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September 1, 2015

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. 150001-EI

Dear Ms. Stauffer:

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

1. Petition of Tampa Electric Company.
2. Prepared Direct Testimony and Exhibit (PAR-3) of Penelope A. Rusk.
3. Prepared Direct Testimony and Exhibit (BSB-2) of Brian S. Buckley.
4. Prepared Direct Testimony of J. Brent Caldwell.
5. Prepared Direct Testimony of Benjamin F. Smith II.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition and Testimonies, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 1st day of September 2015, 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. 150001-EI FILED: September 1, 2015

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, 2015 through December 31, 2015 will be an over-recovery of $27,590,550 (See Exhibit No. ____ (PAR-3), Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2016 through December 31, 2016, 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, 2016 through December 31, 2016, produce a fuel and purchased power factor for the new period of 3.676 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 2016 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 $1,532,270 as provided in the direct testimony of Tampa Electric witness Penelope A. Rusk.

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2015 through December 31, 2015 will be an over-recovery of $2,203,769, 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, 2016 through December 31, 2016, when adjusted for the true-up over-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of 0.151 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.53 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 $1,258,600 for performance during the period January 1, 2014 through December 31, 2014.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2016 through December 31, 2016 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Brian S. Buckley filed herewith.

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

DATED this 1st day of September 2015.

Respectfully submitted,

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

<ins>CERTIFICATE OF SERVICE</ins>

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 1st day of September 2015, to the following:

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ATTORNEY

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2016 THROUGH DECEMBER 2016

TESTIMONY AND EXHIBIT

OF

PENELOPE A. RUSK

FILED: SEPTEMBER 1, 2015

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 18 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 2016 through December 2016. 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 2016.

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 2016 through December 2016 as well as Schedule H1 for January through December, 2013 through 2016. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company’s projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

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

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

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (PAR-3), Document No. 1, Tampa Electric requests recovery of $28,290,255 after jurisdictional separation and prior year true-up, for estimated expenses in 2016.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2016 through December 2016.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.178	
GS and TS Secondary	0.166	
GSD, SBF Standard		
Secondary		0.53

Primary		0.52
Transmission		0.52
IS, IST, SBI		
Primary		0.43
Transmission		0.42
GSD Optional		
Secondary	0.123	
Primary	0.122	
LS1 Secondary	0.021	

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 0.151 cents per kWh compare to the factor for January 2015 through December 2015?

A. The proposed capacity cost recovery factor is 0.021 cents per kWh (or $0.21 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.172 cents per kWh for the January 2015 through December 2015 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 2016?

A. The appropriate amount for the 2016 period is 3.676 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 2016 through December 2016.

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 $1,258,600, 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 2015 through December 2015 period. The net true-up amount for this period is an over-recovery of $27,590,550.

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 2016 through

December 2016. 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 2016 through December 2016.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	3.676
Tier I (Up to 1,000 kWh)	3.361
Tier II (Over 1,000 kWh)	4.361
Distribution Primary	3.639
Transmission	3.602
Lighting Service	3.627
Distribution Secondary	3.937 (on-peak)
	3.564 (off-peak)
Distribution Primary	3.898 (on-peak)
	3.528 (off-peak)
Transmission	3.858 (on-peak)
	3.493 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.676 cents per kWh compare to the levelized fuel adjustment factor for the January 2015 through December 2015 period?

A. The proposed fuel charge factor is 0.198 cents per kWh (or $1.98 per 1,000 kWh) lower than the average fuel charge factor of 3.874 cents per kWh for the January 2015 through December 2015 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2016 fuel and purchased power and capacity cost recovery projections?

A. Yes. There is one significant event reflected in the 2016 projections: the purchase of additional natural gas for use at Big Bend Station. This is described in the testimony of witness J. Brent Caldwell.

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 2016 through December 2016?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2016 through December 2016 are $3,812,311. This is shown in Exhibit No. _____ (PAR-3), Document No. 4.

Q. Does Tampa Electric's estimated Polk Unit 1 ignition oil conversion project fuel savings exceed estimated costs for the period January 2016 through December 2016?

A. Yes, as reflected in Exhibit No. _____ (PAR-3), Document No. 4, fuel savings exceed costs for the period January 2016 through December 2016.

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

A. Yes. The January 2016 through December 2016 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2016 through December 2016?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2016 through December 2016 are $4,894,041. This is shown in Document No. 4 of my exhibit.

Q. Does Tampa Electric's estimated Big Bend ignition oil conversion project fuel savings exceed estimated costs for the period of January 2016 through December 2016?

A. Yes, fuel savings exceed costs for the period January 2016 through December 2016. 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 2016 through December 2016 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

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

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

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric’s projected wholesale incentive benchmark for 2016?

A. The company’s projected 2016 benchmark is $1,532,270, which is the three-year average of $894,045, $3,298,966 and $403,800 in gains on the company’s non-separated wholesale sales, excluding emergency sales, for 2013, 2014 and 2015 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2016 from non-separated wholesale sales to exceed its 2016 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2016. 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 $2.25 beginning January 2016, when compared to the January 2015 through October 2015 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 2016.

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 2016 - DECEMBER 2016

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2016 THROUGH DECEMBER 2016
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	53.76%	8,914,762	1,893	1.07778	1.05339	9,390,726	2,040	47.58%	56.88%	56.16%
GS, TS	58.00%	1,014,240	200	1.07778	1.05338	1,068,375	215	5.41%	5.99%	5.95%
GSD Optional	3.90%	389,753	56	1.07348	1.04958	409,078	60	2.07%	1.67%	1.70%
GSD, SBF	75.17%	7,517,283	1,085	1.07348	1.04958	7,890,009	1,165	39.97%	32.48%	33.06%
IS,SBI	83.49%	739,587	101	1.02887	1.01847	753,250	104	3.82%	2.90%	2.97%
LS1	864.97%	214,899	3	1.07778	1.05339	226,373	3	1.15%	0.08%	0.16%
TOTAL		18,790,524	3,338			19,737,811	3,587	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2015 projected calendar data.
(2) Projected MWH sales for the period January 2016 thru December 2016.
(3) Based on 12 months average CP at meter.
(4) Based on 2015 projected demand losses.
(5) Based on 2015 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 2016 THROUGH DECEMBER 2016
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,216,570	1,216,570	1,216,570	1,216,570	3,616,570	3,616,570	3,616,570	3,616,570	3,616,570	3,616,570	3,616,570	1,216,570	31,398,840
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,098)	(77,092)	(925,170)
4	TOTAL CAPACITY DOLLARS	$1,139,472	$1,139,472	$1,139,472	$1,139,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$1,139,478	$30,473,670
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	$1,139,472	$1,139,472	$1,139,472	$1,139,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$3,539,472	$1,139,478	$30,473,670
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2015 - DEC. 2015													(2,203,769)
8	TOTAL													$28,269,901
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$28,290,255

DOCKET NO. 150001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 1, PAGE 2 OF 4

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2016 THROUGH DECEMBER 2016
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	47.58%	56.88%	1,035,113	14,854,060	15,889,173	8,914,762	8,914,762				0.00178
GS, CS	5.41%	5.99%	117,696	1,564,273	1,681,969	1,014,240	1,014,240				0.00166
GSD, SBF											
Secondary						6,169,757	6,169,757			0.53	
Primary						1,337,292	1,323,919			0.52	
Transmission						10,234	10,029			0.52	
GSD, SBF - Standard	39.97%	32.48%	869,556	8,482,066	9,351,622	7,517,283	7,503,705	58.63%	17,530,792		
GSD - Optional	2.07%	1.67%	45,033	436,116	481,149						
Secondary						375,012	375,012				0.00123
Primary						14,741	14,594				0.00122
IS, SBI											
Primary						176,340	174,577			0.43	
Transmission						563,247	551,982			0.42	
Total IS, SBI	3.82%	2.90%	83,105	757,327	840,432	739,587	726,559	50.89%	1,955,828		
LS1	1.15%	0.08%	25,018	20,892	45,910	214,899	214,899				0.00021
TOTAL	100.00%	100.00%	2,175,521	26,114,734	28,290,255	18,790,524	18,763,771				0.00151

(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 2016 through December 2016.
(7) Projected kWh sales at secondary for the period January 2016 through December 2016.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2016 through December 2016.
(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 2016 THROUGH DECEMBER 2016

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
CALPINE	11/1/2011	12/31/2016	LT
PASCO COGEN	1/1/2009	12/31/2018	LT
SEMINOLE ELECTRIC **	6/1/1992	--------	

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
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
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 ($)
CALPINE - D	[redacted]												
PASCO COGEN - D													
VARIOUS - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,139,472	1,139,472	1,139,472	1,139,472	3,539,472	3,539,472	3,539,472	3,539,472	3,539,472	3,539,472	3,539,472	1,139,478	30,473,670
TOTAL CAPACITY	**$1,139,472**	**$1,139,472**	**$1,139,472**	**$1,139,472**	**$3,539,472**	**$3,539,472**	**$3,539,472**	**$3,539,472**	**$3,539,472**	**$3,539,472**	**$3,539,472**	**$1,139,478**	**$30,473,670**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2016 - DECEMBER 2016

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 2016 THROUGH DECEMBER 2016

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	672,037,541	18,868,690	3.56165
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	4,894,041	18,868,690 [1]	0.02594
4b.	Polk 1 Conversion Depreciation & ROI	3,812,311	18,868,690 [1]	0.02020
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**680,743,893**	**18,868,690**	**3.60780**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	19,799,520	539,580	3.66943
7.	Energy Cost of Economy Purchases (E9)	13,554,320	331,150	4.09311
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,333,480	90,110	2.58959
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**35,687,320**	**960,840**	**3.71418**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,829,530	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	307,140	10,350	2.96754
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	459,409	14,940	3.07502
14.	Gains on Sales	59,601	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**826,150**	**25,290**	**3.26671**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		572	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**715,605,063**	**19,803,668**	**3.61350**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,214,136 [1]	33,600	0.00646
22.	T & D Losses	35,395,817 [1]	979,544	0.18837
23.	System MWH Sales	715,605,063	18,790,524	3.80833
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	715,605,063	18,790,524	3.80833
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	715,605,063	18,790,524	3.80833
28.	True-up [2]	(27,590,550)	18,790,524	(0.14683)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	688,014,513	18,790,524	3.66150
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	688,509,883	18,790,524	3.66414
32.	GPIF Adjusted for Taxes [2]	1,258,600	18,790,524	0.00670
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	689,768,483	18,790,524	3.67084
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.671**

(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 2016 THROUGH DECEMBER 2016

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2015 - December 2015 (6 months actual, 6 months estimated)	$30,509,575
2.	FINAL TRUE-UP (January 2014 - December 2014) (Per True-Up filed March 3, 2015)	(2,919,025)
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2016 through December 2016 (Schedule E1, line 28)	$27,590,550
4.	JURISDICTIONAL MWH SALES (Projected January 2016 through December 2016)	18,790,524
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.1468)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2016 through December 2016)	$1,258,600	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2015 through December 2015)	$27,590,550	
2.	TOTAL SALES (January 2016 through December 2016)	18,790,524	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0067**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.1468)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.15	$30.48
OFF PEAK	69.85	$27.59
	100.00	1.1047

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$715,605,063		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,790,524		
2a	Effective MWH Sales (Jurisd)		18,763,770		
3	Cost Per KWH Sold	(line 1 / line 2)	3.8083		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($27,590,550)		
7	TOTAL	(line 1 x line 4)+line 6	$688,014,513		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.6694		
10	GPIF Factor	(Sch E1-C line 3a)	0.0067		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.6761	3.9369	3.5636
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.676	3.937	3.564

13	Hours: ON PEAK	24.92%
14	OFF PEAK	75.08%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,688,670	16,688,670
Distribution Primary	1,528,373	1,513,089
Transmission	573,481	562,011
Total	18,790,524	18,763,770

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.676	3.937	3.564
Distribution Primary	3.639	3.898	3.528
Transmission	3.602	3.858	3.493
RS 1st Tier	3.361		
RS 2nd Tier	4.361		
Lighting	3.627		

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SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

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)		3.361	4.361
Distribution Secondary	3.676		
Distribution Primary	3.639		
Transmission	3.602		
Lighting Service [(1)]	3.627		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.937		
Distribution Secondary - Off-Peak	3.564		
Distribution Primary - On-Peak	3.898		
Distribution Primary - Off-Peak	3.528		
Transmission - On-Peak	3.858		
Transmission - Off-Peak	3.493		

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

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

	(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(g)	(h)	(i)	(j)	(k)	(l)	(m) TOTAL
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	PERIOD
1. Fuel Cost of System Net Generation	53,577,196	46,821,157	50,982,332	50,566,783	58,906,564	64,851,046	65,285,273	66,595,694	61,371,801	55,202,075	46,532,897	51,344,723	672,037,541
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	51,977	56,385	87,239	61,962	65,045	90,903	79,909	66,643	79,494	67,939	57,508	61,146	826,150
4. Fuel Cost of Purchased Power	81,460	950,010	466,530	299,900	2,169,900	2,600,290	2,765,050	2,267,870	2,289,820	3,604,230	1,795,010	509,450	19,799,520
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	209,980	188,330	264,560	204,910	206,820	234,200	169,920	147,190	195,030	142,960	151,940	217,640	2,333,480
7. Energy Cost of Economy Purchases	760,140	921,870	914,760	768,920	1,186,390	1,001,050	1,426,620	1,035,810	1,344,070	2,246,200	942,830	1,005,660	13,554,320
8. Big Bend Units 1-4 Igniters Conversion Project	420,383	418,103	415,820	413,540	411,259	408,976	406,696	404,415	402,133	399,852	397,572	395,292	4,894,041
9. Polk 1 Conversion Depreciation & ROI	328,799	326,781	324,761	322,740	320,722	318,703	316,682	314,664	312,643	310,625	308,605	306,586	3,812,311
10. TOTAL FUEL & NET POWER TRANSACTIONS	**55,325,981**	**49,569,866**	**53,281,524**	**52,514,831**	**63,136,610**	**69,323,362**	**70,290,332**	**70,699,000**	**65,836,003**	**61,838,003**	**50,071,346**	**53,718,205**	**715,605,063**
11. Jurisdictional MWH Sold	1,483,012	1,346,993	1,321,034	1,379,498	1,513,993	1,767,371	1,828,244	1,824,812	1,878,651	1,658,501	1,403,067	1,385,348	18,790,524
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)	55,325,981	49,569,866	53,281,524	52,514,831	63,136,610	69,323,362	70,290,332	70,699,000	65,836,003	61,838,003	50,071,346	53,718,205	715,605,063
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)	**55,325,981**	**49,569,866**	**53,281,524**	**52,514,831**	**63,136,610**	**69,323,362**	**70,290,332**	**70,699,000**	**65,836,003**	**61,838,003**	**50,071,346**	**53,718,205**	**715,605,063**
16. Cost Per kWh Sold (Cents/kWh)	3.7306	3.6800	4.0333	3.8068	4.1702	3.9224	3.8447	3.8743	3.5044	3.7285	3.5687	3.8776	3.8083
17. True-up (Cents/kWh) [2]	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)	(0.1468)
18. Total (Cents/kWh) (Line 16+17)	3.5838	3.5332	3.8865	3.6600	4.0234	3.7756	3.6979	3.7275	3.3576	3.5817	3.4219	3.7308	3.6615
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)	3.5864	3.5357	3.8893	3.6626	4.0263	3.7783	3.7006	3.7302	3.3600	3.5843	3.4244	3.7335	3.6641
21. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**3.5931**	**3.5424**	**3.8960**	**3.6693**	**4.0330**	**3.7850**	**3.7073**	**3.7369**	**3.3667**	**3.5910**	**3.4311**	**3.7402**	**3.6708**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.593**	**3.542**	**3.896**	**3.669**	**4.033**	**3.785**	**3.707**	**3.737**	**3.367**	**3.591**	**3.431**	**3.740**	**3.671**

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

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

SCHEDULE E3

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	68,460	64,565	76,965	61,824	59,234	76,551
3. COAL	35,402,875	26,186,115	28,634,342	23,988,972	29,577,713	36,717,103
4. NATURAL GAS	18,105,861	20,570,477	22,271,025	26,515,987	29,269,617	28,057,392
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**53,577,196**	**46,821,157**	**50,982,332**	**50,566,783**	**58,906,564**	**64,851,046**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	280	280	330	260	260	330
10. COAL	1,028,590	591,860	531,100	451,730	476,330	624,400
11. NATURAL GAS	442,210	686,920	869,650	1,017,690	1,196,710	1,180,690
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	280	290	350	340	360	310
14. TOTAL (MWH)	**1,471,360**	**1,279,350**	**1,401,430**	**1,470,020**	**1,673,660**	**1,805,730**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	540	510	610	490	470	610
17. COAL (TON)	462,110	265,750	243,810	203,510	211,970	277,620
18. NATURAL GAS (MCF)	3,428,340	5,566,420	7,110,050	8,083,670	9,787,710	9,770,990
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	3,070	2,950	3,470	2,860	2,760	3,560
23. COAL	10,723,870	6,188,060	5,596,660	4,782,970	5,020,110	6,558,280
24. NATURAL GAS	3,508,660	5,705,560	7,276,630	8,289,170	10,040,890	10,026,310
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**14,235,600**	**11,896,570**	**12,876,760**	**13,075,000**	**15,063,760**	**16,588,150**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.02	0.02
30. COAL	69.91	46.27	37.91	30.73	28.46	34.57
31. NATURAL GAS	30.05	53.69	62.05	69.23	71.50	65.39
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.02	0.02	0.02	0.02	0.02	0.02
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)	126.78	126.60	126.17	126.17	126.03	125.49
37. COAL ($/TON)	76.61	98.54	117.45	117.88	139.54	132.26
38. NATURAL GAS ($/MCF)	5.28	3.70	3.13	3.28	2.99	2.87
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.30	21.89	22.18	21.62	21.46	21.50
43. COAL	3.30	4.23	5.12	5.02	5.89	5.60
44. NATURAL GAS	5.16	3.61	3.06	3.20	2.92	2.80
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)	**3.76**	**3.94**	**3.96**	**3.87**	**3.91**	**3.91**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,964	10,536	10,515	11,000	10,615	10,788
50. COAL	10,426	10,455	10,538	10,588	10,539	10,503
51. NATURAL GAS	7,934	8,306	8,367	8,145	8,390	8,492
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,675**	**9,299**	**9,188**	**8,894**	**9,000**	**9,186**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	24.45	23.06	23.32	23.78	22.78	23.20
57. COAL	3.44	4.42	5.39	5.31	6.21	5.88
58. NATURAL GAS	4.09	2.99	2.56	2.61	2.45	2.38
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)	**3.64**	**3.66**	**3.64**	**3.44**	**3.52**	**3.59**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

SCHEDULE E3

		Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	59,021	58,932	76,172	58,737	61,116	72,108	793,685
3.	COAL	36,347,799	37,746,673	35,129,511	34,932,851	29,339,729	29,492,943	383,496,626
4.	NATURAL GAS	28,878,453	28,790,089	26,166,118	20,210,487	17,132,052	21,779,672	287,747,230
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**65,285,273**	**66,595,694**	**61,371,801**	**55,202,075**	**46,532,897**	**51,344,723**	**672,037,541**
	SYSTEM NET GENERATION (MWH)							
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	260	260	330	260	260	300	3,410
10.	COAL	786,110	808,980	992,870	1,055,590	882,270	902,930	9,132,760
11.	NATURAL GAS	1,074,220	1,098,680	762,070	463,220	406,250	530,520	9,728,830
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	310	310	270	310	290	270	3,690
14.	**TOTAL (MWH)**	**1,860,900**	**1,908,230**	**1,755,540**	**1,519,380**	**1,289,070**	**1,434,020**	**18,868,690**
	UNITS OF FUEL BURNED							
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	470	470	610	470	490	580	6,320
17.	COAL (TON)	349,040	361,330	445,140	473,530	394,590	406,200	4,094,600
18.	NATURAL GAS (MCF)	8,643,690	8,755,200	5,696,040	3,492,900	3,053,550	4,015,300	77,403,860
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)							
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	2,760	2,760	3,560	2,760	2,860	3,370	36,740
23.	COAL	8,212,620	8,452,360	10,363,400	11,006,090	9,202,910	9,430,530	95,537,860
24.	NATURAL GAS	8,867,640	8,984,620	5,837,220	3,572,610	3,104,700	4,105,150	79,319,160
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,083,020**	**17,439,740**	**16,204,180**	**14,581,460**	**12,310,470**	**13,539,050**	**174,893,760**
	GENERATION MIX (% MWH)							
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.02	0.02	0.02	0.02	0.02
30.	COAL	42.24	42.39	56.55	69.47	68.45	62.96	48.40
31.	NATURAL GAS	57.73	57.58	43.41	30.49	31.51	37.00	51.56
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.02	0.02	0.02	0.02	0.02	0.02	0.02
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
	FUEL COST PER UNIT							
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	125.58	125.39	124.87	124.97	124.73	124.32	125.58
37.	COAL ($/TON)	104.14	104.47	78.92	73.77	74.35	72.61	93.66
38.	NATURAL GAS ($/MCF)	3.34	3.29	4.59	5.79	5.61	5.42	3.72
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	21.38	21.35	21.40	21.28	21.37	21.40	21.60
43.	COAL	4.43	4.47	3.39	3.17	3.19	3.13	4.01
44.	NATURAL GAS	3.26	3.20	4.48	5.66	5.52	5.31	3.63
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)**	**3.82**	**3.82**	**3.79**	**3.79**	**3.78**	**3.79**	**3.84**
	BTU BURNED PER KWH (BTU/KWH)							
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,615	10,615	10,788	10,615	11,000	11,233	10,774
50.	COAL	10,447	10,448	10,438	10,426	10,431	10,444	10,461
51.	NATURAL GAS	8,255	8,178	7,660	7,713	7,642	7,738	8,153
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,180**	**9,139**	**9,230**	**9,597**	**9,550**	**9,441**	**9,269**
	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	22.70	22.67	23.08	22.59	23.51	24.04	23.28
57.	COAL	4.62	4.67	3.54	3.31	3.33	3.27	4.20
58.	NATURAL GAS	2.69	2.62	3.43	4.36	4.22	4.11	2.96
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)**	**3.51**	**3.49**	**3.50**	**3.63**	**3.61**	**3.58**	**3.56**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.4**	**280**	**26.9**	-	**26.9**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	32,460	-	-	-	11,176	NG CO-FIRE	352,900	1,027,997	362,780.0	2,087,968	6.43	5.92
3. B.B.#1 COAL	-	152,860	-	-	-	10,656	COAL	69,500	23,437,266	1,628,890.0	4,954,412	3.24	71.29
4. TOTAL BIG BEND #1	**395**	**185,320**	**63.1**	**76.4**	**78.3**	**10,747**		**-**	**-**	**1,991,670.0**	**7,042,380**	**3.80**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#2 COAL	-	230,620	-	-	-	10,434	COAL	102,730	23,423,245	2,406,270.0	7,323,258	3.18	71.29
7. TOTAL BIG BEND #2	**395**	**230,620**	**78.5**	**83.3**	**90.7**	**10,434**		**-**	**-**	**2,406,270.0**	**7,323,258**	**3.18**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	233,160	-	-	-	10,413	COAL	108,610	22,353,374	2,427,800.0	7,742,422	3.32	71.29
10. TOTAL BIG BEND #3	**400**	**233,160**	**78.3**	**82.6**	**88.2**	**10,413**		**-**	**-**	**2,427,800.0**	**7,742,422**	**3.32**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	275,100	-	-	-	10,316	COAL	128,450	22,094,122	2,837,990.0	9,183,242	3.34	71.49
13. TOTAL BIG BEND #4	**442**	**275,100**	**83.7**	**86.6**	**94.2**	**10,316**		**-**	**-**	**2,837,990.0**	**9,183,242**	**3.34**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	12,930	-	13,290.0	76,502	-	5.92
15. BIG BEND 1-4 TOTAL	**1,632**	**924,200**	**76.1**	**82.3**	**88.2**	**10,456**	**-**	**-**	**-**	**-**	**31,367,804**	**3.39**	**-**
16. B.B.C.T.#4 OIL	61	40	0.1	-	8.2	11,250	LGT OIL	80	5,625,000	450.0	10,711	26.78	133.89
17. B.B.C.T.#4 GAS	61	1,130	2.5	-	88.2	11,558	GAS	12,700	1,028,346	13,060.0	75,141	6.65	5.92
18. B.B.C.T.#4 TOTAL	**61**	**1,170**	**2.6**	**98.2**	**66.1**	**11,547**	**-**	**-**	**-**	**13,510.0**	**85,852**	**7.34**	**-**
19. BIG BEND STATION TOTAL	**1,693**	**925,370**	**73.5**	**82.9**	**88.2**	**10,458**	**-**	**-**	**-**	**9,677,240.0**	**31,453,656**	**3.40**	**-**
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,398	COAL	52,820	26,939,038	1,422,920.0	4,035,071	2.95	76.39
21. POLK #1 CT GAS [5]	195	0	0.0	-	0.0	0	GAS	2,330	0	0.0	0	0.00	0.00
22. POLK #1 TOTAL	**220**	**136,850**	**83.6**	**82.5**	**97.3**	**10,398**	**-**	**-**	**-**	**1,422,920.0**	**4,035,071**	**2.95**	**-**
23. POLK #2 CT GAS	183	3,690	2.7	-	91.7	11,721	GAS	42,080	1,027,804	43,250.0	248,970	6.75	5.92
24. POLK #2 CT OIL	187	120	0.1	-	12.8	10,917	LGT OIL	230	5,695,652	1,310.0	28,875	24.06	125.54
25. POLK #2 TOTAL	**183**	**3,810**	**2.8**	**91.6**	**76.8**	**11,696**	**-**	**-**	**-**	**44,560.0**	**277,845**	**7.29**	**-**
26. POLK #3 CT GAS	183	3,500	2.6	-	90.8	11,743	GAS	39,980	1,028,014	41,100.0	236,546	6.76	5.92
27. POLK #3 CT OIL	187	120	0.1	-	12.8	10,917	LGT OIL	230	5,695,652	1,310.0	28,874	24.06	125.54
28. POLK #3 TOTAL	**183**	**3,620**	**2.7**	**90.7**	**75.6**	**11,715**	**-**	**-**	**-**	**42,410.0**	**265,420**	**7.33**	**-**
29. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**952**	**144,280**	**20.4**	**54.2**	**96.0**	**10,465**	**-**	**-**	**-**	**1,509,890.0**	**4,578,336**	**3.17**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	792	201,150	34.1	64.1	61.2	7,319	GAS	1,432,020	1,028,002	1,472,120.0	8,472,690	4.21	5.92
34. BAYSIDE #2	1,047	198,180	25.4	93.0	26.0	7,831	GAS	1,509,720	1,027,999	1,551,990.0	8,932,409	4.51	5.92
35. BAYSIDE #3	61	570	1.3	98.6	84.9	11,509	GAS	6,370	1,029,827	6,560.0	37,689	6.61	5.92
36. BAYSIDE #4	61	110	0.2	98.6	90.2	11,273	GAS	1,210	1,024,793	1,240.0	7,159	6.51	5.92
37. BAYSIDE #5	61	680	1.5	98.6	85.8	11,838	GAS	7,830	1,028,097	8,050.0	46,327	6.81	5.92
38. BAYSIDE #6	61	740	1.6	98.6	86.7	11,500	GAS	8,270	1,029,021	8,510.0	48,930	6.61	5.92
39. BAYSIDE TOTAL	**2,083**	**401,430**	**25.9**	**82.7**	**36.7**	**7,594**	**GAS**	**2,965,420**	**1,028,006**	**3,048,470.0**	**17,545,204**	**4.37**	**5.92**
40. SYSTEM	**4,729**	**1,471,360**	**41.8**	**77.0**	**64.1**	**9,675**	**-**	**-**	**-**	**14,235,600.0**	**53,577,196**	**3.64**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] AC rating
[5] Units burned are ignition associated with Polk #1 Gasifier.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR (4)	**1.4**	**290**	**29.8**	-	**29.8**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	95,490	-	-	-	10,948	NG CO-FIRE	1,016,990	1,028,004	1,045,470.0	5,010,687	5.25	4.93
3. B.B.#1 COAL	-	83,540	-	-	-	10,447	COAL	37,170	23,479,957	872,750.0	2,672,694	3.20	71.90
4. TOTAL BIG BEND #1	**395**	**179,030**	**65.1**	**76.4**	**80.8**	**10,715**		**-**	**-**	**1,918,220.0**	**7,683,381**	**4.29**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	32,760	-	-	-	11,237	NG CO-FIRE	358,090	1,028,010	368,120.0	1,764,302	5.39	4.93
6. B.B.#2 COAL	-	155,190	-	-	-	10,730	COAL	71,050	23,436,594	1,665,170.0	5,108,816	3.29	71.90
7. TOTAL BIG BEND #2	**395**	**187,950**	**68.4**	**83.3**	**78.9**	**10,818**		**-**	**-**	**2,033,290.0**	**6,873,118**	**3.66**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	0	-	-	-	0	COAL	0	0	0.0	0	0.00	0.00
10. TOTAL BIG BEND #3	**400**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	264,880	-	-	-	10,300	COAL	123,470	22,095,651	2,728,150.0	8,960,127	3.38	72.57
13. TOTAL BIG BEND #4	**442**	**264,880**	**86.1**	**86.6**	**96.8**	**10,300**		**-**	**-**	**2,728,150.0**	**8,960,127**	**3.38**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	10,430	-	10,720.0	51,388	-	4.93
15. BIG BEND 1-4 TOTAL	**1,632**	**631,860**	**55.6**	**62.1**	**86.2**	**10,571**	**-**	**-**	**-**	**-**	**23,568,014**	**3.73**	**-**
16. B.B.C.T.#4 OIL	61	40	0.1	-	13.1	10,750	LGT OIL	70	6,142,857	430.0	9,437	23.59	134.81
17. B.B.C.T.#4 GAS	61	12,090	28.5	-	87.3	11,329	GAS	133,230	1,028,072	136,970.0	656,421	5.43	4.93
18. B.B.C.T.#4 TOTAL	**61**	**12,130**	**28.6**	**98.2**	**85.7**	**11,327**	**-**	**-**	**-**	**137,400.0**	**665,858**	**5.49**	**-**
19. BIG BEND STATION TOTAL	**1,693**	**643,990**	**54.7**	**63.4**	**86.1**	**10,586**	**-**	**-**	**-**	**6,817,060.0**	**24,233,872**	**3.76**	**-**
20. POLK #1 GASIFIER	220	88,250	57.6	-	97.4	10,447	COAL	34,060	27,069,583	921,990.0	2,618,101	2.97	76.87
21. POLK #1 CT GAS	195	5,400	4.0	-	89.3	8,431	GAS	50,140	908,057	45,530.0	218,265	4.04	4.35
22. POLK #1 TOTAL	**220**	**93,650**	**61.2**	**0.0**	**96.9**	**10,331**	**-**	**-**	**-**	**967,520.0**	**2,836,366**	**3.03**	**-**
23. POLK #2 CT GAS	183	9,520	7.5	-	94.6	11,686	GAS	108,210	1,028,094	111,250.0	533,148	5.60	4.93
24. POLK #2 CT OIL	187	120	0.1	-	16.0	10,500	LGT OIL	220	5,727,273	1,260.0	27,564	22.97	125.29
25. POLK #2 TOTAL	**183**	**9,640**	**7.6**	**91.6**	**89.2**	**11,671**	**-**	**-**	**-**	**112,510.0**	**560,712**	**5.82**	**-**
26. POLK #3 CT GAS	183	5,470	4.3	-	93.2	11,744	GAS	62,500	1,027,840	64,240.0	307,936	5.63	4.93
27. POLK #3 CT OIL	187	120	0.1	-	16.0	10,500	LGT OIL	220	5,727,273	1,260.0	27,564	22.97	125.29
28. POLK #3 TOTAL	**183**	**5,590**	**4.4**	**90.7**	**84.5**	**11,717**	**-**	**-**	**-**	**65,500.0**	**335,500**	**6.00**	**-**
29. POLK #4 CT GAS	**183**	**1,970**	**1.6**	**93.8**	**98.1**	**11,629**	**GAS**	**22,280**	**1,028,276**	**22,910.0**	**109,773**	**5.57**	**4.93**
30. POLK #5 CT GAS	**183**	**680**	**0.5**	**0.0**	**92.9**	**11,809**	**GAS**	**7,810**	**1,028,169**	**8,030.0**	**38,480**	**5.66**	**4.93**
31. POLK STATION TOTAL	**952**	**111,530**	**16.8**	**53.1**	**95.4**	**10,548**	**-**	**-**	**-**	**1,176,470.0**	**3,880,831**	**3.48**	**-**
32. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	792	317,020	57.5	90.3	81.4	7,223	GAS	2,227,320	1,028,002	2,289,690.0	10,973,956	3.46	4.93
34. BAYSIDE #2	1,047	182,240	25.0	0.0	61.7	7,331	GAS	1,299,570	1,027,994	1,335,950.0	6,402,954	3.51	4.93
35. BAYSIDE #3	61	5,120	12.1	98.6	86.5	11,418	GAS	56,870	1,027,959	58,460.0	280,197	5.47	4.93
36. BAYSIDE #4	61	2,470	5.8	98.6	82.6	11,672	GAS	28,040	1,028,174	28,830.0	138,152	5.59	4.93
37. BAYSIDE #5	61	9,420	22.2	98.6	87.2	11,384	GAS	104,320	1,027,991	107,240.0	513,982	5.46	4.93
38. BAYSIDE #6	61	7,270	17.1	98.6	87.0	11,399	GAS	80,620	1,027,909	82,870.0	397,213	5.46	4.93
39. BAYSIDE TOTAL	**2,083**	**523,540**	**36.1**	**45.9**	**73.4**	**7,455**	**GAS**	**3,796,740**	**1,027,998**	**3,903,040.0**	**18,706,454**	**3.57**	**4.93**
40. SYSTEM	**4,729**	**1,279,350**	**38.9**	**53.6**	**81.1**	**9,299**	**-**	**-**	**-**	**11,896,570.0**	**46,821,157**	**3.66**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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) AC rating

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.4**	**350**	**33.6**	-	**33.6**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	101,350	-	-	-	10,880	NG CO-FIRE	1,072,640	1,027,996	1,102,670.0	5,004,366	4.94	4.67
3. B.B.#1 COAL	-	93,940	-	-	-	10,445	COAL	41,800	23,474,880	981,250.0	3,019,445	3.21	72.24
4. TOTAL BIG BEND #1	**395**	**195,290**	**66.5**	**76.4**	**82.5**	**10,671**		**-**	**-**	**2,083,920.0**	**8,023,811**	**4.11**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	91,110	-	-	-	10,998	NG CO-FIRE	974,730	1,027,997	1,002,020.0	4,547,570	4.99	4.67
6. B.B.#2 COAL	-	114,100	-	-	-	10,634	COAL	51,710	23,463,933	1,213,320.0	3,735,301	3.27	72.24
7. TOTAL BIG BEND #2	**395**	**205,210**	**69.8**	**83.3**	**80.7**	**10,795**		**-**	**-**	**2,215,340.0**	**8,282,871**	**4.04**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	24,660	-	-	-	10,735	NG CO-FIRE	257,500	1,028,039	264,720.0	1,201,358	4.87	4.67
9. B.B.#3 COAL	-	147,720	-	-	-	10,644	COAL	70,350	22,351,102	1,572,400.0	5,081,769	3.44	72.24
10. TOTAL BIG BEND #3	**400**	**172,380**	**57.9**	**66.6**	**80.9**	**10,657**		**-**	**-**	**1,837,120.0**	**6,283,127**	**3.64**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	144,350	-	-	-	10,404	COAL	67,980	22,091,645	1,501,790.0	4,956,012	3.43	72.90
13. TOTAL BIG BEND #4	**442**	**144,350**	**43.9**	**47.5**	**90.0**	**10,404**		**-**	**-**	**1,501,790.0**	**4,956,012**	**3.43**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	26,290	-	27,030.0	122,655	-	4.67
15. BIG BEND 1-4 TOTAL	**1,632**	**717,230**	**59.1**	**67.8**	**83.0**	**10,650**	**-**	**-**	**-**	**-**	**27,668,476**	**3.86**	**-**
16. B.B.C.T.#4 OIL	61	50	0.1	-	13.7	10,200	LGT OIL	90	5,666,667	510.0	11,967	23.93	132.97
17. B.B.C.T.#4 GAS	61	7,770	17.1	-	85.5	11,314	GAS	85,520	1,027,947	87,910.0	398,991	5.14	4.67
18. B.B.C.T.#4 TOTAL	**61**	**7,820**	**17.2**	**98.2**	**82.7**	**11,307**	**-**	**-**	**-**	**88,420.0**	**410,958**	**5.26**	**-**
19. BIG BEND STATION TOTAL	**1,693**	**725,050**	**57.6**	**68.9**	**82.9**	**10,657**	**-**	**-**	**-**	**7,726,590.0**	**28,079,434**	**3.87**	**-**
20. POLK #1 GASIFIER	220	30,990	18.9	-	97.1	10,581	COAL	11,970	27,393,484	327,900.0	965,866	3.12	80.69
21. POLK #1 CT GAS [5]	195	0	0.0	-	0.0	0	GAS	5,300	0	0.0	0	0.00	0.00
22. POLK #1 TOTAL	**220**	**30,990**	**18.9**	**71.8**	**97.1**	**10,581**	**-**	**-**	**-**	**327,900.0**	**965,866**	**3.12**	**-**
23. POLK #2 CT GAS	183	8,300	6.1	-	96.5	11,596	GAS	93,630	1,027,982	96,250.0	436,828	5.26	4.67
24. POLK #2 CT OIL	187	140	0.1	-	15.0	10,571	LGT OIL	260	5,692,308	1,480.0	32,499	23.21	125.00
25. POLK #2 TOTAL	**183**	**8,440**	**6.2**	**0.0**	**88.5**	**11,579**	**-**	**-**	**-**	**97,730.0**	**469,327**	**5.56**	**-**
26. POLK #3 CT GAS	183	3,080	2.3	-	93.3	11,815	GAS	35,400	1,027,966	36,390.0	165,157	5.36	4.67
27. POLK #3 CT OIL	187	140	0.1	-	15.0	10,571	LGT OIL	260	5,692,308	1,480.0	32,499	23.21	125.00
28. POLK #3 TOTAL	**183**	**3,220**	**2.4**	**49.8**	**76.0**	**11,761**	**-**	**-**	**-**	**37,870.0**	**197,656**	**6.14**	**-**
29. POLK #4 CT GAS	**183**	**530**	**0.4**	**93.8**	**96.8**	**11,774**	**GAS**	**6,080**	**1,026,316**	**6,240.0**	**28,366**	**5.35**	**4.67**
30. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**952**	**43,180**	**6.1**	**44.2**	**93.4**	**10,879**	**-**	**-**	**-**	**469,740.0**	**1,661,215**	**3.85**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	792	406,320	69.0	90.3	75.9	7,237	GAS	2,860,360	1,028,000	2,940,450.0	13,344,914	3.28	4.67
34. BAYSIDE #2	1,047	211,870	27.2	90.0	47.8	7,423	GAS	1,529,870	1,027,989	1,572,690.0	7,137,558	3.37	4.67
35. BAYSIDE #3	61	3,270	7.2	82.7	83.8	11,364	GAS	36,140	1,028,224	37,160.0	168,610	5.16	4.67
36. BAYSIDE #4	61	1,280	2.8	70.0	77.7	11,719	GAS	14,600	1,027,397	15,000.0	68,116	5.32	4.67
37. BAYSIDE #5	61	5,530	12.2	70.0	84.7	11,374	GAS	61,180	1,028,114	62,900.0	285,433	5.16	4.67
38. BAYSIDE #6	61	4,580	10.1	70.0	83.4	11,404	GAS	50,810	1,027,947	52,230.0	237,052	5.18	4.67
39. BAYSIDE TOTAL	**2,083**	**632,850**	**40.8**	**88.1**	**63.5**	**7,396**	**GAS**	**4,552,960**	**1,027,997**	**4,680,430.0**	**21,241,683**	**3.36**	**4.67**
40. SYSTEM	**4,729**	**1,401,430**	**39.8**	**72.4**	**73.1**	**9,188**	**-**	**-**	**-**	**12,876,760.0**	**50,982,332**	**3.64**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] AC rating
[5] Units burned are ignition associated with Polk #1 Gasifier.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**340**	**29.5**	-	**29.5**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	52,940	-	-	-	11,133	NG CO-FIRE	573,310	1,028,013	589,370.0	2,554,410	4.83	4.46
3. B.B.#1 COAL	-	42,150	-	-	-	10,539	COAL	18,920	23,478,858	444,220.0	1,311,777	3.11	69.33
4. TOTAL BIG BEND #1	**385**	**95,090**	**34.3**	**40.7**	**79.7**	**10,870**		**-**	**-**	**1,033,590.0**	**3,866,187**	**4.07**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	7,170	-	-	-	11,633	NG CO-FIRE	81,150	1,027,850	83,410.0	361,568	5.04	4.46
6. B.B.#2 COAL	-	3,130	-	-	-	10,780	COAL	1,430	23,594,406	33,740.0	99,143	3.17	69.33
7. TOTAL BIG BEND #2	**385**	**10,300**	**3.7**	**0.0**	**63.7**	**11,374**		**-**	**-**	**117,150.0**	**460,711**	**4.47**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	101,910	-	-	-	10,819	NG CO-FIRE	1,072,500	1,028,000	1,102,530.0	4,778,574	4.69	4.46
9. B.B.#3 COAL	-	99,200	-	-	-	10,578	COAL	46,960	22,344,761	1,049,310.0	3,255,869	3.28	69.33
10. TOTAL BIG BEND #3	**395**	**201,110**	**70.7**	**82.6**	**79.7**	**10,700**		**-**	**-**	**2,151,840.0**	**8,034,443**	**4.00**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	34,940	-	-	-	11,333	NG CO-FIRE	385,210	1,027,985	395,990.0	1,716,321	4.91	4.46
12. B.B.#4 COAL	-	174,870	-	-	-	10,747	COAL	85,110	22,080,954	1,879,310.0	6,015,889	3.44	70.68
13. TOTAL BIG BEND #4	**437**	**209,810**	**66.7**	**86.6**	**75.0**	**10,845**		**-**	**-**	**2,275,300.0**	**7,732,210**	**3.69**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,940	-	18,440.0	79,933	-	4.46
15. BIG BEND 1-4 TOTAL	**1,602**	**516,310**	**44.8**	**53.8**	**77.3**	**10,803**	**-**	**-**	**-**	**-**	**20,173,484**	**3.91**	**-**
16. B.B.C.T.#4 OIL	56	40	0.1	-	14.3	10,500	LGT OIL	70	6,000,000	420.0	9,427	23.57	134.67
17. B.B.C.T.#4 GAS	56	2,650	6.6	-	94.6	11,592	GAS	29,880	1,028,112	30,720.0	133,132	5.02	4.46
18. B.B.C.T.#4 TOTAL	**56**	**2,690**	**6.7**	**78.6**	**87.3**	**11,576**	**-**	**-**	**-**	**31,140.0**	**142,559**	**5.30**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**519,000**	**43.5**	**54.6**	**77.4**	**10,807**	**-**	**-**	**-**	**5,609,020.0**	**20,316,043**	**3.91**	**-**
20. POLK #1 GASIFIER	220	132,380	83.6	-	97.4	10,397	COAL	51,090	26,940,497	1,376,390.0	3,815,488	2.88	74.68
21. POLK #1 CT GAS	195	3,500	2.5	-	85.5	8,843	GAS	32,430	954,363	30,950.0	134,112	3.83	4.14
22. POLK #1 TOTAL	**220**	**135,880**	**85.8**	**82.5**	**97.0**	**10,357**	**-**	**-**	**-**	**1,407,340.0**	**3,949,600**	**2.91**	**-**
23. POLK #2 CT GAS	151	2,110	1.9	-	99.8	12,185	GAS	25,020	1,027,578	25,710.0	111,478	5.28	4.46
24. POLK #2 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,198	23.82	124.75
25. POLK #2 TOTAL	**151**	**2,220**	**2.0**	**79.4**	**80.7**	**12,131**	**-**	**-**	**-**	**26,930.0**	**137,676**	**6.20**	**-**
26. POLK #3 CT GAS	151	1,960	1.8	-	99.5	12,255	GAS	23,370	1,027,813	24,020.0	104,126	5.31	4.46
27. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,199	23.82	124.76
28. POLK #3 TOTAL	**151**	**2,070**	**1.9**	**90.7**	**79.5**	**12,193**	**-**	**-**	**-**	**25,240.0**	**130,325**	**6.30**	**-**
29. POLK #4 CT GAS	**151**	**1,060**	**1.0**	**50.0**	**100.6**	**12,142**	**GAS**	**12,510**	**1,028,777**	**12,870.0**	**55,739**	**5.26**	**4.46**
30. POLK #5 CT GAS	**151**	**300**	**0.3**	**92.2**	**99.3**	**12,100**	**GAS**	**3,530**	**1,028,329**	**3,630.0**	**15,728**	**5.24**	**4.46**
31. POLK STATION TOTAL	**824**	**141,530**	**23.9**	**79.3**	**96.4**	**10,429**	**-**	**-**	**-**	**1,476,010.0**	**4,289,068**	**3.03**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	386,460	76.6	90.3	81.4	7,330	GAS	2,755,680	1,028,000	2,832,840.0	12,278,063	3.18	4.46
34. BAYSIDE #2	929	413,700	61.8	93.0	63.2	7,376	GAS	2,968,370	1,028,002	3,051,490.0	13,225,712	3.20	4.46
35. BAYSIDE #3	56	2,080	5.2	98.6	88.4	11,736	GAS	23,740	1,028,222	24,410.0	105,775	5.09	4.46
36. BAYSIDE #4	56	1,390	3.4	98.6	85.6	11,964	GAS	16,190	1,027,177	16,630.0	72,135	5.19	4.46
37. BAYSIDE #5	56	3,070	7.6	98.6	87.0	11,717	GAS	34,990	1,028,008	35,970.0	155,900	5.08	4.46
38. BAYSIDE #6	56	2,450	6.1	98.6	89.3	11,686	GAS	27,850	1,028,007	28,630.0	124,087	5.06	4.46
39. BAYSIDE TOTAL	**1,854**	**809,150**	**60.6**	**92.7**	**71.0**	**7,403**	**GAS**	**5,826,820**	**1,028,000**	**5,989,970.0**	**25,961,672**	**3.21**	**4.46**
40. SYSTEM	**4,338**	**1,470,020**	**47.1**	**75.5**	**75.1**	**8,894**	**-**	**-**	**-**	**13,075,000.0**	**50,566,783**	**3.44**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] AC rating

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR (4)	**1.6**	**360**	**30.2**	-	**30.2**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	86,390	-	-	-	11,011	NG CO-FIRE	925,350	1,028,000	951,260.0	4,108,969	4.76	4.44
3. B.B.#1 COAL	-	109,130	-	-	-	10,491	COAL	48,790	23,466,079	1,144,910.0	3,504,548	3.21	71.83
4. TOTAL BIG BEND #1	**385**	**195,520**	**68.3**	**76.4**	**84.8**	**10,721**		-	-	**2,096,170.0**	**7,613,517**	**3.89**	-
5. B.B.#2 NAT GAS CO-FIRE	-	10,320	-	-	-	11,336	NG CO-FIRE	113,810	1,027,941	116,990.0	505,367	4.90	4.44
6. B.B.#2 COAL	-	7,150	-	-	-	10,694	COAL	3,260	23,453,988	76,460.0	234,165	3.28	71.83
7. TOTAL BIG BEND #2	**385**	**17,470**	**6.1**	**13.4**	**72.0**	**11,073**		-	-	**193,450.0**	**739,532**	**4.23**	-
8. B.B.#3 NAT GAS CO-FIRE	-	113,930	-	-	-	10,788	NG CO-FIRE	1,195,560	1,027,995	1,229,030.0	5,308,822	4.66	4.44
9. B.B.#3 COAL	-	100,010	-	-	-	10,522	COAL	47,090	22,346,146	1,052,280.0	3,382,434	3.38	71.83
10. TOTAL BIG BEND #3	**395**	**213,940**	**72.8**	**82.6**	**81.9**	**10,663**		-	-	**2,281,310.0**	**8,691,256**	**4.06**	-
11. B.B.#4 NAT GAS CO-FIRE	-	86,470	-	-	-	11,189	NG CO-FIRE	941,130	1,027,998	967,480.0	4,179,039	4.83	4.44
12. B.B.#4 COAL	-	123,190	-	-	-	10,744	COAL	60,010	22,055,324	1,323,540.0	4,355,734	3.54	72.58
13. TOTAL BIG BEND #4	**437**	**209,660**	**64.5**	**86.6**	**72.6**	**10,927**		-	-	**2,291,020.0**	**8,534,773**	**4.07**	-
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,940	-	18,440.0	79,662	-	4.44
15. BIG BEND 1-4 TOTAL	**1,602**	**636,590**	**53.4**	**65.6**	**79.1**	**10,779**	-	-	-	-	**25,658,741**	**4.03**	-
16. B.B.C.T.#4 OIL	56	40	0.1	-	17.9	10,000	LGT OIL	70	5,714,286	400.0	9,423	23.56	134.61
17. B.B.C.T.#4 GAS	56	7,000	16.8	-	100.0	11,377	GAS	77,480	1,027,878	79,640.0	344,046	4.91	4.44
18. B.B.C.T.#4 TOTAL	**56**	**7,040**	**16.9**	**98.2**	**97.5**	**11,369**	-	-	-	**80,040.0**	**353,469**	**5.02**	-
19. BIG BEND STATION TOTAL	**1,658**	**643,630**	**52.2**	**66.7**	**79.3**	**10,786**	-	-	-	**6,941,990.0**	**26,012,210**	**4.04**	-
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,398	COAL	52,820	26,939,038	1,422,920.0	3,918,972	2.86	74.19
21. POLK #1 CT GAS	195	3,390	2.3	-	96.6	8,437	GAS	30,150	948,590	28,600.0	123,533	3.64	4.10
22. POLK #1 TOTAL	**220**	**140,240**	**85.7**	**82.5**	**97.3**	**10,350**	-	-	-	**1,451,520.0**	**4,042,505**	**2.88**	-
23. POLK #2 CT GAS	151	9,210	8.2	-	100.0	12,064	GAS	108,080	1,028,035	111,110.0	479,924	5.21	4.44
24. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,905	22.64	124.53
25. POLK #2 TOTAL	**151**	**9,320**	**8.3**	**70.9**	**94.6**	**12,048**	-	-	-	**112,290.0**	**504,829**	**5.42**	-
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,906	22.64	124.53
28. POLK #3 TOTAL	**151**	**110**	**0.1**	**0.0**	**17.3**	**10,727**	-	-	-	**1,180.0**	**24,906**	**22.64**	-
29. POLK #4 CT GAS	**151**	**6,190**	**5.5**	**93.8**	**100.2**	**12,074**	**GAS**	**72,700**	**1,028,061**	**74,740.0**	**322,821**	**5.22**	**4.44**
30. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**824**	**155,860**	**25.4**	**52.1**	**97.0**	**10,521**	-	-	-	**1,639,730.0**	**4,895,061**	**3.14**	-
32. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	400,640	76.8	90.3	83.3	7,329	GAS	2,856,140	1,027,999	2,936,110.0	12,682,543	3.17	4.44
34. BAYSIDE #2	929	457,290	66.2	93.0	67.5	7,355	GAS	3,271,970	1,027,998	3,363,580.0	14,529,014	3.18	4.44
35. BAYSIDE #3	56	3,690	8.9	98.6	94.1	11,461	GAS	41,130	1,028,203	42,290.0	182,636	4.95	4.44
36. BAYSIDE #4	56	2,200	5.3	98.6	95.8	11,614	GAS	24,870	1,027,342	25,550.0	110,434	5.02	4.44
37. BAYSIDE #5	56	5,610	13.5	98.6	93.6	11,474	GAS	62,620	1,027,946	64,370.0	278,061	4.96	4.44
38. BAYSIDE #6	56	4,380	10.5	98.6	94.2	11,447	GAS	48,780	1,027,880	50,140.0	216,605	4.95	4.44
39. BAYSIDE TOTAL	**1,854**	**873,810**	**63.3**	**92.7**	**74.4**	**7,418**	**GAS**	**6,305,510**	**1,027,996**	**6,482,040.0**	**27,999,293**	**3.20**	**4.44**
40. SYSTEM	**4,338**	**1,673,660**	**51.9**	**75.0**	**77.9**	**9,000**	-	-	-	**15,063,760.0**	**58,906,564**	**3.52**	-

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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) AC rating

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**310**	**26.9**	-	**26.9**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	9,410	-	-	-	10,777	NG CO-FIRE	98,650	1,027,978	101,410.0	445,781	4.74	4.52
3. B.B.#1 COAL	-	186,890	-	-	-	10,561	COAL	84,250	23,427,418	1,973,760.0	6,238,934	3.34	74.05
4. TOTAL BIG BEND #1	**385**	**196,300**	**70.8**	**76.4**	**87.9**	**10,571**		**-**	**-**	**2,075,170.0**	**6,684,715**	**3.41**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	108,920	-	-	-	11,027	NG CO-FIRE	1,168,300	1,027,998	1,201,010.0	5,279,328	4.85	4.52
6. B.B.#2 COAL	-	90,890	-	-	-	10,547	COAL	40,820	23,483,097	958,580.0	3,022,828	3.33	74.05
7. TOTAL BIG BEND #2	**385**	**199,810**	**72.1**	**83.3**	**83.2**	**10,808**		**-**	**-**	**2,159,590.0**	**8,302,156**	**4.16**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	108,650	-	-	-	10,837	NG CO-FIRE	1,145,340	1,028,000	1,177,410.0	5,175,576	4.76	4.52
9. B.B.#3 COAL	-	90,740	-	-	-	10,551	COAL	42,850	22,343,291	957,410.0	3,173,151	3.50	74.05
10. TOTAL BIG BEND #3	**395**	**199,390**	**70.1**	**82.6**	**79.0**	**10,707**		**-**	**-**	**2,134,820.0**	**8,348,727**	**4.19**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	105,900	-	-	-	10,988	NG CO-FIRE	1,131,900	1,027,997	1,163,590.0	5,114,843	4.83	4.52
12. B.B.#4 COAL	-	123,500	-	-	-	10,463	COAL	58,610	22,046,408	1,292,140.0	4,424,174	3.58	75.48
13. TOTAL BIG BEND #4	**437**	**229,400**	**72.9**	**86.6**	**82.0**	**10,705**		**-**	**-**	**2,455,730.0**	**9,539,017**	**4.16**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	15,450	-	15,870.0	69,816	-	4.52
15. BIG BEND 1-4 TOTAL	**1,602**	**824,900**	**71.5**	**82.4**	**82.9**	**10,699**	**-**	**-**	**-**	**-**	**32,944,430**	**3.99**	**-**
16. B.B.C.T.#4 OIL	56	50	0.1	-	11.2	10,400	LGT OIL	90	5,777,778	520.0	11,948	23.90	132.76
17. B.B.C.T.#4 GAS	56	6,610	16.4	-	100.0	11,377	GAS	73,140	1,028,165	75,200.0	330,506	5.00	4.52
18. B.B.C.T.#4 TOTAL	**56**	**6,660**	**16.5**	**98.2**	**94.4**	**11,369**	**-**	**-**	**-**	**75,720.0**	**342,454**	**5.14**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**831,560**	**69.7**	**82.9**	**82.9**	**10,704**	**-**	**-**	**-**	**8,901,030.0**	**33,286,884**	**4.00**	**-**
20. POLK #1 GASIFIER	220	132,380	83.6	-	97.4	10,397	COAL	51,090	26,940,497	1,376,390.0	3,772,673	2.85	73.84
21. POLK #1 CT GAS	195	6,660	4.7	-	92.3	8,395	GAS	56,710	985,893	55,910.0	245,733	3.69	4.33
22. POLK #1 TOTAL	**220**	**139,040**	**87.8**	**82.5**	**97.1**	**10,301**	**-**	**-**	**-**	**1,432,300.0**	**4,018,406**	**2.89**	**-**
23. POLK #2 CT GAS	151	3,620	3.3	-	99.9	12,102	GAS	42,620	1,027,921	43,810.0	192,591	5.32	4.52
24. POLK #2 CT OIL	159	140	0.1	-	17.6	10,857	LGT OIL	260	5,846,154	1,520.0	32,301	23.07	124.23
25. POLK #2 TOTAL	**151**	**3,760**	**3.5**	**0.0**	**85.1**	**12,056**	**-**	**-**	**-**	**45,330.0**	**224,892**	**5.98**	**-**
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	140	0.1	-	17.6	10,857	LGT OIL	260	5,846,154	1,520.0	32,302	23.07	124.24
28. POLK #3 TOTAL	**151**	**140**	**0.1**	**0.0**	**17.6**	**10,857**	**-**	**-**	**-**	**1,520.0**	**32,302**	**23.07**	**-**
29. POLK #4 CT GAS	**151**	**4,980**	**4.6**	**71.9**	**100.2**	**12,100**	**GAS**	**58,620**	**1,027,977**	**60,260.0**	**264,893**	**5.32**	**4.52**
30. POLK #5 CT GAS	**151**	**2,260**	**2.1**	**6.1**	**99.8**	**12,093**	**GAS**	**26,580**	**1,028,217**	**27,330.0**	**120,110**	**5.31**	**4.52**
31. POLK STATION TOTAL	**824**	**150,180**	**25.3**	**36.3**	**96.5**	**10,432**	**-**	**-**	**-**	**1,566,740.0**	**4,660,603**	**3.10**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	379,030	75.1	90.3	81.7	7,338	GAS	2,705,510	1,028,002	2,781,270.0	12,225,690	3.23	4.52
34. BAYSIDE #2	929	429,920	64.3	93.0	65.6	7,371	GAS	3,082,770	1,027,998	3,169,080.0	13,930,458	3.24	4.52
35. BAYSIDE #3	56	3,140	7.8	98.6	91.9	11,592	GAS	35,400	1,028,249	36,400.0	159,966	5.09	4.52
36. BAYSIDE #4	56	2,330	5.8	98.6	92.5	11,618	GAS	26,330	1,028,105	27,070.0	118,980	5.11	4.52
37. BAYSIDE #5	56	4,990	12.4	98.6	92.8	11,517	GAS	55,910	1,027,902	57,470.0	252,647	5.06	4.52
38. BAYSIDE #6	56	4,270	10.6	98.6	93.0	11,496	GAS	47,760	1,027,848	49,090.0	215,818	5.05	4.52
39. BAYSIDE TOTAL	**1,854**	**823,680**	**61.7**	**92.7**	**72.6**	**7,431**	**GAS**	**5,953,680**	**1,027,999**	**6,120,380.0**	**26,903,559**	**3.27**	**4.52**
40. SYSTEM	**4,338**	**1,805,730**	**57.8**	**78.2**	**78.7**	**9,186**	**-**	**-**	**-**	**16,588,150.0**	**64,851,046**	**3.59**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] **AC rating**

DOCKET NO. 150001-EI
EXHIBIT NO. ____ (PAR-3)
DOCUMENT NO. 2, PAGE 15 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**310**	**26.0**	-	**26.0**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	215,810	-	-	-	10,398	COAL	95,800	23,424,008	2,244,020.0	7,076,986	3.28	73.87
4. TOTAL BIG BEND #1	**385**	**215,810**	**75.3**	**76.4**	**93.6**	**10,398**		**-**	**-**	**2,244,020.0**	**7,076,986**	**3.28**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	47,420	-	-	-	11,190	NG CO-FIRE	516,150	1,028,015	530,610.0	2,355,051	4.97	4.56
6. B.B.#2 COAL	-	160,960	-	-	-	10,577	COAL	72,640	23,436,399	1,702,420.0	5,366,099	3.33	73.87
7. TOTAL BIG BEND #2	**385**	**208,380**	**72.7**	**83.3**	**84.0**	**10,716**		**-**	**-**	**2,233,030.0**	**7,721,150**	**3.71**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	55,860	-	-	-	10,951	NG CO-FIRE	595,060	1,028,014	611,730.0	2,715,096	4.86	4.56
9. B.B.#3 COAL	-	167,020	-	-	-	10,396	COAL	77,690	22,348,822	1,736,280.0	5,739,152	3.44	73.87
10. TOTAL BIG BEND #3	**395**	**222,880**	**75.8**	**82.6**	**85.4**	**10,535**		**-**	**-**	**2,348,010.0**	**8,454,248**	**3.79**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	107,990	-	-	-	11,287	NG CO-FIRE	1,185,670	1,028,001	1,218,870.0	5,409,888	5.01	4.56
12. B.B.#4 COAL	-	105,470	-	-	-	10,473	COAL	50,090	22,051,907	1,104,580.0	3,751,855	3.56	74.90
13. TOTAL BIG BEND #4	**437**	**213,460**	**65.7**	**86.6**	**73.9**	**10,885**		**-**	**-**	**2,323,450.0**	**9,161,743**	**4.29**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	12,930	-	13,290.0	58,996	-	4.56
15. BIG BEND 1-4 TOTAL	**1,602**	**860,530**	**72.2**	**82.4**	**83.7**	**10,631**	**-**	**-**	**-**	**-**	**32,473,123**	**3.77**	**-**
16. B.B.C.T.#4 OIL	56	40	0.1	-	7.9	10,000	LGT OIL	70	5,714,286	400.0	9,413	23.53	134.47
17. B.B.C.T.#4 GAS	56	7,220	17.3	-	99.9	11,352	GAS	79,730	1,027,969	81,960.0	363,786	5.04	4.56
18. B.B.C.T.#4 TOTAL	**56**	**7,260**	**17.4**	**98.2**	**93.9**	**11,344**	**-**	**-**	**-**	**82,360.0**	**373,199**	**5.14**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**867,790**	**70.3**	**82.9**	**83.7**	**10,637**	**-**	**-**	**-**	**9,230,870.0**	**32,846,322**	**3.79**	**-**
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,415	COAL	52,820	26,984,476	1,425,320.0	3,874,676	2.83	73.36
21. POLK #1 CT GAS	195	3,390	2.3	-	86.9	8,690	GAS	33,330	883,888	29,460.0	130,768	3.86	3.92
22. POLK #1 TOTAL	**220**	**140,240**	**85.7**	**82.5**	**97.1**	**10,374**	**-**	**-**	**-**	**1,454,780.0**	**4,005,444**	**2.86**	**-**
23. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,804	22.55	124.02
25. POLK #2 TOTAL	**151**	**110**	**0.1**	**26.6**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**24,804**	**22.55**	**-**
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,804	22.55	124.02
28. POLK #3 TOTAL	**151**	**110**	**0.1**	**11.7**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**24,804**	**22.55**	**-**
29. POLK #4 CT GAS	**151**	**10,570**	**9.4**	**0.0**	**100.3**	**12,059**	**GAS**	**123,990**	**1,027,986**	**127,460.0**	**565,732**	**5.35**	**4.56**
30. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**824**	**151,030**	**24.6**	**29.0**	**96.6**	**10,492**	**-**	**-**	**-**	**1,584,600.0**	**4,620,784**	**3.06**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	387,780	74.4	90.3	80.3	7,343	GAS	2,770,080	1,028,003	2,847,650.0	12,639,117	3.26	4.56
34. BAYSIDE #2	929	436,760	63.2	93.0	64.5	7,379	GAS	3,135,270	1,027,998	3,223,050.0	14,305,379	3.28	4.56
35. BAYSIDE #3	56	3,370	8.1	98.6	95.5	11,407	GAS	37,390	1,028,082	38,440.0	170,600	5.06	4.56
36. BAYSIDE #4	56	3,570	8.6	98.6	96.6	11,375	GAS	39,500	1,028,101	40,610.0	180,228	5.05	4.56
37. BAYSIDE #5	56	5,640	13.5	98.6	94.1	11,468	GAS	62,920	1,027,972	64,680.0	287,087	5.09	4.56
38. BAYSIDE #6	56	4,650	11.2	98.6	95.4	11,424	GAS	51,670	1,028,063	53,120.0	235,756	5.07	4.56
39. BAYSIDE TOTAL	**1,854**	**841,770**	**61.0**	**92.7**	**71.4**	**7,446**	**GAS**	**6,096,830**	**1,028,001**	**6,267,550.0**	**27,818,167**	**3.30**	**4.56**
40. SYSTEM	**4,338**	**1,860,900**	**57.7**	**76.8**	**78.5**	**9,180**	**-**	**-**	**-**	**17,083,020.0**	**65,285,273**	**3.51**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] **AC rating**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**310**	**26.0**	-	**26.0**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	216,880	-	-	-	10,392	COAL	96,220	23,423,613	2,253,820.0	7,107,883	3.28	73.87
4. TOTAL BIG BEND #1	**385**	**216,880**	**75.7**	**76.4**	**94.0**	**10,392**		-	-	**2,253,820.0**	**7,107,883**	**3.28**	-
5. B.B.#2 NAT GAS CO-FIRE	-	112,550	-	-	-	10,966	NG CO-FIRE	1,200,600	1,028,003	1,234,220.0	5,462,439	4.85	4.55
6. B.B.#2 COAL	-	98,200	-	-	-	10,532	COAL	44,040	23,483,197	1,034,200.0	3,253,285	3.31	73.87
7. TOTAL BIG BEND #2	**385**	**210,750**	**73.6**	**83.3**	**85.0**	**10,764**		-	-	**2,268,420.0**	**8,715,724**	**4.14**	-
8. B.B.#3 NAT GAS CO-FIRE	-	9,480	-	-	-	10,705	NG CO-FIRE	98,720	1,027,958	101,480.0	449,152	4.74	4.55
9. B.B.#3 COAL	-	219,970	-	-	-	10,498	COAL	103,300	22,353,921	2,309,160.0	7,630,891	3.47	73.87
10. TOTAL BIG BEND #3	**395**	**229,450**	**78.1**	**82.6**	**87.9**	**10,506**		-	-	**2,410,640.0**	**8,080,043**	**3.52**	-
11. B.B.#4 NAT GAS CO-FIRE	-	104,410	-	-	-	10,956	NG CO-FIRE	1,112,770	1,028,002	1,143,930.0	5,062,833	4.85	4.55
12. B.B.#4 COAL	-	137,080	-	-	-	10,448	COAL	64,950	22,051,732	1,432,260.0	4,877,890	3.56	75.10
13. TOTAL BIG BEND #4	**437**	**241,490**	**74.3**	**86.6**	**83.6**	**10,668**		-	-	**2,576,190.0**	**9,940,723**	**4.12**	-
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	12,950	-	13,290.0	58,919	-	4.55
15. BIG BEND 1-4 TOTAL	**1,602**	**898,570**	**75.4**	**82.4**	**87.4**	**10,582**	-	-	-	-	**33,903,292**	**3.77**	-
16. B.B.C.T.#4 OIL	56	40	0.1	-	8.9	10,000	LGT OIL	70	5,714,286	400.0	9,409	23.52	134.41
17. B.B.C.T.#4 GAS	56	5,710	13.7	-	100.0	11,391	GAS	63,270	1,027,975	65,040.0	287,863	5.04	4.55
18. B.B.C.T.#4 TOTAL	**56**	**5,750**	**13.8**	**98.2**	**93.3**	**11,381**	-	-	-	**65,440.0**	**297,272**	**5.17**	-
19. BIG BEND STATION TOTAL	**1,658**	**904,320**	**73.3**	**82.9**	**87.4**	**10,588**	-	-	-	**9,574,510.0**	**34,200,564**	**3.78**	-
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,398	COAL	52,820	26,939,038	1,422,920.0	3,843,381	2.81	72.76
21. POLK #1 CT GAS	195	3,390	2.3	-	96.6	8,442	GAS	30,170	948,624	28,620.0	126,665	3.74	4.20
22. POLK #1 TOTAL	**220**	**140,240**	**85.7**	**82.5**	**97.3**	**10,350**	-	-	-	**1,451,540.0**	**3,970,046**	**2.83**	-
23. POLK #2 CT GAS	151	2,420	2.2	-	100.2	12,087	GAS	28,450	1,028,120	29,250.0	129,441	5.35	4.55
24. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,762	22.51	123.81
25. POLK #2 TOTAL	**151**	**2,530**	**2.3**	**0.0**	**82.9**	**12,028**	-	-	-	**30,430.0**	**154,203**	**6.09**	-
26. POLK #3 CT GAS	151	910	0.8	-	100.1	12,055	GAS	10,680	1,027,154	10,970.0	48,591	5.34	4.55
27. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,761	22.51	123.81
28. POLK #3 TOTAL	**151**	**1,020**	**0.9**	**0.0**	**66.0**	**11,912**	-	-	-	**12,150.0**	**73,352**	**7.19**	-
29. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**824**	**143,790**	**23.5**	**22.0**	**96.7**	**10,391**	-	-	-	**1,494,120.0**	**4,197,601**	**2.92**	-
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	412,310	79.1	90.3	82.0	7,330	GAS	2,939,940	1,027,997	3,022,250.0	13,376,013	3.24	4.55
34. BAYSIDE #2	929	436,390	63.1	93.0	64.4	7,380	GAS	3,132,820	1,028,000	3,220,540.0	14,253,570	3.27	4.55
35. BAYSIDE #3	56	2,120	5.1	98.6	94.6	11,538	GAS	23,800	1,027,731	24,460.0	108,284	5.11	4.55
36. BAYSIDE #4	56	1,550	3.7	98.6	95.4	11,510	GAS	17,360	1,027,650	17,840.0	78,984	5.10	4.55
37. BAYSIDE #5	56	4,000	9.6	98.6	92.8	11,573	GAS	45,020	1,028,210	46,290.0	204,830	5.12	4.55
38. BAYSIDE #6	56	3,440	8.3	98.6	93.1	11,549	GAS	38,650	1,027,943	39,730.0	175,848	5.11	4.55
39. BAYSIDE TOTAL	**1,854**	**859,810**	**62.3**	**92.7**	**72.1**	**7,410**	**GAS**	**6,197,590**	**1,027,998**	**6,371,110.0**	**28,197,529**	**3.28**	**4.55**
40. SYSTEM	**4,338**	**1,908,230**	**59.1**	**75.5**	**80.3**	**9,139**	-	-	-	**17,439,740.0**	**66,595,694**	**3.49**	-

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] **AC rating**

DOCKET NO. 150001-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 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**270**	**23.4**	-	**23.4**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	208,620	-	-	-	10,399	COAL	92,620	23,423,883	2,169,520.0	6,852,389	3.28	73.98
4. TOTAL BIG BEND #1	**385**	**208,620**	**75.3**	**76.4**	**93.4**	**10,399**		**-**	**-**	**2,169,520.0**	**6,852,389**	**3.28**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	8,410	-	-	-	10,488	NG CO-FIRE	85,800	1,027,972	88,200.0	428,185	5.09	4.99
6. B.B.#2 COAL	-	220,150	-	-	-	10,423	COAL	97,950	23,427,055	2,294,680.0	7,246,723	3.29	73.98
7. TOTAL BIG BEND #2	**385**	**228,560**	**82.5**	**83.3**	**95.1**	**10,426**		**-**	**-**	**2,382,880.0**	**7,674,908**	**3.36**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	234,480	-	-	-	10,395	COAL	109,050	22,351,674	2,437,450.0	8,067,942	3.44	73.98
10. TOTAL BIG BEND #3	**395**	**234,480**	**82.4**	**82.6**	**92.9**	**10,395**		**-**	**-**	**2,437,450.0**	**8,067,942**	**3.44**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	32,200	-	-	-	11,151	NG CO-FIRE	349,290	1,028,000	359,070.0	1,743,134	5.41	4.99
12. B.B.#4 COAL	-	197,240	-	-	-	10,573	COAL	94,430	22,083,554	2,085,350.0	7,011,847	3.55	74.25
13. TOTAL BIG BEND #4	**437**	**229,440**	**72.9**	**86.6**	**82.0**	**10,654**		**-**	**-**	**2,444,420.0**	**8,754,981**	**3.82**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	15,440	-	15,870.0	77,053	-	4.99
15. BIG BEND 1-4 TOTAL	**1,602**	**901,100**	**78.1**	**82.4**	**90.5**	**10,470**	**-**	**-**	**-**	**-**	**31,427,273**	**3.49**	**-**
16. B.B.C.T.#4 OIL	56	50	0.1	-	11.2	10,400	LGT OIL	90	5,777,778	520.0	11,930	23.86	132.56
17. B.B.C.T.#4 GAS	56	5,150	12.8	-	100.0	11,437	GAS	57,290	1,028,103	58,900.0	285,906	5.55	4.99
18. B.B.C.T.#4 TOTAL	**56**	**5,200**	**12.9**	**98.2**	**92.9**	**11,427**	**-**	**-**	**-**	**59,420.0**	**297,836**	**5.73**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**906,300**	**75.9**	**82.9**	**90.5**	**10,475**	**-**	**-**	**-**	**9,493,690.0**	**31,725,109**	**3.50**	**-**
20. POLK #1 GASIFIER	220	132,380	83.6	-	97.4	10,397	COAL	51,090	26,940,693	1,376,400.0	3,702,238	2.80	72.47
21. POLK #1 CT GAS	195	4,410	3.1	-	94.2	8,476	GAS	38,700	965,891	37,380.0	181,505	4.12	4.69
22. POLK #1 TOTAL	**220**	**136,790**	**86.4**	**82.5**	**97.3**	**10,335**	**-**	**-**	**-**	**1,413,780.0**	**3,883,743**	**2.84**	**-**
23. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. POLK #2 CT OIL	159	140	0.1	-	17.6	10,857	LGT OIL	260	5,846,154	1,520.0	32,121	22.94	123.54
25. POLK #2 TOTAL	**151**	**140**	**0.1**	**0.0**	**17.6**	**10,857**	**-**	**-**	**-**	**1,520.0**	**32,121**	**22.94**	**-**
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	140	0.1	-	17.6	10,857	LGT OIL	260	5,846,154	1,520.0	32,121	22.94	123.54
28. POLK #3 TOTAL	**151**	**140**	**0.1**	**0.0**	**17.6**	**10,857**	**-**	**-**	**-**	**1,520.0**	**32,121**	**22.94**	**-**
29. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**824**	**137,070**	**23.1**	**22.0**	**96.4**	**10,336**	**-**	**-**	**-**	**1,416,820.0**	**3,947,985**	**2.88**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	290,530	57.6	0.0	78.1	7,352	GAS	2,077,810	1,027,996	2,135,980.0	10,369,322	3.57	4.99
34. BAYSIDE #2	929	410,900	61.4	93.0	62.7	7,392	GAS	2,954,540	1,027,998	3,037,260.0	14,744,648	3.59	4.99
35. BAYSIDE #3	56	2,240	5.6	98.6	97.6	11,482	GAS	25,020	1,027,978	25,720.0	124,862	5.57	4.99
36. BAYSIDE #4	56	1,750	4.3	98.6	97.7	11,509	GAS	19,600	1,027,551	20,140.0	97,814	5.59	4.99
37. BAYSIDE #5	56	3,570	8.9	98.6	95.1	11,532	GAS	40,050	1,027,965	41,170.0	199,870	5.60	4.99
38. BAYSIDE #6	56	2,910	7.2	98.6	96.2	11,478	GAS	32,500	1,027,692	33,400.0	162,191	5.57	4.99
39. BAYSIDE TOTAL	**1,854**	**711,900**	**53.3**	**58.5**	**68.6**	**7,436**	**GAS**	**5,149,520**	**1,027,993**	**5,293,670.0**	**25,698,707**	**3.61**	**4.99**
40. SYSTEM	**4,338**	**1,755,540**	**56.2**	**60.9**	**80.5**	**9,230**	**-**	**-**	**-**	**16,204,180.0**	**61,371,801**	**3.50**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] AC rating

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DOCKET NO. 150001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 18 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR [4]	**1.6**	**310**	**26.0**	-	**26.0**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	211,320	-	-	-	10,429	COAL	94,080	23,425,170	2,203,840.0	6,939,173	3.28	73.76
4. TOTAL BIG BEND #1	**385**	**211,320**	**73.8**	**76.4**	**91.6**	**10,429**		**-**	**-**	**2,203,840.0**	**6,939,173**	**3.28**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#2 COAL	-	227,640	-	-	-	10,470	COAL	101,740	23,426,283	2,383,390.0	7,504,154	3.30	73.76
7. TOTAL BIG BEND #2	**385**	**227,640**	**79.5**	**83.3**	**91.8**	**10,470**		**-**	**-**	**2,383,390.0**	**7,504,154**	**3.30**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	206,370	-	-	-	10,464	COAL	96,610	22,351,620	2,159,390.0	7,125,778	3.45	73.76
10. TOTAL BIG BEND #3	**395**	**206,370**	**70.2**	**82.6**	**87.5**	**10,464**		**-**	**-**	**2,159,390.0**	**7,125,778**	**3.45**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	273,410	-	-	-	10,366	COAL	128,280	22,093,467	2,834,150.0	9,464,827	3.46	73.78
13. TOTAL BIG BEND #4	**437**	**273,410**	**84.1**	**86.6**	**94.7**	**10,366**		**-**	**-**	**2,834,150.0**	**9,464,827**	**3.46**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	12,930	-	13,290.0	75,194	-	5.82
15. BIG BEND 1-4 TOTAL	**1,602**	**918,740**	**77.1**	**82.4**	**91.6**	**10,428**	**-**	**-**	**-**	**-**	**31,109,126**	**3.39**	**-**
16. B.B.C.T.#4 OIL	56	40	0.1	-	17.9	10,000	LGT OIL	70	5,714,286	400.0	9,399	23.50	134.27
17. B.B.C.T.#4 GAS	56	8,690	20.9	-	97.0	11,379	GAS	96,190	1,027,965	98,880.0	559,390	6.44	5.82
18. B.B.C.T.#4 TOTAL	**56**	**8,730**	**21.0**	**98.2**	**95.1**	**11,372**	**-**	**-**	**-**	**99,280.0**	**568,789**	**6.52**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**927,470**	**75.2**	**82.9**	**91.6**	**10,437**	**-**	**-**	**-**	**9,680,050.0**	**31,677,915**	**3.42**	**-**
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,415	COAL	52,820	26,984,476	1,425,320.0	3,823,725	2.79	72.39
21. POLK #1 CT GAS	195	5,640	3.9	-	96.4	8,271	GAS	50,050	932,068	46,650.0	263,906	4.68	5.27
22. POLK #1 TOTAL	**220**	**142,490**	**87.1**	**82.5**	**97.3**	**10,330**	**-**	**-**	**-**	**1,471,970.0**	**4,087,631**	**2.87**	**-**
23. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,669	22.43	123.35
25. POLK #2 TOTAL	**151**	**110**	**0.1**	**0.0**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**24,669**	**22.43**	**-**
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	24,669	22.43	123.35
28. POLK #3 TOTAL	**151**	**110**	**0.1**	**32.2**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**24,669**	**22.43**	**-**
29. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. POLK STATION TOTAL	**824**	**142,710**	**23.3**	**27.9**	**96.6**	**10,331**	**-**	**-**	**-**	**1,474,330.0**	**4,136,969**	**2.90**	**-**
32. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #2	929	422,190	61.1	93.0	62.3	7,396	GAS	3,037,560	1,027,999	3,122,610.0	17,664,824	4.18	5.82
35. BAYSIDE #3	56	6,420	15.4	98.6	97.2	11,391	GAS	71,140	1,027,973	73,130.0	413,712	6.44	5.82
36. BAYSIDE #4	56	5,400	13.0	98.6	99.4	11,356	GAS	59,650	1,027,997	61,320.0	346,893	6.42	5.82
37. BAYSIDE #5	56	7,810	18.7	98.6	94.9	11,439	GAS	86,900	1,028,078	89,340.0	505,364	6.47	5.82
38. BAYSIDE #6	56	7,070	17.0	98.6	95.6	11,412	GAS	78,480	1,028,033	80,680.0	456,398	6.46	5.82
39. BAYSIDE TOTAL	**1,854**	**448,890**	**32.5**	**58.5**	**63.7**	**7,635**	**GAS**	**3,333,730**	**1,028,002**	**3,427,080.0**	**19,387,191**	**4.32**	**5.82**
40. SYSTEM	**4,338**	**1,519,380**	**47.1**	**62.0**	**81.4**	**9,597**	**-**	**-**	**-**	**14,581,460.0**	**55,202,075**	**3.63**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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] AC rating

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DOCKET NO. 150001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 19 OF 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR (4)	**1.6**	**290**	**25.2**	-	**25.2**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	205,590	-	-	-	10,422	COAL	91,470	23,424,948	2,142,680.0	6,778,486	3.30	74.11
4. TOTAL BIG BEND #1	**385**	**205,590**	**74.2**	**76.4**	**92.1**	**10,422**		**-**	**-**	**2,142,680.0**	**6,778,486**	**3.30**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#2 COAL	-	222,220	-	-	-	10,455	COAL	99,180	23,425,691	2,323,360.0	7,349,844	3.31	74.11
7. TOTAL BIG BEND #2	**385**	**222,220**	**80.2**	**83.3**	**92.5**	**10,455**		**-**	**-**	**2,323,360.0**	**7,349,844**	**3.31**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	169,850	-	-	-	10,460	COAL	79,480	22,352,667	1,776,590.0	5,889,953	3.47	74.11
10. TOTAL BIG BEND #3	**395**	**169,850**	**59.7**	**55.0**	**87.8**	**10,460**		**-**	**-**	**1,776,590.0**	**5,889,953**	**3.47**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	174,290	-	-	-	10,381	COAL	81,890	22,094,273	1,809,300.0	6,072,024	3.48	74.15
13. TOTAL BIG BEND #4	**437**	**174,290**	**55.4**	**57.7**	**93.4**	**10,381**		**-**	**-**	**1,809,300.0**	**6,072,024**	**3.48**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	27,570	-	28,310.0	156,394	-	5.67
15. BIG BEND 1-4 TOTAL	**1,602**	**771,950**	**66.9**	**67.7**	**91.5**	**10,431**	**-**	**-**	**-**	**-**	**26,246,701**	**3.40**	**-**
16. B.B.C.T.#4 OIL	56	40	0.1	-	14.3	10,500	LGT OIL	70	6,000,000	420.0	9,395	23.49	134.21
17. B.B.C.T.#4 GAS	56	2,950	7.3	-	95.8	11,373	GAS	32,630	1,028,195	33,550.0	185,097	6.27	5.67
18. B.B.C.T.#4 TOTAL	**56**	**2,990**	**7.4**	**98.2**	**89.0**	**11,361**	**-**	**-**	**-**	**33,970.0**	**194,492**	**6.50**	**-**
19. BIG BEND STATION TOTAL	**1,658**	**774,940**	**64.9**	**68.7**	**91.5**	**10,434**	**-**	**-**	**-**	**8,085,900.0**	**26,441,193**	**3.41**	**-**
20. POLK #1 GASIFIER	220	110,320	69.6	-	97.4	10,433	COAL	42,570	27,037,350	1,150,980.0	3,093,028	2.80	72.66
21. POLK #1 CT GAS	195	6,540	4.7	-	95.8	8,474	GAS	59,750	927,531	55,420.0	305,810	4.68	5.12
22. POLK #1 TOTAL	**220**	**116,860**	**73.8**	**68.7**	**97.3**	**10,323**	**-**	**-**	**-**	**1,206,400.0**	**3,398,838**	**2.91**	**-**
23. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
24. POLK #2 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	25,860	23.51	123.14
25. POLK #2 TOTAL	**151**	**110**	**0.1**	**30.5**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**25,860**	**23.51**	**-**
26. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	25,861	23.51	123.15
28. POLK #3 TOTAL	**151**	**110**	**0.1**	**0.0**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**25,861**	**23.51**	**-**
29. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. POLK #5 CT GAS	**151**	**5,130**	**4.7**	**92.2**	**99.9**	**12,060**	**GAS**	**60,190**	**1,027,912**	**61,870.0**	**341,434**	**6.66**	**5.67**
31. POLK STATION TOTAL	**824**	**122,210**	**20.6**	**40.8**	**96.6**	**10,398**	**-**	**-**	**-**	**1,270,710.0**	**3,791,993**	**3.10**	**-**
32. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	701	37,340	7.4	90.3	40.7	7,790	GAS	282,950	1,028,026	290,880.0	1,605,063	4.30	5.67
34. BAYSIDE #2	929	346,050	51.7	65.1	58.7	7,422	GAS	2,498,520	1,027,997	2,568,470.0	14,173,110	4.10	5.67
35. BAYSIDE #3	56	1,730	4.3	98.6	93.6	11,491	GAS	19,330	1,028,453	19,880.0	109,651	6.34	5.67
36. BAYSIDE #4	56	1,310	3.2	98.6	97.5	11,389	GAS	14,510	1,028,256	14,920.0	82,309	6.28	5.67
37. BAYSIDE #5	56	2,690	6.7	98.6	92.4	11,465	GAS	30,010	1,027,657	30,840.0	170,235	6.33	5.67
38. BAYSIDE #6	56	2,510	6.2	98.6	91.5	11,502	GAS	28,090	1,027,768	28,870.0	159,343	6.35	5.67
39. BAYSIDE TOTAL	**1,854**	**391,630**	**29.3**	**78.7**	**56.7**	**7,542**	**GAS**	**2,873,410**	**1,027,998**	**2,953,860.0**	**16,299,711**	**4.16**	**5.67**
40. SYSTEM	**4,338**	**1,289,070**	**41.3**	**67.7**	**77.4**	**9,550**	**-**	**-**	**-**	**12,310,470.0**	**46,532,897**	**3.61**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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) AC rating

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2016

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR (4)	**1.4**	**270**	**25.9**	-	**25.9**	-	**SOLAR**	-	-	-	-	-	-
2. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
3. B.B.#1 COAL	-	138,650	-	-	-	10,404	COAL	61,590	23,421,822	1,442,550.0	4,461,391	3.22	72.44
4. TOTAL BIG BEND #1	**395**	**138,650**	**47.2**	**51.7**	**86.5**	**10,404**		**-**	**-**	**1,442,550.0**	**4,461,391**	**3.22**	**-**
5. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#2 COAL	-	151,890	-	-	-	10,484	COAL	67,980	23,424,095	1,592,370.0	4,924,269	3.24	72.44
7. TOTAL BIG BEND #2	**395**	**151,890**	**51.7**	**56.5**	**88.0**	**10,484**		**-**	**-**	**1,592,370.0**	**4,924,269**	**3.24**	**-**
8. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#3 COAL	-	231,620	-	-	-	10,420	COAL	107,980	22,351,824	2,413,550.0	7,821,744	3.38	72.44
10. TOTAL BIG BEND #3	**400**	**231,620**	**77.8**	**82.6**	**87.6**	**10,420**		**-**	**-**	**2,413,550.0**	**7,821,744**	**3.38**	**-**
11. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#4 COAL	-	243,920	-	-	-	10,492	COAL	115,830	22,093,931	2,559,140.0	8,394,867	3.44	72.48
13. TOTAL BIG BEND #4	**442**	**243,920**	**74.2**	**86.6**	**83.5**	**10,492**		**-**	**-**	**2,559,140.0**	**8,394,867**	**3.44**	**-**
14. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	19,610	-	20,160.0	106,952	-	5.45
15. BIG BEND 1-4 TOTAL	**1,632**	**766,080**	**63.1**	**69.9**	**86.1**	**10,453**	**-**	**-**	**-**	**-**	**25,709,223**	**3.36**	**-**
16. B.B.C.T.#4 OIL	61	40	0.1	-	13.1	12,250	LGT OIL	80	6,125,000	490.0	10,653	26.63	133.16
17. B.B.C.T.#4 GAS	61	6,270	13.8	-	84.9	11,362	GAS	69,310	1,027,846	71,240.0	378,015	6.03	5.45
18. B.B.C.T.#4 TOTAL	**61**	**6,310**	**13.9**	**98.2**	**82.1**	**11,368**	**-**	**-**	**-**	**71,730.0**	**388,668**	**6.16**	**-**
19. BIG BEND STATION TOTAL	**1,693**	**772,390**	**61.3**	**70.9**	**86.1**	**10,460**	**-**	**-**	**-**	**8,079,340.0**	**26,097,891**	**3.38**	**-**
20. POLK #1 GASIFIER	220	136,850	83.6	-	97.3	10,398	COAL	52,820	26,939,038	1,422,920.0	3,783,720	2.76	71.63
21. POLK #1 CT GAS	195	6,820	4.7	-	99.9	8,491	GAS	58,670	987,046	57,910.0	307,277	4.51	5.24
22. POLK #1 TOTAL	**220**	**143,670**	**87.8**	**82.5**	**97.5**	**10,307**	**-**	**-**	**-**	**1,480,830.0**	**4,090,997**	**2.85**	**-**
23. POLK #2 CT GAS	183	4,160	3.1	-	94.7	11,654	GAS	47,160	1,027,990	48,480.0	257,209	6.18	5.45
24. POLK #2 CT OIL	187	130	0.1	-	13.9	11,077	LGT OIL	250	5,760,000	1,440.0	30,728	23.64	122.91
25. POLK #2 TOTAL	**183**	**4,290**	**3.2**	**91.6**	**80.5**	**11,636**	**-**	**-**	**-**	**49,920.0**	**287,937**	**6.71**	**-**
26. POLK #3 CT GAS	183	1,250	0.9	-	97.3	11,664	GAS	14,170	1,028,934	14,580.0	77,283	6.18	5.45
27. POLK #3 CT OIL	187	130	0.1	-	13.9	11,077	LGT OIL	250	5,760,000	1,440.0	30,727	23.64	122.91
28. POLK #3 TOTAL	**183**	**1,380**	**1.0**	**67.3**	**62.2**	**11,609**	**-**	**-**	**-**	**16,020.0**	**108,010**	**7.83**	**-**
29. POLK #4 CT GAS	**183**	**360**	**0.3**	**93.8**	**98.6**	**11,639**	**GAS**	**4,080**	**1,026,961**	**4,190.0**	**22,252**	**6.18**	**5.45**
30. POLK #5 CT GAS	**183**	**7,840**	**5.8**	**92.2**	**97.4**	**11,526**	**GAS**	**87,890**	**1,028,103**	**90,360.0**	**479,349**	**6.11**	**5.45**
31. POLK STATION TOTAL	**952**	**157,540**	**22.2**	**85.3**	**96.4**	**10,418**	**-**	**-**	**-**	**1,641,320.0**	**4,988,545**	**3.17**	**-**
32. CITY OF TAMPA GAS (3)	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. BAYSIDE #1	792	301,300	51.1	90.3	65.6	7,300	GAS	2,139,560	1,027,996	2,199,460.0	11,669,100	3.87	5.45
34. BAYSIDE #2	1,047	186,300	23.9	93.0	30.3	7,702	GAS	1,395,790	1,027,991	1,434,860.0	7,612,599	4.09	5.45
35. BAYSIDE #3	61	3,940	8.7	98.6	86.1	11,297	GAS	43,300	1,027,945	44,510.0	236,157	5.99	5.45
36. BAYSIDE #4	61	2,570	5.7	98.6	87.8	11,393	GAS	28,490	1,027,729	29,280.0	155,384	6.05	5.45
37. BAYSIDE #5	61	5,100	11.2	98.6	86.2	11,335	GAS	56,240	1,027,916	57,810.0	306,731	6.01	5.45
38. BAYSIDE #6	61	4,610	10.2	98.6	84.9	11,382	GAS	51,030	1,028,219	52,470.0	278,316	6.04	5.45
39. BAYSIDE TOTAL	**2,083**	**503,820**	**32.5**	**92.6**	**46.1**	**7,579**	**GAS**	**3,714,410**	**1,027,994**	**3,818,390.0**	**20,258,287**	**4.02**	**5.45**
40. SYSTEM	**4,729**	**1,434,020**	**40.8**	**83.4**	**66.5**	**9,441**	**-**	**-**	**-**	**13,539,050.0**	**51,344,723**	**3.58**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
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) AC rating

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
	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)	540	510	610	490	470	610
16.	UNIT COST ($/BBL)	99.50	99.63	99.31	98.73	98.74	99.01
17.	AMOUNT ($)	53,730	50,810	60,581	48,380	46,409	60,399
18.	BURNED:						
19.	UNITS (BBL)	540	510	610	490	470	610
20.	UNIT COST ($/BBL)	126.78	126.60	126.17	126.17	126.03	125.49
21.	AMOUNT ($)	68,460	64,565	76,965	61,824	59,234	76,551
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	75,864	75,864	75,864	75,864	75,864	75,864
24.	UNIT COST ($/BBL)	126.08	125.91	125.70	125.53	125.37	125.16
25.	AMOUNT ($)	9,565,205	9,552,008	9,536,185	9,523,301	9,511,036	9,495,444
26.	DAYS SUPPLY: NORMAL	4,393	4,804	5,254	5,942	6,640	7,484
27.	DAYS SUPPLY: EMERGENCY	11	11	11	11	11	11
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	345,460	308,460	253,460	253,460	313,460	278,460
30.	UNIT COST ($/TON)	74.08	74.09	75.70	76.58	73.95	76.41
31.	AMOUNT ($)	25,592,336	22,854,342	19,187,578	19,410,562	23,179,914	21,278,448
32.	BURNED:						
33.	UNITS (TONS)	462,110	265,750	243,810	203,510	211,970	277,620
34.	UNIT COST ($/TON)	76.61	98.54	117.45	117.88	139.54	132.26
35.	AMOUNT ($)	35,402,875	26,186,115	28,634,342	23,988,972	29,577,713	36,717,103
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	483,961	526,671	536,320	586,270	687,760	688,600
38.	UNIT COST ($/TON)	87.33	87.22	88.57	89.73	87.97	89.03
39.	AMOUNT ($)	42,262,160	45,938,719	47,499,976	52,603,351	60,502,669	61,306,574
40.	DAYS SUPPLY:	45	66	75	77	75	64
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	3,428,340	5,566,420	7,110,050	8,083,670	10,079,538	9,770,990
43.	UNIT COST ($/MCF)	5.94	4.92	4.66	4.43	4.40	4.52
44.	AMOUNT ($)	20,371,417	27,411,228	33,122,561	35,835,374	44,398,783	44,186,624
45.	BURNED:						
46.	UNITS (MCF)	3,428,340	5,566,420	7,110,050	8,083,670	9,787,710	9,770,990
47.	UNIT COST ($/MCF)	5.28	3.70	3.13	3.28	2.99	2.87
48.	AMOUNT ($)	18,105,861	20,570,477	22,271,025	26,515,987	29,269,617	28,057,392
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	875,486	875,486	875,486	875,486	1,167,315	1,167,315
51.	UNIT COST ($/MCF)	3.51	3.49	3.43	3.23	3.22	3.25
52.	AMOUNT ($)	3,069,900	3,055,500	3,006,360	2,824,560	3,761,520	3,794,880
53.	DAYS SUPPLY:	4	4	4	4	6	6
	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 2016 THROUGH DECEMBER 2016

		Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	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)	470	470	610	470	490	580	6,320
16.	UNIT COST ($/BBL)	99.47	99.99	100.48	101.03	101.43	101.83	99.94
17.	AMOUNT ($)	46,751	46,993	61,293	47,484	49,701	59,060	631,591
18.	BURNED:							
19.	UNITS (BBL)	470	470	610	470	490	580	6,320
20.	UNIT COST ($/BBL)	125.58	125.39	124.87	124.97	124.73	124.32	125.58
21.	AMOUNT ($)	59,021	58,932	76,172	58,737	61,116	72,108	793,685
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	75,864	75,864	75,864	75,864	75,864	75,864	75,864
24.	UNIT COST ($/BBL)	125.01	124.86	124.67	124.53	124.39	124.22	124.22
25.	AMOUNT ($)	9,483,734	9,472,354	9,458,036	9,447,342	9,436,487	9,424,000	9,424,000
26.	DAYS SUPPLY: NORMAL	8,961	10,569	12,879	17,981	25,879	47,742	-
27.	DAYS SUPPLY: EMERGENCY	11	11	11	11	11	11	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	278,460	335,460	413,460	353,460	383,460	363,464	3,880,522
30.	UNIT COST ($/TON)	76.50	75.98	73.45	75.25	73.84	74.20	74.87
31.	AMOUNT ($)	21,302,960	25,489,576	30,370,372	26,597,190	28,314,746	26,967,309	290,545,333
32.	BURNED:							
33.	UNITS (TONS)	349,040	361,330	445,140	473,530	394,590	406,200	4,094,600
34.	UNIT COST ($/TON)	104.14	104.47	78.92	73.77	74.35	72.61	93.66
35.	AMOUNT ($)	36,347,799	37,746,673	35,129,511	34,932,851	29,339,729	29,492,943	383,496,626
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	618,020	592,149	560,469	440,399	429,269	386,533	386,533
38.	UNIT COST ($/TON)	92.13	94.35	95.42	103.10	104.08	109.73	109.73
39.	AMOUNT ($)	56,937,664	55,872,031	53,478,182	45,407,328	44,677,157	42,414,072	42,414,072
40.	DAYS SUPPLY:	49	43	39	32	31	29	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	8,643,690	8,755,200	5,696,040	3,492,900	2,761,722	4,015,300	77,403,860
43.	UNIT COST ($/MCF)	4.57	4.55	4.99	5.83	5.94	5.49	4.80
44.	AMOUNT ($)	39,477,672	39,841,713	28,416,518	20,350,039	16,408,134	22,041,532	371,861,595
45.	BURNED:							
46.	UNITS (MCF)	8,643,690	8,755,200	5,696,040	3,492,900	3,053,550	4,015,300	77,403,860
47.	UNIT COST ($/MCF)	3.34	3.29	4.59	5.79	5.61	5.42	3.72
48.	AMOUNT ($)	28,878,453	28,790,089	26,166,118	20,210,487	17,132,052	21,779,672	287,747,230
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,167,315	1,167,315	1,167,315	1,167,315	875,486	875,486	875,486
51.	UNIT COST ($/MCF)	3.28	3.29	3.28	3.31	3.38	3.54	3.54
52.	AMOUNT ($)	3,833,760	3,841,440	3,831,840	3,869,040	2,955,600	3,097,800	3,097,800
53.	DAYS SUPPLY:	7	7	7	7	5	5	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

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

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

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-16	SEMINOLE	JURISD.	SCH. - D	810.0	0.0	810.0	2.722	2.843	22,050.00	23,027.00	977.00
	VARIOUS	JURISD.	MKT. BASE	1,000.0	0.0	1,000.0	2.632	2.895	26,315.55	28,950.00	2,634.45
	TOTAL			**1,810.0**	**0.0**	**1,810.0**	**2.672**	**2.872**	**48,365.55**	**51,977.00**	**3,611.45**
Feb-16	SEMINOLE	JURISD.	SCH. - D	670.0	0.0	670.0	3.216	3.359	21,550.00	22,505.00	955.00
	VARIOUS	JURISD.	MKT. BASE	970.0	0.0	970.0	3.175	3.493	30,796.92	33,880.00	3,083.08
	TOTAL			**1,640.0**	**0.0**	**1,640.0**	**3.192**	**3.438**	**52,346.92**	**56,385.00**	**4,038.08**
Mar-16	SEMINOLE	JURISD.	SCH. - D	890.0	0.0	890.0	2.864	2.991	25,490.00	26,619.00	1,129.00
	VARIOUS	JURISD.	MKT. BASE	2,590.0	0.0	2,590.0	2.128	2.341	55,103.58	60,620.00	5,516.42
	TOTAL			**3,480.0**	**0.0**	**3,480.0**	**2.316**	**2.507**	**80,593.58**	**87,239.00**	**6,645.42**
Apr-16	SEMINOLE	JURISD.	SCH. - D	1,080.0	0.0	1,080.0	2.699	2.819	29,150.00	30,442.00	1,292.00
	VARIOUS	JURISD.	MKT. BASE	1,060.0	0.0	1,060.0	2.703	2.974	28,651.68	31,520.00	2,868.32
	TOTAL			**2,140.0**	**0.0**	**2,140.0**	**2.701**	**2.895**	**57,801.68**	**61,962.00**	**4,160.32**
May-16	SEMINOLE	JURISD.	SCH. - D	930.0	0.0	930.0	2.876	3.004	26,750.00	27,935.00	1,185.00
	VARIOUS	JURISD.	MKT. BASE	920.0	0.0	920.0	3.667	4.034	33,732.99	37,110.00	3,377.01
	TOTAL			**1,850.0**	**0.0**	**1,850.0**	**3.269**	**3.516**	**60,482.99**	**65,045.00**	**4,562.01**
Jun-16	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	2.833	2.959	28,050.00	29,293.00	1,243.00
	VARIOUS	JURISD.	MKT. BASE	2,510.0	0.0	2,510.0	2.231	2.455	56,003.49	61,610.00	5,606.51
	TOTAL			**3,500.0**	**0.0**	**3,500.0**	**2.402**	**2.597**	**84,053.49**	**90,903.00**	**6,849.51**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

(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		(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
						(A) FUEL COST	(B) TOTAL COST			
Jul-16	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	3.103	3.240	31,340.00	32,729.00	1,389.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	4.765	5.242	42,886.62	47,180.00	4,293.38
	TOTAL		**1,910.0**	**0.0**	**1,910.0**	**3.886**	**4.184**	**74,226.62**	**79,909.00**	**5,682.38**
Aug-16	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	3.008	3.141	30,080.00	31,413.00	1,333.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	3.558	3.914	32,024.07	35,230.00	3,205.93
	TOTAL		**1,900.0**	**0.0**	**1,900.0**	**3.269**	**3.508**	**62,104.07**	**66,643.00**	**4,538.93**
Sep-16	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	2.987	3.119	29,870.00	31,194.00	1,324.00
	VARIOUS	JURISD. MKT. BASE	1,160.0	0.0	1,160.0	3.785	4.164	43,904.70	48,300.00	4,395.30
	TOTAL		**2,160.0**	**0.0**	**2,160.0**	**3.415**	**3.680**	**73,774.70**	**79,494.00**	**5,719.30**
Oct-16	SEMINOLE	JURISD. SCH. - D	730.0	0.0	730.0	3.584	3.742	26,160.00	27,319.00	1,159.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	4.103	4.513	36,923.58	40,620.00	3,696.42
	TOTAL		**1,630.0**	**0.0**	**1,630.0**	**3.870**	**4.168**	**63,083.58**	**67,939.00**	**4,855.42**
Nov-16	SEMINOLE	JURISD. SCH. - D	640.0	0.0	640.0	2.955	3.086	18,910.00	19,748.00	838.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	3.691	4.060	34,323.84	37,760.00	3,436.16
	TOTAL		**1,570.0**	**0.0**	**1,570.0**	**3.391**	**3.663**	**53,233.84**	**57,508.00**	**4,274.16**
Dec-16	SEMINOLE	JURISD. SCH. - D	600.0	0.0	600.0	2.957	3.088	17,740.00	18,526.00	786.00
	VARIOUS	JURISD. MKT. BASE	1,100.0	0.0	1,100.0	3.522	3.875	38,741.58	42,620.00	3,878.42
	TOTAL		**1,700.0**	**0.0**	**1,700.0**	**3.322**	**3.597**	**56,481.58**	**61,146.00**	**4,664.42**
TOTAL	SEMINOLE	JURISD. SCH. - D	10,350.0	0.0	10,350.0	2.968	3.099	307,140.00	320,750.00	13,610.00
Jan-16	VARIOUS	JURISD. MKT. BASE	14,940.0	0.0	14,940.0	3.075	3.383	459,408.60	505,400.00	45,991.40
THRU Dec-16	**TOTAL**		**25,290.0**	**0.0**	**25,290.0**	**3.031**	**3.267**	**766,548.60**	**826,150.00**	**59,601.40**

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DOCKET NO. 150001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 25 OF 31

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

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-16									
	VARIOUS	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	2,310.0	0.0	0.0	2,310.0	3.526	3.526	81,460.00
	TOTAL		**2,310.0**	**0.0**	**0.0**	**2,310.0**	**3.526**	**3.526**	**81,460.00**
Feb-16									
	VARIOUS	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	27,110.0	0.0	0.0	27,110.0	3.504	3.504	950,010.00
	TOTAL		**27,110.0**	**0.0**	**0.0**	**27,110.0**	**3.504**	**3.504**	**950,010.00**
Mar-16									
	VARIOUS	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	260.0	0.0	0.0	260.0	7.750	7.750	20,150.00
	PASCO COGEN	SCH. - D	12,950.0	0.0	0.0	12,950.0	3.447	3.447	446,380.00
	TOTAL		**13,210.0**	**0.0**	**0.0**	**13,210.0**	**3.532**	**3.532**	**466,530.00**
Apr-16									
	VARIOUS	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	8,760.0	0.0	0.0	8,760.0	3.424	3.424	299,900.00
	TOTAL		**8,760.0**	**0.0**	**0.0**	**8,760.0**	**3.424**	**3.424**	**299,900.00**
May-16									
	VARIOUS	SCH. - D	34,110.0	0.0	0.0	34,110.0	3.573	3.573	1,218,650.00
	CALPINE	SCH. - D	2,950.0	0.0	0.0	2,950.0	6.382	6.382	188,270.00
	PASCO COGEN	SCH. - D	22,930.0	0.0	0.0	22,930.0	3.327	3.327	762,980.00
	TOTAL		**59,990.0**	**0.0**	**0.0**	**59,990.0**	**3.617**	**3.617**	**2,169,900.00**
Jun-16									
	VARIOUS	SCH. - D	47,980.0	0.0	0.0	47,980.0	3.649	3.649	1,750,980.00
	CALPINE	SCH. - D	1,400.0	0.0	0.0	1,400.0	6.691	6.691	93,670.00
	PASCO COGEN	SCH. - D	22,400.0	0.0	0.0	22,400.0	3.373	3.373	755,640.00
	TOTAL		**71,780.0**	**0.0**	**0.0**	**71,780.0**	**3.623**	**3.623**	**2,600,290.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

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-16									
	VARIOUS	SCH. - D	44,730.0	0.0	0.0	44,730.0	3.680	3.680	1,646,260.00
	CALPINE	SCH. - D	5,170.0	0.0	0.0	5,170.0	6.269	6.269	324,130.00
	PASCO COGEN	SCH. - D	23,470.0	0.0	0.0	23,470.0	3.386	3.386	794,660.00
	TOTAL		**73,370.0**	**0.0**	**0.0**	**73,370.0**	**3.769**	**3.769**	**2,765,050.00**
Aug-16									
	VARIOUS	SCH. - D	38,410.0	0.0	0.0	38,410.0	3.760	3.760	1,444,190.00
	CALPINE	SCH. - D	1,790.0	0.0	0.0	1,790.0	6.227	6.227	111,470.00
	PASCO COGEN	SCH. - D	20,890.0	0.0	0.0	20,890.0	3.409	3.409	712,210.00
	TOTAL		**61,090.0**	**0.0**	**0.0**	**61,090.0**	**3.712**	**3.712**	**2,267,870.00**
Sep-16									
	VARIOUS	SCH. - D	36,190.0	0.0	0.0	36,190.0	3.736	3.736	1,352,100.00
	CALPINE	SCH. - D	3,010.0	0.0	0.0	3,010.0	6.531	6.531	196,590.00
	PASCO COGEN	SCH. - D	21,780.0	0.0	0.0	21,780.0	3.403	3.403	741,130.00
	TOTAL		**60,980.0**	**0.0**	**0.0**	**60,980.0**	**3.755**	**3.755**	**2,289,820.00**
Oct-16									
	VARIOUS	SCH. - D	71,520.0	0.0	0.0	71,520.0	3.449	3.449	2,466,390.00
	CALPINE	SCH. - D	11,980.0	0.0	0.0	11,980.0	5.439	5.439	651,610.00
	PASCO COGEN	SCH. - D	14,210.0	0.0	0.0	14,210.0	3.422	3.422	486,230.00
	TOTAL		**97,710.0**	**0.0**	**0.0**	**97,710.0**	**3.689**	**3.689**	**3,604,230.00**
Nov-16									
	VARIOUS	SCH. - D	39,710.0	0.0	0.0	39,710.0	3.486	3.486	1,384,140.00
	CALPINE	SCH. - D	2,210.0	0.0	0.0	2,210.0	5.420	5.420	119,780.00
	PASCO COGEN	SCH. - D	8,390.0	0.0	0.0	8,390.0	3.469	3.469	291,090.00
	TOTAL		**50,310.0**	**0.0**	**0.0**	**50,310.0**	**3.568**	**3.568**	**1,795,010.00**
Dec-16									
	VARIOUS	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	2,020.0	0.0	0.0	2,020.0	6.169	6.169	124,610.00
	PASCO COGEN	SCH. - D	10,940.0	0.0	0.0	10,940.0	3.518	3.518	384,840.00
	TOTAL		**12,960.0**	**0.0**	**0.0**	**12,960.0**	**3.931**	**3.931**	**509,450.00**
TOTAL	VARIOUS	SCH. - D	312,650.0	0.0	0.0	312,650.0	3.602	3.602	11,262,710.00
Jan-16	CALPINE	SCH. - D	30,790.0	0.0	0.0	30,790.0	5.944	5.944	1,830,280.00
THRU	PASCO COGEN	SCH. - D	196,140.0	0.0	0.0	196,140.0	3.419	3.419	6,706,530.00
Dec-16	**TOTAL**		**539,580.0**	**0.0**	**0.0**	**539,580.0**	**3.669**	**3.669**	**19,799,520.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUST-
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	MENT
Jan-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.796	2.796	209,980.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.796**	**2.796**	**209,980.00**
Feb-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,490.0	0.0	0.0	7,490.0	2.514	2.514	188,330.00
	TOTAL		**7,490.0**	**0.0**	**0.0**	**7,490.0**	**2.514**	**2.514**	**188,330.00**
Mar-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,620.0	0.0	0.0	7,620.0	3.472	3.472	264,560.00
	TOTAL		**7,620.0**	**0.0**	**0.0**	**7,620.0**	**3.472**	**3.472**	**264,560.00**
Apr-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.747	2.747	204,910.00
	TOTAL		**7,460.0**	**0.0**	**0.0**	**7,460.0**	**2.747**	**2.747**	**204,910.00**
May-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,470.0	0.0	0.0	7,470.0	2.769	2.769	206,820.00
	TOTAL		**7,470.0**	**0.0**	**0.0**	**7,470.0**	**2.769**	**2.769**	**206,820.00**
Jun-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,570.0	0.0	0.0	7,570.0	3.094	3.094	234,200.00
	TOTAL		**7,570.0**	**0.0**	**0.0**	**7,570.0**	**3.094**	**3.094**	**234,200.00**
Jul-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.278	2.278	169,920.00
	TOTAL		**7,460.0**	**0.0**	**0.0**	**7,460.0**	**2.278**	**2.278**	**169,920.00**
Aug-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,480.0	0.0	0.0	7,480.0	1.968	1.968	147,190.00
	TOTAL		**7,480.0**	**0.0**	**0.0**	**7,480.0**	**1.968**	**1.968**	**147,190.00**
Sep-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,540.0	0.0	0.0	7,540.0	2.587	2.587	195,030.00
	TOTAL		**7,540.0**	**0.0**	**0.0**	**7,540.0**	**2.587**	**2.587**	**195,030.00**
Oct-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,520.0	0.0	0.0	7,520.0	1.901	1.901	142,960.00
	TOTAL		**7,520.0**	**0.0**	**0.0**	**7,520.0**	**1.901**	**1.901**	**142,960.00**
Nov-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,380.0	0.0	0.0	7,380.0	2.059	2.059	151,940.00
	TOTAL		**7,380.0**	**0.0**	**0.0**	**7,380.0**	**2.059**	**2.059**	**151,940.00**
Dec-16	**VARIOUS**	**CO-GEN.**							
		AS AVAIL.	7,610.0	0.0	0.0	7,610.0	2.860	2.860	217,640.00
	TOTAL		**7,610.0**	**0.0**	**0.0**	**7,610.0**	**2.860**	**2.860**	**217,640.00**
TOTAL	**VARIOUS**	**CO-GEN.**							
Jan-16		AS AVAIL.	90,110.0	0.0	0.0	90,110.0	2.590	2.590	2,333,480.00
THRU	**TOTAL**		**90,110.0**	**0.0**	**0.0**	**90,110.0**	**2.590**	**2.590**	**2,333,480.00**
Dec-16									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E9

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) TRANSACT. COST cents/KWH	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) COST IF GENERATED (A) CENTS PER KWH	(9) COST IF GENERATED (B) ($000)	(10) FUEL SAVINGS (9B)-(8)
Jan-16	VARIOUS	ECONOMY	25,000.0	0.0	25,000.0	3.041	760,140.00	3.041	760,140.00	0.00
Feb-16	VARIOUS	ECONOMY	25,040.0	0.0	25,040.0	3.682	921,870.00	3.759	941,340.00	19,470.00
Mar-16	VARIOUS	ECONOMY	27,370.0	0.0	27,370.0	3.342	914,760.00	3.427	938,100.00	23,340.00
Apr-16	VARIOUS	ECONOMY	23,390.0	0.0	23,390.0	3.287	768,920.00	3.696	864,480.00	95,560.00
May-16	VARIOUS	ECONOMY	27,620.0	0.0	27,620.0	4.295	1,186,390.00	4.618	1,275,570.00	89,180.00
Jun-16	VARIOUS	ECONOMY	27,250.0	0.0	27,250.0	3.674	1,001,050.00	4.182	1,139,490.00	138,440.00
Jul-16	VARIOUS	ECONOMY	28,680.0	0.0	28,680.0	4.974	1,426,620.00	5.095	1,461,340.00	34,720.00
Aug-16	VARIOUS	ECONOMY	25,060.0	0.0	25,060.0	4.133	1,035,810.00	4.420	1,107,770.00	71,960.00
Sep-16	VARIOUS	ECONOMY	30,950.0	0.0	30,950.0	4.343	1,344,070.00	4.429	1,370,770.00	26,700.00
Oct-16	VARIOUS	ECONOMY	39,340.0	0.0	39,340.0	5.710	2,246,200.00	5.719	2,249,680.00	3,480.00
Nov-16	VARIOUS	ECONOMY	23,560.0	0.0	23,560.0	4.002	942,830.00	4.014	945,790.00	2,960.00
Dec-16	VARIOUS	ECONOMY	27,890.0	0.0	27,890.0	3.606	1,005,660.00	3.606	1,005,660.00	0.00
TOTAL	VARIOUS	ECONOMY	**331,150.0**	**0.0**	**331,150.0**	**4.093**	**13,554,320.00**	**4.246**	**14,060,130.00**	**505,810.00**

DOCKET NO. 150001-EI
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2, PAGE 29 OF 31

SCHEDULE E10

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

	Current Jan 15 - Oct 15	Step Increase Nov 15 - Dec 15	Difference $	Difference %	Projected Jan 16 - Dec 16	Difference $	Difference %
Base Rate Revenue *	61.50	61.94	0.44	0.7%	61.94	0.00	0.0%
Fuel Recovery Revenue	35.59	35.59	0.00	0.0%	33.61	(1.98)	-5.6%
Conservation Revenue	2.55	2.55	0.00	0.0%	1.91	(0.64)	-25.1%
Capacity Revenue	2.04	2.04	0.00	0.0%	1.78	(0.26)	-12.7%
Environmental Revenue	4.08	4.08	0.00	0.0%	4.32	0.24	5.9%
Florida Gross Receipts Tax Revenue	2.71	2.72	0.01	0.4%	2.66	(0.06)	-2.2%
TOTAL REVENUE	**$108.47**	**$108.92**	**$0.45**	**0.4%**	**$106.22**	**($2.70)**	**-2.5%**

*** Base rate change effective November 1, 2015.**

SCHEDULE H1

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

		ACTUAL 2013	ACTUAL 2014	ACT/EST 2015	EST 2016	DIFFERENCE (%) 2014-2013	2015-2014	2016-2015
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2	LIGHT OIL [1]	2,070,617	0	470,793	793,685	-100.0%	0.0%	68.6%
3	COAL	380,570,736	413,363,010	343,168,205	383,496,626	8.6%	-17.0%	11.8%
4	NATURAL GAS	300,114,267	307,201,884	324,133,233	287,747,230	2.4%	5.5%	-11.2%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**682,755,620**	**720,564,894**	**667,772,231**	**672,037,541**	**5.5%**	**-7.3%**	**0.6%**
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9	LIGHT OIL [1]	8,475	0	1,882	3,410	-100.0%	0.0%	81.2%
10	COAL	10,821,031	11,594,881	10,134,621	9,132,760	7.2%	-12.6%	-9.9%
11	NATURAL GAS	7,601,115	7,115,927	8,781,813	9,728,830	-6.4%	23.4%	10.8%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	0	0	3,690	0.0%	0.0%	0.0%
14	**TOTAL (MWH)**	**18,430,621**	**18,710,808**	**18,918,316**	**18,868,690**	**1.5%**	**1.1%**	**-0.3%**
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16	LIGHT OIL (BBL) [1]	16,398	0	4,719	6,320	-100.0%	0.0%	33.9%
17	COAL (TON)	4,702,698	4,989,298	4,520,530	4,094,600	6.1%	-9.4%	-9.4%
18	NATURAL GAS (MCF)	56,560,899	52,983,025	66,185,257	77,403,860	-6.3%	24.9%	17.0%
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]	83,760	0	21,492	36,740	-100.0%	0.0%	70.9%
23	COAL	113,471,450	120,048,010	106,225,526	95,537,860	5.8%	-11.5%	-10.1%
24	NATURAL GAS	57,416,563	54,096,745	67,817,414	79,319,160	-5.8%	25.4%	17.0%
25	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26	OTHER	0	0	0	0	0.0%	0.0%	0.0%
27	**TOTAL (MMBTU)**	**170,971,773**	**174,144,756**	**174,064,433**	**174,893,760**	**1.9%**	**0.0%**	**0.5%**
	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]	0.05	0.00	0.01	0.02	-100.0%	0.0%	100.0%
30	COAL	58.71	61.97	53.57	48.40	5.6%	-13.6%	-9.7%
31	NATURAL GAS	41.24	38.03	46.42	51.56	-7.8%	22.1%	11.1%
32	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33	OTHER	0.00	0.00	0.00	0.02	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]	126.27	0.00	99.77	125.58	-100.0%	0.0%	25.9%
37	COAL ($/TON)	80.93	82.85	75.91	93.66	2.4%	-8.4%	23.4%
38	NATURAL GAS ($/MCF)	5.31	5.80	4.90	3.72	9.2%	-15.5%	-24.1%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42	LIGHT OIL [1]	24.72	0.00	21.91	21.60	-100.0%	0.0%	-1.4%
43	COAL	3.35	3.44	3.23	4.01	2.7%	-6.1%	24.1%
44	NATURAL GAS	5.23	5.68	4.78	3.63	8.6%	-15.8%	-24.1%
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)**	**3.99**	**4.14**	**3.84**	**3.84**	**3.8%**	**-7.2%**	**0.0%**
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49	LIGHT OIL [1]	9,883	0	11,420	10,774	-100.0%	0.0%	-5.7%
50	COAL	10,486	10,354	10,481	10,461	-1.3%	1.2%	-0.2%
51	NATURAL GAS	7,554	7,602	7,722	8,153	0.6%	1.6%	5.6%
52	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53	OTHER	0	0	0	0	0.0%	0.0%	0.0%
54	**TOTAL (BTU/KWH)**	**9,277**	**9,307**	**9,201**	**9,269**	**0.3%**	**-1.1%**	**0.7%**
	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]	24.43	0.00	25.02	23.28	-100.0%	0.0%	-7.0%
57	COAL	3.52	3.57	3.39	4.20	1.4%	-5.0%	23.9%
58	NATURAL GAS	3.95	4.32	3.69	2.96	9.4%	-14.6%	-19.8%
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)**	**3.70**	**3.85**	**3.53**	**3.56**	**4.1%**	**-8.3%**	**0.8%**

[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 2016 - DECEMBER 2016

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2016 through December 2016

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	6,068,457	3.676	223,076,497	3.361	203,960,856
TIER II (Over 1,000) kWh	2,790,605	3.676	102,582,623	4.361	121,698,264
Total	8,859,062		325,659,120		325,659,120

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2016 - DECEMBER 2016

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2016 THROUGH DECEMBER 2016

	PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1 BEGINNING BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951
2 **ADD INVESTMENT**	$ -	$ -	$ -	$ -	$ -	$ -		$ -					$ -
3 LESS RETIREMENTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4 ENDING BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951
5													
6													
7 AVERAGE BALANCE	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	$ 16,143,951	
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9 DEPRECIATION EXPENSE	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	8,067,199	8,336,424	8,605,649	8,874,874	9,144,099	9,413,324	9,682,549	9,951,774	10,220,999	10,490,224	10,759,449	11,028,674	8,067,199
12 ENDING BALANCE DEPRECIATION	8,336,424	8,605,649	8,874,874	9,144,099	9,413,324	9,682,549	9,951,774	10,220,999	10,490,224	10,759,449	11,028,674	11,297,899	11,297,899
13													
14													
15 ENDING NET INVESTMENT	$ 7,807,527	$ 7,538,302	$ 7,269,077	$ 6,999,852	$ 6,730,627	$ 6,461,402	$ 6,192,177	$ 5,922,952	$ 5,653,726	$ 5,384,501	$ 5,115,276	$ 4,846,051	$ 4,846,051
16													
17													
18 AVERAGE INVESTMENT	$ 7,942,140	$ 7,672,914	$ 7,403,689	$ 7,134,464	$ 6,865,239	$ 6,596,014	$ 6,326,789	$ 6,057,564	$ 5,788,339	$ 5,519,114	$ 5,249,889	$ 4,980,664	
19 ALLOWED EQUITY RETURN	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	
20 EQUITY COMPONENT AFTER-TAX	28,604	27,635	26,665	25,695	24,726	23,756	22,786	21,817	20,847	19,878	18,908	17,938	279,255
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	46,687	45,106	43,523	41,939	40,358	38,775	37,191	35,610	34,026	32,445	30,862	29,278	455,800
23													
24 ALLOWED DEBT RETURN	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	
25 DEBT COMPONENT	12,887	12,450	12,013	11,576	11,139	10,703	10,266	9,829	9,392	8,955	8,518	8,082	125,810
26													
27 TOTAL RETURN REQUIREMENTS	59,574	57,556	55,536	53,515	51,497	49,478	47,457	45,439	43,418	41,400	39,380	37,360	581,610
28													
29 TOTAL DEPRECIATION & RETURN	328,799	326,781	324,761	322,740	320,722	318,703	316,682	314,664	312,643	310,625	308,605	306,585	3,812,311
30													
31 ESTIMATED FUEL SAVINGS	$0	$1,022,220	$0	$699,650	$644,100	$1,290,708	$633,591	$636,303	$829,962	$1,001,100	$1,231,482	$1,293,072	9,282,188
32 RECOVERABLE TOTAL DEPRECIATION & RETURN	328,799	326,781	324,761	322,740	320,722	318,703	316,682	314,664	312,643	310,625	308,605	306,585	3,812,311
33 NET BENEFIT (COST) TO RATEPAYER	(328,799)	695,439	(324,761)	376,910	323,378	972,005	316,909	321,639	517,319	690,475	922,877	986,487	5,469,877

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2016 THROUGH DECEMBER 2016

	PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1 BEGINNING BALANCE	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455
2 **ADD INVESTMENT**								-					-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455
5													
6													
7 AVERAGE BALANCE	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	18,247,455	
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	304,124	304,124	304,124	304,124	304,124	304,124	304,124	304,124	304,124	304,124	304,124	304,124	3,649,491
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	2,596,406	2,900,531	3,204,655	3,508,779	3,812,903.41	4,117,028	4,421,152	4,725,276	5,029,400	5,333,525	5,637,649	5,941,773	2,596,406
12 ENDING BALANCE DEPRECIATION	2,900,531	3,204,655	3,508,779	3,812,903	4,117,027.66	4,421,152	4,725,276	5,029,400	5,333,525	5,637,649	5,941,773	6,245,897	6,245,897
13													
14													
15 ENDING NET INVESTMENT	15,346,924	15,042,800	14,738,676	14,434,551	14,130,427	13,826,303	13,522,179	13,218,054	12,913,930	12,609,806	12,305,682	12,001,557	12,001,557
16													
17													
18 AVERAGE INVESTMENT	$15,498,986	$15,194,862	$14,890,738	$14,586,614	$14,282,489	$13,978,365	$13,674,241	$13,370,117	$13,065,992	$12,761,868	$12,457,744	$12,153,620	
19 ALLOWED EQUITY RETURN	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	
20 EQUITY COMPONENT AFTER-TAX	55,821	54,726	53,630	52,535	51,440	50,344	49,249	48,154	47,058	45,963	44,868	43,772	597,560
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	$91,111	$89,324	$87,535	$85,748	$83,960	$82,171	$80,384	$78,597	$76,808	$75,021	$73,234	$71,445	$975,338
23													
24 ALLOWED DEBT RETURN	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	
25 DEBT COMPONENT	$25,148	$24,655	$24,161	$23,668	$23,175	$22,681	$22,188	$21,694	$21,201	$20,707	$20,214	$19,720	$269,212
26													
27 TOTAL RETURN REQUIREMENTS	$116,259	$113,979	$111,696	$109,416	$107,135	$104,852	$102,572	$100,291	$98,009	$95,728	$93,448	$91,165	$1,244,550
28 PRIOR MONTH TRUE-UP													-
29 TOTAL DEPRECIATION & RETURN	$420,383	$418,103	$415,820	$413,540	$411,259	$408,976	$406,696	$404,415	$402,133	$399,852	$397,572	$395,289	$4,894,041
30													
31 ESTIMATED FUEL SAVINGS	$369,439	$266,931	$581,990	$462,887	$502,255	$382,860	$398,847	$398,595	$372,609	$372,706	$602,758	$426,192	$5,138,068
32 TOTAL DEPRECIATION & RETURN	$420,383	$418,103	$415,820	$413,540	$411,259	$408,976	$406,696	$404,415	$402,133	$399,852	$397,572	$395,289	$4,894,041
33 NET BENEFIT (COST) TO RATEPAYER	($50,945)	($151,172)	$166,169	$49,347	$90,996	($26,117)	($7,849)	($5,820)	($29,524)	($27,146)	$205,186	$30,902	$244,027

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company

Calculation of Revenue Requirement Rate of Return for Cost Recovery Clauses

January 2016 to December 2016 Estimated Period

	(1) Jurisdictional Rate Base *Actual May 2015* Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,500,445	35.24%	5.33%	1.8783%
Short Term Debt	25,918	0.61%	0.71%	0.0043%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	108,557	2.55%	2.27%	0.0579%
Common Equity	1,791,818	42.09%	10.25%	4.3142%
Deferred ITC - Weighted Cost	7,573	0.18%	7.96%	0.0143%
Accumulated Deferred Income Taxes & Zero Cost ITCs	823,006	19.33%	0.00%	0.0000%
Total	$ 4,257,317	100.00%		6.27%

ITC split between Debt and Equity:

Long Term Debt	$ 1,500,445	Long Term Debt	45.22%
Short Term Debt	25,918	Short Term Debt	0.78%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,791,818	Equity - Common	54.00%
Total	$ 3,318,181	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0143% * 46.00%	0.0066%
Equity = .0143% * 54.00%	0.0077%
Weighted Cost	0.0143%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3142%
Deferred ITC - Weighted Cost	0.0077%
	4.3219%
Times Tax Multiplier	1.632200
Total Equity Component	7.0542%

Total Debt Cost Rate:

Long Term Debt	1.8783%
Short Term Debt	0.0043%
Customer Deposits	0.0579%
Deferred ITC - Weighted Cost	0.0066%
Total Debt Component	1.9471%
	9.0013%

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)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2016 THROUGH DECEMBER 2016

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: SEPTEMBER 1, 2015

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 2016 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 2, Big Bend Unit 3, and Polk 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. Big Bend Units 1-4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2016 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 2016 period, the projected EUOF for Bayside Unit 1 is 6.2 percent, and the POF is 17.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 76.1 percent or:

$$100\% - (6.2\% + 17.8\%) = 76.1\%$$

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

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

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

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

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

$$EAF_{MAX} = 1 - [0.80\ (6.2\%) + 0.95\ (17.8\%)] = 78.2\%$$

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,

$$EAF_{MIN} = 1 - [1.40\ (6.2\%) + 1.10\ (17.8\%)] = 71.8\%$$

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 2016 are shown on page 21 of Document No. 1. Five GPIF units have a major outage of 28 days or greater in 2016; therefore, five 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 January 30, 2016 to February 7, 2016 and September 24, 2016 to November 18, 2016. There are 1,561 planned outage hours scheduled for the 2016 period, and a total of 8,784 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 17.8 percent or:

$$\frac{1{,}561}{8{,}784} \times 100\% = 17.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 6.6 percent. Big Bend Unit 2 has a POF of 18.0 percent. Big Bend Unit 3 has a POF of 12.3 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 10.4 percent. Bayside Unit 1 has a POF of 17.8 percent, and Bayside Unit 2 has a POF of 10.6 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 6.2 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

$$EUOF = \frac{(219 + 322)}{8,784} \times 100\% = 6.2\%$$

Relative to Bayside Unit 1, the EUOF of 6.2 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 14.7 percent. The unit will have two planned outages in 2016, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 78.7 percent.

Big Bend Unit 2

The projected EUOF for this unit is 13.2 percent. The unit will have two planned outages in 2016, and the POF is 18.0 percent. Therefore, the target equivalent availability for this unit is 68.7 percent.

Big Bend Unit 3

The projected EUOF for this unit is 11.1 percent. The unit will have two planned outages in 2016, and the POF is 12.3 percent. Therefore, the target equivalent availability for this unit is 76.6 percent.

Big Bend Unit 4

The projected EUOF for this unit is 16.5 percent. The unit will have two planned outages in 2016, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 76.9 percent.

Polk Unit 1

The projected EUOF for this unit is 8.1 percent. The unit will have two planned outages in 2016, and the POF is 10.4 percent. Therefore, the target equivalent availability for this unit is 81.5 percent.

Bayside Unit 1

The projected EUOF for this unit is 6.2 percent. The unit will have two planned outages in 2016, and the POF is 17.8 percent. Therefore, the target equivalent availability for this unit is 76.1 percent.

Bayside Unit 2

The projected EUOF for this unit is 6.3 percent. The unit will have two planned outages in 2016, and the POF is 10.6 percent. Therefore, the target equivalent availability for this unit is 83.1 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 77.6 percent is shown on Page 5 of Document No. 1. This target is similar to the last three years' 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 January, February, September, and November, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of January, February, September, and November, the Equivalent Unplanned Outage Rate exceeds the

Equivalent Unplanned Outage Factor due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

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

Q. How were these targets determined?

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

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

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

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

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2016 period.

A. The heat rate target for Big Bend Unit 1 is 10,683 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 210 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,460 Btu/Net kWh with a range of ± 435 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,654 Btu/Net kWh, with a range of ± 213 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,458 Btu/Net kWh with a range of ± 383 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,191 Btu/Net kWh with a range of ± 354 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,232

Btu/Net kWh with a range of ± 265 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,484 Btu/Net kWh with a range of ± 217 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 $679,116,440 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 $20,269,972 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 14.36 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 6,967 average net operating heat rate, fuel savings would equal $2,911,564 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 $20,269,972. 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 2016 is $2,300,227,560. This produces the maximum allowed jurisdictional incentive of $9,386,068 shown on line 21.

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

A. Yes. As Order No. PSC-13-0665-FOF-EI issued in Docket No. 130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $9,386,068.

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):

$$\begin{aligned} GPIP: = (&0.0189\ EAP_{BB1} + 0.0441\ EAP_{BB2} \\ &+ 0.0320\ EAP_{BB3} + 0.0332\ EAP_{BB4} \\ &+ 0.0076\ EAP_{PK1} + 0.0412\ EAP_{BAY1} \\ &+ 0.0844\ EAP_{BAY2} + 0.0690\ HRP_{BB1} \\ &+ 0.1247\ HRP_{BB2} + 0.0659\ HRP_{BB3} \\ &+ 0.1312\ HRP_{BB4} + 0.0651\ HRP_{PK1} \\ &+ 0.1436\ HRP_{BAY1} + 0.1389\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2016 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 2016 – DECEMBER 2016

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2016 - DECEMBER 2016
TARGETS

TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2016 - DECEMBER 2016

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	20,270.0	9,386.1
+9	18,243.0	8,447.5
+8	16,216.0	7,508.9
+7	14,189.0	6,570.2
+6	12,162.0	5,631.6
+5	10,135.0	4,693.0
+4	8,108.0	3,754.4
+3	6,081.0	2,815.8
+2	4,054.0	1,877.2
+1	2,027.0	938.6
0	0.0	0.0
-1	(2,042.1)	(938.6)
-2	(4,084.3)	(1,877.2)
-3	(6,126.4)	(2,815.8)
-4	(8,168.5)	(3,754.4)
-5	(10,210.6)	(4,693.0)
-6	(12,252.8)	(5,631.6)
-7	(14,294.9)	(6,570.2)
-8	(16,337.0)	(7,508.9)
-9	(18,379.2)	(8,447.5)
-10	(20,421.3)	(9,386.1)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2016 - DECEMBER 2016

Line 1	Beginning of period balance of common equity: End of month common equity:		$2,271,393,000	
Line 2	Month of January	2016	$2,216,992,000	
Line 3	Month of February	2016	$2,235,928,807	
Line 4	Month of March	2016	$2,255,027,365	
Line 5	Month of April	2016	$2,290,654,692	
Line 6	Month of May	2016	$2,310,220,701	
Line 7	Month of June	2016	$2,329,953,836	
Line 8	Month of July	2016	$2,274,929,054	
Line 9	Month of August	2016	$2,294,360,740	
Line 10	Month of September	2016	$2,313,958,405	
Line 11	Month of October	2016	$2,349,718,897	
Line 12	Month of November	2016	$2,369,789,413	
Line 13	Month of December	2016	$2,390,031,364	
Line 14	(Summation of line 1 through line 13 divided by 13)		$2,300,227,560	
Line 15	25 Basis points		0.0025	
Line 16	Revenue Expansion Factor		61.27%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$9,386,068	
Line 18	Jurisdictional Sales		18,790,524	MWH
Line 19	Total Sales		18,790,524	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)		$9,386,068	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$9,386,068	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$9,386,068	

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

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2016 - DECEMBER 2016

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	1.89%	78.7	82.0	72.2	382.8	(960.8)
BIG BEND 2	4.41%	68.7	72.3	61.6	893.6	(504.8)
BIG BEND 3	3.20%	76.6	79.5	71.0	648.9	(561.3)
BIG BEND 4	3.32%	76.9	80.6	69.7	673.1	(1,958.4)
POLK 1	0.76%	81.5	83.7	77.2	153.6	(511.0)
BAYSIDE 1	4.12%	76.1	78.2	71.8	835.8	(136.0)
BAYSIDE 2	8.44%	83.1	84.9	79.5	1,711.3	(818.2)
GPIF SYSTEM	**26.14%**					

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	6.90%	10,683	91.1	10,473	10,893	1,399.4	(1,399.4)
BIG BEND 2	12.47%	10,460	92.2	10,025	10,895	2,528.1	(2,528.1)
BIG BEND 3	6.59%	10,654	89.6	10,441	10,867	1,336.8	(1,336.8)
BIG BEND 4	13.12%	10,458	91.0	10,075	10,842	2,659.8	(2,659.8)
POLK 1	6.51%	10,191	94.0	9,837	10,545	1,319.6	(1,319.6)
BAYSIDE 1	14.36%	7,232	71.6	6,967	7,496	2,911.6	(2,911.6)
BAYSIDE 2	13.89%	7,484	53.5	7,267	7,701	2,815.6	(2,815.6)
GPIF SYSTEM	**73.86%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 16 - DEC 16 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 14 - DEC 14 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 13 - DEC 13 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 12 - DEC 12 POF	EUOF	EUOR
BIG BEND 1	1.89%	7.2%	6.6	14.7	15.8	5.6	10.8	11.5	10.8	17.6	19.8	6.8	26.2	28.3
BIG BEND 2	4.41%	16.9%	18.0	13.2	16.1	8.4	10.6	11.6	6.1	18.3	19.5	4.0	17.9	18.7
BIG BEND 3	3.20%	12.2%	12.3	11.1	12.6	5.1	15.8	16.7	25.0	8.5	11.3	2.8	25.0	25.7
BIG BEND 4	3.32%	12.7%	6.6	16.5	17.7	20.7	11.2	14.2	4.8	17.6	18.5	8.2	16.2	17.6
POLK 1	0.76%	2.9%	10.4	8.1	9.0	5.0	8.7	10.6	15.3	6.7	8.8	12.7	17.3	21.0
BAYSIDE 1	4.12%	15.8%	17.8	6.2	7.5	6.2	11.5	14.1	3.8	7.5	8.7	1.9	3.0	2.0
BAYSIDE 2	8.44%	32.3%	10.6	6.3	7.0	5.0	5.4	5.7	4.1	12.2	13.1	16.5	7.5	2.9
GPIF SYSTEM	**26.14%**	**100.0%**	**12.4**	**10.0**	**11.4**	**7.8**	**9.7**	**11.0**	**7.8**	**13.0**	**14.3**	**8.5**	**13.4**	**12.5**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**77.6**			**82.5**			**79.2**			**78.0**	

		3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
	100.00%				
2006	**51.9%**				
2005		**8.1**	**12.0**	**12.6**	**79.9**
2004	**51.9%**				

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 16 - DEC 16	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 14 - DEC 14	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 13 - DEC 13	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 12 - DEC 12
BIG BEND 1	6.90%	9.3%	10,683	10,534	10,477	10,496
BIG BEND 2	12.47%	16.9%	10,460	10,251	10,266	10,305
BIG BEND 3	6.59%	8.9%	10,654	10,445	10,565	10,544
BIG BEND 4	13.12%	17.8%	10,458	10,238	10,407	10,384
POLK 1	6.51%	8.8%	10,191	10,198	10,587	10,662
BAYSIDE 1	14.36%	19.4%	7,232	7,249	7,164	7,139
BAYSIDE 2	13.89%	18.8%	7,484	7,477	7,451	7,396
GPIF SYSTEM	**73.86%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,287**	**9,182**	**9,233**	**9,227**

DOCKET NO. 150001-EI
GPIF 2016 PROJECTION
EXHIBIT NO. ___ (BSB-2), DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.16E
PAGE 5 OF 40

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2016 - DECEMBER 2016
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	679,116.4	678,733.7	382.8	1.89%
EA_2 BIG BEND 2	679,116.4	678,222.8	893.6	4.41%
EA_3 BIG BEND 3	679,116.4	678,467.5	648.9	3.20%
EA_4 BIG BEND 4	679,116.4	678,443.4	673.1	3.32%
EA_5 POLK 1	679,116.4	678,962.8	153.6	0.76%
EA_6 BAYSIDE 1	679,116.4	678,280.7	835.8	4.12%
EA_7 BAYSIDE 2	679,116.4	677,405.1	1,711.3	8.44%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	679,116.4	677,717.0	1,399.4	6.90%
AHR_2 BIG BEND 2	679,116.4	676,588.4	2,528.1	12.47%
AHR_3 BIG BEND 3	679,116.4	677,779.7	1,336.8	6.59%
AHR_4 BIG BEND 4	679,116.4	676,456.7	2,659.8	13.12%
AHR_5 POLK 1	679,116.4	677,796.9	1,319.6	6.51%
AHR_6 BAYSIDE 1	679,116.4	676,204.9	2,911.6	14.36%
AHR_7 BAYSIDE 2	679,116.4	676,300.8	2,815.6	13.89%
TOTAL SAVINGS			**20,270.0**	**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 2016 - DECEMBER 2016

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	382.8	82.0	+10	1,399.4	10,473
+9	344.5	81.7	+9	1,259.5	10,486
+8	306.2	81.3	+8	1,119.5	10,500
+7	267.9	81.0	+7	979.6	10,513
+6	229.7	80.7	+6	839.7	10,527
+5	191.4	80.3	+5	699.7	10,540
+4	153.1	80.0	+4	559.8	10,554
+3	114.8	79.7	+3	419.8	10,567
+2	76.6	79.4	+2	279.9	10,581
+1	38.3	79.0	+1	139.9	10,594
					10,608
0	0.0	78.7	0	0.0	10,683
					10,758
-1	(96.1)	78.1	-1	(139.9)	10,772
-2	(192.2)	77.4	-2	(279.9)	10,785
-3	(288.2)	76.7	-3	(419.8)	10,799
-4	(384.3)	76.1	-4	(559.8)	10,812
-5	(480.4)	75.4	-5	(699.7)	10,826
-6	(576.5)	74.8	-6	(839.7)	10,839
-7	(672.5)	74.1	-7	(979.6)	10,853
-8	(768.6)	73.5	-8	(1,119.5)	10,866
-9	(864.7)	72.8	-9	(1,259.5)	10,880
-10	(960.8)	72.2	-10	(1,399.4)	10,893
	Weighting Factor =	1.89%		Weighting Factor =	6.90%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	893.6	72.3	+10	2,528.1	10,025
+9	804.2	71.9	+9	2,275.3	10,061
+8	714.9	71.6	+8	2,022.5	10,097
+7	625.5	71.2	+7	1,769.7	10,133
+6	536.2	70.9	+6	1,516.8	10,169
+5	446.8	70.5	+5	1,264.0	10,205
+4	357.4	70.2	+4	1,011.2	10,241
+3	268.1	69.8	+3	758.4	10,277
+2	178.7	69.4	+2	505.6	10,313
+1	89.4	69.1	+1	252.8	10,349
					10,385
0	0.0	68.7	0	0.0	10,460
					10,535
-1	(50.5)	68.0	-1	(252.8)	10,571
-2	(101.0)	67.3	-2	(505.6)	10,607
-3	(151.4)	66.6	-3	(758.4)	10,643
-4	(201.9)	65.9	-4	(1,011.2)	10,679
-5	(252.4)	65.2	-5	(1,264.0)	10,715
-6	(302.9)	64.5	-6	(1,516.8)	10,751
-7	(353.4)	63.8	-7	(1,769.7)	10,787
-8	(403.9)	63.1	-8	(2,022.5)	10,823
-9	(454.3)	62.3	-9	(2,275.3)	10,859
-10	(504.8)	61.6	-10	(2,528.1)	10,895
	Weighting Factor =	4.41%		Weighting Factor =	12.47%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	648.9	79.5	+10	1,336.8	10,441
+9	584.0	79.2	+9	1,203.1	10,455
+8	519.1	78.9	+8	1,069.4	10,469
+7	454.2	78.6	+7	935.7	10,483
+6	389.4	78.3	+6	802.1	10,496
+5	324.5	78.1	+5	668.4	10,510
+4	259.6	77.8	+4	534.7	10,524
+3	194.7	77.5	+3	401.0	10,538
+2	129.8	77.2	+2	267.4	10,551
+1	64.9	76.9	+1	133.7	10,565
					10,579
0	0.0	76.6	0	0.0	10,654
					10,729
-1	(56.1)	76.1	-1	(133.7)	10,743
-2	(112.3)	75.5	-2	(267.4)	10,757
-3	(168.4)	74.9	-3	(401.0)	10,770
-4	(224.5)	74.4	-4	(534.7)	10,784
-5	(280.6)	73.8	-5	(668.4)	10,798
-6	(336.8)	73.3	-6	(802.1)	10,812
-7	(392.9)	72.7	-7	(935.7)	10,825
-8	(449.0)	72.1	-8	(1,069.4)	10,839
-9	(505.1)	71.6	-9	(1,203.1)	10,853
-10	(561.3)	71.0	-10	(1,336.8)	10,867
	Weighting Factor =	3.20%		Weighting Factor =	6.59%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	673.1	80.6	+10	2,659.8	10,075
+9	605.8	80.2	+9	2,393.8	10,106
+8	538.5	79.8	+8	2,127.8	10,136
+7	471.2	79.5	+7	1,861.8	10,167
+6	403.8	79.1	+6	1,595.9	10,198
+5	336.5	78.8	+5	1,329.9	10,229
+4	269.2	78.4	+4	1,063.9	10,260
+3	201.9	78.0	+3	797.9	10,291
+2	134.6	77.7	+2	532.0	10,321
+1	67.3	77.3	+1	266.0	10,352
					10,383
0	0.0	76.9	0	0.0	10,458
					10,533
-1	(195.8)	76.2	-1	(266.0)	10,564
-2	(391.7)	75.5	-2	(532.0)	10,595
-3	(587.5)	74.8	-3	(797.9)	10,626
-4	(783.4)	74.0	-4	(1,063.9)	10,657
-5	(979.2)	73.3	-5	(1,329.9)	10,687
-6	(1,175.1)	72.6	-6	(1,595.9)	10,718
-7	(1,370.9)	71.9	-7	(1,861.8)	10,749
-8	(1,566.7)	71.1	-8	(2,127.8)	10,780
-9	(1,762.6)	70.4	-9	(2,393.8)	10,811
-10	(1,958.4)	69.7	-10	(2,659.8)	10,842
	Weighting Factor =	3.32%		Weighting Factor =	13.12%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	153.6	83.7	+10	1,319.6	9,837
+9	138.2	83.4	+9	1,187.6	9,865
+8	122.9	83.2	+8	1,055.7	9,892
+7	107.5	83.0	+7	923.7	9,920
+6	92.2	82.8	+6	791.8	9,948
+5	76.8	82.6	+5	659.8	9,976
+4	61.4	82.4	+4	527.8	10,004
+3	46.1	82.2	+3	395.9	10,032
+2	30.7	81.9	+2	263.9	10,060
+1	15.4	81.7	+1	132.0	10,088
					10,116
0	0.0	81.5	0	0.0	10,191
					10,266
-1	(51.1)	81.1	-1	(132.0)	10,294
-2	(102.2)	80.7	-2	(263.9)	10,322
-3	(153.3)	80.2	-3	(395.9)	10,350
-4	(204.4)	79.8	-4	(527.8)	10,377
-5	(255.5)	79.4	-5	(659.8)	10,405
-6	(306.6)	79.0	-6	(791.8)	10,433
-7	(357.7)	78.5	-7	(923.7)	10,461
-8	(408.8)	78.1	-8	(1,055.7)	10,489
-9	(459.9)	77.7	-9	(1,187.6)	10,517
-10	(511.0)	77.2	-10	(1,319.6)	10,545
	Weighting Factor =	0.76%		Weighting Factor =	6.51%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	835.8	78.2	+10	2,911.6	6,967
+9	752.2	78.0	+9	2,620.4	6,986
+8	668.6	77.8	+8	2,329.3	7,005
+7	585.0	77.6	+7	2,038.1	7,024
+6	501.5	77.3	+6	1,746.9	7,043
+5	417.9	77.1	+5	1,455.8	7,062
+4	334.3	76.9	+4	1,164.6	7,081
+3	250.7	76.7	+3	873.5	7,100
+2	167.2	76.5	+2	582.3	7,119
+1	83.6	76.3	+1	291.2	7,138
					7,157
0	0.0	76.1	0	0.0	7,232
					7,307
-1	(13.6)	75.6	-1	(291.2)	7,326
-2	(27.2)	75.2	-2	(582.3)	7,345
-3	(40.8)	74.8	-3	(873.5)	7,364
-4	(54.4)	74.4	-4	(1,164.6)	7,383
-5	(68.0)	73.9	-5	(1,455.8)	7,402
-6	(81.6)	73.5	-6	(1,746.9)	7,420
-7	(95.2)	73.1	-7	(2,038.1)	7,439
-8	(108.8)	72.7	-8	(2,329.3)	7,458
-9	(122.4)	72.2	-9	(2,620.4)	7,477
-10	(136.0)	71.8	-10	(2,911.6)	7,496
	Weighting Factor =	4.12%		Weighting Factor =	14.36%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2016 - DECEMBER 2016

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	1,711.3	84.9	+10	2,815.6	7,267
+9	1,540.2	84.7	+9	2,534.1	7,282
+8	1,369.1	84.5	+8	2,252.5	7,296
+7	1,197.9	84.3	+7	1,970.9	7,310
+6	1,026.8	84.1	+6	1,689.4	7,324
+5	855.7	84.0	+5	1,407.8	7,338
+4	684.5	83.8	+4	1,126.3	7,352
+3	513.4	83.6	+3	844.7	7,367
+2	342.3	83.4	+2	563.1	7,381
+1	171.1	83.3	+1	281.6	7,395
					7,409
0	0.0	83.1	0	0.0	7,484
					7,559
-1	(81.8)	82.7	-1	(281.6)	7,573
-2	(163.6)	82.4	-2	(563.1)	7,587
-3	(245.4)	82.0	-3	(844.7)	7,602
-4	(327.3)	81.6	-4	(1,126.3)	7,616
-5	(409.1)	81.3	-5	(1,407.8)	7,630
-6	(490.9)	80.9	-6	(1,689.4)	7,644
-7	(572.7)	80.6	-7	(1,970.9)	7,658
-8	(654.5)	80.2	-8	(2,252.5)	7,672
-9	(736.3)	79.9	-9	(2,534.1)	7,687
-10	(818.2)	79.5	-10	(2,815.6)	7,701
	Weighting Factor =	8.44%		Weighting Factor =	13.89%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	84.2	84.2	84.2	44.9	84.2	84.2	84.2	84.2	84.2	84.2	84.2	57.1	78.7
2. POF	0.0	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	15.8	15.8	15.8	8.4	15.8	15.8	15.8	15.8	15.8	15.8	15.8	10.7	14.7
4. EUOR	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	674	630	674	348	674	652	674	674	652	674	652	456	7,434
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	70	66	69	372	70	68	70	70	68	70	69	288	1,350
9. POH	0	0	0	336	0	0	0	0	0	0	0	240	576
10. EFOH	100	93	99	51	100	96	100	100	96	100	96	67	1,098
11. EMOH	18	17	18	9	18	17	18	18	17	18	17	12	196
12. OPER BTU (GBTU)	2,568	2,443	2,599	1,288	2,527	2,462	2,540	2,548	2,461	2,517	2,445	1,703	28,104
13. NET GEN (MWH)	240,010	229,060	243,430	120,280	236,550	230,770	238,000	238,840	230,660	235,480	228,920	158,680	2,630,680
14. ANOHR (Btu/kwh)	10,699	10,667	10,678	10,706	10,682	10,669	10,673	10,668	10,670	10,689	10,682	10,734	10,683
15. NOF (%)	90.2	92.0	91.4	89.8	91.2	91.9	91.7	92.0	91.9	90.7	91.2	88.1	91.1
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	-16.858	) +		12,219								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	83.9	83.9	83.9	5.6	8.1	83.9	83.9	83.9	83.9	83.9	83.9	56.8	68.7
2. POF	0.0	0.0	0.0	93.3	90.3	0.0	0.0	0.0	0.0	0.0	0.0	32.3	18.0
3. EUOF	16.1	16.1	16.1	1.1	1.6	16.1	16.1	16.1	16.1	16.1	16.1	10.9	13.2
4. EUOR	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	663	620	663	43	65	641	663	663	641	663	641	449	6,415
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	81	76	80	677	679	79	81	81	79	81	80	295	2,369
9. POH	0	0	0	672	672	0	0	0	0	0	0	240	1,584
10. EFOH	90	84	90	6	9	87	90	90	87	90	87	61	870
11. EMOH	30	28	30	2	3	29	30	30	29	30	29	20	292
12. OPER BTU (GBTU)	2,477	2,373	2,538	151	224	2,401	2,484	2,488	2,401	2,444	2,382	1,657	24,016
13. NET GEN (MWH)	235,730	227,110	242,890	14,260	21,050	230,070	238,000	238,510	230,090	233,220	227,770	157,270	2,295,970
14. ANOHR (Btu/kwh)	10,507	10,448	10,447	10,591	10,635	10,437	10,437	10,432	10,437	10,477	10,457	10,536	10,460
15. NOF (%)	90.0	92.7	92.7	86.1	84.1	93.2	93.2	93.4	93.2	91.4	92.3	88.7	92.2
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388

17. ANOHR EQUATION ANOHR = NOF(-21.726) + 12,462

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	87.4	0.0	70.4	87.4	87.4	87.4	87.4	87.4	87.4	78.9	67.0	87.4	76.6
2. POF	0.0	100.0	19.4	0.0	0.0	0.0	0.0	0.0	0.0	9.7	23.3	0.0	12.3
3. EUOF	12.6	0.0	10.2	12.6	12.6	12.6	12.6	12.6	12.6	11.4	9.7	12.6	11.1
4. EUOR	12.6	0.0	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	706	0	569	683	706	683	706	706	683	638	524	706	7,310
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	38	696	174	37	38	37	38	38	37	106	197	38	1,474
9. POH	0	696	144	0	0	0	0	0	0	72	168	0	1,080
10. EFOH	68	0	55	66	68	66	68	68	66	62	51	68	709
11. EMOH	25	0	20	25	25	25	25	25	25	23	19	25	263
12. OPER BTU (GBTU)	2,597	0	2,175	2,610	2,700	2,615	2,701	2,722	2,625	2,338	1,946	2,631	27,665
13. NET GEN (MWH)	242,250	0	204,200	245,580	254,070	246,100	254,200	256,520	247,200	218,400	182,180	245,980	2,596,680
14. ANOHR (Btu/kwh)	10,719	0	10,651	10,629	10,627	10,625	10,627	10,612	10,618	10,704	10,680	10,696	10,654
15. NOF (%)	85.8	0.0	89.7	91.0	91.1	91.2	91.2	92.0	91.6	86.7	88.0	87.1	89.6
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397
17. ANOHR EQUATION	ANOHR = NOF(		-17.139	) +	12,189								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:
BIG BEND 4	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
1. EAF (%)	82.3	82.3	45.1	82.3	82.3	82.3
2. POF	0.0	0.0	45.2	0.0	0.0	0.0
3. EUOF	17.7	17.7	9.7	17.7	17.7	17.7
4. EUOR	17.7	17.7	17.7	17.7	17.7	17.7
5. PH	744	696	743	720	744	720
6. SH	660	618	362	639	660	639
7. RSH	0	0	0	0	0	0
8. UH	84	78	381	81	84	81
9. POH	0	0	336	0	0	0
10. EFOH	104	97	57	101	104	101
11. EMOH	27	26	15	27	27	27
12. OPER BTU (GBTU)	2,744	2,620	1,512	2,661	2,754	2,678
13. NET GEN (MWH)	261,920	250,810	144,380	254,440	263,390	256,280
14. ANOHR (Btu/kwh)	10,476	10,447	10,469	10,457	10,454	10,448
15. NOF (%)	89.8	91.8	90.2	91.1	91.3	91.8
16. NPC (MW)	442	442	442	437	437	437

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	82.3	82.3	82.3	82.3	54.9	82.3	76.9
2. POF	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	17.7	17.7	17.7	17.7	11.8	17.7	16.5
4. EUOR	17.7	17.7	17.7	17.7	17.7	17.7	17.7
5. PH	744	744	720	744	721	744	8,784
6. SH	660	660	639	660	426	660	7,283
7. RSH	0	0	0	0	0	0	0
8. UH	84	84	81	84	295	84	1,501
9. POH	0	0	0	0	240	0	576
10. EFOH	104	104	101	104	67	104	1,146
11. EMOH	27	27	27	27	18	27	303
12. OPER BTU (GBTU)	2,764	2,771	2,679	2,734	1,749	2,756	30,421
13. NET GEN (MWH)	264,490	265,320	256,400	261,290	166,910	263,210	2,908,840
14. ANOHR (Btu/kwh)	10,449	10,445	10,447	10,464	10,478	10,470	10,458
15. NOF (%)	91.7	92.0	91.8	90.6	89.7	90.2	91.0
16. NPC (MW)	437	437	437	437	437	442	439

17. ANOHR EQUATION   ANOHR = NOF(-13.919) + 11,725

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	91.0	62.7	20.4	91.0	91.0	91.0	91.0	91.0	91.0	91.0	75.8	91.0	81.5
2. POF	0.0	31.0	77.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	10.4
3. EUOF	9.0	6.2	2.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	7.5	9.0	8.1
4. EUOR	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	720	491	163	696	736	708	729	720	698	731	613	720	7,725
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	24	205	580	24	8	12	15	24	22	13	108	24	1,059
9. POH	0	216	576	0	0	0	0	0	0	0	120	0	912
10. EFOH	34	22	8	33	34	33	34	34	33	34	28	34	362
11. EMOH	33	21	7	32	33	32	33	33	32	33	27	33	349
12. OPER BTU (GBTU)	1,519	1,033	343	1,469	1,547	1,491	1,536	1,519	1,472	1,540	1,289	1,519	16,276
13. NET GEN (MWH)	149,060	101,270	33,660	144,160	151,680	146,340	150,780	149,060	144,540	151,160	126,380	149,060	1,597,150
14. ANOHR (Btu/kwh)	10,188	10,196	10,193	10,187	10,198	10,191	10,190	10,188	10,187	10,190	10,197	10,188	10,191
15. NOF (%)	94.1	93.8	93.9	94.1	93.7	94.0	94.0	94.1	94.1	94.0	93.7	94.1	94.0
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(		-22.730	) +	12,327								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	86.5	70.2	92.5	92.5	92.5	92.5	92.5	92.5	70.9	0.0	37.0	92.5	76.1
2. POF	6.5	24.1	0.0	0.0	0.0	0.0	0.0	0.0	23.3	100.0	60.1	0.0	17.8
3. EUOF	7.0	5.7	7.5	7.5	7.5	7.5	7.5	7.5	5.7	0.0	3.0	7.5	6.2
4. EUOR	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0.0	7.5	7.5	7.5
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	378	484	668	580	669	666	671	669	471	0	197	614	6,067
7. RSH	266	4	19	86	19	0	17	19	40	0	69	74	615
8. UH	100	208	56	54	56	54	56	56	209	744	455	56	2,102
9. POH	48	168	0	0	0	0	0	0	168	744	433	0	1,561
10. EFOH	21	16	23	22	23	22	23	23	17	0	9	23	219
11. EMOH	31	24	33	32	33	32	33	33	25	0	13	33	322
12. OPER BTU (GBTU)	1,265	2,083	2,696	2,236	2,556	2,497	2,541	2,577	1,759	0	601	2,156	22,983
13. NET GEN (MWH)	170,740	290,040	372,020	311,790	355,930	346,790	353,430	359,350	244,160	0	81,310	292,530	3,178,090
14. ANOHR (Btu/kwh)	7,408	7,183	7,247	7,170	7,180	7,199	7,189	7,171	7,203	0	7,386	7,370	7,232
15. NOF (%)	57.0	75.7	70.3	76.7	75.9	74.3	75.1	76.6	73.9	0.0	58.9	60.2	71.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731

17. ANOHR EQUATION ANOHR = NOF(-12.105) + 8,099

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2016 - DECEMBER 2016

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-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1. EAF (%)	93.0	38.5	54.1	93.0	93.0	93.0	93.0	93.0	93.0	93.0	83.7	75.0	83.1
2. POF	0.0	58.6	41.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	19.4	10.6
3. EUOF	7.0	2.9	4.1	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.3	5.7	6.3
4. EUOR	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	692	268	402	669	692	669	692	692	669	692	603	558	7,297
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	52	428	341	51	52	51	52	52	51	52	118	186	1,487
9. POH	0	408	311	0	0	0	0	0	0	0	72	144	935
10. EFOH	29	11	17	28	29	28	29	29	28	29	25	24	308
11. EMOH	23	9	13	22	23	22	23	23	22	23	20	19	244
12. OPER BTU (GBTU)	1,500	1,285	1,210	2,759	2,994	2,773	2,912	2,993	2,954	3,121	2,330	1,325	28,289
13. NET GEN (MWH)	194,450	173,410	158,810	371,270	404,430	373,400	392,610	404,400	399,670	423,020	312,180	172,240	3,779,890
14. ANOHR (Btu/kwh)	7,716	7,412	7,621	7,430	7,402	7,427	7,418	7,402	7,391	7,377	7,465	7,693	7,484
15. NOF (%)	26.8	61.8	37.8	59.7	62.9	60.0	61.1	62.9	64.3	65.8	55.7	29.5	53.5
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(		-8.685	) +	7,949								

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ORIGINAL SHEET NO. 8.401.16E
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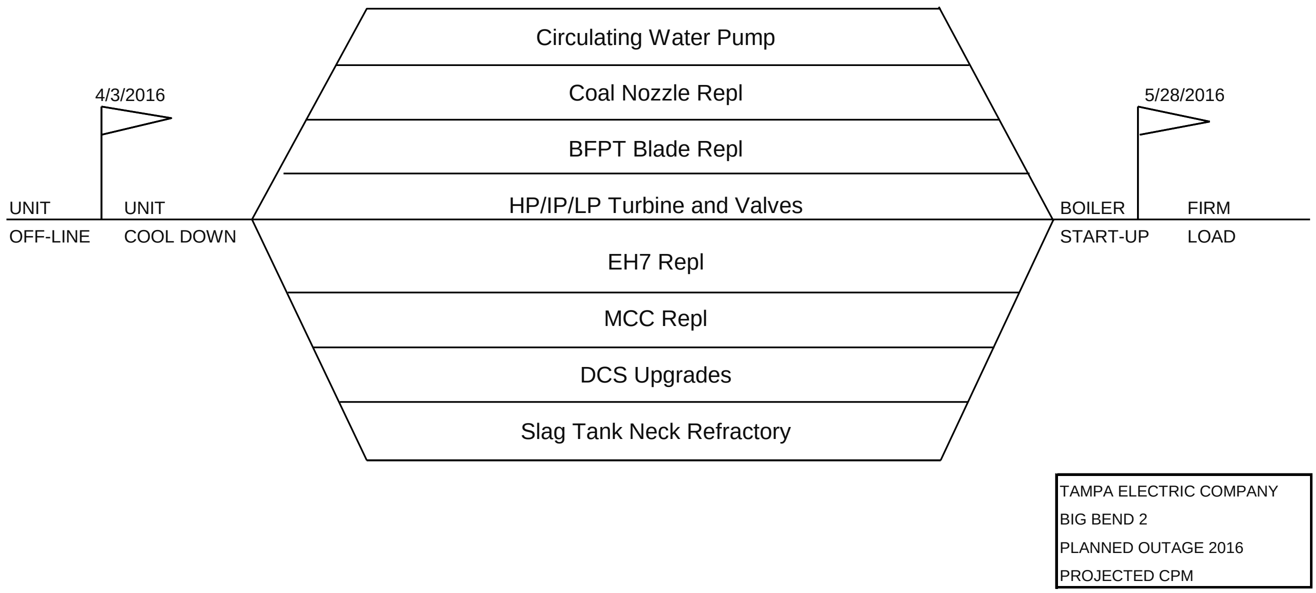
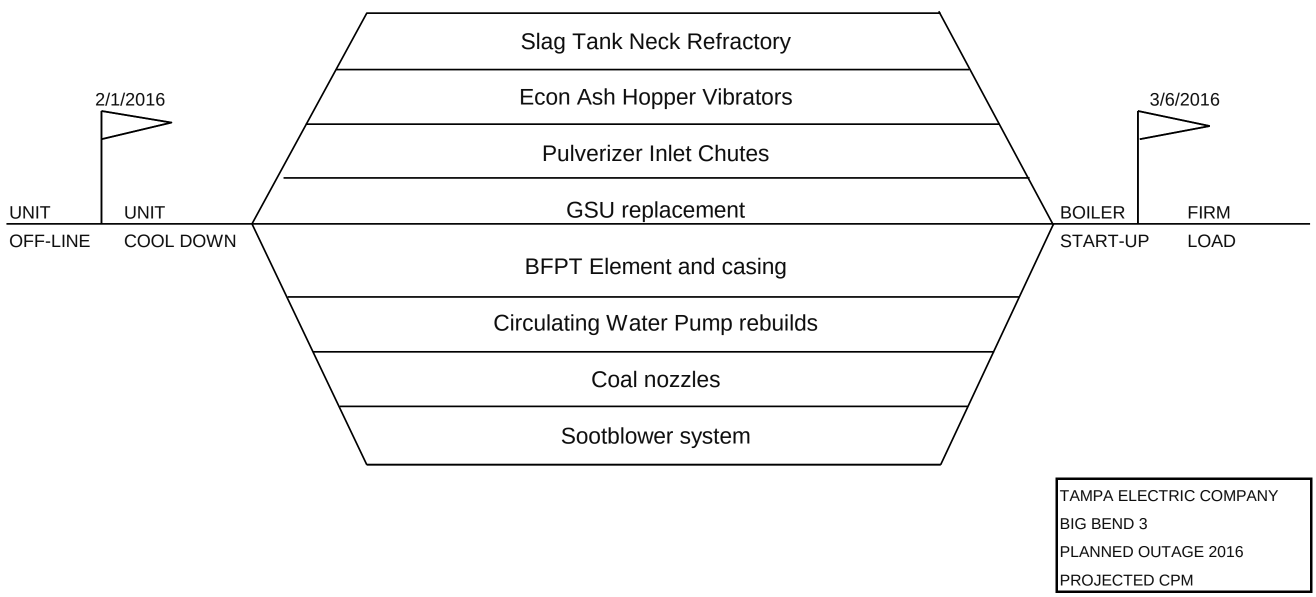
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2016 - DECEMBER 2016

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Apr 02	-	Apr 15	Fuel System Cleanup and FGD/SCR work
		Dec 03	-	Dec 12	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 2	Apr 03	-	May 28	Circulating Water Pump, Coal Nozzle Repl, BFPT Blade Repl, EH7 Repl, HP/IP/LP Turbine and Valves, MCC Repl, DCS Upgrades, Slag Tank Neck Refractory
		Dec 04	-	Dec 13	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 3	Feb 01	-	Mar 06	GSU replacement, Circulating Water Pump rebuilds, Econ Ash Hopper Vibrators, Slag Tank Neck Refractory, Pulverizer Inlet Chutes, Coal nozzles, Sootblower system, BFPT Element and casing
		Oct 29	-	Nov 07	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Mar 14	-	Mar 27	Fuel System Cleanup and FGD/SCR work
		Nov 12	-	Nov 21	Fuel System Cleanup and FGD/SCR work
+	POLK 1	Feb 21	-	Mar 24	Replace CT 1 Stage nozzles, CT Combustion Inspection, Replace HRSG Module 1 Roof, Replace MAC filters, Hydrolase ASU Heat Exchangers, Replace Rich/Lean Amine Heat Exchanger, Replace Geho Check Valve Components, Clean COS Hydrolysis Knock Out Drum
		Nov 13	-	Nov 17	Gasifier Outage
+	BAYSIDE 1	Jan 30	-	Feb 07	Fuel System Cleanup
		Sep 24	-	Nov 18	GSU replacement, HP/IP/LP steam turbine ring and seal replacement, turbine valves, generator inspection
+	BAYSIDE 2	Feb 13	-	Mar 13	Upgrading the reheat stop valves, turbine valves, Unit 2 cooling tower replacement, CT inspections
		Nov 28	-	Dec 06	Fuel System Cleanup

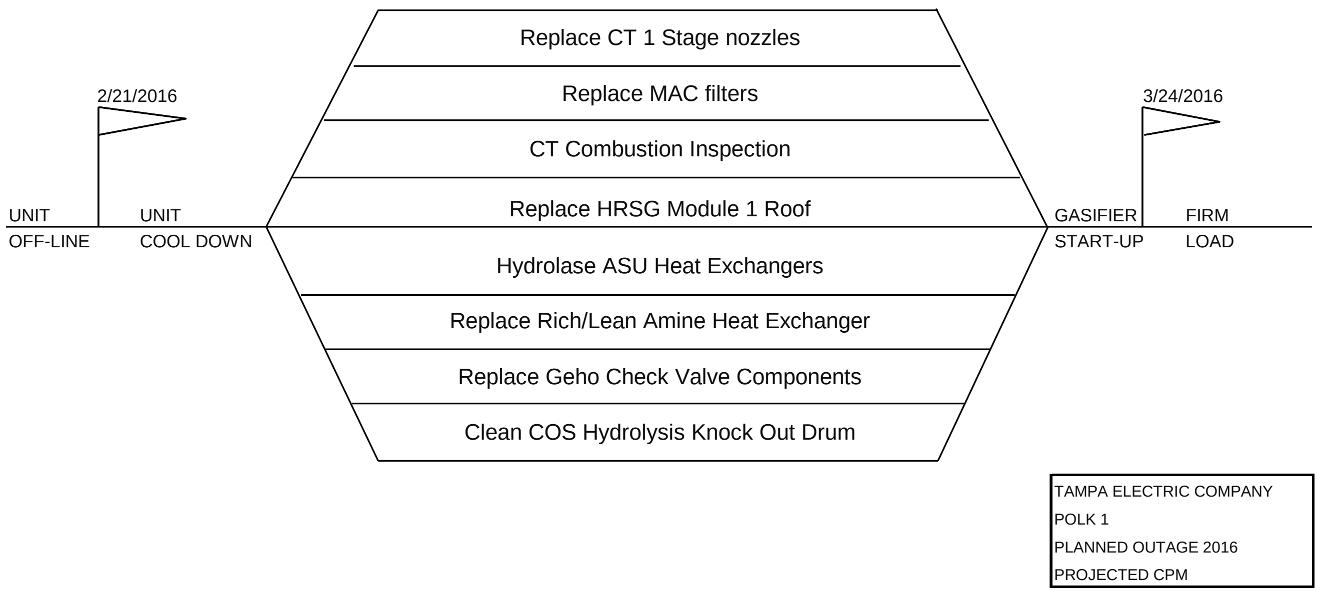
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

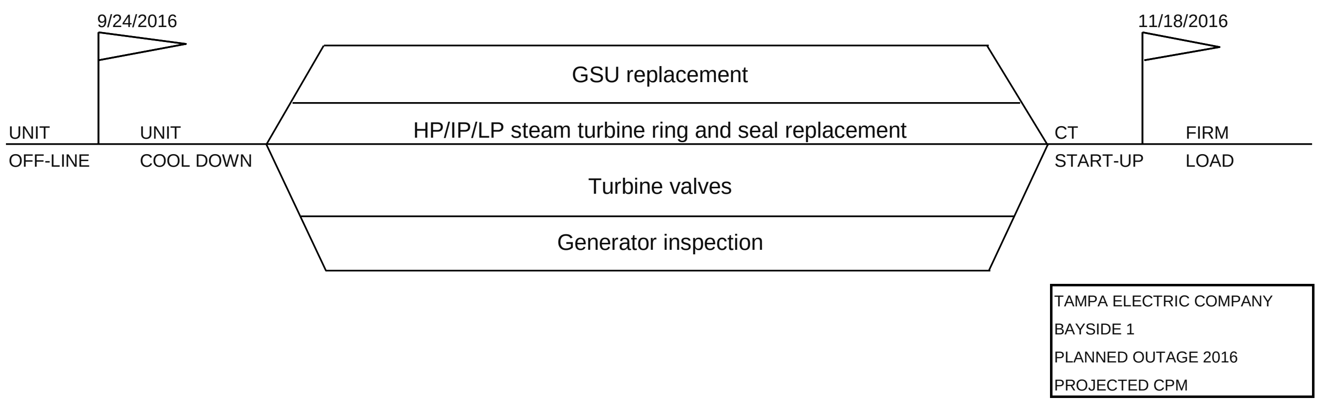
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2016 - DECEMBER 2016

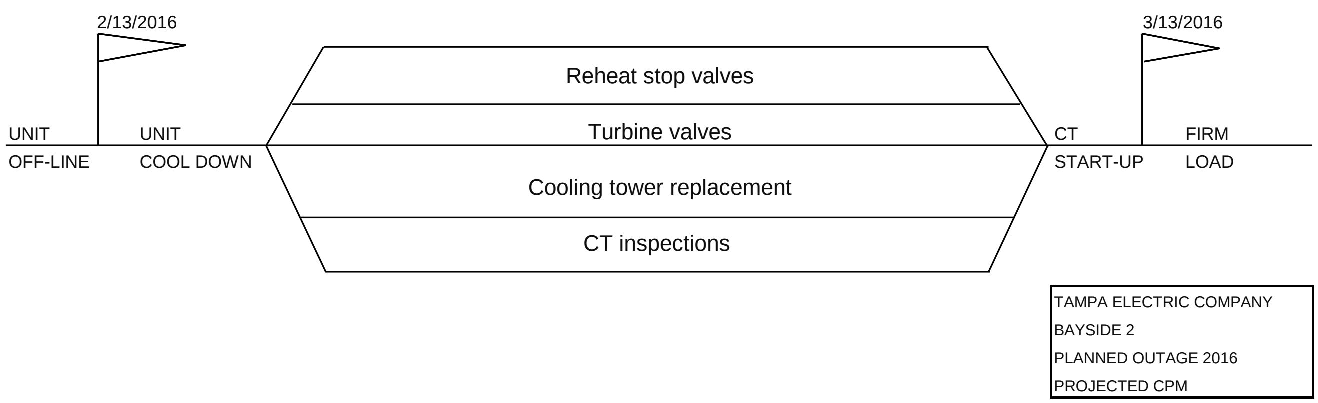


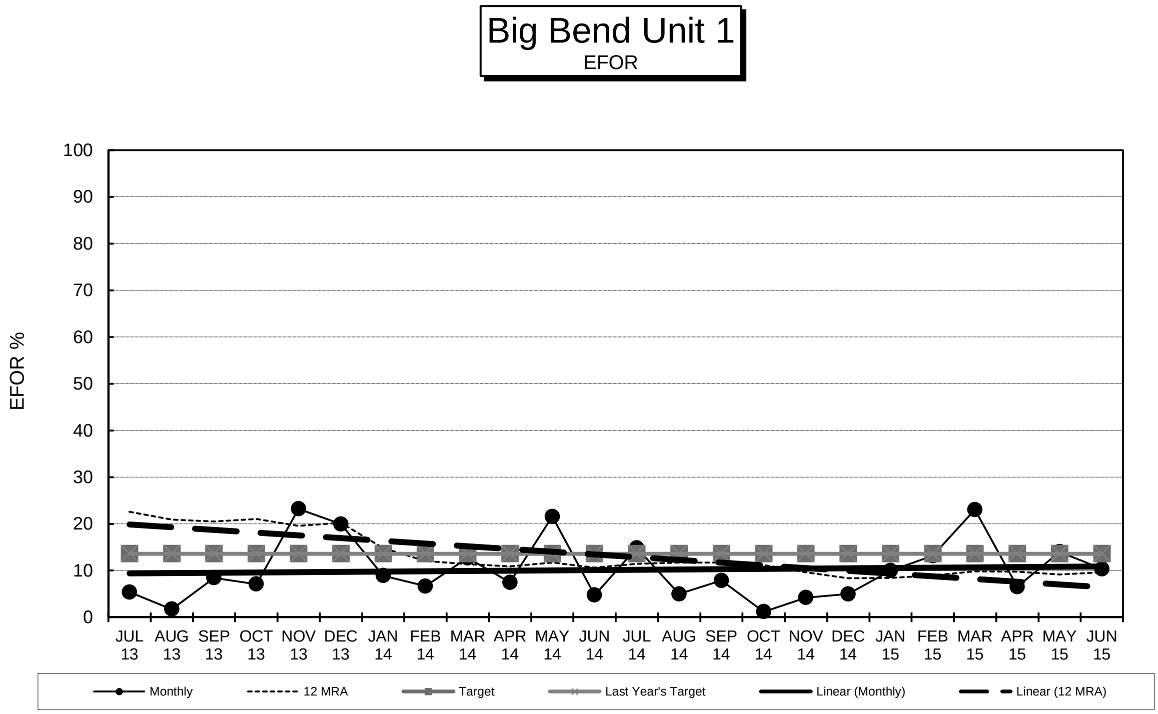


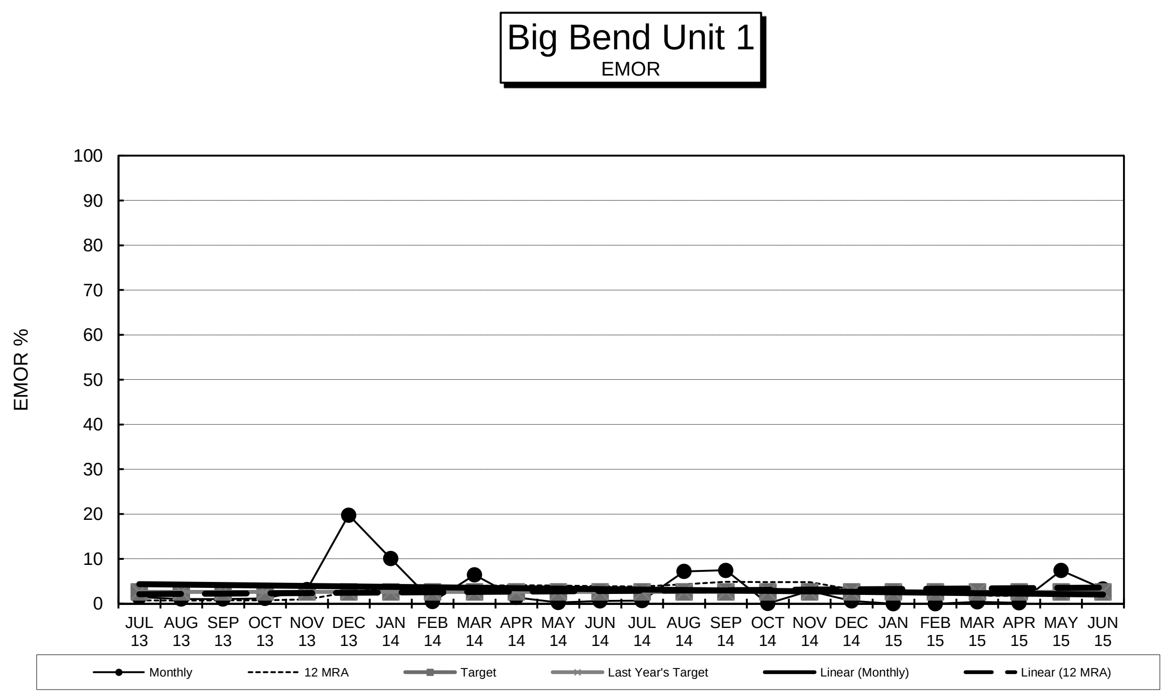
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2016 - DECEMBER 2016








Big Bend Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR
EMOR %
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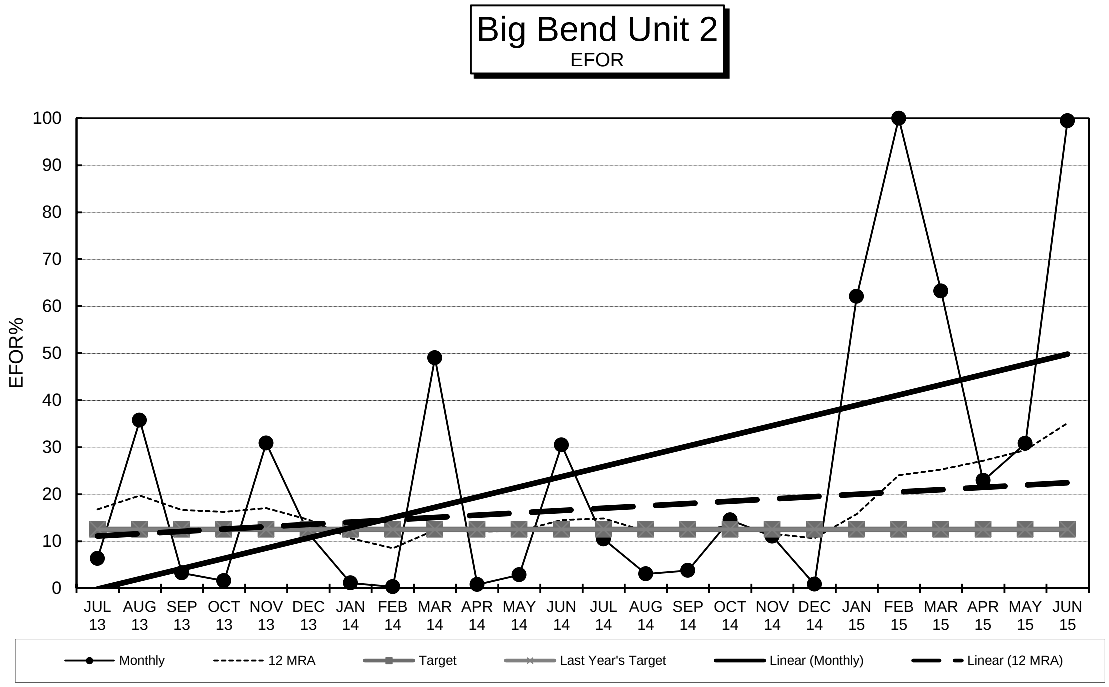
80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR%
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AUG 13
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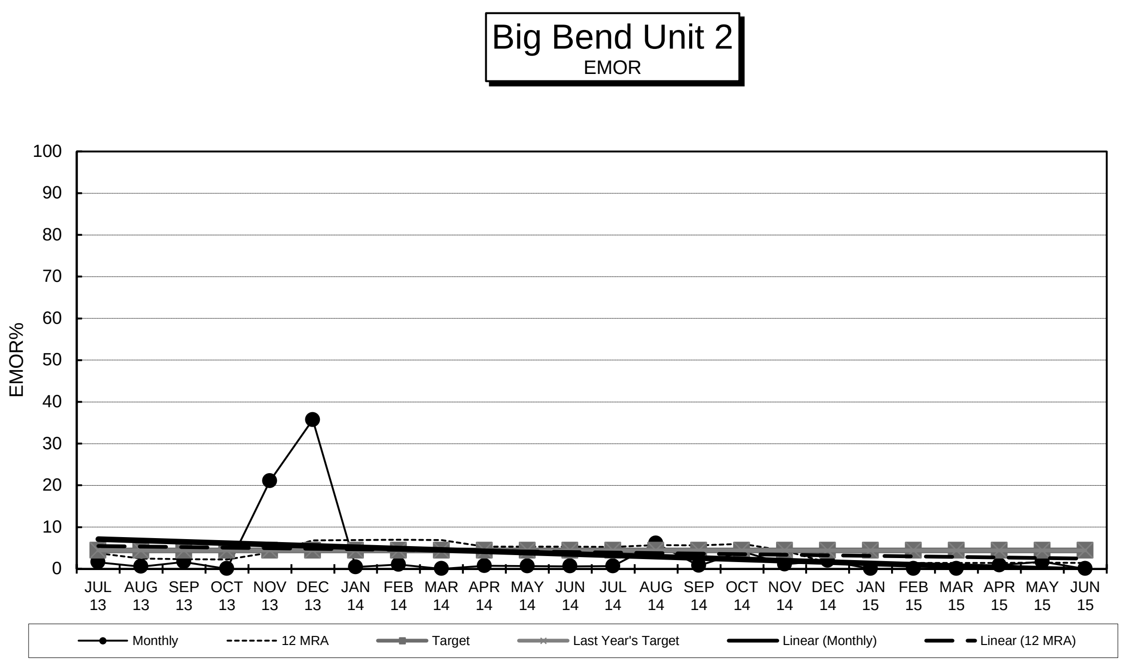
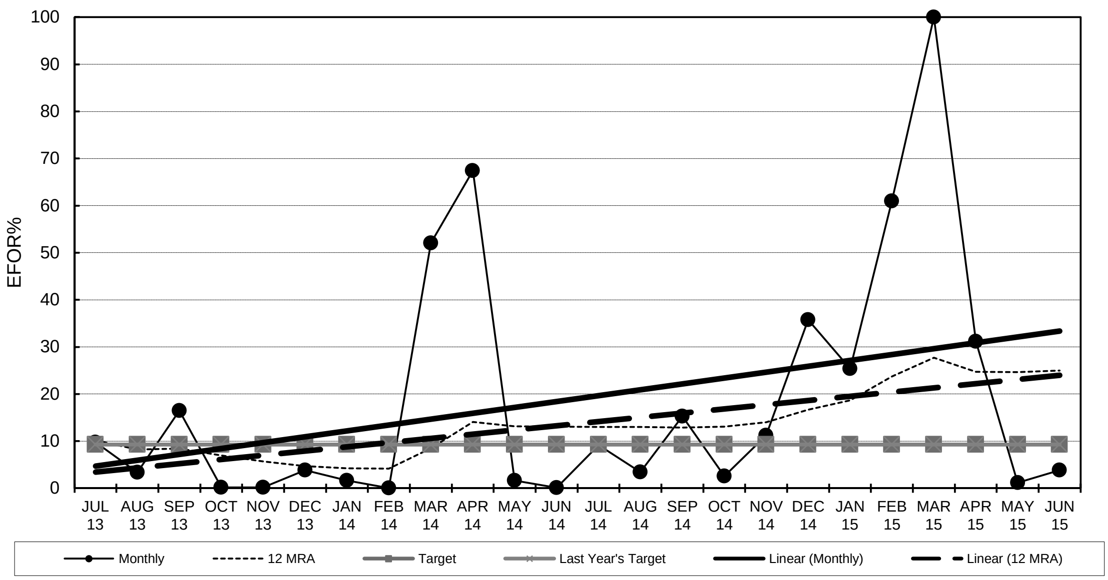
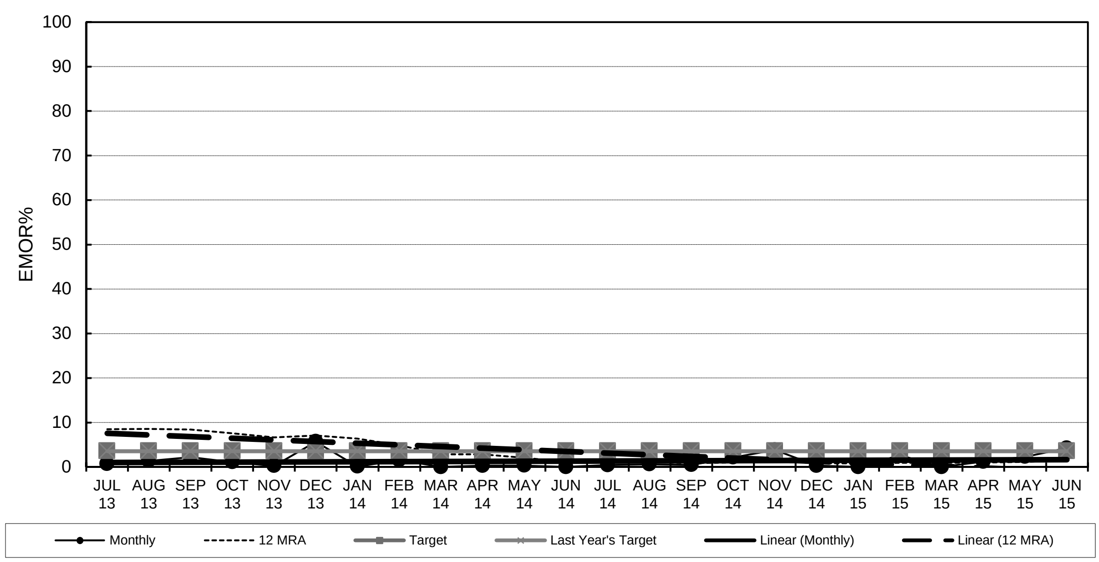
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

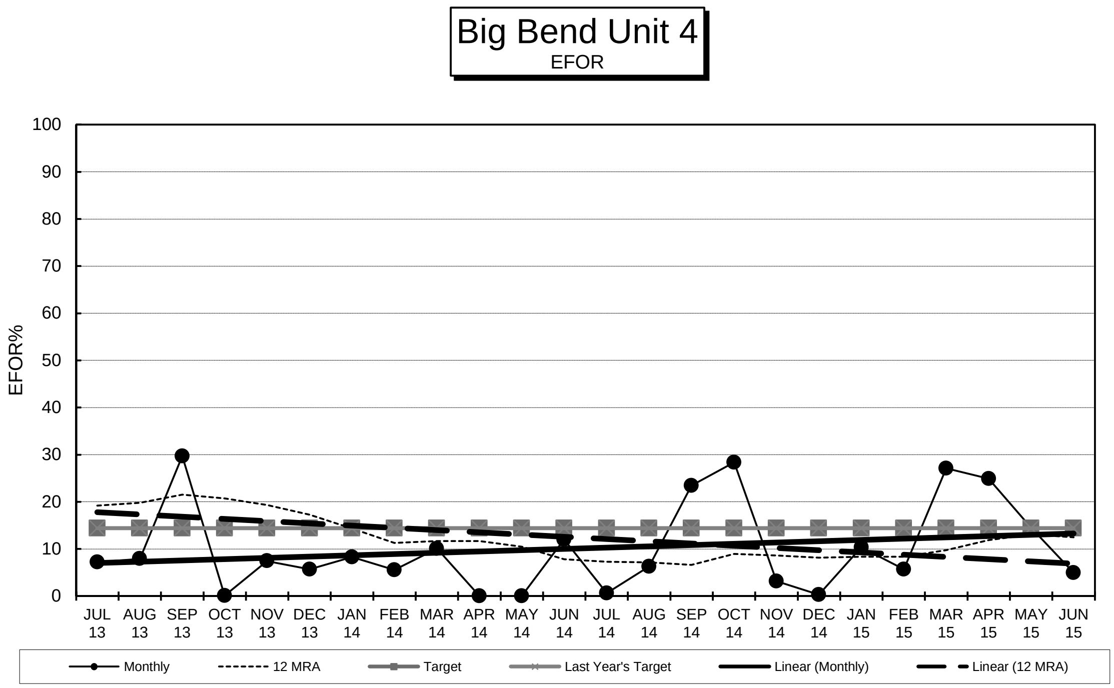

Big Bend Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

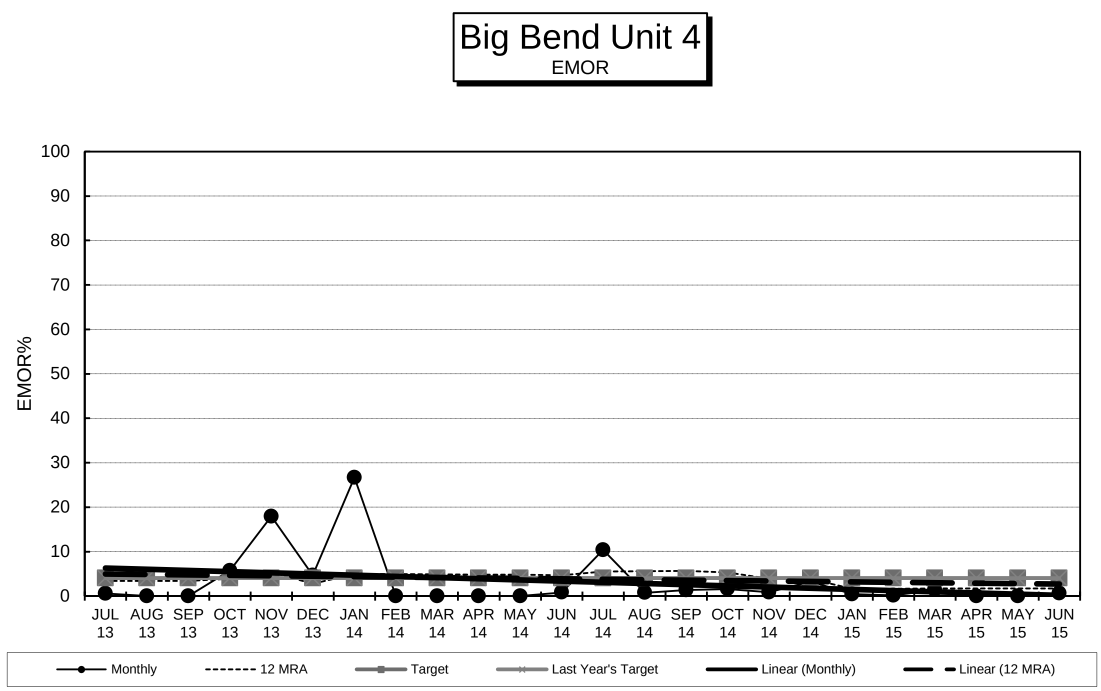
Big Bend Unit 3
EFOR



Big Bend Unit 3
EMOR




Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
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MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
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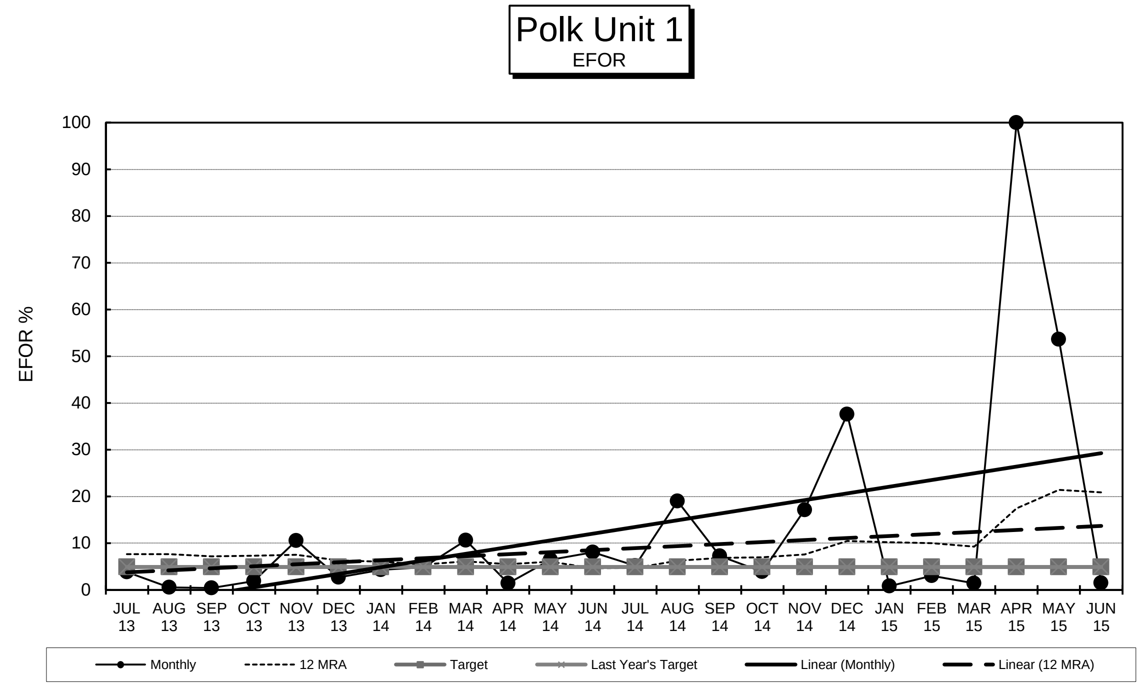
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
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EFOR %
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80
70
60
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
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APR 14
MAY 14
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JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
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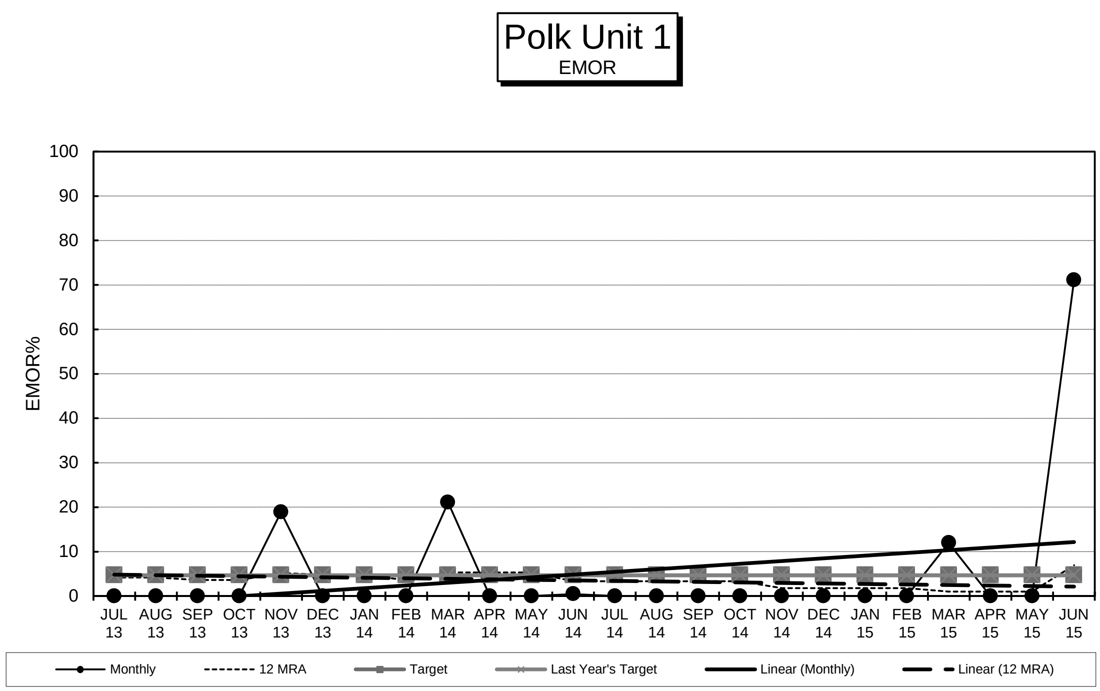
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
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70
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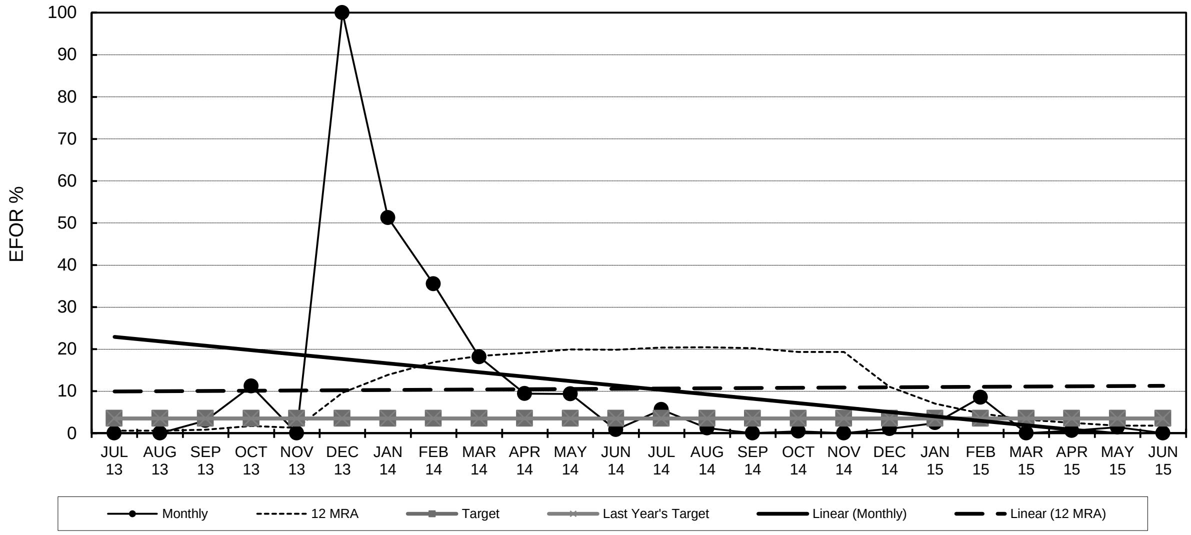
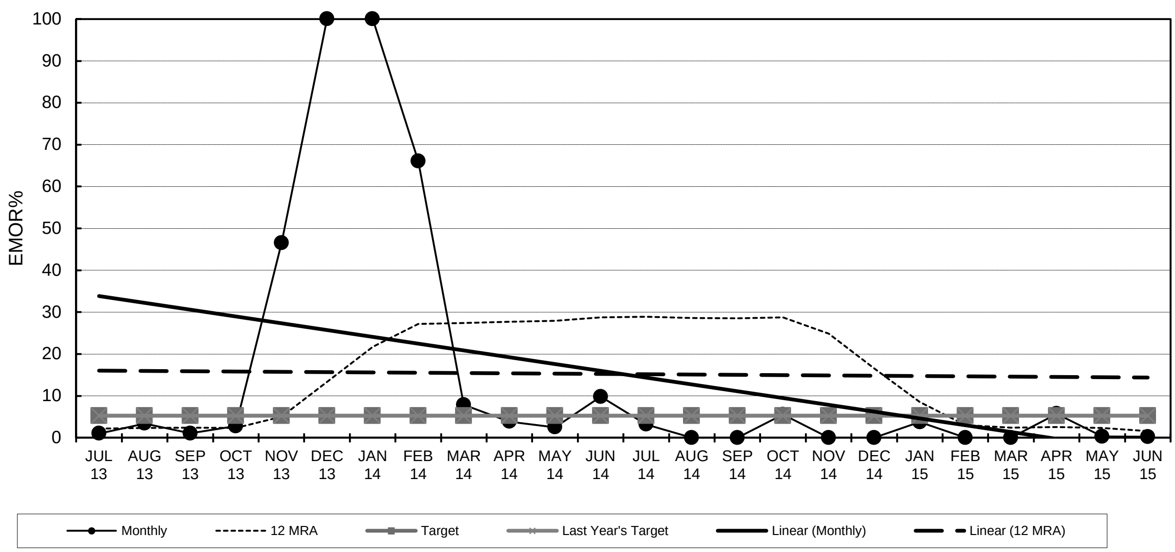
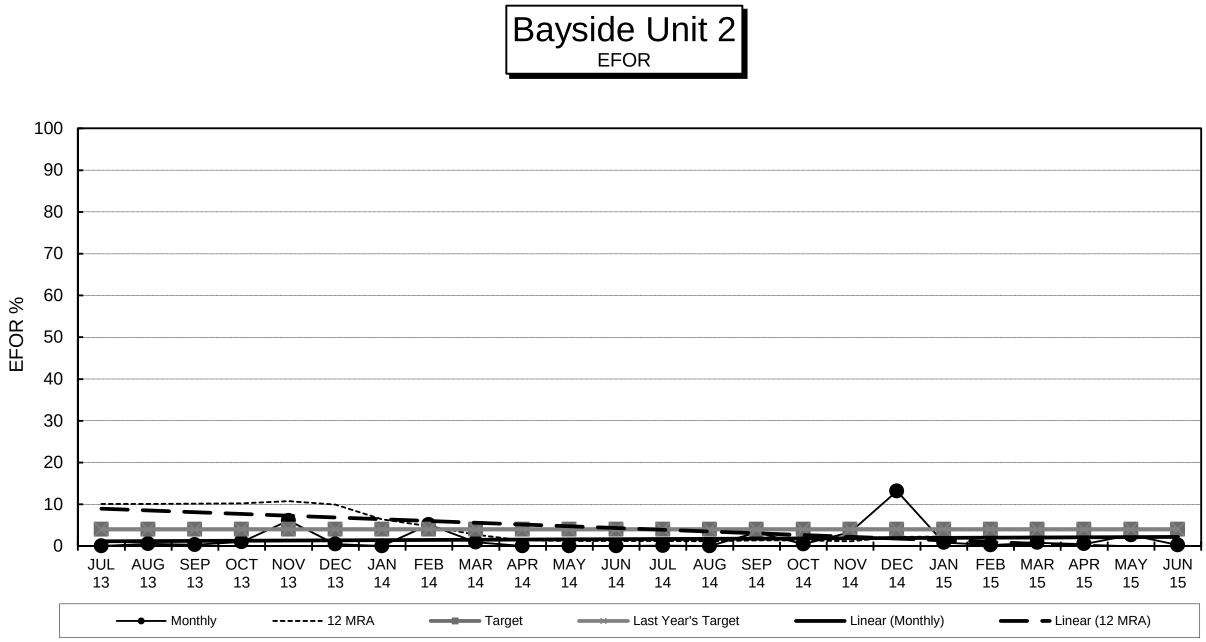
50
40
30
20
10
0
JUL 13
AUG 13
SEP 13
OCT 13
NOV 13
DEC 13
JAN 14
FEB 14
MAR 14
APR 14
MAY 14
JUN 14
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Bayside Unit 1
EFOR



Bayside Unit 1
EMOR




Bayside Unit 2
EFOR
EFOR %
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80
70
60
50
40
30
20
10
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JUL 13
AUG 13
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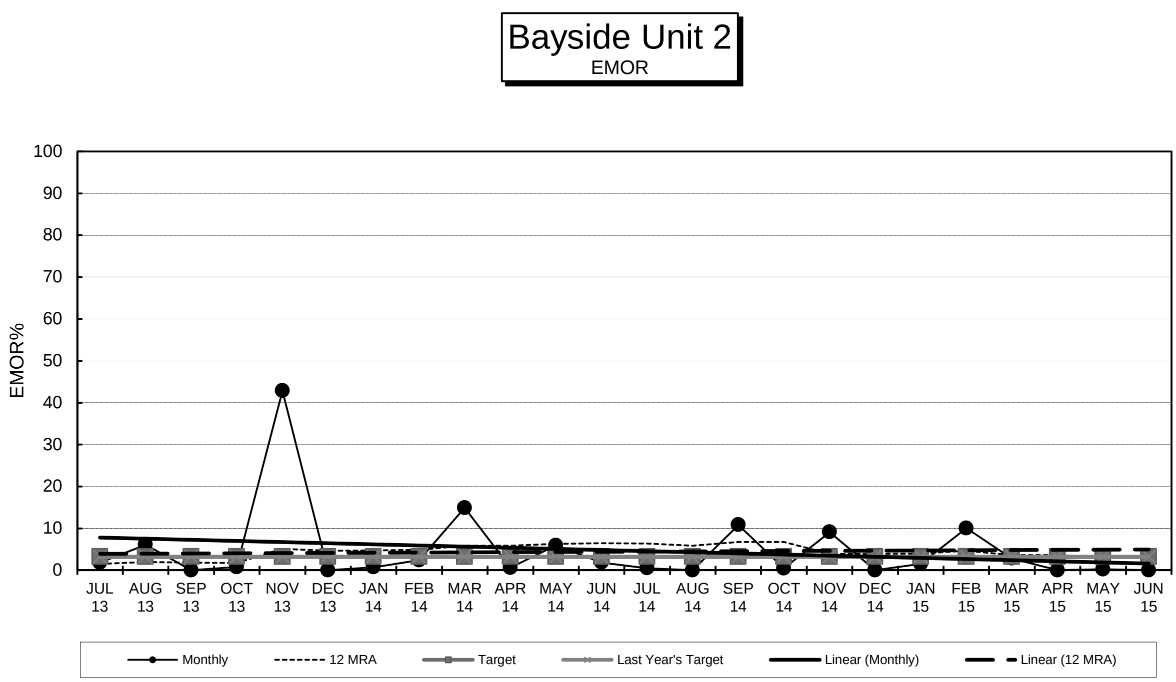
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
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EMOR%
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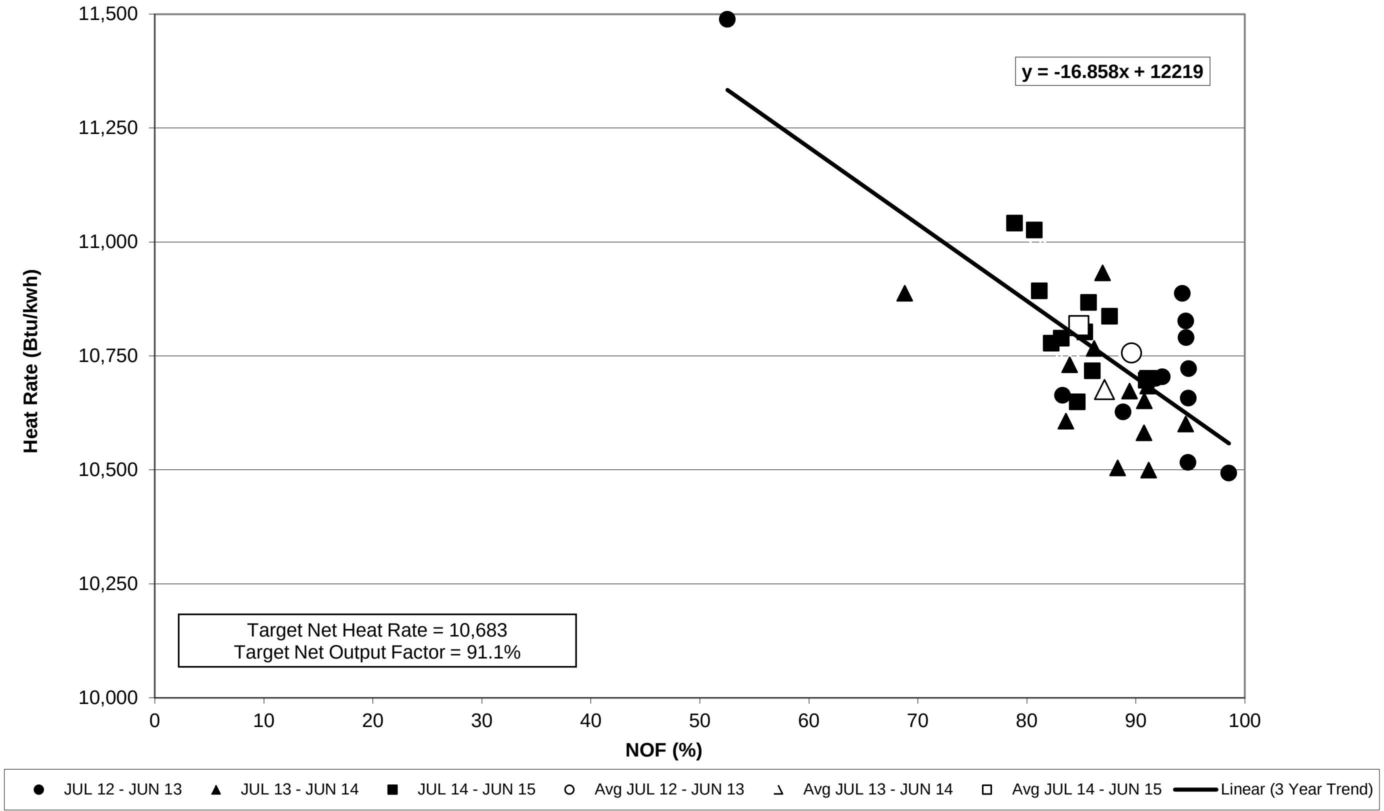
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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



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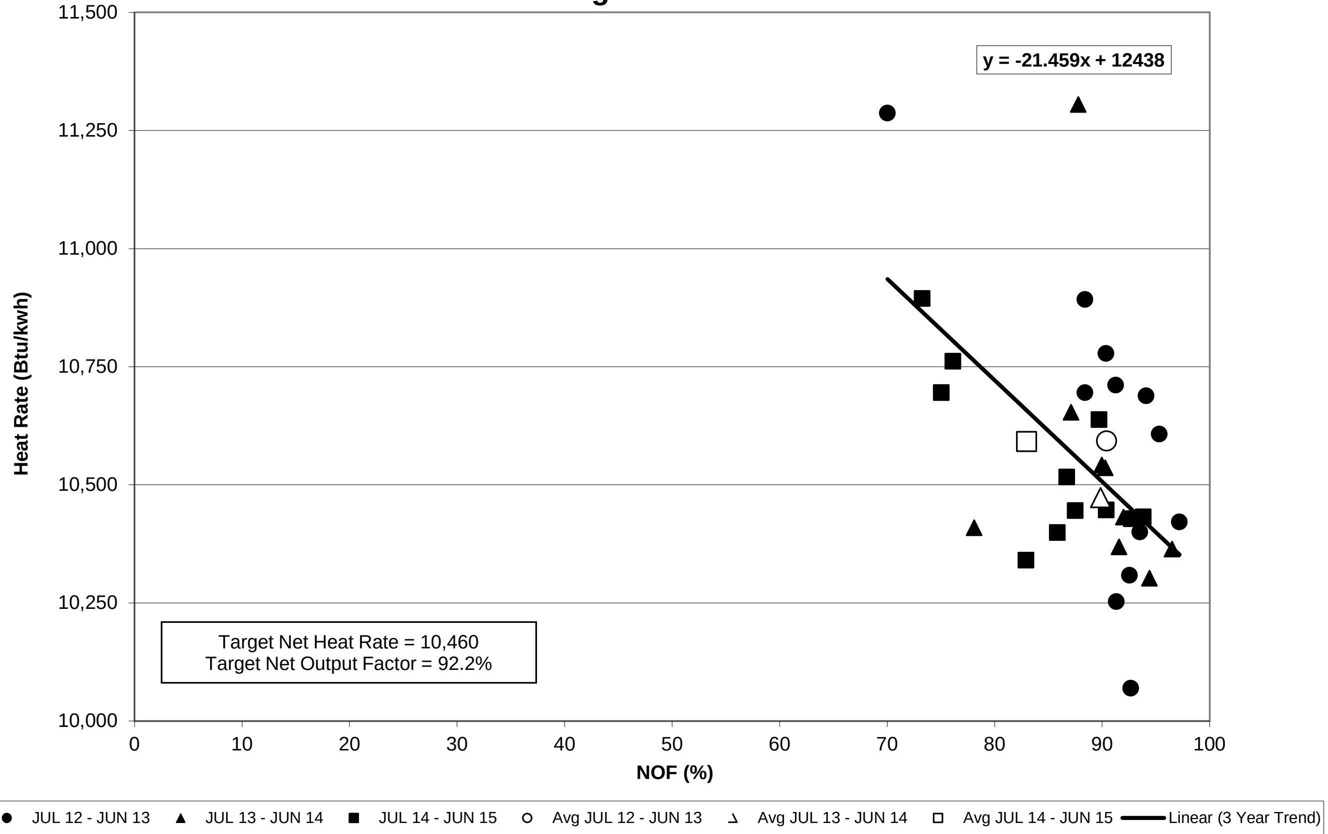
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



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ORIGINAL SHEET NO. 8.401.16E
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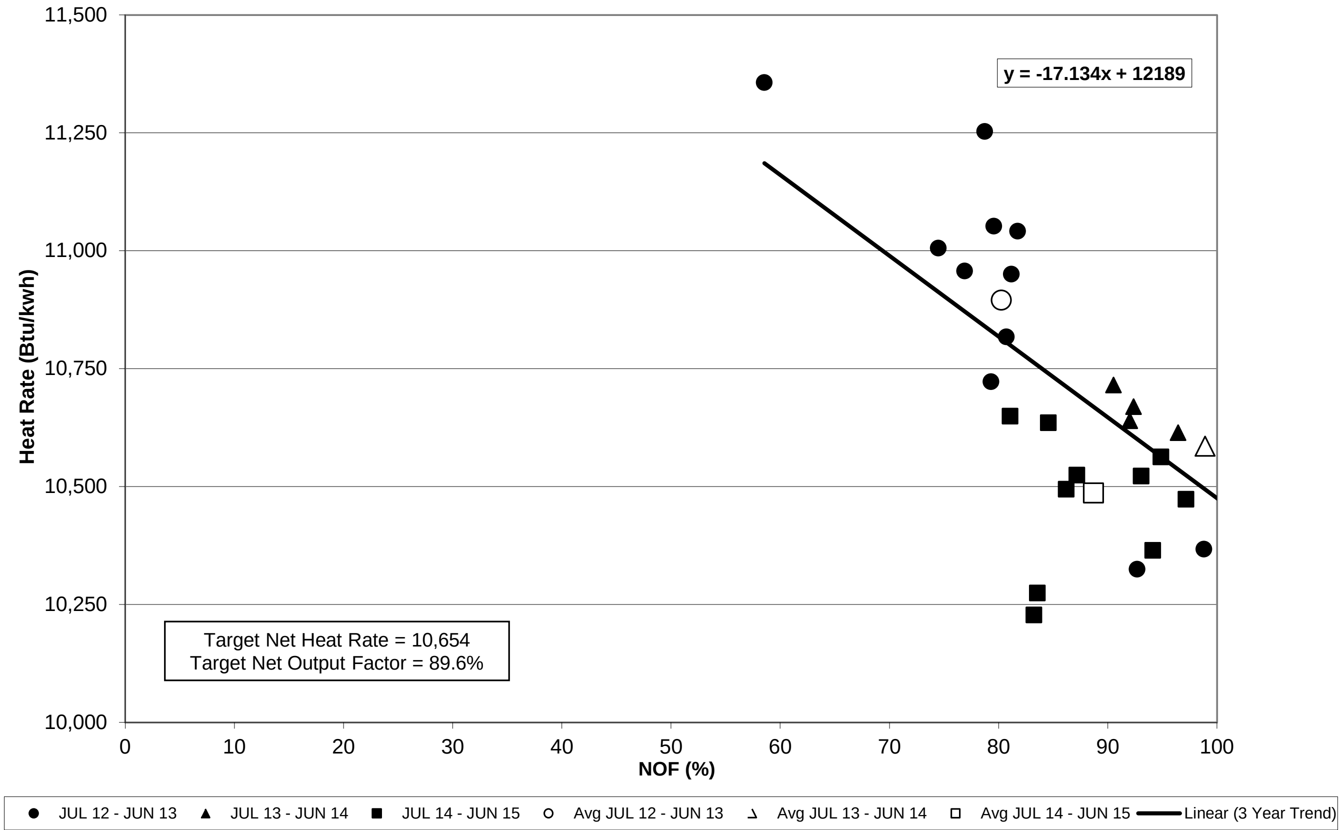
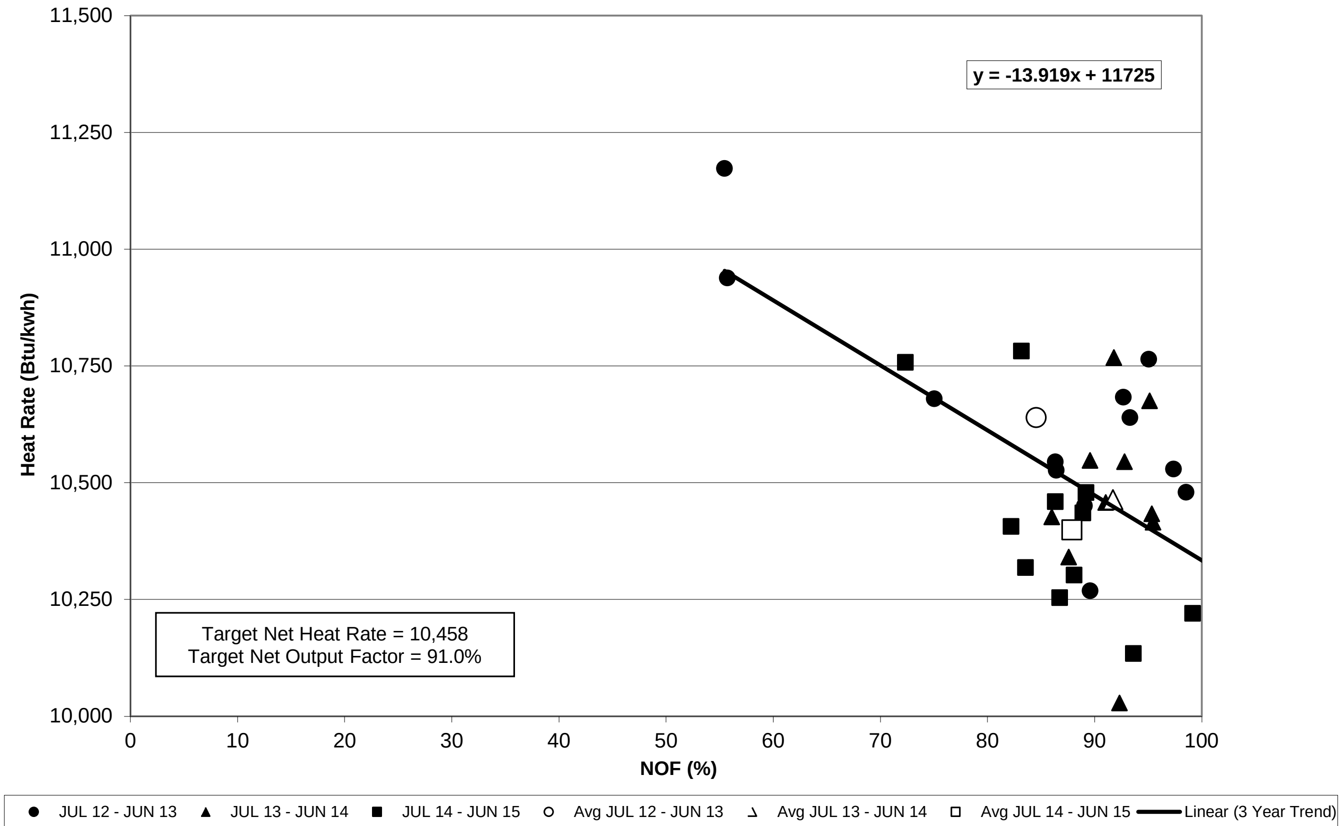
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3



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



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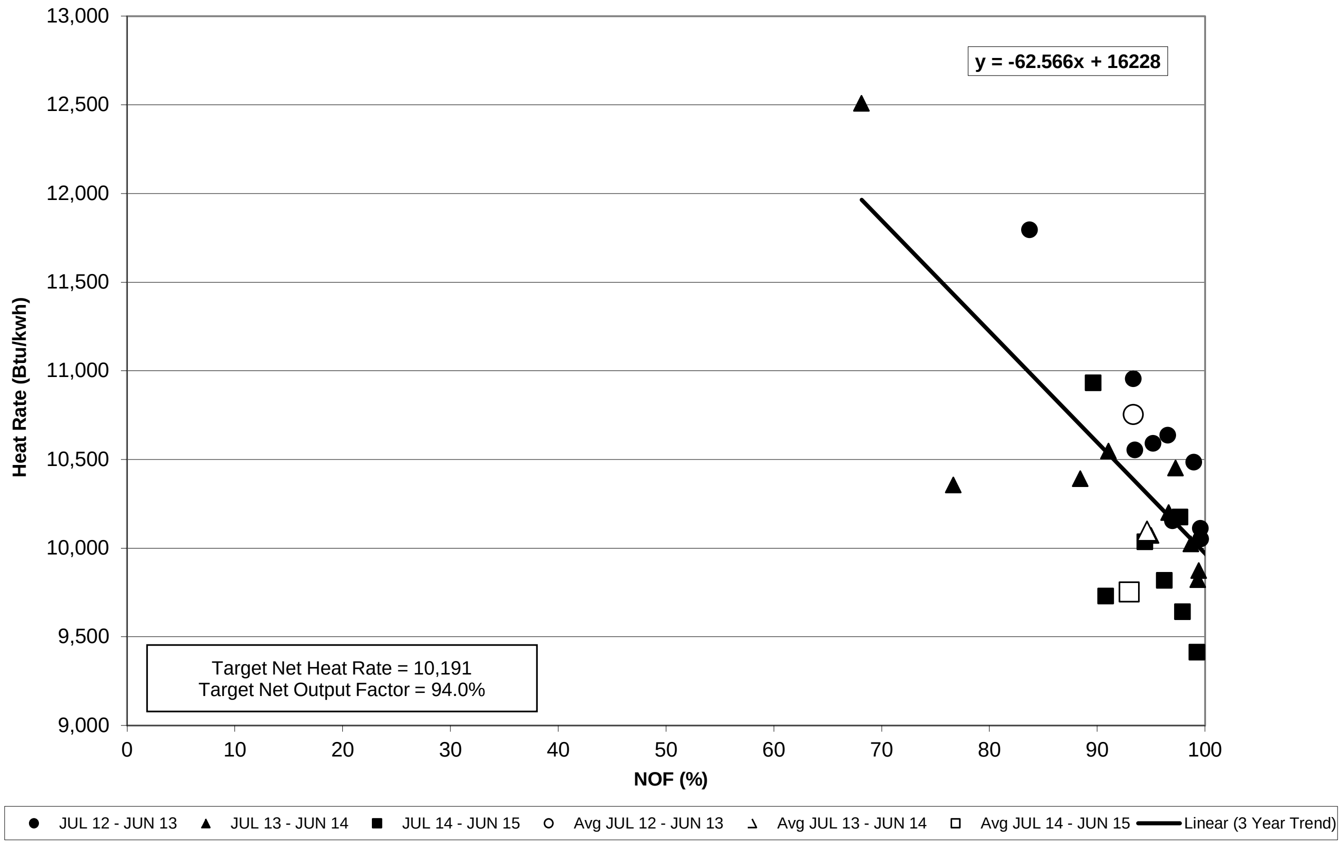
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1



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

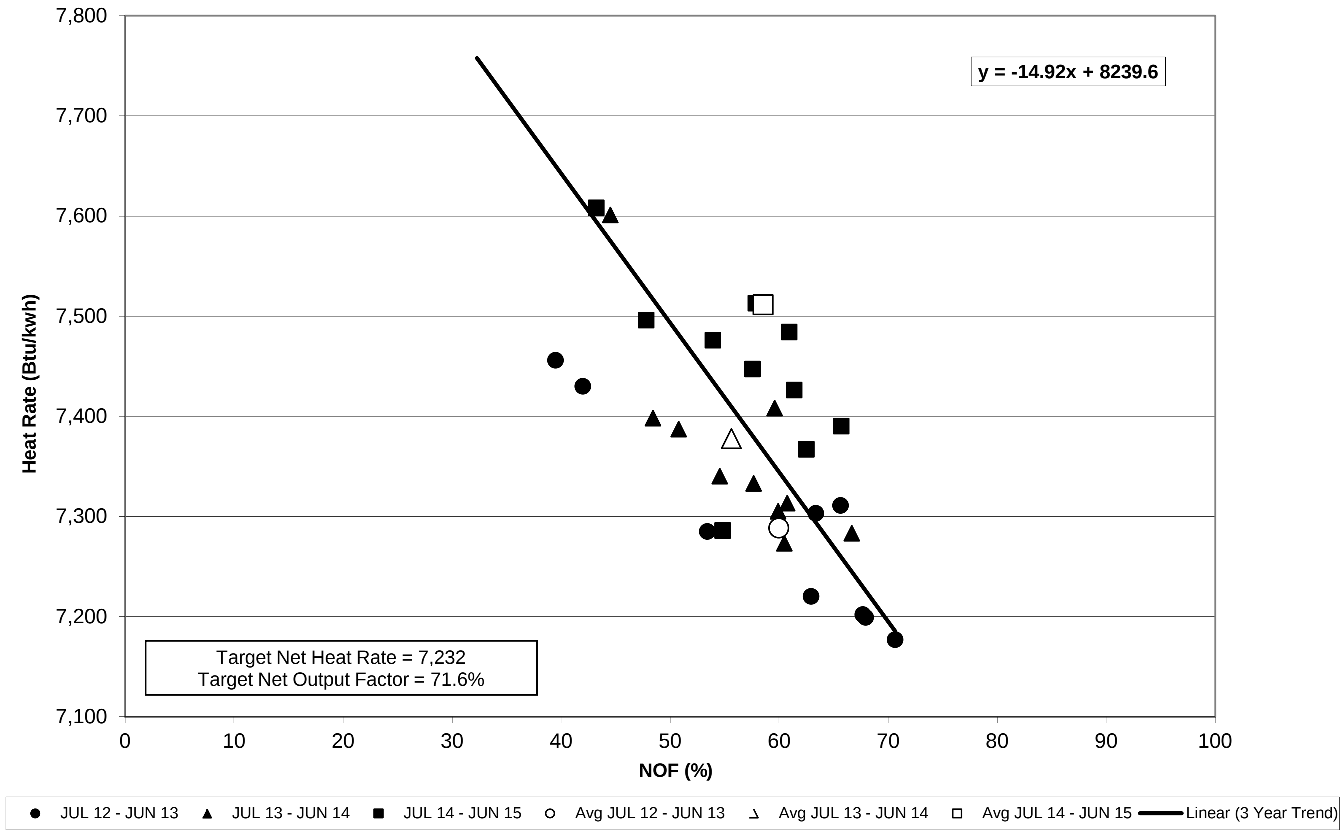


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EXHIBIT NO.___(BSB-2), DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.16E
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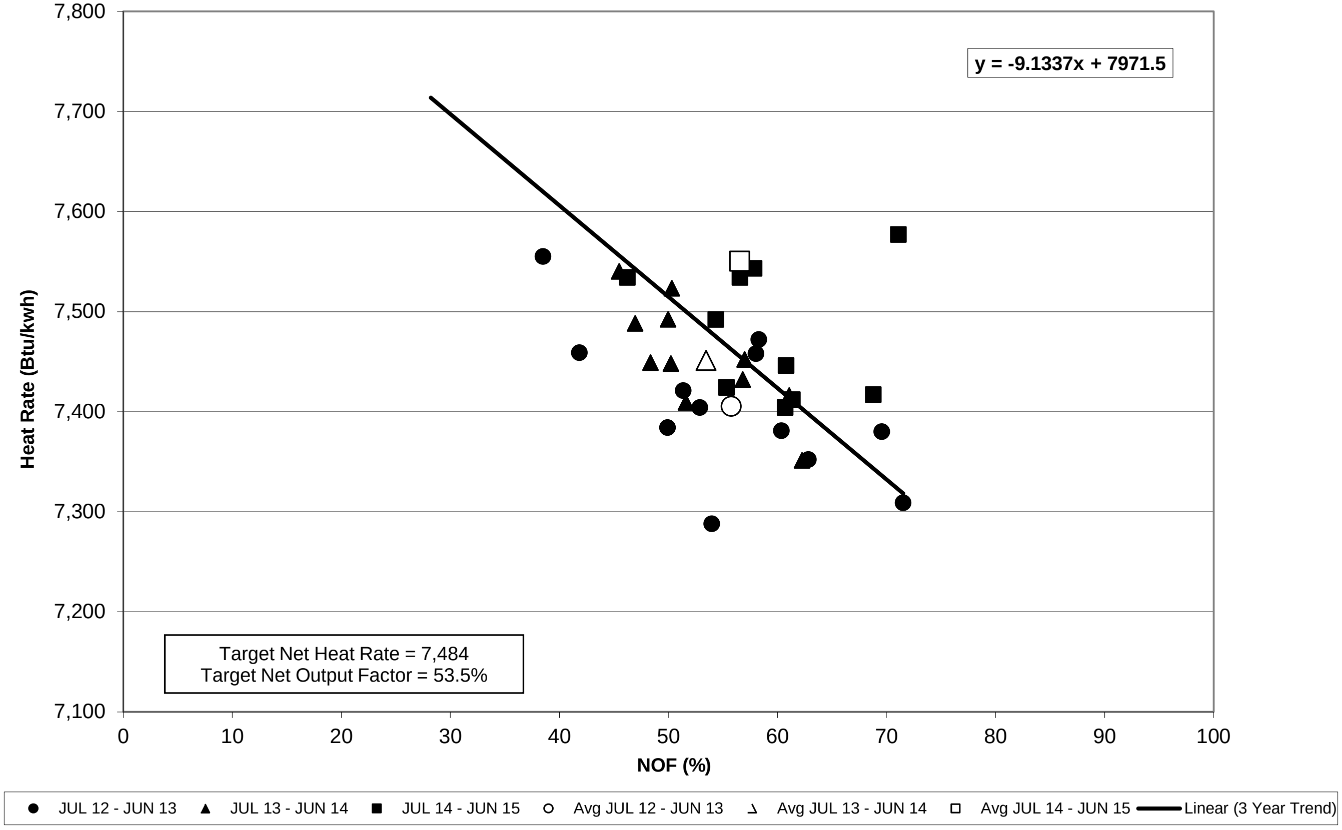
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2016 - DECEMBER 2016

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,730	3,532
	SYSTEM TOTAL	**4,674**	**4,467**
	% OF SYSTEM TOTAL	**79.8%**	**79.1%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2016 - DECEMBER 2016

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,779	1,670
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,674**	**4,467**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2016 - DECEMBER 2016

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	3,779,890	19.64%	19.64%
BAYSIDE	1	3,178,090	16.51%	36.15%
BIG BEND	4	2,908,840	15.11%	51.26%
BIG BEND	1	2,630,680	13.67%	64.93%
BIG BEND	3	2,596,680	13.49%	78.42%
BIG BEND	2	2,295,970	11.93%	90.35%
POLK	1	1,597,150	8.30%	98.64%
BIG BEND CT	4	57,780	0.30%	98.94%
BAYSIDE	5	48,040	0.25%	99.19%
BAYSIDE	6	36,770	0.19%	99.39%
POLK	2	30,620	0.16%	99.54%
BAYSIDE	3	30,480	0.16%	99.70%
BAYSIDE	4	20,720	0.11%	99.81%
POLK	3	15,060	0.08%	99.89%
POLK	4	12,970	0.07%	99.96%
POLK	5	8,480	0.04%	100.00%
TOTAL GENERATION		19,248,220	100.00%	

GENERATION BY COAL UNITS:	12,610,730 MWH	GENERATION BY NATURAL GAS UNITS:	6,637,490 MWH
% GENERATION BY COAL UNITS	65.52%	% GENERATION BY NATURAL GAS UNITS:	34.48%
GENERATION BY OIL UNITS:	- MWH	GENERATION BY GPIF UNITS:	18,987,300 MWH
% GENERATION BY OIL UNITS:	0.00%	% GENERATION BY GPIF UNITS:	98.64%

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2016 – DECEMBER 2016

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2016 - DECEMBER 2016

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	78.7	6.6	14.7	10,683
Big Bend 2[2]	68.7	18.0	13.2	10,460
Big Bend 3[3]	76.6	12.3	11.1	10,654
Big Bend 4[4]	76.9	6.6	16.5	10,458
Polk 1[5]	81.5	10.4	8.1	10,191
Bayside 1[6]	76.1	17.8	6.2	7,232
Bayside 2[7]	83.1	10.6	6.3	7,484

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2 Original Sheet 8.401.16E, Page 15

3 Original Sheet 8.401.16E, Page 16

4 Original Sheet 8.401.16E, Page 17

5 Original Sheet 8.401.16E, Page 18

6 Original Sheet 8.401.16E, Page 19

7 Original Sheet 8.401.16E, Page 20

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2016 THROUGH DECEMBER 2016

TESTIMONY
OF
J. BRENT CALDWELL

FILED: September 1, 2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor 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 Docket No. 130040-EI, 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.

Fuel Mix and Procurement Strategies

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

A. Tampa Electric’s fuel mix includes coal, natural gas, and oil. In 2015, as in previous years, coal is the fuel for

Big Bend Station; the Polk Unit 1 integrated gasification combined cycle utilizes coal as the primary fuel and natural gas as a secondary fuel; and Bayside Station combined cycles and the company’s collection of peakers (*i.e.*, simple cycle and aero derivative combustion turbines) utilize natural gas. Some of Tampa Electric’s peakers utilize oil as a secondary fuel. In 2015, the company expects total system generation to be 54 percent coal, 46 percent natural gas, and less than one percent oil.

During the upcoming year, Tampa Electric plans to test natural gas as a co-fired fuel in Big Bend station. The natural gas co-firing affects the system’s coal and natural gas consumption, as I describe later in my testimony. In 2016, coal-fired generation is expected to be approximately 48 percent of total generation and natural-gas fired generation, including the Big Bend co-fired volumes, is expected to be 52 percent. Generation from oil is expected to remain less than one percent of the total generation.

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

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

Coal Supply Strategy

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

A. Tampa Electric uses solid fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content and chlorine content. Since coal is not a homogenous product, fuel selection is based on 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. 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 2015.

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

Q. Has Tampa Electric entered into coal supply transactions for 2016 delivery?

A. Yes, Tampa Electric has contracted for approximately three-fourths of its 2016 expected coal needs through agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases or consumed from inventory during 2015 and 2016.

Coal Transportation

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

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

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2015 and 2016?

A. Yes. Tampa Electric expects to receive over one and one-half million tons of coal for use at Big Bend Station through the Big Bend rail facility during 2016.

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

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

Q. Please summarize the company's current coal waterborne transportation agreements.

A. In 2014, Tampa Electric issued Requests for Proposals ("RFP") for all three legs of transportation for solid fuel originating from the Illinois Basin and delivered to Big Bend Station--river barges along the inland waterways, terminal service at the mouth of the Mississippi River, and transit across the Gulf of Mexico. Tampa Electric executed four new solid fuel transportation agreements with respondents to the RFP. The agreements were finalized in late 2014 and early 2015 and took effect in 2015.

Q. Please describe the four agreements.

REDACTED

A. For river barge transportation, Tampa Electric executed an agreement with Ingram Barge Company. This agreement provides river barge services from numerous docks on the inland waterway system to various terminals around New Orleans, Louisiana. The agreement expires at the end of [redacted] and provides annual transportation volumes between [redacted] tons and [redacted] tons. Tampa Electric also entered an agreement with an existing coal supplier, Knight Hawk Coal Company, to receive its supply delivered to the terminal. This effectively provides river transportation for [redacted] to [redacted] tons per year through [redacted]. The rates for these new contracts are approximately [redacted] to [redacted] per ton less than the previous river transportation agreement.

For terminal service, Tampa Electric entered an agreement with United Bulk Terminal. The agreement is through [redacted] with Tampa Electric having a unilateral right to extend the agreement through [redacted]. The new agreement provides over 500,000 tons of storage capacity, blending capability, no minimum throughput, discount opportunities and pricing flexibility. The new contract is priced approximately [redacted] to [redacted] per ton lower than the agreement that it replaced.

REDACTED

For Gulf transportation, Tampa Electric entered into an agreement with United Ocean Services through [redacted] with Tampa Electric's unilateral right to extend through [redacted]. The new agreement reduces the annual commitment from [redacted] tons to [redacted] tons. The cost to transport across the Gulf of Mexico also decreased by over [redacted] per ton.

Q. Please describe any other solid fuel transportation agreements that changed recently.

A. In 2014, Tampa Electric also issued an RFP for trucking service between Big Bend Station and Polk Station. The company entered an agreement with Dillon trucking to begin in 2015. Dillon subsequently agreed to start performing under the contract in late 2014 when Tampa Electric's previous truck transportation supplier found it difficult to perform as they began losing drivers when the contract with Tampa Electric neared expiration. The Dillon agreement continues through [redacted] at a fixed price, and Tampa Electric has the unilateral option to extend at a known price through [redacted]. The Dillon trucks are larger than the previous provider's trucks, thereby reducing volume of truck traffic at the stations and on the roadways. In addition, Dillon's trucks use compressed natural gas as fuel, providing cost savings and emission reductions. The price for trucking services under the Dillon agreement is slightly less than the prior agreement.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2016 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 will affect the types of coal, the 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 significantly each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

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

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

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

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

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero-derivative

REDACTED

combustion turbine and coal unit startup. Polk Station receives natural gas from FGT to support the four natural gas combustion turbines at that station.

Q. What actions has Tampa Electric taken to enhance the reliability of its natural gas transportation portfolio?

A. In 2015, Tampa Electric acquired 20,000 MMBtu per day of firm FGT FTS-3 capacity at the discounted rate of [redacted] per MMBtu. The quantity grows to a maximum of [redacted] MMBtu per day by [redacted] and remains at that level through the [redacted] year term of the agreement.

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

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

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT

Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

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

Q. Does Tampa Electric have plans to secure additional natural gas supply for 2016 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately two-thirds of the company's expected natural gas requirements for 2016. The balance of Tampa Electric's natural gas supply will be acquired through seasonal, monthly and daily purchases to meet its varying operational needs.

Q. Will Tampa Electric's generating stations require a greater volume of natural gas in 2016 compared to expected usage during 2015?

A. Yes, the company expects to use additional natural gas at its Big Bend Station. During 2015, the company has been converting the igniters on the coal-fired Big Bend Units 1 through 4 to run on natural gas instead of oil. This work is expected to be completed in October 2015. In 2016, Tampa Electric plans to test the co-firing capabilities of the units. Co-firing, using natural gas to supplement the coal-fueled input of the four coal units, will allow the company to respond quickly to operational changes, environmental constraints, and shifting customer demand. Co-firing is also expected to increase the reliability of these units' operation.

Q. Will Tampa Electric need to enter additional supply or transportation contracts for the natural gas to be used at Big Bend Station?

A. In isolation, no, Tampa Electric does not need to add additional supply or transportation contracts for the natural gas to be consumed at Big Bend Station in 2016, particularly since the gas is for testing purposes and for startup. However, the FGT FTS-3 pipeline capacity added in 2015 is needed to account for the cumulative demand from Big Bend start-up, potential restrictions on coal-fired generation from environmental regulations associated with the Clean Power Plan, increased operational limits proposed by interstate pipelines, and overall competition for gas supply and pipeline capacity for delivery to the surging natural gas-fueled generation market in Florida.

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

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

Projected 2016 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences. Tampa Electric utilized the average of the five daily NYMEX natural gas futures settlement prices for the period April 30, 2015 – May 4, 2015 to prepare the fuel price forecast.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices 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 2016 projected fuel prices compare to the fuel prices projected for 2015?

A. Fuel prices for coal and natural gas for 2016 are projected to be lower than the prices projected for 2015. Continued natural gas production from shale reserves coupled with low crude oil prices is pushing prices down for all fuel commodities. Natural gas prices are projected to be slightly higher in 2016 than the natural gas prices projected for 2015 in the company's actual-estimated analysis. The lower coal demand resulting from coal-fired unit closures is expected to keep coal prices low despite some consolidation and production cuts in domestic coal supply.

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

A. Yes. While 2016 projected prices for coal and natural gas are expected to be similar to 2015 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 and Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

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

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on August 4, 2015 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2015 and 2016 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2015 natural gas supply needs and a portion of its expected 2016 natural gas supply needs in accordance with the company's hedge plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 14, 2015.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2015 and 2016 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, 2015 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the Risk Management Plan filed with this Commission, which was approved by the company’s Risk Authorizing Committee. On April 7, 2015, the company filed its 2014 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 2015, in this docket on August 14, 2015.

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

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

Hedging Issues

Q. Have you reviewed the issues raised by OPC regarding the appropriateness of financial hedging?

A. Yes, I have. I believe the following two uncontested issues have been raised by OPC:

> One, is it in the consumers' best interest for the utilities to continue financial hedging activities?
>
> And two, what changes, if any, should be made to the manner in which electric utilities conduct their financial hedging activities?

Tampa Electric will await and review the interveners' positions stated in testimony, due September 23, 2015, prior to the company formulating a response. However, statements by the Commission in its orders addressing financial hedging and hedging audits by the Commission's Staff suggest that utilities hedge using systematic and prudent methods, consumers benefit from the utilities' financial hedging activities, and no changes need to be made to the manner in which electric utilities conduct their financial hedging activities.

Q. Please identify the orders and audit results to which you refer.

A. In 2002 the Commission issued an order[1] ("the Hedging Order") approving a proposed resolution of issues relating to financial hedging, between and among Florida

[1] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI

Power & Light ("FPL"), Duke Energy Florida's "DEF" predecessor, Gulf Power, Tampa Electric, OPC and FIPUG. The Hedging Order established a framework and direction for the Commission and the parties to follow with respect to risk management for fuel procurement. That framework, with some later modifications, constitutes the risk management policy and procedures the Commission follows today. In the Hedging Order, the Commission noted that the resolution it approved appeared to remove disincentives that may have existed for IOUs to engage in financial hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred financial hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.

Order No. PSC-08-0316-PAA-EI[2] was the first of two clarifications in 2008 to the Hedging Order. This Order established a requirement that each IOU file a current-year, financial hedging review (Hedging Information Report) that provides actual hedging information for the period August 1 through July 31. The reporting requirement was established to enhance the Commission's

[2] Order No. PSC-08-0316-PAA-EI, issued May 14, 2008 in Docket No. 080001-EI

tools for reviewing the prudence of the utilities' most recent financial hedging activities.

The Commission then entered Order No. PSC-08-0667-PAA-EI[3], in which it affirmed its long-term support for financial hedging. In reviewing FPL's guidelines for financial hedging, the Commission noted that hedging can reduce the volatility of fuel adjustment charges paid by customers and that a well-managed financial hedging program does not involve speculation. The Commission further noted that in the 2008 mid-course corrections for DEF, FPL and Gulf, hedging gains significantly reduced the projected under-recoveries. The Commission said that it had previously found that customers benefit from stable rates that allow the customers to budget for electric bills and hedging has contributed to the stability of fuel factors.

In its ruling in Order No. PSC-08-0667-PAA-EI, the Commission stated that by approving FPL's proposed guidelines, "we demonstrate our support for hedging." The Commission further stated:

> “We find that utility hedging programs provide benefits to customers. By approving these guidelines we provide

[3] Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No. 080001-EI

> regulatory support and guidance regarding hedging programs.”

The benefits of hedging were highlighted in a management audit conducted by the Commission's Staff in 2008. Upon completion of the Staff's audits of IOU hedging activities, the management audit concluded:

> Overall, audit staff believes that the use of financial hedges for fuel purchases provides a benefit to utility customers. Each program is appropriately controlled, efficiently organized, and operates under a non-speculative format. There are areas of improvement, which are outlined later in each company's chapter. Generally, each company has successfully mitigated the price volatility for its customers. There have been years in which each company's hedging program provided a gain on its fuel cost, and years in which each program has incurred losses. This is to be expected. Hedging commodities involves the risk of higher prices at the expense of attempting to reduce price volatility. For each company, there is an acceptable level

of risk tolerance between the two. Each utility must continue to gauge its customers' tolerance of the cost associated with hedging versus the benefits of reduced fuel cost volatility and any resulting rate increases.

Through its initial approval of the proposed resolutions in 2001 and later, through subsequent orders clarifying the Commission view on Hedging, the Commission and its staff have recognized the benefits of financial hedging and the impact on the utilities’ customers. Additionally, the Commission has carefully monitored and evaluated the conduct of each IOU’s financial hedging activities with no noted suggestion of imprudence. Tampa Electric will address any points raised by intervenor witnesses regarding whether or not financial hedging should continue in its present form or be modified in future rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2016 THROUGH DECEMBER 2016

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: SEPTEMBER 1, 2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

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

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of Wholesale Business Development in Tampa Electric's Fuels Management department. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract 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 2015 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 2015 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 this year, 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 2015?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2015.

Q. Does Tampa Electric anticipate entering into any wholesale energy purchases for 2016 as a result of the Polk Unit 2-5 combined cycle conversion?

A. Yes. In Order No. PSC-13-0014-FOF-EI, issued on January 8, 2013, in Docket 120234-EI, the Commission approved Tampa Electric's determination of need for the Polk Unit 2-5 combined cycle ("CC") conversion, which is to be called Polk Unit 2 CC. The anticipated Polk Unit 2 CC in-service date is January 1, 2017, and its construction timeline requires the Polk combustion turbines ("CT") to be taken off-line from May through November for combined cycle tie-in and testing. This creates a projected need for capacity and energy to meet system reserve margin requirements and ensure operational flexibility. Therefore, Tampa Electric included a 300 MW purchase in the 2016 projection. On August 31, 2015, Tampa Electric issued a market solicitation for proposals to provide the needed firm power. Tampa Electric’s objective is to secure the necessary purchased power for customers at the best possible price.

Q. Does Tampa Electric anticipate entering into any other new wholesale energy purchases for 2016 and beyond?

A. No. At this time, Tampa Electric expects purchased power to meet approximately three percent of its 2016 energy needs. This energy includes contributions from the previously mentioned firm purchases. Tampa Electric will continue to evaluate the short-term purchased power market as part of its purchasing strategy for 2016 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 in 2015?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. The 121 MW purchased from Pasco Cogen, 117 MW from Calpine, and 160 MW purchased from Southern Power Company 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 continues to evaluate its options in light of changing circumstances and new opportunities. Tampa Electric also maintains a mix of short- and long-term capacity and energy purchases to augment the company’s own generation for the year 2015 and beyond.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers’ fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company’s three existing 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 evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric’s wholesale energy sales for 2015 and 2016.

A. Tampa Electric entered into various non-separated wholesale sales in 2015, and the company anticipates making additional non-separated sales during the balance of 2015 and in 2016. 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 2015, Tampa Electric projects the company's gains from non-separated wholesale sales to be $403,800, which is less than the 2015 threshold of $1,479,981. Therefore, Tampa Electric expects customers to receive 100 percent of the 2015 non-separated sales gains. Likewise, in 2016, the company projects gains to be $59,601, of which customers would receive 100 percent, since the amount is less than the 2016 projected three-year rolling average threshold of $1,532,270.

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.