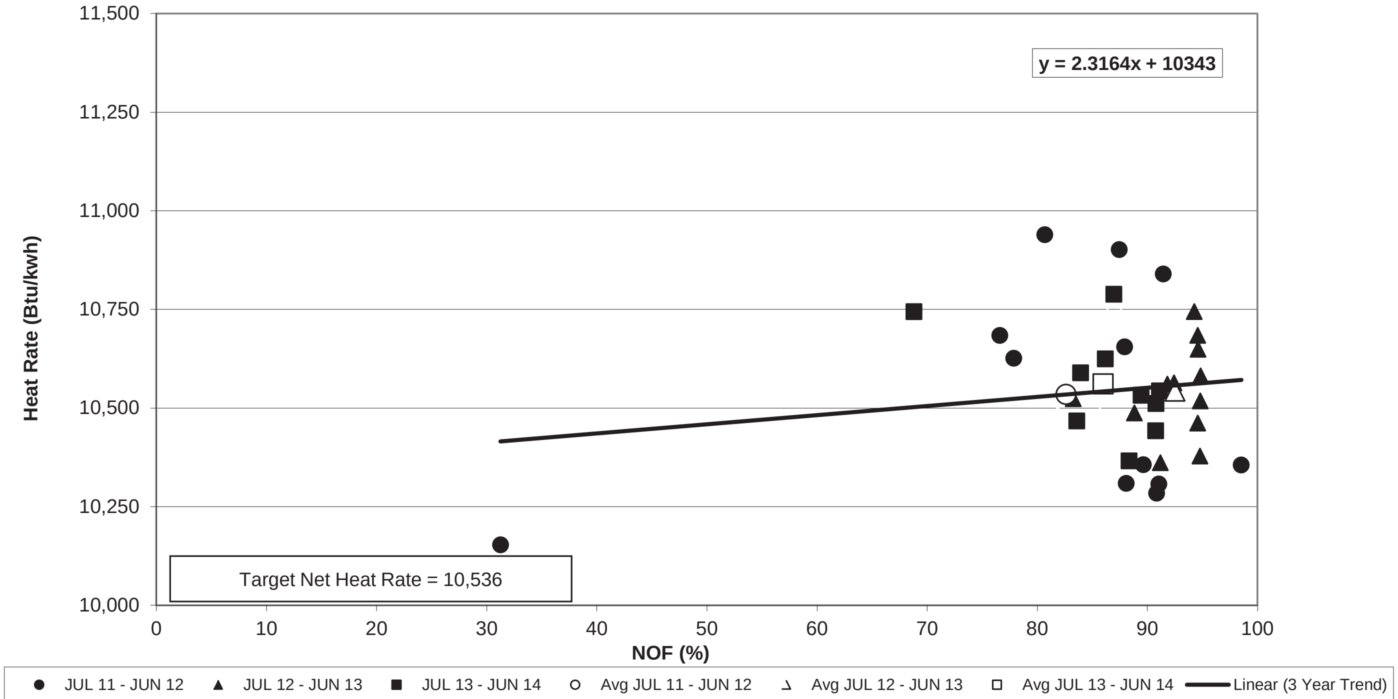
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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



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DOCUMENT NO. 1, PAGE 31 OF 40

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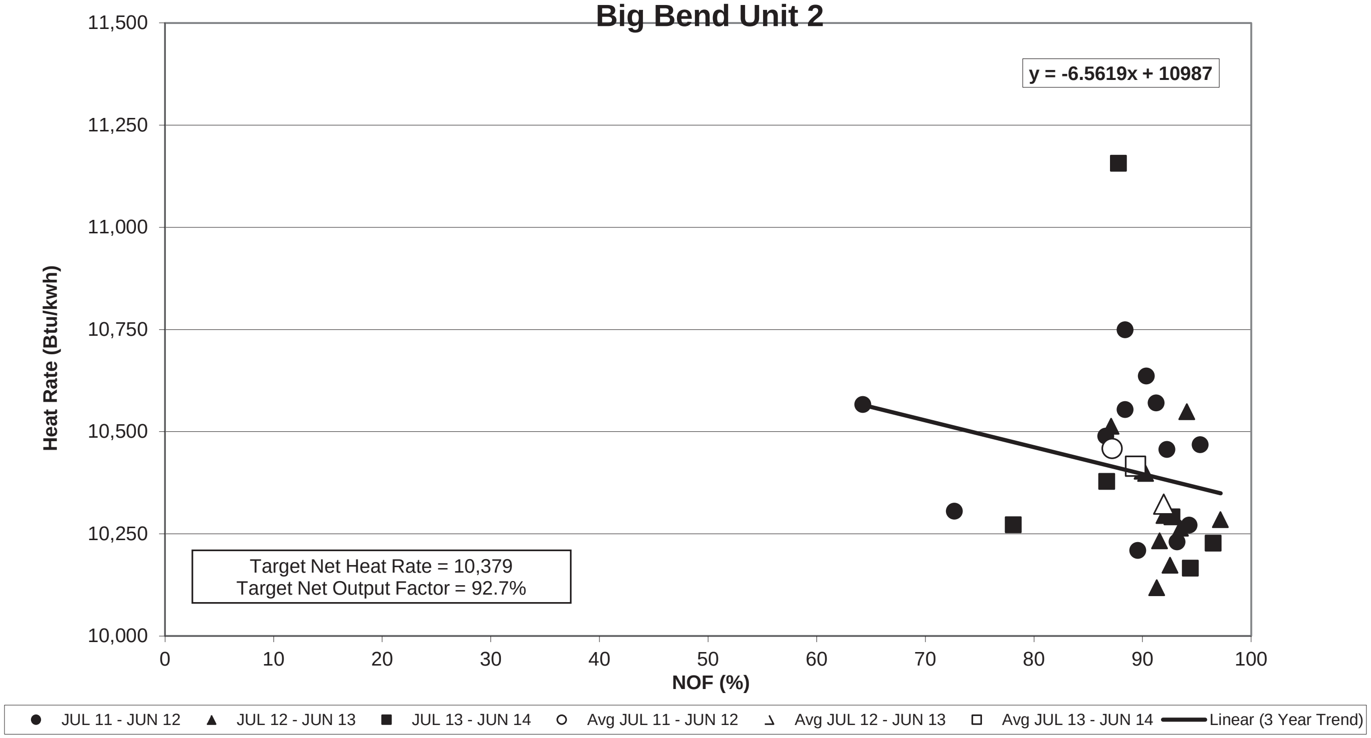
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



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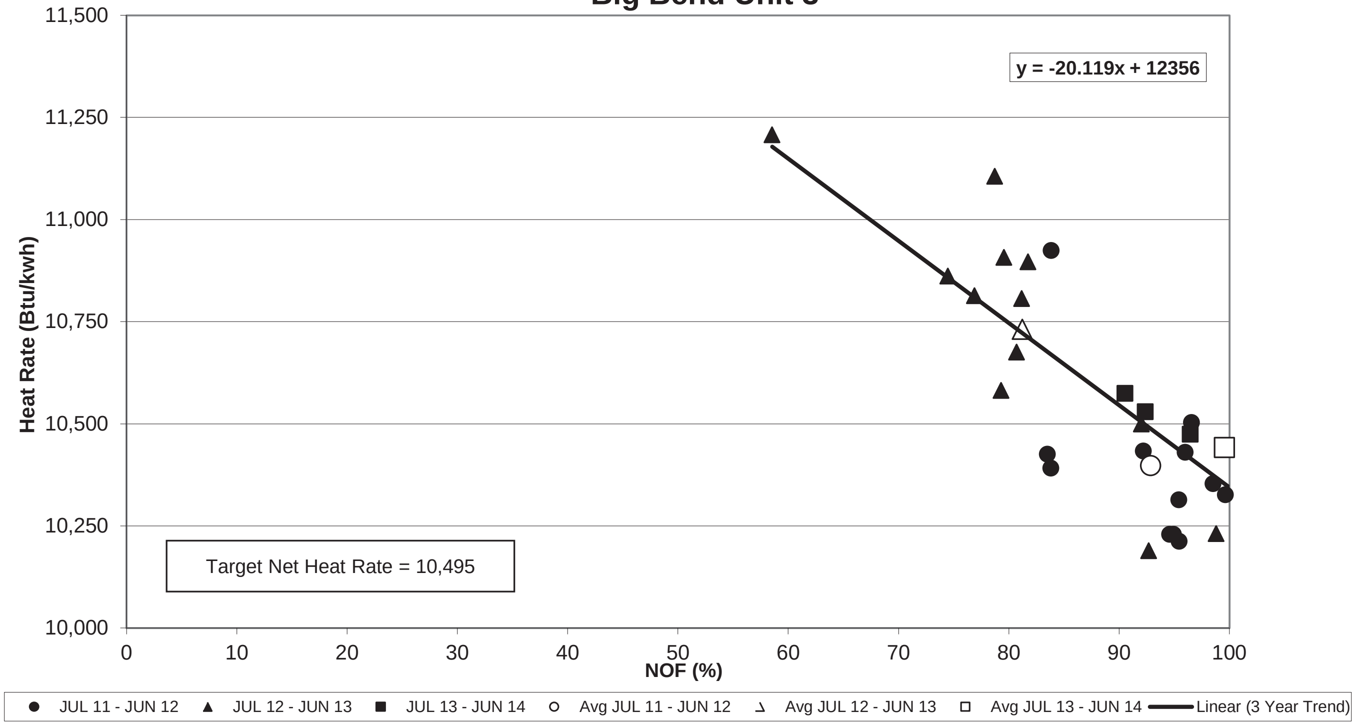
GPIF 2015 PROJECTION FILING
EXHIBIT NO. ___ (BSB-2)
DOCUMENT NO. 1, PAGE 32 OF 40

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



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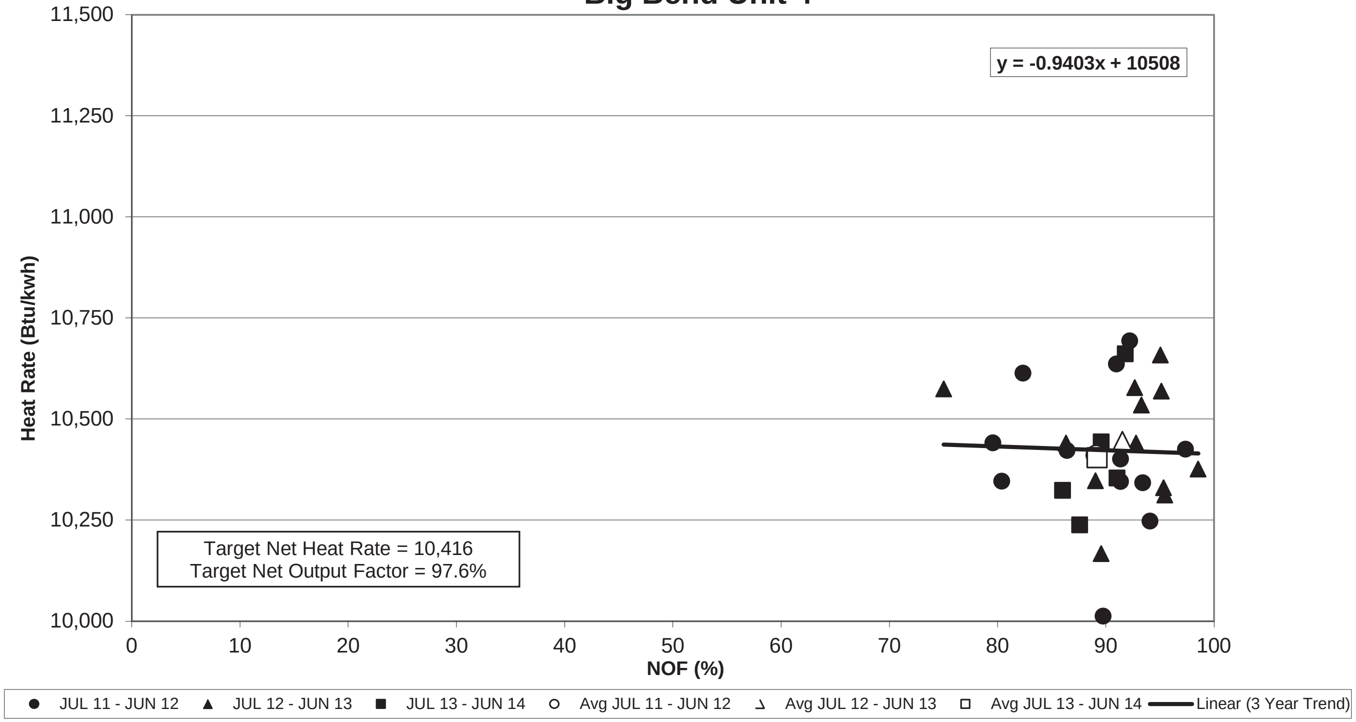
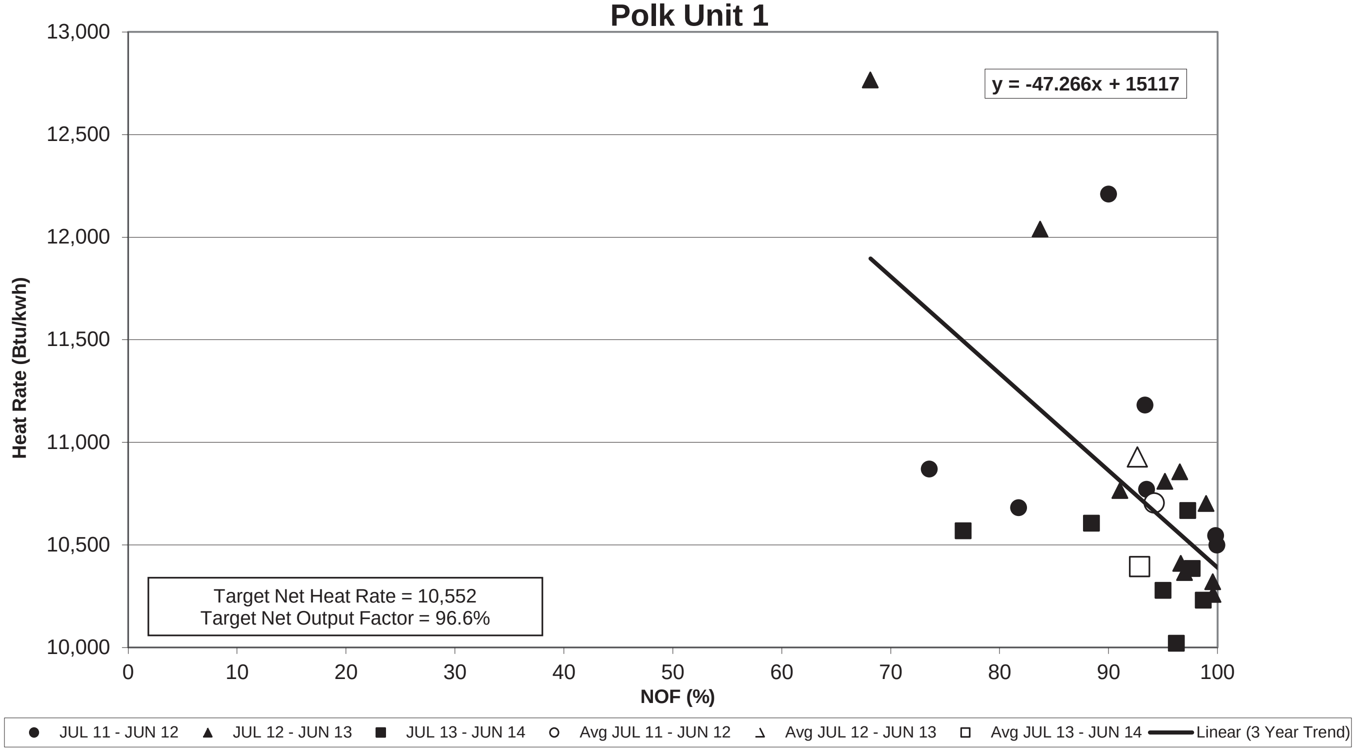
GPIF 2015 PROJECTION FILING
EXHIBIT NO. ___ (BSB-2)
DOCUMENT NO. 1, PAGE 33 OF 40

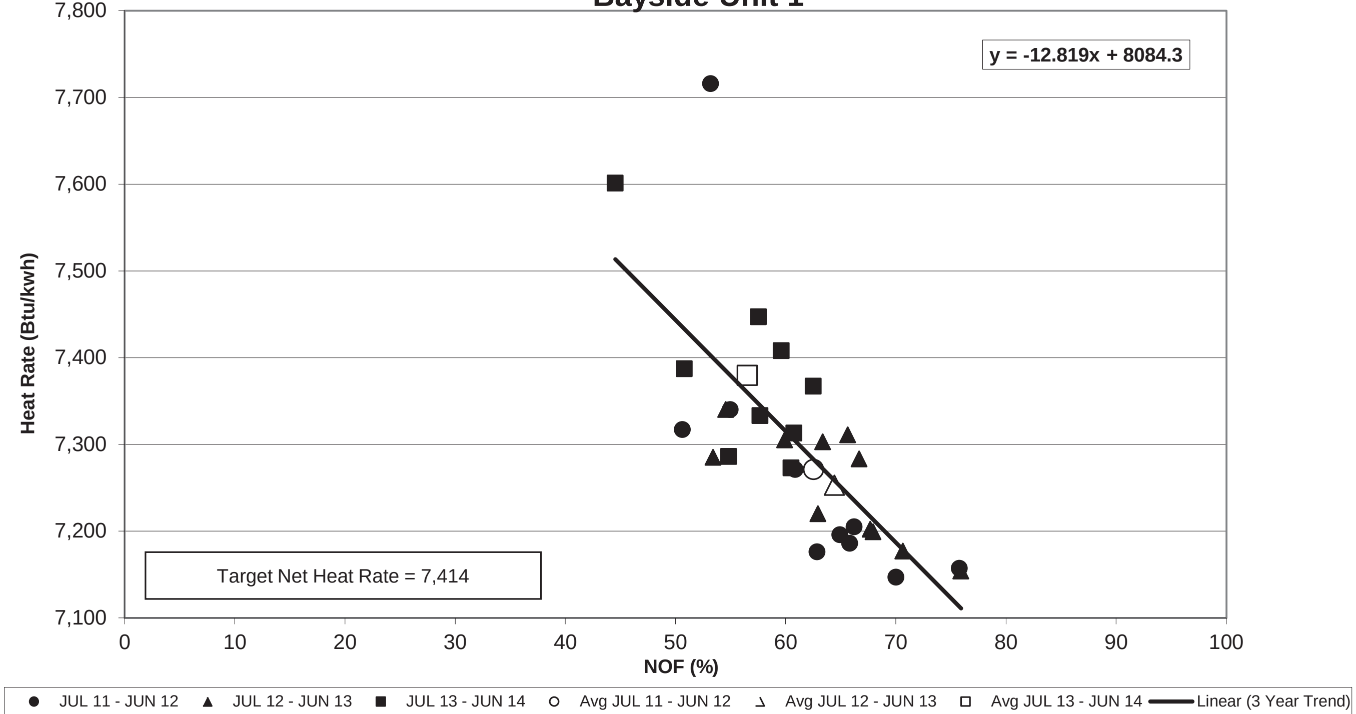
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4



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



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



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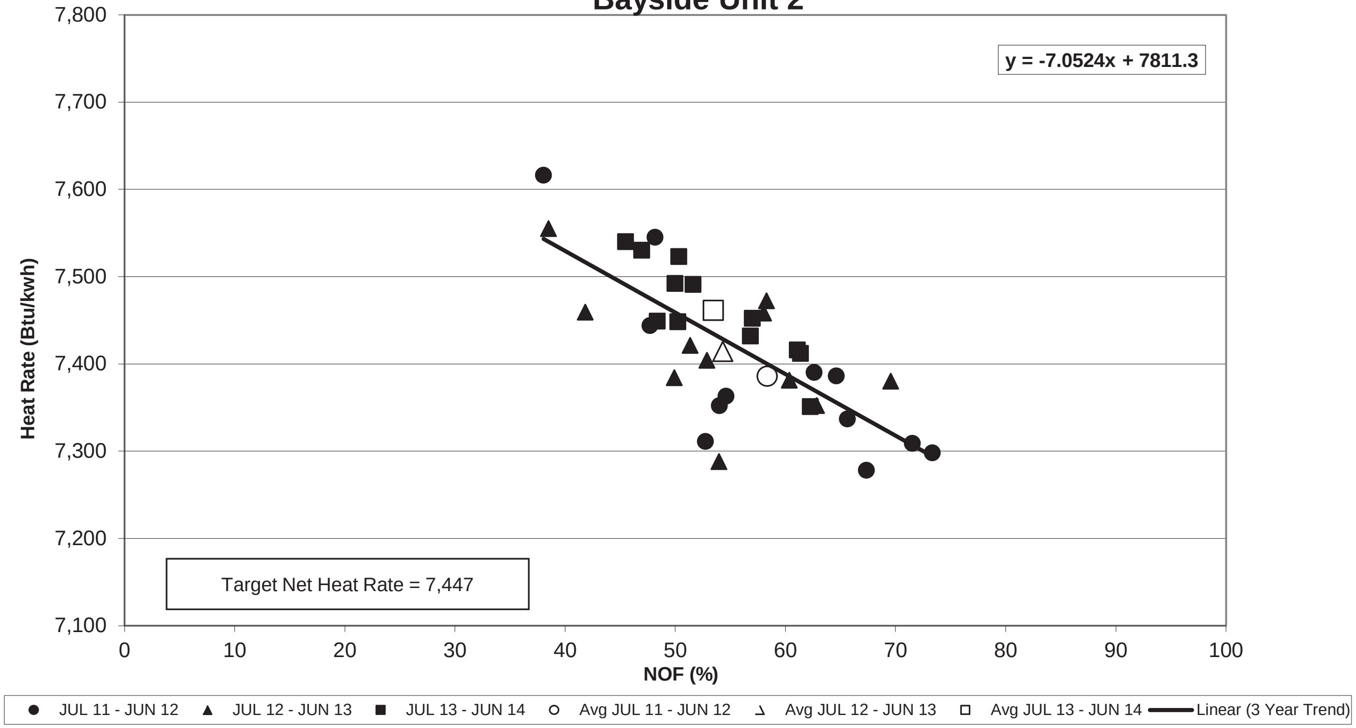
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



DOCKET NO. 140001-EI
GPIF 2015 PROJECTION FILING
EXHIBIT NO. ___ (BSB-2)
DOCUMENT NO. 1, PAGE 37 OF 40

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2015 - DECEMBER 2015

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		443	410
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,701	3,503
	SYSTEM TOTAL	**4,645**	**4,439**
	% OF SYSTEM TOTAL	**79.7%**	**78.9%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2015 - DECEMBER 2015

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		443	410
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,750	1,641
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,645**	**4,439**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2015 - DECEMBER 2015

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	3,795,880	20.16%	20.16%
BIG BEND	4	2,932,880	15.57%	35.73%
BIG BEND	3	2,696,630	14.32%	50.05%
BIG BEND	2	2,625,660	13.94%	63.99%
BAYSIDE	1	2,619,610	13.91%	77.90%
BIG BEND	1	2,171,630	11.53%	89.44%
POLK	1	1,410,150	7.49%	96.92%
POLK	2	183,400	0.97%	97.90%
POLK	3	120,920	0.64%	98.54%
POLK	4	96,690	0.51%	99.05%
POLK	5	49,820	0.26%	99.32%
BAYSIDE	5	40,200	0.21%	99.53%
BAYSIDE	6	31,440	0.17%	99.70%
BAYSIDE	3	27,550	0.15%	99.84%
BAYSIDE	4	18,350	0.10%	99.94%
BIG BEND CT	4	10,860	0.06%	100.00%
TOTAL GENERATION		18,831,670	100.00%	

GENERATION BY COAL UNITS:	11,836,950 MWH		GENERATION BY NATURAL GAS UNITS:	6,994,720 MWH
% GENERATION BY COAL UNITS	62.86%		% GENERATION BY NATURAL GAS UNITS:	37.14%
GENERATION BY OIL UNITS:	- MWH		GENERATION BY GPIF UNITS:	18,252,440 MWH
% GENERATION BY OIL UNITS:	0.00%		% GENERATION BY GPIF UNITS:	96.92%

EXHIBIT TO THE TESTIMONY OF
BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2015 - DECEMBER 2015

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1[1]	61.2	23.0	15.8	10,563
Big Bend 2[2]	75.2	6.6	18.2	10,379
Big Bend 3[3]	79.2	6.6	14.2	10,495
Big Bend 4[4]	80.3	6.6	13.1	10,416
Polk 1[5]	77.1	13.7	9.2	10,552
Bayside 1[6]	89.9	4.9	5.2	7,414
Bayside 2[7]	86.6	6.0	7.4	7,447

1 Original Sheet 8.401.15E, Page 14

2 Original Sheet 8.401.15E, Page 15

3 Original Sheet 8.401.15E, Page 16

4 Original Sheet 8.401.15E, Page 17

5 Original Sheet 8.401.15E, Page 18

6 Original Sheet 8.401.15E, Page 19

7 Original Sheet 8.401.15E, Page 20

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2015 THROUGH DECEMBER 2015

TESTIMONY
OF
J. BRENT CALDWELL

FILED: AUGUST 22, 2014

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, Bulk Fuel and Power.

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 degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2011, and I testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project.

Q. What is the purpose of your testimony?

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

2015 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2015?

A. In 2015, coal-fired generation is expected to be approximately 63 percent, and natural-gas fired generation is expected to be 37 percent, of total generation. Generation from oil is expected to be less than one percent of the total generation.

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

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

Coal Supply Strategy

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

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

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

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2014.

A. Tampa Electric supplies Big Bend Station's coal needs through a combination of two coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2015 delivery?

A. Yes, Tampa Electric has contracted for more than three-fourths of its 2015 expected coal needs through 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 2014 and 2015.

Coal Transportation

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

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

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

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

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2014 and 2015?

A. Yes. Tampa Electric expects to receive over two million tons of coal through the Big Bend rail facility during 2015, for use at Big Bend Station.

As part of the CSX transportation agreement, Tampa Electric receives a per ton discount, treated as a reimbursement, for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause. Although the current agreement with CSX was scheduled to expire at the end of 2014, the company has reached an agreement to extend the contract. In addition to the term extension, the contract amendment extends the available per ton discount for rail transportation, treated as a reimbursement, and replaces the minimum annual throughput with a fixed capacity reservation. The per-ton discount, or reimbursement, will continue to be flowed through to customers through the fuel and purchased power cost recovery clause. The amended contract rate structure makes the effective rate lower than the previous agreement at the expected level of rail deliveries.

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.

Tampa Electric's existing waterborne transportation agreements for river, terminal and Gulf expire at the end of 2014. Tampa Electric issued an RFP for waterborne transportation services in early 2014. The company is negotiating agreements with the terminal services and ocean transportation providers, and Tampa Electric expects to finish negotiating new agreements for these two transportation components by the end of the third quarter of 2014. Tampa Electric is in the process of selecting river transportation provider(s) and expects to make a final selection by the end of August 2014, with final agreement(s) in place by the end of the fourth quarter of 2014. Tampa Electric anticipates that the new waterborne transportation agreements will provide greater flexibility and reduce overall waterborne transportation costs. These estimated lower transportation costs are incorporated in the company’s 2015 delivered fuel cost projections.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2015 solid fuel supply portfolio.

A. Tampa Electric placed an emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. There are several environmental regulations being enacted or proposed to be enacted in the next few years. These regulations may affect the types or quantities of coal that can be consumed at the stations or most likely, both. Also, Tampa Electric and Florida’s generation assets continue to evolve. Tampa Electric is in the process of converting the natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined cycle unit. Several new natural gas combined cycle units recently have been built within the state. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

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

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

Tampa Electric 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 2015 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately two-thirds of the company’s expected natural gas requirements for 2015. The balance of Tampa Electric’s natural gas supply will be acquired through seasonal, monthly and daily purchases to meet its varying operational needs.

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

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

Projected 2015 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 2015 projected fuel prices compare to the fuel prices projected for 2014?

A. Fuel prices for coal and natural gas for 2015 are projected to be similar to the prices projected for 2014. The colder than expected 2013 through 2014 winter increased demand for natural gas and coal in the short term. However, natural gas production from shale reserves has easily met this increased natural gas demand and is keeping prices relatively stable. Natural gas prices are projected to be slightly higher in 2015 than the actual/estimated natural gas prices expected for 2014, primarily driven by anticipated improvement to the economy and a market adjustment to shale gas production. Similarly, the higher coal demand is offset by coal-fired unit closures that will reduce demand, and coal prices are expected to remain stable.

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

A. Yes. While projected 2015 prices for coal and natural gas are expected to be similar to 2014 prices, Tampa Electric recognizes that there is uncertainty in future prices. Therefore, Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 35 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 20 percent. Due to Tampa Electric’s generating mix combined with its Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

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

A. Tampa Electric complies with its risk management plan as approved by the company’s Risk Authorizing Committee. Tampa Electric’s plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan (“Risk Management Plan”), submitted to the Commission on July 25, 2014 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2014 and 2015 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2014 natural gas supply needs and a portion of its expected 2015 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company’s Natural Gas Hedging Activities report submitted to the Commission in this docket on August 13, 2014.

Q. Are the company’s strategies adequate for mitigating price risk for Tampa Electric’s 2014 and 2015 natural gas purchases?

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

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

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

Q. Were Tampa Electric's efforts through July 31, 2014 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 March 28, 2014, the company filed its 2013 Natural Gas Hedging Activities report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2014, in this docket on August 13, 2014.

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's hedging program requires consistent hedging based on expected needs. The company does not engage in speculative hedging strategies aimed at out-guessing the market. This discipline ensures hedges will be in place should prices spike and also means hedges are in place when prices decline and removes some of the volatility and uncertainty in natural gas prices from the fuel costs to generate electricity for 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. 140001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2015 THROUGH DECEMBER 2015

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: AUGUST 22, 2014

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

Wholesale Products and Fuel Services in Tampa Electric's Wholesale Marketing group. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structure, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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

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

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

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

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

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

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

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

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

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

Q. Please describe Tampa Electric's 2014 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 five percent of the expected energy needs for 2014 will be met using purchased power. This purchased power energy includes economy purchases, qualifying facilities, and existing firm purchased power agreements with Pasco Cogen, Calpine, and Southern Power Company. The testimony in previous years describes each existing firm purchased power agreement. However, in summary, all three purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is 121 MW of intermediate capacity and continues through 2018. Both Calpine and Southern Power Company are peaking purchases with capacities of 117 MW and 160 MW, respectively. The Southern Power Company purchase continues through 2015, while the Calpine purchase continues through 2016. All of the aforementioned purchases provide supply reliability, help reduce fuel price volatility, and were previously approved by the Commission as being cost-effective for Tampa Electric customers.

In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during the company’s peak periods and spring and fall generation maintenance periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2014?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2014.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2015 and beyond?

A. In 2015, the Tampa Electric expects purchased power to meet approximately five percent of its energy needs. This energy includes contributions from the three previously mentioned firm purchases. Beyond 2015, Tampa Electric expects the company's remaining two firm purchases (*i.e.*, Pasco Cogen and Calpine) to keep contributing positively to customers' level of electric service in the applicable years. Tampa Electric will continue to evaluate the short-term purchased power market as part of its purchasing strategy for 2015 and beyond.

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

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

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2014?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 160 MW purchased from

Southern Power Company and 121 MW purchased from Pasco Cogen are reliable, cost-based call options for power. These purchases serve as both a physical hedge and reliable source of economic power. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company’s own generation for the year 2014 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 sellers’ fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company’s existing three firm purchased power agreements are from dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric’s wholesale energy sales for 2014 and 2015.

A. Tampa Electric entered into various non-separated wholesale sales in 2014, and the company anticipates making additional non-separated sales during the balance of 2014 and in 2015. 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 2014, Tampa Electric anticipates its gains from non-separated wholesale sales to be $3,069,762, which will exceed the three-year rolling average threshold of $681,121. Of the total gains from non-separated wholesale sales, customers will receive $2,592,034, which represents 100 percent of the $681,121 threshold value, plus $1,910,913 or 80 percent of the margin above the threshold. Tampa Electric will receive $477,728, which is the remaining 20 percent of the gains above the threshold.

The company did not project exceeding the threshold in 2014. However, the cold 2014 winter resulted in a higher than expected level of sales in January and February. In 2015, the company's projected gains from non-separated wholesale sales are $581,933, of which 100 percent is expected to be passed on to customers since they are less than the projected three-year rolling average threshold for that year of $1,403,580.

Q. Please summarize your testimony.

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

Q. Does this conclude your testimony?

A. Yes.