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August 24, 2017

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. 20170001-EI

Dear Ms. Stauffer:

Attached for filing in the above docket on behalf of Tampa Electric Company are 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 24th day of August 2017, 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. 20170001-EI FILED: August 24, 2017

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, 2017 through December 31, 2017 will be an over-recovery of $17,081,137 (See Exhibit No. PAR-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2018 through December 31, 2018, when adjusted for the proposed GPIF reward and true-up over-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2018 through December 31, 2018, produce a fuel and purchased power factor for the new period of 3.132 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 2018 for gains on non-separated wholesale energy sales eligible for the shareholder incentive as set forth by Order No. PSC-2000-1744-PAA-EI, in Docket No. 19991779 is $881,885 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, 2017 through December 31, 2017 will be an under-recovery of $2,762,938, 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, 2018 through December 31, 2018, when adjusted for the true-up under-recovery amount and spread over projected kilowatt-hour sales for the period, produce a capacity cost recovery factor for the period of 0.00056 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.20 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 $47,392 for performance during the period January 1, 2016 through December 31, 2016.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2018 through December 31, 2018 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 24th day of August 2017.

Respectfully submitted,

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

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 24th day of August 2017, to the following:

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ATTORNEY

TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY AND EXHIBIT
OF
PENELOPE A. RUSK

FILED: AUGUST 24, 2017

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 N. 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. Have you previously filed testimony in Docket No. 20170001-EI?

A. Yes, I submitted direct testimony on March 1, 2017 and July 27, 2017.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 wholesale incentive benchmark for January 2018 through December 2018. I 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 2018.

Q. Have you prepared an exhibit to support your direct 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 2018 through December 2018 as well as Schedule H1 for January through December, 2015 through 2018. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company projects that have been approved 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 $10,902,732 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2018.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2018 through December 2018.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per Kw**
RS Secondary	0.066	
GS and CS Secondary	0.060	
GSD, SBF Standard		
Secondary		0.20
Primary		0.20
Transmission		0.20
IS, IST, SBI		
Primary		0.14
Transmission		0.14
GSD Optional		
Secondary	0.047	
Primary	0.047	
LS1 Secondary	0.016	

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 0.056 cents per kWh compare to the factor for January 2017 through December 2017?

A. The proposed capacity cost recovery factor is 0.018 cents per kWh (or $0.18 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.074 cents per kWh for the January 2017 through December 2017 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 2018?

A. The appropriate amount for the 2018 period is 3.132 cents per kWh before the application of the 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 2018 through December 2018.

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 $47,392, 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 2017 through December 2017 period. The net true-up amount for this period is an over-recovery of $17,081,137.

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 2018 through December 2018. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering level.

Q. Please describe the information presented 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 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 2018 through December 2018.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.132
Tier I (Up to 1,000 kWh)	2.818
Tier II (Over 1,000 kWh)	3.818
Distribution Primary	3.101
Transmission	3.069
Lighting Service	3.095
Distribution Secondary	3.330 (on-peak)
	3.047 (off-peak)

Distribution Primary	3.297 (on-peak)
	3.017 (off-peak)
Transmission	3.263 (on-peak)
	2.986 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor 3.132 cents per kWh compare to the levelized fuel adjustment factor for the January 2017 through December 2017 period?

A. The proposed fuel charge factor is 0.176 cents per kWh (or $1.76 per 1,000 kWh) higher than the average fuel charge factor of 2.956 cents per kWh for the January 2017 through December 2017 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2018 fuel and purchased power and capacity cost recovery projections?

A. No, there are not any significant events that are reflected in the 2018 projection.

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 2018 through December 2018?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2018 through December 2018 are $1,650,886. This is shown in Exhibit PAR-3, Document No. 4.

Q. Do Tampa Electric's estimated Polk Unit 1 ignition oil conversion project savings exceed estimated costs for the period January 2018 through December 2018?

A. Yes, as reflected in Exhibit No. PAR-3, Document No. 4, fuel savings exceed costs for the period January 2018 through December 2018.

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

A. Yes. The January 2018 through December 2018 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-2012-0498-PAA-EI, issued in Docket No. 20120153-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 2018 through December 2018?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $4,877,765. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Big Bend Units 1-4 ignition oil conversion project fuel savings exceed costs for the period January 2018 through December 2018?

A. Yes, fuel savings exceed costs for the period January 2018 through December 2018. This information is also presented in Exhibit No. PAR-3, Document No. 4.

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 2018 through December 2018 estimated fuel savings are greater than the projected 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-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates relied upon 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 2018?

A. The company's projected 2018 benchmark is $881,855, which is the three-year average of $496,810, $683,509 and $1,465,247 in gains on the company's non-separated wholesale sales, excluding emergency sales for 2015, 2016 and 2017 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2018 from non-separated wholesale sales to exceed its 2018 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected wholesale benchmark for 2018. Therefore, all sales margins are expected to flow back to the customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is an increase of $1.32 beginning January 2018, when compared to the January 2017 through December 2017 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 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2018 - DECEMBER 2018

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2018 THROUGH DECEMBER 2018
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	54.90%	9,247,032	1,923	1.07913	1.05247	9,732,187	2,075	47.46%	56.37%	55.68%
GS, TS	60.53%	947,710	179	1.07913	1.05245	997,418	193	4.86%	5.24%	5.21%
GSD Optional	3.53%	373,897	55	1.07468	1.04884	392,159	59	1.91%	1.60%	1.62%
GSD, SBF	74.34%	7,873,825	1,154	1.07468	1.04884	8,258,409	1,240	40.27%	33.69%	34.20%
IS,SBI	100.93%	911,875	103	1.02898	1.01784	928,138	106	4.53%	2.88%	3.01%
LS1	291.75%	189,780	7	1.07913	1.05247	199,737	8	0.97%	0.22%	0.28%
TOTAL		19,544,119	3,421			20,508,048	3,681	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2017 projected calendar data.
(2) Projected MWH sales for the period January 2018 thru December 2018.
(3) Based on 12 months average CP at meter.
(4) Based on 2017 projected demand losses.
(5) Based on 2017 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 2018 THROUGH DECEMBER 2018
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	839,740	839,740	839,740	839,740	839,740	839,740	839,740	839,740	839,740	839,740	839,740	812,650	10,049,790
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(159,820)	(1,917,840)
4	TOTAL CAPACITY DOLLARS	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$652,830	$8,131,950
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	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$679,920	$652,830	$8,131,950
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2017 - DEC. 2017													2,762,938
8	TOTAL													$10,894,888
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$10,902,732

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2018 THROUGH DECEMBER 2018
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	47.46%	56.37%	397,914	5,673,253	6,071,167	9,247,032	9,247,032				0.00066
GS, CS	4.86%	5.24%	40,747	527,370	568,117	947,710	947,710				0.00060
GSD, SBF											
Secondary						6,412,460	6,412,460			0.20	
Primary						1,452,710	1,438,183			0.20	
Transmission						8,655	8,482			0.20	
GSD, SBF - Standard	40.27%	33.69%	337,632	3,390,667	3,728,299	7,873,825	7,859,125	58.99%	18,250,438		
GSD - Optional	1.91%	1.60%	16,014	161,029	177,043						
Secondary						363,508	363,508				0.00047
Primary						10,389	10,285				0.00047
IS, SBI											
Primary						184,182	182,340			0.14	
Transmission						727,693	713,139			0.14	
Total IS, SBI	4.53%	2.88%	37,980	289,852	327,832	911,875	895,479	52.85%	2,321,101		
LS1	0.97%	0.22%	8,133	22,141	30,274	189,780	189,780				0.00016
TOTAL	100.00%	100.00%	838,420	10,064,312	10,902,732	19,544,119	19,512,919				0.00056

(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 2018 through December 2018.
(7) Projected kWh sales at secondary for the period January 2018 through December 2018.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2018 through December 2018.
(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 2018 THROUGH DECEMBER 2018

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
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
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 ($)
PASCO COGEN - D	[redacted]												
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	679,920	679,920	679,920	679,920	679,920	679,920	679,920	679,920	679,920	679,920	679,920	652,830	8,131,950
TOTAL CAPACITY	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$679,920**	**$652,830**	**$8,131,950**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2018 - DECEMBER 2018

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 2018 THROUGH DECEMBER 2018

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	606,993,585	20,067,160	3.02481
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	4,877,765	20,067,160 [1]	0.02431
4b.	Polk Unit 1 Ignition Conversion Project	1,650,886	20,067,160 [1]	0.00823
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**613,522,236**	**20,067,160**	**3.05734**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	2,681,380	67,450	3.97536
7.	Energy Cost of Economy Purchases (E9)	9,706,470	313,280	3.09834
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,579,410	90,110	2.86251
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**14,967,260**	**470,840**	**3.17884**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,538,000	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	270,150	10,340	2.61267
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	361,827	11,990	3.01774
14.	Gains on Sales	54,590	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**686,567**	**22,330**	**3.07464**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		(598)	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**627,802,929**	**20,516,268**	**3.06003**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,064,890 [1]	34,800	0.00545
22.	T & D Losses	28,683,156 [1]	937,349	0.14676
23.	System MWH Sales	627,802,929	19,544,119	3.21223
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	627,802,929	19,544,119	3.21223
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	627,802,929	19,544,119	3.21223
28.	True-up [2]	(17,081,137)	19,544,119	(0.08740)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	610,721,792	19,544,119	3.12484
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	611,161,512	19,544,119	3.12709
32.	GPIF Adjusted for Taxes [2]	47,392	19,544,119	0.00024
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	611,208,904	19,544,119	3.12733
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.127**

[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 2018 THROUGH DECEMBER 2018

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2017 - December 2017 (6 months actual, 6 months estimated)	$38,652,694
2.	FINAL TRUE-UP (January 2016 - December 2016) (Per True-Up filed March 1, 2017)	(21,571,557)
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2018 through December 2018 (Schedule E1, line 28)	$17,081,137
4.	JURISDICTIONAL MWH SALES (Projected January 2018 through December 2018)	19,544,119
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0874)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2018 through December 2018)	$47,392	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2017 through December 2017)	$17,081,137	
2.	TOTAL SALES (January 2018 through December 2018)	19,544,119	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0002**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0874)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.13	$24.05
OFF PEAK	69.87	$22.01
	100.00	1.0927

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$627,802,929		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,544,119		
2a	Effective MWH Sales (Jurisd)		19,512,919		
3	Cost Per KWH Sold	(line 1 / line 2)	3.2122		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($17,081,137)		
7	TOTAL	(line 1 x line 4)+line 6	$610,721,792		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.1321		
10	GPIF Factor	(Sch E1-C line 3a)	0.0002		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.1323	3.3296	3.0472
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.132	3.330	3.047

13	Hours: ON PEAK	25.38%
14	OFF PEAK	74.62%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	17,160,490	17,160,490
Distribution Primary	1,647,281	1,630,808
Transmission	736,348	721,621
Total	19,544,119	19,512,919

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.132	3.330	3.047
Distribution Primary	3.101	3.297	3.017
Transmission	3.069	3.263	2.986
RS 1st Tier	2.818		
RS 2nd Tier	3.818		
Lighting	3.095		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.818	3.818
Distribution Secondary	3.132		
Distribution Primary	3.101		
Transmission	3.069		
Lighting Service (1)	3.095		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.330		
Distribution Secondary - Off-Peak	3.047		
Distribution Primary - On-Peak	3.297		
Distribution Primary - Off-Peak	3.017		
Transmission - On-Peak	3.263		
Transmission - Off-Peak	2.986		

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

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	ESTIMATED												TOTAL
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	PERIOD
1. Fuel Cost of System Net Generation	48,013,965	42,401,087	47,784,228	45,706,999	52,094,831	57,479,687	59,460,784	60,772,408	55,242,221	50,276,622	42,752,770	45,007,983	606,993,585
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	60,351	54,428	69,944	58,306	51,273	53,454	63,542	71,188	52,994	64,355	38,714	48,018	686,567
4. Fuel Cost of Purchased Power	35,830	60,680	162,060	107,650	147,910	288,370	391,020	309,040	254,740	362,720	423,770	137,590	2,681,380
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	283,760	230,640	185,740	158,380	219,420	183,820	220,950	259,590	184,910	241,610	220,790	189,800	2,579,410
7. Energy Cost of Economy Purchases	787,240	720,460	864,050	930,880	730,820	707,410	927,720	963,660	897,480	870,580	595,610	710,560	9,706,470
8. Big Bend Units 1-4 Igniters Conversion Project	420,537	417,981	415,425	412,870	410,315	407,757	405,202	402,647	400,092	397,535	394,980	392,424	4,877,765
9. Polk Unit 1 Ignition Conversion Project	280,083	278,109	276,136	274,161	272,186	270,211	0	0	0	0	0	0	1,650,886
10. TOTAL FUEL & NET POWER TRANSACTIONS	**49,761,064**	**44,054,529**	**49,617,695**	**47,532,634**	**53,824,209**	**59,283,801**	**61,342,134**	**62,636,157**	**56,926,449**	**52,084,712**	**44,349,206**	**46,390,339**	**627,802,929**
11. Jurisdictional MWH Sold	1,503,217	1,350,421	1,353,832	1,444,680	1,584,433	1,851,326	1,928,300	1,914,344	1,972,230	1,748,364	1,457,563	1,435,409	19,544,119
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)	49,761,064	44,054,529	49,617,695	47,532,634	53,824,209	59,283,801	61,342,134	62,636,157	56,926,449	52,084,712	44,349,206	46,390,339	627,802,929
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)	**49,761,064**	**44,054,529**	**49,617,695**	**47,532,634**	**53,824,209**	**59,283,801**	**61,342,134**	**62,636,157**	**56,926,449**	**52,084,712**	**44,349,206**	**46,390,339**	**627,802,929**
16. Cost Per kWh Sold (Cents/kWh)	3.3103	3.2623	3.6650	3.2902	3.3971	3.2022	3.1812	3.2719	2.8864	2.9791	3.0427	3.2319	3.2122
17. True-up (Cents/kWh) [2]	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)	(0.0874)
18. Total (Cents/kWh) (Line 16+17)	3.2229	3.1749	3.5776	3.2028	3.3097	3.1148	3.0938	3.1845	2.7990	2.8917	2.9553	3.1445	3.1248
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)	3.2252	3.1772	3.5802	3.2051	3.3121	3.1170	3.0960	3.1868	2.8010	2.8938	2.9574	3.1468	3.1270
21. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**3.2254**	**3.1774**	**3.5804**	**3.2053**	**3.3123**	**3.1172**	**3.0962**	**3.1870**	**2.8012**	**2.8940**	**2.9576**	**3.1470**	**3.1272**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.225**	**3.177**	**3.580**	**3.205**	**3.312**	**3.117**	**3.096**	**3.187**	**2.801**	**2.894**	**2.958**	**3.147**	**3.127**

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

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH JUNE 2018

SCHEDULE E3

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	66,291	56,093	50,993	53,543	66,291	53,543
3. COAL	15,655,404	13,607,271	13,486,830	12,065,932	14,195,155	15,854,483
4. NATURAL GAS	32,292,270	28,737,723	34,246,405	33,587,524	37,833,385	41,571,661
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**48,013,965**	**42,401,087**	**47,784,228**	**45,706,999**	**52,094,831**	**57,479,687**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	280	240	220	220	280	220
10. COAL	537,300	452,910	434,830	384,760	449,160	496,070
11. NATURAL GAS	941,940	850,750	1,004,250	1,151,110	1,345,730	1,453,840
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	3,030	3,200	4,370	4,870	5,150	4,530
14. TOTAL (MWH)	**1,482,550**	**1,307,100**	**1,443,670**	**1,540,960**	**1,800,320**	**1,954,660**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	520	440	400	420	520	420
17. COAL (TON)	228,730	194,850	182,600	162,120	190,710	212,270
18. NATURAL GAS (MCF)	6,542,810	5,862,520	7,276,570	8,223,690	9,567,090	10,557,220
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	2,980	2,580	2,360	2,440	2,960	2,440
23. COAL	5,535,180	4,673,320	4,474,730	3,991,810	4,659,160	5,147,330
24. NATURAL GAS	6,713,440	6,010,490	7,430,670	8,430,630	9,807,370	10,814,500
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,251,600**	**10,686,390**	**11,907,760**	**12,424,880**	**14,469,490**	**15,964,270**
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	0.01	0.02	0.01
30. COAL	36.24	34.65	30.12	24.97	24.94	25.38
31. NATURAL GAS	63.54	65.09	69.56	74.70	74.75	74.38
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.20	0.24	0.30	0.32	0.29	0.23
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)	127.48	127.48	127.48	127.48	127.48	127.48
37. COAL ($/TON)	68.44	69.83	73.86	74.43	74.43	74.69
38. NATURAL GAS ($/MCF)	4.94	4.90	4.71	4.08	3.95	3.94
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	22.25	21.74	21.61	21.94	22.40	21.94
43. COAL	2.83	2.91	3.01	3.02	3.05	3.08
44. NATURAL GAS	4.81	4.78	4.61	3.98	3.86	3.84
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)	**3.92**	**3.97**	**4.01**	**3.68**	**3.60**	**3.60**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,643	10,750	10,727	11,091	10,571	11,091
50. COAL	10,302	10,318	10,291	10,375	10,373	10,376
51. NATURAL GAS	7,127	7,065	7,399	7,324	7,288	7,439
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,264**	**8,176**	**8,248**	**8,063**	**8,037**	**8,167**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	23.68	23.37	23.18	24.34	23.68	24.34
57. COAL	2.91	3.00	3.10	3.14	3.16	3.20
58. NATURAL GAS	3.43	3.38	3.41	2.92	2.81	2.86
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)	**3.24**	**3.24**	**3.31**	**2.97**	**2.89**	**2.94**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2018 THROUGH DECEMBER 2018

SCHEDULE E3

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	50,993	63,742	53,543	66,291	40,795	66,291	688,409
3.	COAL	16,474,522	14,572,656	11,925,854	13,013,277	15,849,558	13,905,918	170,606,860
4.	NATURAL GAS	42,935,269	46,136,010	43,262,824	37,197,054	26,862,417	31,035,774	435,698,316
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**59,460,784**	**60,772,408**	**55,242,221**	**50,276,622**	**42,752,770**	**45,007,983**	**606,993,585**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	220	280	220	280	180	280	2,920
10.	COAL	513,350	457,910	376,400	404,900	503,610	445,770	5,456,970
11.	NATURAL GAS	1,499,930	1,586,040	1,496,860	1,258,190	844,760	1,031,760	14,465,160
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	4,420	4,260	29,420	30,310	25,660	22,890	142,110
14.	**TOTAL (MWH)**	**2,017,920**	**2,048,490**	**1,902,900**	**1,693,680**	**1,374,210**	**1,500,700**	**20,067,160**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	400	500	420	520	320	520	5,400
17.	COAL (TON)	219,420	200,420	169,900	174,790	215,060	187,780	2,338,650
18.	NATURAL GAS (MCF)	10,839,890	11,657,860	10,955,480	9,360,880	6,349,920	7,276,700	104,470,630
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	2,360	2,960	2,440	2,960	1,820	3,040	31,340
23.	COAL	5,320,520	4,747,190	3,914,400	4,211,090	5,211,620	4,591,740	56,478,090
24.	NATURAL GAS	11,096,940	11,957,950	11,233,460	9,577,140	6,506,600	7,457,170	107,036,360
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**16,419,820**	**16,708,100**	**15,150,300**	**13,791,190**	**11,720,040**	**12,051,950**	**163,545,790**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.01	0.02	0.01	0.02	0.01
30.	COAL	25.44	22.36	19.78	23.90	36.65	29.70	27.20
31.	NATURAL GAS	74.33	77.42	78.66	74.29	61.47	68.75	72.08
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.22	0.21	1.55	1.79	1.87	1.53	0.71
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)	127.48	127.48	127.48	127.48	127.48	127.48	127.48
37.	COAL ($/TON)	75.08	72.71	70.19	74.45	73.70	74.05	72.95
38.	NATURAL GAS ($/MCF)	3.96	3.96	3.95	3.97	4.23	4.27	4.17
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	21.61	21.53	21.94	22.40	22.41	21.81	21.97
43.	COAL	3.10	3.07	3.05	3.09	3.04	3.03	3.02
44.	NATURAL GAS	3.87	3.86	3.85	3.88	4.13	4.16	4.07
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)**	**3.62**	**3.64**	**3.65**	**3.65**	**3.65**	**3.73**	**3.71**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,727	10,571	11,091	10,571	10,111	10,857	10,733
50.	COAL	10,364	10,367	10,400	10,400	10,349	10,301	10,350
51.	NATURAL GAS	7,398	7,540	7,505	7,612	7,702	7,228	7,400
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**8,137**	**8,156**	**7,962**	**8,143**	**8,529**	**8,031**	**8,150**
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	23.18	22.77	24.34	23.68	22.66	23.68	23.58
57.	COAL	3.21	3.18	3.17	3.21	3.15	3.12	3.13
58.	NATURAL GAS	2.86	2.91	2.89	2.96	3.18	3.01	3.01
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)**	**2.95**	**2.97**	**2.90**	**2.97**	**3.11**	**3.00**	**3.02**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	230	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	180	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	2,620	18.2	-	18.2	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR [3]	**22.5**	**3,030**	**18.1**	**-**	**18.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
7. B.B.#1 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**395**	**0**	**0.0**	**43.2**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
10. B.B.#2 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**395**	**0**	**0.0**	**56.7**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	10,010	7.3	-	-	-	NG CO-FIRE	100,290	1,028,019	103,100.0	495,912	4.95	4.94
13. B.B.#3 COAL	400	190,280	63.9	-	-	-	COAL	85,020	23,040,108	1,958,870.0	5,483,654	2.88	64.50
14. TOTAL BIG BEND #3	**400**	**200,290**	**67.3**	**67.7**	**86.0**	**10,295**		**-**	**-**	**2,061,970.0**	**5,979,566**	**2.99**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	11,250	8.6	-	-	-	NG CO-FIRE	113,360	1,028,052	116,540.0	560,540	4.98	4.94
16. B.B.#4 COAL	442	213,790	65.0	-	-	-	COAL	96,100	23,041,103	2,214,250.0	6,198,297	2.90	64.50
17. TOTAL BIG BEND #4	**442**	**225,040**	**68.4**	**68.8**	**85.7**	**10,357**		**-**	**-**	**2,330,790.0**	**6,758,837**	**3.00**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	9,600	-	9,870.0	47,470	-	4.94
19. BIG BEND 1-4 COAL TOTAL	**1,632**	**404,070**	**33.3**	**59.4**	**81.6**	**10,328**	**COAL**	**181,120**	**23,040,636**	**4,173,120.0**	**11,681,951**	**2.89**	**64.50**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	61	260	0.6	-	85.2	12,269	GAS	3,110	1,025,723	3,190.0	15,378	5.91	4.94
22. B.B.C.T.#4 TOTAL	**61**	**260**	**0.6**	**98.3**	**85.2**	**12,269**	**-**	**-**	**-**	**3,190.0**	**15,378**	**5.91**	**-**
23. BIG BEND STATION TOTAL	**1,693**	**425,590**	**33.8**	**60.8**	**85.9**	**10,329**	**-**	**-**	**-**	**4,395,950.0**	**12,801,251**	**3.01**	**-**
24. POLK #1 GASIFIER	220	133,230	81.4	-	97.0	10,223	COAL	47,610	28,608,696	1,362,060.0	3,925,983	2.95	82.46
25. POLK #1 CT GAS	205	0	0.0	-	0.0	0	GAS	2,630	0	0.0	0	0.00	0.00
26. POLK #1 TOTAL	**220**	**133,230**	**81.4**	**72.7**	**97.0**	**10,223**	**-**	**-**	**-**	**1,362,060.0**	**3,925,983**	**2.95**	**-**
27. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
28. POLK #2 CT (OIL)	187	140	0.1	-	15.0	10,643	LGT OIL	260	5,730,769	1,490.0	33,146	23.68	127.48
29. POLK #2 TOTAL [4]	**180**	**140**	**0.1**	**-**	**15.0**	**10,643**	**-**	**-**	**-**	**1,490.0**	**33,146**	**23.68**	**-**
30. POLK #3 CT GAS	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL	187	140	0.1	-	15.0	10,643	LGT OIL	260	5,730,769	1,490.0	33,145	23.68	127.48
32. POLK #3 TOTAL [4]	**180**	**140**	**0.1**	**-**	**15.0**	**10,643**	**-**	**-**	**-**	**1,490.0**	**33,145**	**23.68**	**-**
33. POLK #4 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK #5 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	880	1.0	-	81.5	8,182	GAS	7,000	1,028,571	7,200.0	34,613	3.93	4.94
36. POLK #2 ST W/O DUCT FIRING	360	617,090	-	-	-	-	GAS	4,055,120	1,028,002	4,168,670.0	20,051,670	3.25	4.94
37. POLK #2 CC TOTAL	**1,200**	**617,970**	**69.2**	**97.3**	**69.3**	**6,757**	**GAS**	**-**	**-**	**4,175,870.0**	**20,086,283**	**3.25**	**-**
38. POLK STATION TOTAL	**1,420**	**751,480**	**71.1**	**93.5**	**81.5**	**7,373**	**-**	**-**	**-**	**5,540,910.0**	**24,078,557**	**3.20**	**-**
39. BAYSIDE #1	792	221,240	37.5	96.5	43.0	7,502	GAS	1,614,440	1,027,997	1,659,640.0	7,983,048	3.61	4.94
40. BAYSIDE #2	1,047	81,160	10.4	96.2	27.1	8,064	GAS	636,630	1,027,991	654,450.0	3,147,994	3.88	4.94
41. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. BAYSIDE #5	61	50	0.1	98.6	82.0	13,000	GAS	630	1,031,746	650.0	3,115	6.23	4.94
44. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. BAYSIDE TOTAL	**2,083**	**302,450**	**19.5**	**87.9**	**37.1**	**7,653**	**GAS**	**2,251,700**	**1,027,997**	**2,314,740.0**	**11,134,157**	**3.68**	**4.94**
46. SYSTEM	**5,218**	**1,482,550**	**38.2**	**80.3**	**86.5**	**8,264**	**-**	**-**	**-**	**12,251,600.0**	**48,013,965**	**3.24**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

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DOCKET NO. 20170001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 10 OF 30

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2018

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	230	21.4	-	21.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	170	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	2,800	21.5	-	21.5	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR [3]	**22.5**	**3,200**	**21.2**	**-**	**21.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
7. B.B.#1 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**395**	**0**	**0.0**	**40.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
10. B.B.#2 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**395**	**0**	**0.0**	**52.7**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	9,060	7.3	-	-	-	NG CO-FIRE	90,760	1,027,986	93,300.0	446,097	4.92	4.92
13. B.B.#3 COAL	400	172,220	64.1	-	-	-	COAL	76,940	23,039,771	1,772,680.0	5,109,184	2.97	66.40
14. TOTAL BIG BEND #3	**400**	**181,280**	**67.4**	**67.7**	**86.2**	**10,293**		**-**	**-**	**1,865,980.0**	**5,555,281**	**3.06**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	10,020	8.5	-	-	-	NG CO-FIRE	101,030	1,028,011	103,860.0	496,575	4.96	4.92
16. B.B.#4 COAL	442	190,440	64.1	-	-	-	COAL	85,650	23,038,996	1,973,290.0	5,687,572	2.99	66.40
17. TOTAL BIG BEND #4	**442**	**200,460**	**67.5**	**68.8**	**85.6**	**10,362**		**-**	**-**	**2,077,150.0**	**6,184,147**	**3.08**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	9,600	-	9,870.0	47,185	-	4.92
19. BIG BEND 1-4 COAL TOTAL	**1,632**	**362,660**	**33.1**	**57.7**	**81.6**	**10,329**	**COAL**	**162,590**	**23,039,363**	**3,745,970.0**	**10,796,756**	**2.98**	**66.40**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	61	540	1.3	-	88.5	11,778	GAS	6,190	1,027,464	6,360.0	30,425	5.63	4.92
22. B.B.C.T.#4 TOTAL	**61**	**540**	**1.3**	**98.3**	**88.5**	**11,778**	**-**	**-**	**-**	**6,360.0**	**30,425**	**5.63**	**-**
23. BIG BEND STATION TOTAL	**1,693**	**382,280**	**33.6**	**59.2**	**85.9**	**10,331**	**-**	**-**	**-**	**3,949,490.0**	**11,817,038**	**3.09**	**-**
24. POLK #1 GASIFIER	220	90,250	61.0	-	97.0	10,275	COAL	32,260	28,746,125	927,350.0	2,763,330	3.06	85.66
25. POLK #1 CT GAS	205	4,730	3.4	-	82.4	8,165	GAS	43,710	883,551	38,620.0	184,711	3.91	4.23
26. POLK #1 TOTAL	**220**	**94,980**	**64.2**	**54.5**	**96.1**	**10,170**	**-**	**-**	**-**	**965,970.0**	**2,948,041**	**3.10**	**-**
27. POLK #2 CT (GAS)	180	1,130	0.9	-	69.8	12,027	GAS	13,220	1,027,988	13,590.0	64,977	5.75	4.92
28. POLK #2 CT (OIL)	187	120	0.1	-	16.0	10,750	LGT OIL	220	5,863,636	1,290.0	28,046	23.37	127.48
29. POLK #2 TOTAL [4]	**180**	**1,250**	**1.0**	**-**	**52.8**	**11,904**	**-**	**-**	**-**	**14,880.0**	**93,023**	**7.44**	**-**
30. POLK #3 CT GAS	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL	187	120	0.1	-	16.0	10,750	LGT OIL	220	5,863,636	1,290.0	28,047	23.37	127.49
32. POLK #3 TOTAL [4]	**180**	**120**	**0.1**	**-**	**16.0**	**10,750**	**-**	**-**	**-**	**1,290.0**	**28,047**	**23.37**	**-**
33. POLK #4 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK #5 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	1,960	2.4	-	65.3	8,168	GAS	15,580	1,027,599	16,010.0	76,578	3.91	4.92
36. POLK #2 ST W/O DUCT FIRING	360	567,040	-	-	-	-	GAS	3,728,500	1,028,001	3,832,900.0	18,326,056	3.23	4.92
37. POLK #2 CC TOTAL	**1,200**	**569,000**	**70.6**	**97.3**	**68.9**	**6,764**	**GAS**	**-**	**-**	**3,848,910.0**	**18,402,634**	**3.23**	**-**
38. POLK STATION TOTAL	**1,420**	**665,350**	**69.7**	**90.7**	**79.2**	**7,261**	**-**	**-**	**-**	**4,831,050.0**	**21,471,745**	**3.23**	**-**
39. BAYSIDE #1	792	255,270	48.0	96.5	49.4	7,420	GAS	1,842,440	1,028,001	1,894,030.0	9,055,829	3.55	4.92
40. BAYSIDE #2	1,047	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
41. BAYSIDE #3	61	170	0.4	98.6	92.9	11,647	GAS	1,930	1,025,907	1,980.0	9,486	5.58	4.92
42. BAYSIDE #4	61	120	0.3	98.6	98.4	11,083	GAS	1,290	1,031,008	1,330.0	6,341	5.28	4.92
43. BAYSIDE #5	61	430	1.0	98.6	88.1	12,070	GAS	5,050	1,027,723	5,190.0	24,821	5.77	4.92
44. BAYSIDE #6	61	280	0.7	98.6	91.8	11,857	GAS	3,220	1,031,056	3,320.0	15,827	5.65	4.92
45. BAYSIDE TOTAL	**2,083**	**256,270**	**18.3**	**48.2**	**49.4**	**7,437**	**GAS**	**1,853,930**	**1,028,005**	**1,905,850.0**	**9,112,304**	**3.56**	**4.92**
46. SYSTEM	**5,218**	**1,307,100**	**37.3**	**63.1**	**100.0**	**8,176**	**-**	**-**	**-**	**10,686,390.0**	**42,401,087**	**3.24**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

[1] **As burned fuel cost system total includes ignition**
[2] **Fuel burned (MM BTU) system total excludes ignition**
[3] **AC rating**
[4] **In Simple Cycle Mode**

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	280	23.5	-	23.5	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	230	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	3,860	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**22.5**	**4,370**	**26.2**	**-**	**26.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	15,440	11.2	-	-	-	NG CO-FIRE	183,240	1,027,996	188,370.0	868,156	5.62	4.74
7. B.B.#1 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**395**	**15,440**	**5.3**	**26.5**	**46.5**	**12,200**		**-**	**-**	**188,370.0**	**868,156**	**5.62**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	49,300	35.8	-	-	-	NG CO-FIRE	542,360	1,027,989	557,540.0	2,569,599	5.21	4.74
10. B.B.#2 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**395**	**49,300**	**16.8**	**34.8**	**52.7**	**11,309**		**-**	**-**	**557,540.0**	**2,569,599**	**5.21**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	10,000	7.3	-	-	-	NG CO-FIRE	100,160	1,027,955	102,960.0	474,539	4.75	4.74
13. B.B.#3 COAL	400	190,010	63.8	-	-	-	COAL	84,910	23,038,982	1,956,240.0	5,782,856	3.04	68.11
14. TOTAL BIG BEND #3	**400**	**200,010**	**67.2**	**67.7**	**85.9**	**10,295**		**-**	**-**	**2,059,200.0**	**6,257,395**	**3.13**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	5,870	4.5	-	-	-	NG CO-FIRE	59,070	1,027,933	60,720.0	279,862	4.77	4.74
16. B.B.#4 COAL	442	111,590	33.9	-	-	-	COAL	50,080	23,037,740	1,153,730.0	3,410,736	3.06	68.11
17. TOTAL BIG BEND #4	**442**	**117,460**	**35.7**	**37.7**	**86.6**	**10,339**		**-**	**-**	**1,214,450.0**	**3,690,598**	**3.14**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	43,000	-	44,200.0	203,726	-	4.74
19. BIG BEND 1-4 COAL TOTAL	**1,632**	**301,600**	**24.8**	**41.6**	**60.9**	**10,312**	**COAL**	**134,990**	**23,038,521**	**3,109,970.0**	**9,193,592**	**3.05**	**68.11**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	61	3,590	7.9	-	84.1	11,735	GAS	40,980	1,028,062	42,130.0	194,155	5.41	4.74
22. B.B.C.T.#4 TOTAL	**61**	**3,590**	**7.9**	**98.3**	**84.1**	**11,735**	**-**	**-**	**-**	**42,130.0**	**194,155**	**5.41**	**-**
23. BIG BEND STATION TOTAL	**1,693**	**385,800**	**30.6**	**43.7**	**77.2**	**10,528**	**-**	**-**	**-**	**4,061,690.0**	**13,783,630**	**3.57**	**-**
24. POLK #1 GASIFIER	220	133,230	81.4	-	97.0	10,244	COAL	47,610	28,665,406	1,364,760.0	4,089,512	3.07	85.90
25. POLK #1 CT GAS	205	11,570	7.6	-	99.0	8,174	GAS	97,250	972,442	94,570.0	435,879	3.77	4.48
26. POLK #1 TOTAL	**220**	**144,800**	**88.5**	**72.7**	**97.2**	**10,078**	**-**	**-**	**-**	**1,459,330.0**	**4,525,391**	**3.13**	**-**
27. POLK #2 CT (GAS)	180	1,720	1.3	-	95.6	10,919	GAS	18,270	1,027,915	18,780.0	86,558	5.03	4.74
28. POLK #2 CT (OIL)	187	110	0.1	-	14.7	10,727	LGT OIL	200	5,900,000	1,180.0	25,497	23.18	127.49
29. POLK #2 TOTAL (4)	**180**	**1,830**	**1.4**	**-**	**71.8**	**10,907**	**-**	**-**	**-**	**19,960.0**	**112,055**	**6.12**	**-**
30. POLK #3 CT GAS	180	1,720	1.3	-	95.6	10,901	GAS	18,250	1,027,397	18,750.0	86,465	5.03	4.74
31. POLK #3 CT OIL	187	110	0.1	-	14.7	10,727	LGT OIL	200	5,900,000	1,180.0	25,496	23.18	127.48
32. POLK #3 TOTAL (4)	**180**	**1,830**	**1.4**	**-**	**71.8**	**10,891**	**-**	**-**	**-**	**19,930.0**	**111,961**	**6.12**	**-**
33. POLK #4 CT GAS (4)	**180**	**1,380**	**1.0**	**-**	**95.8**	**10,884**	**GAS**	**14,620**	**1,027,360**	**15,020.0**	**69,267**	**5.02**	**4.74**
34. POLK #5 CT GAS (4)	**180**	**1,030**	**0.8**	**-**	**95.4**	**10,951**	**GAS**	**10,970**	**1,028,259**	**11,280.0**	**51,974**	**5.05**	**4.74**
35. POLK #2 ST DUCT FIRING	120	11,670	13.1	-	84.6	8,175	GAS	92,800	1,028,017	95,400.0	439,669	3.77	4.74
36. POLK #2 ST W/O DUCT FIRING	360	614,980	-	-	-	-	GAS	4,048,100	1,027,998	4,161,440.0	19,179,128	3.12	4.74
37. POLK #2 CC TOTAL	**1,200**	**626,650**	**70.2**	**97.3**	**61.5**	**6,793**	**GAS**	**-**	**-**	**4,256,840.0**	**19,618,797**	**3.13**	**-**
38. POLK STATION TOTAL	**1,420**	**777,520**	**73.6**	**93.5**	**77.5**	**7,437**	**-**	**-**	**-**	**5,782,360.0**	**24,489,445**	**3.15**	**-**
39. BAYSIDE #1	792	270,830	46.0	96.5	52.4	7,396	GAS	1,948,400	1,027,997	2,002,950.0	9,231,148	3.41	4.74
40. BAYSIDE #2	1,047	0	0.0	0.0	0.0	0	GAS	0	0	0.0	1	0.00	0.00
41. BAYSIDE #3	61	1,150	2.5	98.6	89.8	11,600	GAS	12,990	1,026,944	13,340.0	61,544	5.35	4.74
42. BAYSIDE #4	61	640	1.4	98.6	95.4	11,578	GAS	7,200	1,029,167	7,410.0	34,112	5.33	4.74
43. BAYSIDE #5	61	2,270	5.0	98.6	80.9	11,925	GAS	26,320	1,028,495	27,070.0	124,699	5.49	4.74
44. BAYSIDE #6	61	1,090	2.4	98.6	85.1	11,872	GAS	12,590	1,027,800	12,940.0	59,649	5.47	4.74
45. BAYSIDE TOTAL	**2,083**	**275,980**	**17.8**	**48.2**	**52.8**	**7,478**	**GAS**	**2,007,500**	**1,028,000**	**2,063,710.0**	**9,511,153**	**3.45**	**4.74**
46. SYSTEM	**5,218**	**1,443,670**	**37.2**	**58.9**	**99.1**	**8,248**	**-**	**-**	**-**	**11,907,760.0**	**47,784,228**	**3.31**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) **As burned fuel cost system total includes ignition**
(2) **Fuel burned (MM BTU) system total excludes ignition**
(3) **AC rating**
(4) **In Simple Cycle Mode**

DOCKET NO. 20170001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 12 OF 30

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	280	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	4,320	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**22.5**	**4,870**	**30.1**	**-**	**30.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	15,050	11.3	-	-	-	NG CO-FIRE	180,730	1,027,998	185,790.0	740,185	4.92	4.10
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**15,050**	**5.4**	**43.2**	**48.3**	**12,345**		**-**	**-**	**185,790.0**	**740,185**	**4.92**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	16,840	12.6	-	-	-	NG CO-FIRE	185,460	1,027,984	190,650.0	759,557	4.51	4.10
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**16,840**	**6.1**	**56.7**	**54.7**	**11,321**		**-**	**-**	**190,650.0**	**759,557**	**4.51**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	5,790	4.3	-	-	-	NG CO-FIRE	58,860	1,028,033	60,510.0	241,063	4.16	4.10
13. B.B.#3 COAL	395	110,080	38.7	-	-	-	COAL	49,900	23,040,681	1,149,730.0	3,436,449	3.12	68.87
14. TOTAL BIG BEND #3	**395**	**115,870**	**40.7**	**45.2**	**78.0**	**10,445**		**-**	**-**	**1,210,240.0**	**3,677,512**	**3.17**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	7,670	6.1	-	-	-	NG CO-FIRE	78,010	1,028,073	80,200.0	319,492	4.17	4.10
16. B.B.#4 COAL	437	145,750	46.3	-	-	-	COAL	66,140	23,038,555	1,523,770.0	4,554,847	3.13	68.87
17. TOTAL BIG BEND #4	**437**	**153,420**	**48.8**	**68.8**	**82.2**	**10,455**		**-**	**-**	**1,603,970.0**	**4,874,339**	**3.18**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	20,040	-	20,600.0	82,074	-	4.10
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**255,830**	**22.2**	**53.9**	**64.4**	**10,450**	**COAL**	**116,040**	**23,039,469**	**2,673,500.0**	**7,991,296**	**3.12**	**68.87**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	1,340	3.3	-	99.7	11,784	GAS	15,360	1,027,995	15,790.0	62,907	4.69	4.10
22. B.B.C.T.#4 TOTAL	**56**	**1,340**	**3.3**	**98.3**	**99.7**	**11,784**	**-**	**-**	**-**	**15,790.0**	**62,907**	**4.69**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**302,520**	**25.3**	**55.4**	**75.9**	**10,599**	**-**	**-**	**-**	**3,206,440.0**	**10,196,575**	**3.37**	**-**
24. POLK #1 GASIFIER	220	128,930	81.4	-	97.0	10,225	COAL	46,080	28,609,158	1,318,310.0	3,992,562	3.10	86.64
25. POLK #1 CT GAS	195	12,400	8.8	-	89.6	8,116	GAS	100,530	1,001,094	100,640.0	400,952	3.23	3.99
26. POLK #1 TOTAL	**220**	**141,330**	**89.2**	**72.7**	**96.3**	**10,040**	**-**	**-**	**-**	**1,418,950.0**	**4,393,514**	**3.11**	**-**
27. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
28. POLK #2 CT (OIL)	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,771	24.34	127.48
29. POLK #2 TOTAL (4)	**150**	**110**	**0.1**	**-**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**26,772**	**24.34**	**-**
30. POLK #3 CT GAS	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,772	24.34	127.49
32. POLK #3 TOTAL (4)	**150**	**110**	**0.1**	**-**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**26,772**	**24.34**	**-**
33. POLK #4 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK #5 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	7,620	8.8	-	71.3	8,269	GAS	61,300	1,027,896	63,010.0	251,056	3.29	4.10
36. POLK #2 ST W/O DUCT FIRING	341	627,200	-	-	-	-	GAS	4,120,910	1,027,999	4,236,290.0	16,877,310	2.69	4.10
37. POLK #2 CC TOTAL	**1,061**	**634,820**	**83.1**	**97.3**	**74.8**	**6,772**	**GAS**	**-**	**-**	**4,299,300.0**	**17,128,366**	**2.70**	**-**
38. POLK STATION TOTAL	**1,281**	**776,370**	**84.2**	**93.1**	**84.3**	**7,369**	**-**	**-**	**-**	**5,720,690.0**	**21,575,424**	**2.78**	**-**
39. BAYSIDE #1	701	152,920	30.3	57.9	60.3	7,478	GAS	1,112,380	1,027,994	1,143,520.0	4,555,786	2.98	4.10
40. BAYSIDE #2	929	301,710	45.1	96.2	47.9	7,703	GAS	2,260,690	1,028,000	2,323,990.0	9,258,723	3.07	4.10
41. BAYSIDE #3	56	770	1.9	82.2	98.2	11,727	GAS	8,790	1,027,304	9,030.0	36,000	4.68	4.10
42. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. BAYSIDE #5	56	980	2.4	92.0	97.2	11,745	GAS	11,200	1,027,679	11,510.0	45,870	4.68	4.10
44. BAYSIDE #6	56	820	2.0	98.6	97.6	11,829	GAS	9,430	1,028,632	9,700.0	38,621	4.71	4.10
45. BAYSIDE TOTAL	**1,854**	**457,200**	**34.3**	**78.3**	**51.6**	**7,650**	**GAS**	**3,402,490**	**1,027,997**	**3,497,750.0**	**13,935,000**	**3.05**	**4.10**
46. SYSTEM	**4,815**	**1,540,960**	**44.4**	**74.0**	**91.3**	**8,063**	**-**	**-**	**-**	**12,424,880.0**	**45,706,999**	**2.97**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2018

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	290	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	4,570	31.7	-	31.7	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**22.5**	**5,150**	**30.8**	**-**	**30.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**0**	**0.0**	**43.2**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	17,380	12.6	-	-	-	NG CO-FIRE	191,630	1,028,023	197,000.0	759,939	4.37	3.97
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**17,380**	**6.1**	**56.7**	**54.4**	**11,335**		**-**	**-**	**197,000.0**	**759,939**	**4.37**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	7,720	5.6	-	-	-	NG CO-FIRE	78,510	1,028,022	80,710.0	311,344	4.03	3.97
13. B.B.#3 COAL	395	146,640	49.9	-	-	-	COAL	66,550	23,041,473	1,533,410.0	4,624,124	3.15	69.48
14. TOTAL BIG BEND #3	**395**	**154,360**	**52.5**	**59.0**	**77.1**	**10,457**		**-**	**-**	**1,614,120.0**	**4,935,468**	**3.20**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	8,910	6.8	-	-	-	NG CO-FIRE	90,300	1,028,018	92,830.0	358,099	4.02	3.97
16. B.B.#4 COAL	437	169,290	52.1	-	-	-	COAL	76,550	23,039,713	1,763,690.0	5,318,956	3.14	69.48
17. TOTAL BIG BEND #4	**437**	**178,200**	**54.8**	**68.8**	**83.1**	**10,418**		**-**	**-**	**1,856,520.0**	**5,677,055**	**3.19**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	24,210	-	24,890.0	96,009	-	3.97
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**315,930**	**26.5**	**57.3**	**70.7**	**10,436**	**COAL**	**143,100**	**23,040,531**	**3,297,100.0**	**9,943,080**	**3.15**	**69.48**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	1,230	3.0	-	99.8	11,691	GAS	13,990	1,027,877	14,380.0	55,480	4.51	3.97
22. B.B.C.T.#4 TOTAL	**56**	**1,230**	**3.0**	**82.4**	**99.8**	**11,691**	**-**	**-**	**-**	**14,380.0**	**55,480**	**4.51**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**351,170**	**28.5**	**58.2**	**78.4**	**10,485**	**-**	**-**	**-**	**3,682,020.0**	**11,523,951**	**3.28**	**-**
24. POLK #1 GASIFIER	220	133,230	81.4	-	97.0	10,223	COAL	47,610	28,608,696	1,362,060.0	4,156,066	3.12	87.29
25. POLK #1 CT GAS	195	8,090	5.6	-	90.2	8,156	GAS	66,810	987,577	65,980.0	254,516	3.15	3.81
26. POLK #1 TOTAL	**220**	**141,320**	**86.3**	**72.7**	**96.6**	**10,105**	**-**	**-**	**-**	**1,428,040.0**	**4,410,582**	**3.12**	**-**
27. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	11,227	GAS	16,390	1,027,456	16,840.0	64,997	4.33	3.97
28. POLK #2 CT (OIL)	159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	33,146	23.68	127.48
29. POLK #2 TOTAL (4)	**150**	**1,640**	**1.5**	**-**	**71.5**	**11,171**	**-**	**-**	**-**	**18,320.0**	**98,143**	**5.98**	**-**
30. POLK #3 CT GAS	150	1,500	1.3	-	100.0	11,227	GAS	16,390	1,027,456	16,840.0	64,997	4.33	3.97
31. POLK #3 CT OIL	159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	33,145	23.68	127.48
32. POLK #3 TOTAL (4)	**150**	**1,640**	**1.5**	**-**	**71.5**	**11,171**	**-**	**-**	**-**	**18,320.0**	**98,142**	**5.98**	**-**
33. POLK #4 CT GAS (4)	**150**	**600**	**0.5**	**-**	**100.0**	**11,333**	**GAS**	**6,610**	**1,028,744**	**6,800.0**	**26,213**	**4.37**	**3.97**
34. POLK #5 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	5,210	5.8	-	68.9	8,278	GAS	41,950	1,028,129	43,130.0	166,359	3.19	3.97
36. POLK #2 ST W/O DUCT FIRING	341	659,780	-	-	-	-	GAS	4,336,040	1,028,000	4,457,450.0	17,195,260	2.61	3.97
37. POLK #2 CC TOTAL	**1,061**	**664,990**	**84.2**	**97.3**	**78.6**	**6,768**	**GAS**	**-**	**-**	**4,500,580.0**	**17,361,619**	**2.61**	**-**
38. POLK STATION TOTAL	**1,281**	**810,190**	**85.0**	**93.1**	**86.6**	**7,371**	**-**	**-**	**-**	**5,972,060.0**	**21,994,699**	**2.71**	**-**
39. BAYSIDE #1	701	313,520	60.1	96.5	62.3	7,453	GAS	2,273,050	1,028,002	2,336,700.0	9,014,143	2.88	3.97
40. BAYSIDE #2	929	317,640	46.0	96.2	47.4	7,704	GAS	2,380,530	1,027,998	2,447,180.0	9,440,371	2.97	3.97
41. BAYSIDE #3	56	590	1.4	98.6	95.8	11,932	GAS	6,850	1,027,737	7,040.0	27,165	4.60	3.97
42. BAYSIDE #4	56	380	0.9	98.6	96.9	11,947	GAS	4,410	1,029,478	4,540.0	17,489	4.60	3.97
43. BAYSIDE #5	56	940	2.3	89.1	93.3	11,915	GAS	10,900	1,027,523	11,200.0	43,226	4.60	3.97
44. BAYSIDE #6	56	740	1.8	82.7	94.4	11,824	GAS	8,520	1,026,995	8,750.0	33,787	4.57	3.97
45. BAYSIDE TOTAL	**1,854**	**633,810**	**45.9**	**95.8**	**53.9**	**7,598**	**GAS**	**4,684,260**	**1,027,998**	**4,815,410.0**	**18,576,181**	**2.93**	**3.97**
46. SYSTEM	**4,815**	**1,800,320**	**50.3**	**81.7**	**88.5**	**8,037**	**-**	**-**	**-**	**14,469,490.0**	**52,094,831**	**2.89**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	250	21.7	-	21.7	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	4,010	28.8	-	28.8	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**22.5**	**4,530**	**28.0**	**-**	**28.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	26,920	20.2	-	-	-	NG CO-FIRE	313,720	1,027,987	322,500.0	1,239,728	4.61	3.95
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**26,920**	**9.7**	**43.2**	**53.0**	**11,980**		**-**	**-**	**322,500.0**	**1,239,728**	**4.61**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	35,790	26.9	-	-	-	NG CO-FIRE	400,930	1,028,010	412,160.0	1,584,356	4.43	3.95
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**35,790**	**12.9**	**56.7**	**51.1**	**11,516**		**-**	**-**	**412,160.0**	**1,584,356**	**4.43**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	8,970	6.7	-	-	-	NG CO-FIRE	90,830	1,027,964	93,370.0	358,933	4.00	3.95
13. B.B.#3 COAL	395	170,460	59.9	-	-	-	COAL	77,000	23,039,740	1,774,060.0	5,406,972	3.17	70.22
14. TOTAL BIG BEND #3	**395**	**179,430**	**63.1**	**67.7**	**80.7**	**10,408**		**-**	**-**	**1,867,430.0**	**5,765,905**	**3.21**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	10,350	8.2	-	-	-	NG CO-FIRE	105,210	1,028,039	108,160.0	415,759	4.02	3.95
16. B.B.#4 COAL	437	196,680	62.5	-	-	-	COAL	89,190	23,040,251	2,054,960.0	6,262,964	3.18	70.22
17. TOTAL BIG BEND #4	**437**	**207,030**	**65.8**	**68.8**	**82.1**	**10,448**		**-**	**-**	**2,163,120.0**	**6,678,723**	**3.23**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	34,650	-	35,620.0	136,926	-	3.95
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**367,140**	**31.8**	**59.5**	**61.7**	**10,429**	**COAL**	**166,190**	**23,040,014**	**3,829,020.0**	**11,669,936**	**3.18**	**70.22**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	3,120	7.7	-	96.1	11,814	GAS	35,860	1,027,886	36,860.0	141,708	4.54	3.95
22. B.B.C.T.#4 TOTAL	**56**	**3,120**	**7.7**	**98.3**	**96.1**	**11,814**	**-**	**-**	**-**	**36,860.0**	**141,708**	**4.54**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**452,290**	**37.9**	**60.8**	**75.5**	**10,617**	**-**	**-**	**-**	**4,802,070.0**	**15,547,345**	**3.44**	**-**
24. POLK #1 GASIFIER	220	128,930	81.4	-	97.0	10,225	COAL	46,080	28,609,158	1,318,310.0	4,047,621	3.14	87.84
25. POLK #1 CT GAS	195	8,420	6.0	-	93.9	8,118	GAS	69,120	988,860	68,350.0	262,749	3.12	3.80
26. POLK #1 TOTAL	**220**	**137,350**	**86.7**	**72.7**	**96.8**	**10,096**	**-**	**-**	**-**	**1,386,660.0**	**4,310,370**	**3.14**	**-**
27. POLK #2 CT (GAS)	150	1,050	1.0	-	100.0	11,257	GAS	11,500	1,027,826	11,820.0	45,444	4.33	3.95
28. POLK #2 CT (OIL)	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,771	24.34	127.48
29. POLK #2 TOTAL (4)	**150**	**1,160**	**1.1**	**-**	**68.8**	**11,241**	**-**	**-**	**-**	**13,040.0**	**72,215**	**6.23**	**-**
30. POLK #3 CT GAS	150	900	0.8	-	100.0	11,278	GAS	9,870	1,028,369	10,150.0	39,003	4.33	3.95
31. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,772	24.34	127.49
32. POLK #3 TOTAL (4)	**150**	**1,010**	**0.9**	**-**	**65.8**	**11,257**	**-**	**-**	**-**	**11,370.0**	**65,775**	**6.51**	**-**
33. POLK #4 CT GAS (4)	**150**	**600**	**0.6**	**-**	**100.0**	**11,333**	**GAS**	**6,610**	**1,028,744**	**6,800.0**	**26,121**	**4.35**	**3.95**
34. POLK #5 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	14,250	16.5	-	81.9	8,274	GAS	114,700	1,027,986	117,910.0	453,260	3.18	3.95
36. POLK #2 ST W/O DUCT FIRING	341	649,760	-	-	-	-	GAS	4,271,390	1,028,000	4,390,990.0	16,879,258	2.60	3.95
37. POLK #2 CC TOTAL	**1,061**	**664,010**	**86.9**	**97.3**	**73.1**	**6,790**	**GAS**	**-**	**-**	**4,508,900.0**	**17,332,518**	**2.61**	**-**
38. POLK STATION TOTAL	**1,281**	**804,130**	**87.2**	**93.1**	**83.2**	**7,370**	**-**	**-**	**-**	**5,926,770.0**	**21,806,999**	**2.71**	**-**
39. BAYSIDE #1	701	335,900	66.6	96.5	68.9	7,404	GAS	2,419,160	1,028,001	2,486,900.0	9,559,798	2.85	3.95
40. BAYSIDE #2	929	352,290	52.7	96.2	54.3	7,614	GAS	2,609,150	1,028,001	2,682,210.0	10,310,581	2.93	3.95
41. BAYSIDE #3	56	1,250	3.1	98.6	93.0	11,960	GAS	14,540	1,028,198	14,950.0	57,458	4.60	3.95
42. BAYSIDE #4	56	580	1.4	98.6	94.2	12,276	GAS	6,930	1,027,417	7,120.0	27,385	4.72	3.95
43. BAYSIDE #5	56	2,090	5.2	98.6	91.0	11,995	GAS	24,390	1,027,880	25,070.0	96,382	4.61	3.95
44. BAYSIDE #6	56	1,600	4.0	98.6	92.2	11,988	GAS	18,660	1,027,867	19,180.0	73,739	4.61	3.95
45. BAYSIDE TOTAL	**1,854**	**693,710**	**52.0**	**96.6**	**60.7**	**7,547**	**GAS**	**5,092,830**	**1,028,000**	**5,235,430.0**	**20,125,343**	**2.90**	**3.95**
46. SYSTEM	**4,815**	**1,954,660**	**56.4**	**82.9**	**91.0**	**8,167**	**-**	**-**	**-**	**15,964,270.0**	**57,479,687**	**2.94**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	250	21.0	-	21.0	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	3,900	27.1	-	27.1	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**22.5**	**4,420**	**26.5**	**-**	**26.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	24,280	17.6	-	-	-	NG CO-FIRE	289,980	1,028,002	298,100.0	1,153,380	4.75	3.98
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**24,280**	**8.5**	**43.2**	**48.9**	**12,278**		**-**	**-**	**298,100.0**	**1,153,380**	**4.75**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	25,530	18.5	-	-	-	NG CO-FIRE	284,400	1,027,989	292,360.0	1,131,186	4.43	3.98
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**25,530**	**8.9**	**56.7**	**52.2**	**11,452**		**-**	**-**	**292,360.0**	**1,131,186**	**4.43**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	9,550	6.9	-	-	-	NG CO-FIRE	96,400	1,028,008	99,100.0	383,426	4.01	3.98
13. B.B.#3 COAL	395	181,500	61.8	-	-	-	COAL	81,720	23,040,749	1,882,890.0	5,721,786	3.15	70.02
14. TOTAL BIG BEND #3	**395**	**191,050**	**65.0**	**67.7**	**83.1**	**10,374**		**-**	**-**	**1,981,990.0**	**6,105,212**	**3.20**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	10,450	8.0	-	-	-	NG CO-FIRE	106,270	1,027,948	109,240.0	422,683	4.04	3.98
16. B.B.#4 COAL	437	198,620	61.1	-	-	-	COAL	90,090	23,038,850	2,075,570.0	6,307,832	3.18	70.02
17. TOTAL BIG BEND #4	**437**	**209,070**	**64.3**	**68.8**	**82.3**	**10,450**		**-**	**-**	**2,184,810.0**	**6,730,515**	**3.22**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	42,580	-	43,770.0	169,360	-	3.98
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**380,120**	**31.9**	**59.5**	**65.3**	**10,414**	**COAL**	**171,810**	**23,039,753**	**3,958,460.0**	**12,029,618**	**3.16**	**70.02**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	4,320	10.4	-	98.9	11,713	GAS	49,210	1,028,246	50,600.0	195,730	4.53	3.98
22. B.B.C.T.#4 TOTAL	**56**	**4,320**	**10.4**	**98.3**	**98.9**	**11,713**	**-**	**-**	**-**	**50,600.0**	**195,730**	**4.53**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**454,250**	**36.8**	**60.8**	**77.4**	**10,584**	**-**	**-**	**-**	**4,807,860.0**	**15,485,383**	**3.41**	**-**
24. POLK #1 GASIFIER	220	133,230	81.4	-	97.0	10,223	COAL	47,610	28,608,696	1,362,060.0	4,275,544	3.21	89.80
25. POLK #1 CT GAS	195	2,740	1.9	-	87.8	8,234	GAS	24,580	917,819	22,560.0	87,305	3.19	3.55
26. POLK #1 TOTAL	**220**	**135,970**	**83.1**	**72.7**	**96.8**	**10,183**	**-**	**-**	**-**	**1,384,620.0**	**4,362,849**	**3.21**	**-**
27. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	(1)	0.00	0.00
28. POLK #2 CT (OIL)	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,497	23.18	127.49
29. POLK #2 TOTAL (4)	**150**	**110**	**0.1**	**-**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**25,496**	**23.18**	**-**
30. POLK #3 CT GAS	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,496	23.18	127.48
32. POLK #3 TOTAL (4)	**150**	**110**	**0.1**	**-**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**25,496**	**23.18**	**-**
33. POLK #4 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK #5 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	17,520	19.6	-	82.5	8,272	GAS	140,970	1,028,020	144,920.0	560,701	3.20	3.98
36. POLK #2 ST W/O DUCT FIRING	341	668,330	-	-	-	-	GAS	4,392,990	1,027,999	4,515,990.0	17,472,886	2.61	3.98
37. POLK #2 CC TOTAL	**1,061**	**685,850**	**86.9**	**97.3**	**71.0**	**6,796**	**GAS**	**-**	**-**	**4,660,910.0**	**18,033,587**	**2.63**	**-**
38. POLK STATION TOTAL	**1,281**	**822,040**	**86.3**	**93.1**	**81.3**	**7,357**	**-**	**-**	**-**	**6,047,890.0**	**22,447,428**	**2.73**	**-**
39. BAYSIDE #1	701	356,420	68.3	96.5	70.3	7,395	GAS	2,563,860	1,028,001	2,635,650.0	10,197,618	2.86	3.98
40. BAYSIDE #2	929	372,540	53.9	96.2	55.6	7,598	GAS	2,753,560	1,028,000	2,830,660.0	10,952,139	2.94	3.98
41. BAYSIDE #3	56	1,750	4.2	98.6	94.7	11,891	GAS	20,240	1,028,162	20,810.0	80,504	4.60	3.98
42. BAYSIDE #4	56	1,090	2.6	98.6	97.3	11,817	GAS	12,530	1,027,933	12,880.0	49,837	4.57	3.98
43. BAYSIDE #5	56	2,990	7.2	98.6	93.7	11,833	GAS	34,410	1,028,189	35,380.0	136,864	4.58	3.98
44. BAYSIDE #6	56	2,420	5.8	98.6	93.9	11,855	GAS	27,910	1,027,947	28,690.0	111,011	4.59	3.98
45. BAYSIDE TOTAL	**1,854**	**737,210**	**53.4**	**96.6**	**62.2**	**7,547**	**GAS**	**5,412,510**	**1,028,002**	**5,564,070.0**	**21,527,973**	**2.92**	**3.98**
46. SYSTEM	**4,815**	**2,017,920**	**56.3**	**82.9**	**92.3**	**8,137**	**-**	**-**	**-**	**16,419,820.0**	**59,460,784**	**2.95**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2018

(A) PLANT/UNIT		(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR		1.6	250	21.0	-	21.0	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR		1.5	250	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR		19.4	3,760	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR		-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR	(3)	**22.5**	**4,260**	**25.5**	**-**	**25.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE		185	28,220	20.5	-	-	-	NG CO-FIRE	322,370	1,028,011	331,400.0	1,278,587	4.53	3.97
7. B.B.#1 COAL		385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1		**385**	**28,220**	**9.9**	**43.2**	**56.8**	**11,743**		**-**	**-**	**331,400.0**	**1,278,587**	**4.53**	**-**
9. B.B.#2 NAT GAS CO-FIRE		185	85,850	62.4	-	-	-	NG CO-FIRE	938,060	1,028,005	964,330.0	3,720,542	4.33	3.97
10. B.B.#2 COAL		385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2		**385**	**85,850**	**30.0**	**56.7**	**56.6**	**11,233**		**-**	**-**	**964,330.0**	**3,720,542**	**4.33**	**-**
12. B.B.#3 NAT GAS CO-FIRE		185	9,910	7.2	-	-	-	NG CO-FIRE	99,670	1,027,992	102,460.0	395,312	3.99	3.97
13. B.B.#3 COAL		395	188,360	64.1	-	-	-	COAL	84,500	23,039,290	1,946,820.0	5,891,049	3.13	69.72
14. TOTAL BIG BEND #3		**395**	**198,270**	**67.5**	**67.7**	**86.2**	**10,336**		**-**	**-**	**2,049,280.0**	**6,286,361**	**3.17**	**-**
15. B.B.#4 NAT GAS CO-FIRE		175	10,790	8.3	-	-	-	NG CO-FIRE	109,560	1,028,021	112,630.0	434,538	4.03	3.97
16. B.B.#4 COAL		437	205,080	63.1	-	-	-	COAL	92,880	23,039,298	2,139,890.0	6,475,271	3.16	69.72
17. TOTAL BIG BEND #4		**437**	**215,870**	**66.4**	**68.8**	**83.2**	**10,435**		**-**	**-**	**2,252,520.0**	**6,909,809**	**3.20**	**-**
18. B.B. 1-4 IGNITION		-	-	-	-	-	-	GAS	22,960	-	23,600.0	91,064	-	3.97
19. BIG BEND 1-4 COAL TOTAL		**1,602**	**393,440**	**33.0**	**59.5**	**57.0**	**10,387**	**COAL**	**177,380**	**23,039,294**	**4,086,710.0**	**12,366,320**	**3.14**	**69.72**
20. B.B.C.T.#4 OIL		0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS		56	3,410	8.2	-	98.2	11,698	GAS	38,810	1,027,828	39,890.0	153,929	4.51	3.97
22. B.B.C.T.#4 TOTAL		**56**	**3,410**	**8.2**	**98.3**	**98.2**	**11,698**	**-**	**-**	**-**	**39,890.0**	**153,929**	**4.51**	**-**
23. BIG BEND STATION TOTAL		**1,658**	**531,620**	**43.1**	**60.8**	**76.6**	**10,604**	**-**	**-**	**-**	**5,637,420.0**	**18,440,291**	**3.47**	**-**
24. POLK #1 GASIFIER		220	64,470	39.4	-	97.0	10,245	COAL	23,040	28,666,667	660,480.0	2,115,272	3.28	91.81
25. POLK #1 CT GAS		195	3,960	2.7	-	92.3	8,162	GAS	34,070	948,635	32,320.0	124,698	3.15	3.66
26. POLK #1 TOTAL		**220**	**68,430**	**41.8**	**35.2**	**96.7**	**10,124**	**-**	**-**	**-**	**692,800.0**	**2,239,970**	**3.27**	**-**
27. POLK #2 CT (GAS)		150	1,050	0.9	-	100.0	11,257	GAS	11,500	1,027,826	11,820.0	45,612	4.34	3.97
28. POLK #2 CT (OIL)		159	140	0.1	-	17.6	10,571	LGT OIL	250	5,920,000	1,480.0	31,871	22.77	127.48
29. POLK #2 TOTAL	(4)	**150**	**1,190**	**1.1**	**-**	**64.5**	**11,176**	**-**	**-**	**-**	**13,300.0**	**77,483**	**6.51**	**-**
30. POLK #3 CT GAS		150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL		159	140	0.1	-	17.6	10,571	LGT OIL	250	5,920,000	1,480.0	31,871	22.77	127.48
32. POLK #3 TOTAL	(4)	**150**	**140**	**0.1**	**-**	**17.6**	**10,571**	**-**	**-**	**-**	**1,480.0**	**31,871**	**22.77**	**-**
33. POLK #4 CT GAS	(4)	**150**	**900**	**0.8**	**-**	**100.0**	**11,178**	**GAS**	**9,780**	**1,028,630**	**10,060.0**	**38,790**	**4.31**	**3.97**
34. POLK #5 CT GAS	(4)	**150**	**900**	**0.8**	**-**	**100.0**	**11,278**	**GAS**	**9,870**	**1,028,369**	**10,150.0**	**39,146**	**4.35**	**3.97**
35. POLK #2 ST DUCT FIRING		120	17,040	19.1	-	88.8	8,276	GAS	137,180	1,027,992	141,020.0	544,084	3.19	3.97
36. POLK #2 ST W/O DUCT FIRING		341	674,320	-	-	-	-	GAS	4,433,280	1,027,997	4,557,400.0	17,583,313	2.61	3.97
37. POLK #2 CC TOTAL		**1,061**	**691,360**	**87.6**	**97.3**	**72.9**	**6,796**	**GAS**	**-**	**-**	**4,698,420.0**	**18,127,397**	**2.62**	**-**
38. POLK STATION TOTAL		**1,281**	**762,920**	**80.0**	**86.7**	**79.0**	**7,112**	**-**	**-**	**-**	**5,426,210.0**	**20,554,657**	**2.69**	**-**
39. BAYSIDE #1		701	363,550	69.7	96.5	72.2	7,382	GAS	2,610,460	1,027,999	2,683,550.0	10,353,629	2.85	3.97
40. BAYSIDE #2		929	378,470	54.8	96.2	56.6	7,585	GAS	2,792,640	1,027,995	2,870,820.0	11,076,192	2.93	3.97
41. BAYSIDE #3		56	1,720	4.1	98.6	96.0	11,750	GAS	19,660	1,027,976	20,210.0	77,976	4.53	3.97
42. BAYSIDE #4		56	1,310	3.1	98.6	97.5	11,695	GAS	14,900	1,028,188	15,320.0	59,097	4.51	3.97
43. BAYSIDE #5		56	2,660	6.4	98.6	95.0	11,767	GAS	30,450	1,027,915	31,300.0	120,771	4.54	3.97
44. BAYSIDE #6		56	1,980	4.8	98.6	95.6	11,753	GAS	22,640	1,027,827	23,270.0	89,795	4.54	3.97
45. BAYSIDE TOTAL		**1,854**	**749,690**	**54.3**	**96.6**	**63.5**	**7,529**	**GAS**	**5,490,750**	**1,027,996**	**5,644,470.0**	**21,777,460**	**2.90**	**3.97**
46. SYSTEM		**4,815**	**2,048,490**	**57.2**	**81.2**	**92.3**	**8,156**	**-**	**-**	**-**	**16,708,100.0**	**60,772,408**	**2.97**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) **As burned fuel cost system total includes ignition**
(2) **Fuel burned (MM BTU) system total excludes ignition**
(3) **AC rating**
(4) **In Simple Cycle Mode**

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DOCKET NO. 20170001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 17 OF 30

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	220	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	210	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	3,110	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	77.6	25,880	46.4	-	46.4	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**100.0**	**29,420**	**40.9**	**-**	**40.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	24,950	18.7	-	-	-	NG CO-FIRE	291,100	1,028,032	299,260.0	1,152,487	4.62	3.96
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**24,950**	**9.0**	**43.2**	**52.7**	**11,994**		**-**	**-**	**299,260.0**	**1,152,487**	**4.62**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	66,040	49.6	-	-	-	NG CO-FIRE	724,810	1,027,994	745,100.0	2,869,577	4.35	3.96
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**66,040**	**23.8**	**56.7**	**55.5**	**11,283**		**-**	**-**	**745,100.0**	**2,869,577**	**4.35**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	9,420	7.1	-	-	-	NG CO-FIRE	94,890	1,028,032	97,550.0	375,677	3.99	3.96
13. B.B.#3 COAL	395	179,000	62.9	-	-	-	COAL	80,450	23,038,906	1,853,480.0	5,594,622	3.13	69.54
14. TOTAL BIG BEND #3	**395**	**188,420**	**66.3**	**67.7**	**84.7**	**10,355**		**-**	**-**	**1,951,030.0**	**5,970,299**	**3.17**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	10,390	8.2	-	-	-	NG CO-FIRE	105,520	1,027,957	108,470.0	417,762	4.02	3.96
16. B.B.#4 COAL	437	197,400	62.7	-	-	-	COAL	89,450	23,039,911	2,060,920.0	6,220,497	3.15	69.54
17. TOTAL BIG BEND #4	**437**	**207,790**	**66.0**	**68.8**	**82.4**	**10,440**		**-**	**-**	**2,169,390.0**	**6,638,259**	**3.19**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	27,970	-	28,750.0	110,735	-	3.96
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**376,400**	**32.6**	**59.5**	**58.7**	**10,400**	**COAL**	**169,900**	**23,039,435**	**3,914,400.0**	**11,815,119**	**3.14**	**69.54**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	3,840	9.5	-	99.4	11,656	GAS	43,540	1,028,020	44,760.0	172,378	4.49	3.96
22. B.B.C.T.#4 TOTAL	**56**	**3,840**	**9.5**	**98.3**	**99.4**	**11,656**	**-**	**-**	**-**	**44,760.0**	**172,378**	**4.49**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**491,040**	**41.1**	**60.8**	**76.2**	**10,609**	**-**	**-**	**-**	**5,209,540.0**	**16,913,734**	**3.44**	**-**
24. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
25. POLK #1 CT GAS	195	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
26. POLK #1 TOTAL	**220**	**0**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
27. POLK #2 CT (GAS)	150	1,350	1.3	-	100.0	11,237	GAS	14,760	1,027,778	15,170.0	58,436	4.33	3.96
28. POLK #2 CT (OIL)	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,771	24.34	127.48
29. POLK #2 TOTAL (4)	**150**	**1,460**	**1.4**	**-**	**73.5**	**11,226**	**-**	**-**	**-**	**16,390.0**	**85,207**	**5.84**	**-**
30. POLK #3 CT GAS	150	1,350	1.3	-	100.0	11,237	GAS	14,760	1,027,778	15,170.0	58,436	4.33	3.96
31. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,772	24.34	127.49
32. POLK #3 TOTAL (4)	**150**	**1,460**	**1.4**	**-**	**73.5**	**11,226**	**-**	**-**	**-**	**16,390.0**	**85,208**	**5.84**	**-**
33. POLK #4 CT GAS (4)	**150**	**1,350**	**1.3**	**-**	**100.0**	**11,237**	**GAS**	**14,760**	**1,027,778**	**15,170.0**	**58,436**	**4.33**	**3.96**
34. POLK #5 CT GAS (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	13,790	16.0	-	90.5	8,273	GAS	110,980	1,028,023	114,090.0	439,378	3.19	3.96
36. POLK #2 ST W/O DUCT FIRING	341	656,470	-	-	-	-	GAS	4,316,450	1,027,998	4,437,300.0	17,089,146	2.60	3.96
37. POLK #2 CC TOTAL	**1,061**	**670,260**	**87.7**	**97.3**	**75.4**	**6,790**	**GAS**	**-**	**-**	**4,551,390.0**	**17,528,524**	**2.62**	**-**
38. POLK STATION TOTAL	**1,281**	**674,530**	**73.1**	**80.6**	**75.6**	**6,819**	**-**	**-**	**-**	**4,599,340.0**	**17,757,375**	**2.63**	**-**
39. BAYSIDE #1	701	346,290	68.6	96.5	70.6	7,389	GAS	2,488,980	1,027,999	2,558,670.0	9,854,057	2.85	3.96
40. BAYSIDE #2	929	353,860	52.9	96.2	54.5	7,605	GAS	2,617,700	1,027,998	2,690,990.0	10,363,667	2.93	3.96
41. BAYSIDE #3	56	1,700	4.2	98.6	94.9	11,900	GAS	19,680	1,027,947	20,230.0	77,915	4.58	3.96
42. BAYSIDE #4	56	1,040	2.6	98.6	97.7	11,798	GAS	11,930	1,028,500	12,270.0	47,232	4.54	3.96
43. BAYSIDE #5	56	2,690	6.7	98.6	94.2	11,822	GAS	30,940	1,027,796	31,800.0	122,494	4.55	3.96
44. BAYSIDE #6	56	2,330	5.8	98.6	94.6	11,785	GAS	26,710	1,028,079	27,460.0	105,747	4.54	3.96
45. BAYSIDE TOTAL	**1,854**	**707,910**	**53.0**	**96.6**	**61.7**	**7,545**	**GAS**	**5,195,940**	**1,027,999**	**5,341,420.0**	**20,571,112**	**2.91**	**3.96**
46. SYSTEM	**4,893**	**1,902,900**	**54.0**	**78.3**	**92.6**	**7,962**	**-**	**-**	**-**	**15,150,300.0**	**55,242,221**	**2.90**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2018

(A) PLANT/UNIT		(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR		1.6	250	21.0	-	21.0	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR		1.5	210	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR		19.4	3,200	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR		77.6	26,650	46.2	-	46.2	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR	(3)	**100.0**	**30,310**	**40.7**	**-**	**40.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE		185	27,400	19.9	-	-	-	NG CO-FIRE	318,460	1,028,010	327,380.0	1,271,505	4.64	3.99
7. B.B.#1 COAL		385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1		**385**	**27,400**	**9.6**	**43.2**	**53.5**	**11,948**		**-**	**-**	**327,380.0**	**1,271,505**	**4.64**	**-**
9. B.B.#2 NAT GAS CO-FIRE		185	36,260	26.3	-	-	-	NG CO-FIRE	400,670	1,028,003	411,890.0	1,599,742	4.41	3.99
10. B.B.#2 COAL		385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2		**385**	**36,260**	**12.7**	**56.7**	**53.8**	**11,359**		**-**	**-**	**411,890.0**	**1,599,742**	**4.41**	**-**
12. B.B.#3 NAT GAS CO-FIRE		185	6,030	4.4	-	-	-	NG CO-FIRE	61,350	1,027,873	63,060.0	244,950	4.06	3.99
13. B.B.#3 COAL		395	114,650	39.0	-	-	-	COAL	52,010	23,037,877	1,198,200.0	3,616,757	3.15	69.54
14. TOTAL BIG BEND #3		**395**	**120,680**	**41.1**	**45.9**	**77.5**	**10,451**		**-**	**-**	**1,261,260.0**	**3,861,707**	**3.20**	**-**
15. B.B.#4 NAT GAS CO-FIRE		175	10,530	8.1	-	-	-	NG CO-FIRE	106,780	1,028,001	109,770.0	426,337	4.05	3.99
16. B.B.#4 COAL		437	200,000	61.5	-	-	-	COAL	90,520	23,039,549	2,085,540.0	6,294,731	3.15	69.54
17. TOTAL BIG BEND #4		**437**	**210,530**	**64.8**	**68.8**	**83.3**	**10,428**		**-**	**-**	**2,195,310.0**	**6,721,068**	**3.19**	**-**
18. B.B. 1-4 IGNITION		-	-	-	-	-	-	GAS	38,410	-	39,480.0	153,358	-	3.99
19. BIG BEND 1-4 COAL TOTAL		**1,602**	**314,650**	**26.4**	**54.1**	**59.7**	**10,436**	**COAL**	**142,530**	**23,038,939**	**3,283,740.0**	**9,911,488**	**3.15**	**69.54**
20. B.B.C.T.#4 OIL		0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS		56	4,690	11.3	-	89.1	12,028	GAS	54,880	1,027,879	56,410.0	219,118	4.67	3.99
22. B.B.C.T.#4 TOTAL		**56**	**4,690**	**11.3**	**98.3**	**89.1**	**12,028**	**-**	**-**	**-**	**56,410.0**	**219,118**	**4.67**	**-**
23. BIG BEND STATION TOTAL		**1,658**	**399,560**	**32.4**	**55.6**	**75.1**	**10,642**	**-**	**-**	**-**	**4,252,250.0**	**13,826,499**	**3.46**	**-**
24. POLK #1 GASIFIER		220	90,250	55.1	-	97.0	10,275	COAL	32,260	28,746,125	927,350.0	2,948,431	3.27	91.40
25. POLK #1 CT GAS		195	14,420	9.9	-	96.0	8,021	GAS	118,650	974,884	115,670.0	449,255	3.12	3.79
26. POLK #1 TOTAL		**220**	**104,670**	**63.9**	**49.2**	**96.8**	**9,965**	**-**	**-**	**-**	**1,043,020.0**	**3,397,686**	**3.25**	**-**
27. POLK #2 CT (GAS)		150	14,160	12.7	-	96.3	11,328	GAS	156,040	1,028,006	160,410.0	623,017	4.40	3.99
28. POLK #2 CT (OIL)		159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	33,146	23.68	127.48
29. POLK #2 TOTAL	(4)	**150**	**14,300**	**12.8**	**-**	**92.3**	**11,321**	**-**	**-**	**-**	**161,890.0**	**656,163**	**4.59**	**-**
30. POLK #3 CT GAS		150	11,430	10.2	-	99.0	11,241	GAS	124,980	1,028,004	128,480.0	499,004	4.37	3.99
31. POLK #3 CT OIL		159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	33,145	23.68	127.48
32. POLK #3 TOTAL	(4)	**150**	**11,570**	**10.4**	**-**	**93.7**	**11,232**	**-**	**-**	**-**	**129,960.0**	**532,149**	**4.60**	**-**
33. POLK #4 CT GAS	(4)	**150**	**8,000**	**7.2**	**-**	**98.8**	**11,261**	**GAS**	**87,640**	**1,027,955**	**90,090.0**	**349,917**	**4.37**	**3.99**
34. POLK #5 CT GAS	(4)	**150**	**6,560**	**5.9**	**-**	**99.4**	**11,235**	**GAS**	**71,700**	**1,027,894**	**73,700.0**	**286,274**	**4.36**	**3.99**
35. POLK #2 ST DUCT FIRING		120	7,820	8.8	-	76.7	8,277	GAS	62,970	1,027,950	64,730.0	251,418	3.22	3.99
36. POLK #2 ST W/O DUCT FIRING		341	526,410	-	-	-	-	GAS	3,459,490	1,028,001	3,556,360.0	13,812,595	2.62	3.99
37. POLK #2 CC TOTAL		**1,061**	**534,230**	**67.7**	**78.5**	**74.4**	**6,778**	**GAS**	**-**	**-**	**3,621,090.0**	**14,064,013**	**2.63**	**-**
38. POLK STATION TOTAL		**1,281**	**679,330**	**71.3**	**73.5**	**86.1**	**7,536**	**-**	**-**	**-**	**5,119,750.0**	**19,286,202**	**2.84**	**-**
39. BAYSIDE #1		701	185,200	35.5	52.9	66.5	7,418	GAS	1,336,480	1,027,991	1,373,890.0	5,336,121	2.88	3.99
40. BAYSIDE #2		929	393,330	56.9	96.2	58.6	7,562	GAS	2,893,330	1,027,995	2,974,330.0	11,552,107	2.94	3.99
41. BAYSIDE #3		56	920	2.2	98.6	96.6	11,826	GAS	10,580	1,028,355	10,880.0	42,242	4.59	3.99
42. BAYSIDE #4		56	880	2.1	98.6	98.2	11,716	GAS	10,040	1,026,892	10,310.0	40,086	4.56	3.99
43. BAYSIDE #5		56	2,460	5.9	98.6	89.7	12,077	GAS	28,900	1,028,028	29,710.0	115,388	4.69	3.99
44. BAYSIDE #6		56	1,690	4.1	98.6	94.3	11,876	GAS	19,530	1,027,650	20,070.0	77,977	4.61	3.99
45. BAYSIDE TOTAL		**1,854**	**584,480**	**42.4**	**80.1**	**61.2**	**7,561**	**GAS**	**4,298,860**	**1,027,991**	**4,419,190.0**	**17,163,921**	**2.94**	**3.99**
46. SYSTEM		**4,893**	**1,693,680**	**46.5**	**68.4**	**91.5**	**8,143**	**-**	**-**	**-**	**13,791,190.0**	**50,276,622**	**2.97**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) **As burned fuel cost system total includes ignition**
(2) **Fuel burned (MM BTU) system total excludes ignition**
(3) **AC rating**
(4) **In Simple Cycle Mode**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	230	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	170	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	2,710	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	77.6	22,550	40.4	-	40.4	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**100.0**	**25,660**	**35.6**	**-**	**35.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	9,350	7.0	-	-	-	NG CO-FIRE	111,930	1,027,964	115,060.0	475,043	5.08	4.24
7. B.B.#1 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**385**	**9,350**	**3.4**	**28.8**	**48.6**	**12,306**		**-**	**-**	**115,060.0**	**475,043**	**5.08**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	47,340	35.5	-	-	-	NG CO-FIRE	506,470	1,027,998	520,650.0	2,149,515	4.54	4.24
10. B.B.#2 COAL	385	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**385**	**47,340**	**17.1**	**37.8**	**61.8**	**10,998**		**-**	**-**	**520,650.0**	**2,149,515**	**4.54**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	9,480	7.1	-	-	-	NG CO-FIRE	95,380	1,027,993	98,050.0	404,803	4.27	4.24
13. B.B.#3 COAL	395	180,040	63.3	-	-	-	COAL	80,860	23,040,317	1,863,040.0	5,582,735	3.10	69.04
14. TOTAL BIG BEND #3	**395**	**189,520**	**66.6**	**67.7**	**85.2**	**10,348**		**-**	**-**	**1,961,090.0**	**5,987,538**	**3.16**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	10,240	8.1	-	-	-	NG CO-FIRE	103,940	1,028,093	106,860.0	441,133	4.31	4.24
16. B.B.#4 COAL	437	194,640	61.9	-	-	-	COAL	88,120	23,039,832	2,030,270.0	6,083,982	3.13	69.04
17. TOTAL BIG BEND #4	**437**	**204,880**	**65.1**	**68.8**	**83.7**	**10,431**		**-**	**-**	**2,137,130.0**	**6,525,115**	**3.18**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	76,182	-	4.24
19. BIG BEND 1-4 COAL TOTAL	**1,602**	**374,680**	**32.5**	**51.5**	**66.6**	**10,391**	**COAL**	**168,980**	**23,040,064**	**3,893,310.0**	**11,666,717**	**3.11**	**69.04**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	56	4,230	10.5	-	92.1	11,991	GAS	49,330	1,028,178	50,720.0	209,362	4.95	4.24
22. B.B.C.T.#4 TOTAL	**56**	**4,230**	**10.5**	**98.3**	**92.1**	**11,991**	**-**	**-**	**-**	**50,720.0**	**209,362**	**4.95**	**-**
23. BIG BEND STATION TOTAL	**1,658**	**455,320**	**38.1**	**53.1**	**80.2**	**10,508**	**-**	**-**	**-**	**4,784,650.0**	**15,422,755**	**3.39**	**-**
24. POLK #1 GASIFIER	220	128,930	81.4	-	97.0	10,225	COAL	46,080	28,609,158	1,318,310.0	4,106,659	3.19	89.12
25. POLK #1 CT GAS	195	11,960	8.5	-	98.9	8,180	GAS	97,790	1,000,409	97,830.0	403,870	3.38	4.13
26. POLK #1 TOTAL	**220**	**140,890**	**88.9**	**72.7**	**97.2**	**10,051**	**-**	**-**	**-**	**1,416,140.0**	**4,510,529**	**3.20**	**-**
27. POLK #2 CT (GAS)	150	12,130	11.2	-	96.3	11,345	GAS	133,870	1,027,938	137,610.0	568,159	4.68	4.24
28. POLK #2 CT (OIL)	159	90	0.1	-	18.9	10,111	LGT OIL	160	5,687,500	910.0	20,397	22.66	127.48
29. POLK #2 TOTAL (4)	**150**	**12,220**	**11.3**	**-**	**93.4**	**11,336**	**-**	**-**	**-**	**138,520.0**	**588,556**	**4.82**	**-**
30. POLK #3 CT GAS	150	6,180	5.7	-	98.1	11,301	GAS	67,930	1,028,117	69,840.0	288,302	4.67	4.24
31. POLK #3 CT OIL	159	90	0.1	-	18.9	10,111	LGT OIL	160	5,687,500	910.0	20,398	22.66	127.49
32. POLK #3 TOTAL (4)	**150**	**6,270**	**5.8**	**-**	**92.5**	**11,284**	**-**	**-**	**-**	**70,750.0**	**308,700**	**4.92**	**-**
33. POLK #4 CT GAS (4)	**150**	**2,830**	**2.6**	**-**	**99.3**	**11,237**	**GAS**	**30,930**	**1,028,128**	**31,800.0**	**131,270**	**4.64**	**4.24**
34. POLK #5 CT GAS (4)	**150**	**1,790**	**1.7**	**-**	**99.4**	**11,291**	**GAS**	**19,650**	**1,028,499**	**20,210.0**	**83,397**	**4.66**	**4.24**
35. POLK #2 ST DUCT FIRING	120	1,140	1.3	-	63.3	8,281	GAS	9,180	1,028,322	9,440.0	38,961	3.42	4.24
36. POLK #2 ST W/O DUCT FIRING	341	311,080	-	-	-	-	GAS	2,044,310	1,028,000	2,101,550.0	8,676,277	2.79	4.24
37. POLK #2 CC TOTAL	**1,061**	**312,220**	**40.9**	**48.7**	**79.3**	**6,761**	**GAS**	**-**	**-**	**2,110,990.0**	**8,715,238**	**2.79**	**-**
38. POLK STATION TOTAL	**1,281**	**476,220**	**51.6**	**52.8**	**91.3**	**7,955**	**-**	**-**	**-**	**3,788,410.0**	**14,337,690**	**3.01**	**-**
39. BAYSIDE #1	701	13,110	2.6	6.4	51.9	7,616	GAS	97,130	1,028,004	99,850.0	412,230	3.14	4.24
40. BAYSIDE #2	929	401,470	60.0	96.2	62.8	7,516	GAS	2,935,210	1,028,001	3,017,400.0	12,457,356	3.10	4.24
41. BAYSIDE #3	56	360	0.9	98.6	91.8	12,139	GAS	4,240	1,030,660	4,370.0	17,995	5.00	4.24
42. BAYSIDE #4	56	110	0.3	98.6	98.2	12,182	GAS	1,310	1,022,901	1,340.0	5,560	5.05	4.24
43. BAYSIDE #5	56	1,400	3.5	98.6	89.3	12,221	GAS	16,650	1,027,628	17,110.0	70,664	5.05	4.24
44. BAYSIDE #6	56	560	1.4	98.6	90.9	12,339	GAS	6,720	1,028,274	6,910.0	28,520	5.09	4.24
45. BAYSIDE TOTAL	**1,854**	**417,010**	**31.2**	**62.6**	**62.5**	**7,547**	**GAS**	**3,061,260**	**1,028,002**	**3,146,980.0**	**12,992,325**	**3.12**	**4.24**
46. SYSTEM	**4,893**	**1,374,210**	**39.0**	**55.5**	**89.9**	**8,529**	**-**	**-**	**-**	**11,720,040.0**	**42,752,770**	**3.11**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

(1) **As burned fuel cost system total includes ignition**
(2) **Fuel burned (MM BTU) system total excludes ignition**
(3) **AC rating**
(4) **In Simple Cycle Mode**

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2018

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	220	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	150	13.4	-	13.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	19.4	2,410	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	77.6	20,110	34.9	-	34.9	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR [3]	**100.0**	**22,890**	**30.8**	**-**	**30.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 NAT GAS CO-FIRE	185	0	0.0	-	-	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
7. B.B.#1 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**395**	**0**	**0.0**	**43.2**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 NAT GAS CO-FIRE	185	24,730	18.0	-	-	-	NG CO-FIRE	275,630	1,028,009	283,350.0	1,179,260	4.77	4.28
10. B.B.#2 COAL	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**395**	**24,730**	**8.4**	**56.7**	**50.1**	**11,458**		**-**	**-**	**283,350.0**	**1,179,260**	**4.77**	**-**
12. B.B.#3 NAT GAS CO-FIRE	185	9,990	7.3	-	-	-	NG CO-FIRE	100,080	1,027,978	102,880.0	428,184	4.29	4.28
13. B.B.#3 COAL	400	189,850	63.8	-	-	-	COAL	84,840	23,041,018	1,954,800.0	5,802,496	3.06	68.39
14. TOTAL BIG BEND #3	**400**	**199,840**	**67.2**	**67.7**	**85.8**	**10,297**		**-**	**-**	**2,057,680.0**	**6,230,680**	**3.12**	**-**
15. B.B.#4 NAT GAS CO-FIRE	175	6,460	5.0	-	-	-	NG CO-FIRE	65,270	1,028,037	67,100.0	279,252	4.32	4.28
16. B.B.#4 COAL	442	122,690	37.3	-	-	-	COAL	55,330	23,041,388	1,274,880.0	3,784,205	3.08	68.39
17. TOTAL BIG BEND #4	**442**	**129,150**	**39.3**	**46.6**	**81.6**	**10,391**		**-**	**-**	**1,341,980.0**	**4,063,457**	**3.15**	**-**
18. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	20,040	-	20,600.0	85,739	-	4.28
19. BIG BEND 1-4 COAL TOTAL	**1,632**	**312,540**	**25.7**	**53.4**	**71.0**	**10,334**	**COAL**	**140,170**	**23,041,164**	**3,229,680.0**	**9,586,701**	**3.07**	**68.39**
20. B.B.C.T.#4 OIL	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
21. B.B.C.T.#4 GAS	61	870	1.9	-	83.9	12,379	GAS	10,480	1,027,672	10,770.0	44,838	5.15	4.28
22. B.B.C.T.#4 TOTAL	**61**	**870**	**1.9**	**98.3**	**83.9**	**12,379**	**-**	**-**	**-**	**10,770.0**	**44,838**	**5.15**	**-**
23. BIG BEND STATION TOTAL	**1,693**	**354,590**	**28.2**	**55.0**	**80.3**	**10,417**	**-**	**-**	**-**	**3,693,780.0**	**11,603,975**	**3.27**	**-**
24. POLK #1 GASIFIER	220	133,230	81.4	-	97.0	10,223	COAL	47,610	28,608,696	1,362,060.0	4,233,478	3.18	88.92
25. POLK #1 CT GAS	205	0	0.0	-	0.0	0	GAS	2,630	0	0.0	0	0.00	0.00
26. POLK #1 TOTAL	**220**	**133,230**	**81.4**	**72.7**	**97.0**	**10,223**	**-**	**-**	**-**	**1,362,060.0**	**4,233,478**	**3.18**	**-**
27. POLK #2 CT (GAS)	180	690	0.5	-	95.8	10,942	GAS	7,340	1,028,610	7,550.0	31,404	4.55	4.28
28. POLK #2 CT (OIL)	187	140	0.1	-	12.5	10,857	LGT OIL	260	5,846,154	1,520.0	33,146	23.68	127.48
29. POLK #2 TOTAL [4]	**180**	**830**	**0.6**	**-**	**45.1**	**10,928**	**-**	**-**	**-**	**9,070.0**	**64,550**	**7.78**	**-**
30. POLK #3 CT GAS	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #3 CT OIL	187	140	0.1	-	12.5	10,857	LGT OIL	260	5,846,154	1,520.0	33,145	23.68	127.48
32. POLK #3 TOTAL [4]	**180**	**140**	**0.1**	**-**	**12.5**	**10,857**	**-**	**-**	**-**	**1,520.0**	**33,145**	**23.68**	**-**
33. POLK #4 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK #5 CT GAS [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. POLK #2 ST DUCT FIRING	120	5,060	5.7	-	79.6	8,180	GAS	40,250	1,028,323	41,390.0	172,206	3.40	4.28
36. POLK #2 ST W/O DUCT FIRING	360	623,020	-	-	-	-	GAS	4,099,820	1,028,001	4,214,620.0	17,540,744	2.82	4.28
37. POLK #2 CC TOTAL	**1,200**	**628,080**	**70.3**	**97.3**	**66.5**	**6,776**	**GAS**	**-**	**-**	**4,256,010.0**	**17,712,950**	**2.82**	**-**
38. POLK STATION TOTAL	**1,420**	**762,280**	**72.2**	**93.5**	**79.5**	**7,384**	**-**	**-**	**-**	**5,628,660.0**	**22,044,123**	**2.89**	**-**
39. BAYSIDE #1	792	275,550	46.8	96.5	48.8	7,424	GAS	1,990,090	1,027,999	2,045,810.0	8,514,437	3.09	4.28
40. BAYSIDE #2	1,047	84,560	10.9	59.0	29.7	7,963	GAS	655,030	1,028,014	673,380.0	2,802,493	3.31	4.28
41. BAYSIDE #3	61	100	0.2	98.6	82.0	13,000	GAS	1,270	1,023,622	1,300.0	5,434	5.43	4.28
42. BAYSIDE #4	61	50	0.1	98.6	82.0	13,000	GAS	630	1,031,746	650.0	2,695	5.39	4.28
43. BAYSIDE #5	61	420	0.9	98.6	86.1	12,333	GAS	5,040	1,027,778	5,180.0	21,563	5.13	4.28
44. BAYSIDE #6	61	260	0.6	98.6	85.2	12,269	GAS	3,100	1,029,032	3,190.0	13,263	5.10	4.28
45. BAYSIDE TOTAL	**2,083**	**360,940**	**23.3**	**77.9**	**42.4**	**7,562**	**GAS**	**2,655,160**	**1,028,002**	**2,729,510.0**	**11,359,885**	**3.15**	**4.28**
46. SYSTEM	**5,296**	**1,500,700**	**38.1**	**73.3**	**88.1**	**8,031**	**-**	**-**	**-**	**12,051,950.0**	**45,007,983**	**3.00**	**-**

LEGEND:
B.B. = BIG BEND **NG = NATURAL GAS** **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM**

[1] As burned fuel cost system total includes ignition
[2] Fuel burned (MM BTU) system total excludes ignition
[3] AC rating
[4] In Simple Cycle Mode

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH JUNE 2018

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0
18. BURNED:						
19. UNITS (BBL)	520	440	400	420	520	420
20. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48
21. AMOUNT ($)	66,291	56,093	50,993	53,543	66,291	53,543
22. ENDING INVENTORY:						
23. UNITS (BBL)	41,288	40,848	40,448	40,028	39,508	39,088
24. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48
25. AMOUNT ($)	5,263,517	5,207,425	5,156,432	5,102,889	5,036,597	4,983,055
26. DAYS SUPPLY: NORMAL	2,791	3,055	3,325	3,616	3,984	4,602
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	217,010	217,000	157,000	167,000	162,000	237,000
30. UNIT COST ($/TON)	74.31	73.31	73.41	74.03	73.62	74.48
31. AMOUNT ($)	16,126,287	15,908,963	11,525,353	12,363,466	11,926,807	17,651,878
32. BURNED:						
33. UNITS (TONS)	228,730	194,850	182,600	162,120	190,710	212,270
34. UNIT COST ($/TON)	68.44	69.83	73.86	74.43	74.43	74.69
35. AMOUNT ($)	15,655,404	13,607,271	13,486,830	12,065,932	14,195,155	15,854,483
36. ENDING INVENTORY:						
37. UNITS (TONS)	602,978	625,128	599,528	604,408	575,698	600,428
38. UNIT COST ($/TON)	66.90	68.47	68.72	68.95	68.78	69.41
39. AMOUNT ($)	40,337,134	42,802,936	41,201,064	41,674,448	39,598,544	41,675,053
40. DAYS SUPPLY:	90	103	103	97	85	87
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	6,542,810	5,862,520	7,276,570	8,369,605	9,858,919	10,557,220
43. UNIT COST ($/MCF)	4.95	4.91	4.73	4.03	3.93	3.95
44. AMOUNT ($)	32,408,245	28,786,538	34,402,705	33,690,689	38,745,564	41,746,580
45. BURNED:						
46. UNITS (MCF)	6,542,810	5,862,520	7,276,570	8,223,690	9,567,090	10,557,220
47. UNIT COST ($/MCF)	4.94	4.90	4.71	4.08	3.95	3.94
48. AMOUNT ($)	32,292,270	28,737,723	34,246,405	33,587,524	37,833,385	41,571,661
49. ENDING INVENTORY:						
50. UNITS (MCF)	729,572	729,572	729,572	875,486	1,167,315	1,167,315
51. UNIT COST ($/MCF)	3.78	3.74	3.64	3.05	2.98	3.00
52. AMOUNT ($)	2,759,700	2,731,200	2,658,900	2,669,220	3,474,960	3,502,560
53. DAYS SUPPLY:	3	3	3	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 2018 THROUGH DECEMBER 2018

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	0	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0	0
18.	BURNED:							
19.	UNITS (BBL)	400	500	420	520	320	520	5,400
20.	UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48	127.48
21.	AMOUNT ($)	50,993	63,742	53,543	66,291	40,795	66,291	688,409
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	38,688	38,188	37,768	37,248	36,928	36,408	36,408
24.	UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48	127.48
25.	AMOUNT ($)	4,932,061	4,868,320	4,814,777	4,748,486	4,707,691	4,641,400	4,641,400
26.	DAYS SUPPLY: NORMAL	5,269	6,113	7,745	9,997	16,046	25,556	-
27.	DAYS SUPPLY: EMERGENCY	6	5	5	5	5	5	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	212,000	192,000	162,000	152,000	157,000	168,000	2,200,010
30.	UNIT COST ($/TON)	73.23	69.89	68.06	69.33	69.64	70.21	72.15
31.	AMOUNT ($)	15,524,095	13,418,196	11,025,344	10,538,691	10,934,049	11,795,311	158,738,440
32.	BURNED:							
33.	UNITS (TONS)	219,420	200,420	169,900	174,790	215,060	187,780	2,338,650
34.	UNIT COST ($/TON)	75.08	72.71	70.19	74.45	73.70	74.05	72.95
35.	AMOUNT ($)	16,474,522	14,572,656	11,925,854	13,013,277	15,849,558	13,905,918	170,606,860
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	593,008	584,588	576,688	553,898	495,838	476,058	476,058
38.	UNIT COST ($/TON)	69.14	68.51	68.15	67.07	65.45	64.12	64.12
39.	AMOUNT ($)	41,000,452	40,048,641	39,298,574	37,151,765	32,454,605	30,523,994	30,523,994
40.	DAYS SUPPLY:	93	99	94	88	113	228	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	10,839,890	11,657,860	10,955,480	9,360,880	6,058,091	7,276,700	104,616,545
43.	UNIT COST ($/MCF)	3.98	3.97	3.96	3.99	4.31	4.29	4.18
44.	AMOUNT ($)	43,143,170	46,244,465	43,344,759	37,394,807	26,111,141	31,252,465	437,271,128
45.	BURNED:							
46.	UNITS (MCF)	10,839,890	11,657,860	10,955,480	9,360,880	6,349,920	7,276,700	104,470,630
47.	UNIT COST ($/MCF)	3.96	3.96	3.95	3.97	4.23	4.27	4.17
48.	AMOUNT ($)	42,935,269	46,136,010	43,262,824	37,197,054	26,862,417	31,035,774	435,698,316
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 ($/MCF)	3.02	3.03	3.01	3.02	3.07	3.21	3.21
52.	AMOUNT ($)	3,530,640	3,537,600	3,508,800	3,528,720	2,690,100	2,809,800	2,809,800
53.	DAYS SUPPLY:	8	9	13	19	23	44	-
	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

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TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH JUNE 2018

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-18	SEMINOLE	JURISD. SCH. - D	820.0	0.0	820.0	2.854	3.048	23,400.00	24,991.00	1,591.00
	VARIOUS	JURISD. MKT. BASE	1,140.0	0.0	1,140.0	2.819	3.102	32,142.24	35,360.00	3,217.76
	TOTAL		**1,960.0**	**0.0**	**1,960.0**	**2.834**	**3.079**	**55,542.24**	**60,351.00**	**4,808.76**
Feb-18	SEMINOLE	JURISD. SCH. - D	660.0	0.0	660.0	2.847	3.041	18,790.00	20,068.00	1,278.00
	VARIOUS	JURISD. MKT. BASE	960.0	0.0	960.0	3.253	3.579	31,233.24	34,360.00	3,126.76
	TOTAL		**1,620.0**	**0.0**	**1,620.0**	**3.088**	**3.360**	**50,023.24**	**54,428.00**	**4,404.76**
Mar-18	SEMINOLE	JURISD. SCH. - D	880.0	0.0	880.0	2.899	3.096	25,510.00	27,244.00	1,734.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	4.174	4.591	38,814.30	42,700.00	3,885.70
	TOTAL		**1,810.0**	**0.0**	**1,810.0**	**3.554**	**3.864**	**64,324.30**	**69,944.00**	**5,619.70**
Apr-18	SEMINOLE	JURISD. SCH. - D	1,080.0	0.0	1,080.0	2.501	2.671	27,010.00	28,846.00	1,836.00
	VARIOUS	JURISD. MKT. BASE	990.0	0.0	990.0	2.705	2.976	26,779.14	29,460.00	2,680.86
	TOTAL		**2,070.0**	**0.0**	**2,070.0**	**2.599**	**2.817**	**53,789.14**	**58,306.00**	**4,516.86**
May-18	SEMINOLE	JURISD. SCH. - D	930.0	0.0	930.0	2.377	2.539	22,110.00	23,613.00	1,503.00
	VARIOUS	JURISD. MKT. BASE	1,050.0	0.0	1,050.0	2.395	2.634	25,142.94	27,660.00	2,517.06
	TOTAL		**1,980.0**	**0.0**	**1,980.0**	**2.387**	**2.590**	**47,252.94**	**51,273.00**	**4,020.06**
Jun-18	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	2.458	2.625	24,330.00	25,984.00	1,654.00
	VARIOUS	JURISD. MKT. BASE	960.0	0.0	960.0	2.601	2.861	24,970.23	27,470.00	2,499.77
	TOTAL		**1,950.0**	**0.0**	**1,950.0**	**2.528**	**2.741**	**49,300.23**	**53,454.00**	**4,153.77**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2018 THROUGH DECEMBER 2018

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jul-18	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	2.592	2.768	25,920.00	27,682.00	1,762.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	3.622	3.984	32,596.74	35,860.00	3,263.26
	TOTAL		**1,900.0**	**0.0**	**1,900.0**	**3.080**	**3.344**	**58,516.74**	**63,542.00**	**5,025.26**
Aug-18	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	2.661	2.842	26,880.00	28,708.00	1,828.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	3.417	3.759	38,614.32	42,480.00	3,865.68
	TOTAL		**2,140.0**	**0.0**	**2,140.0**	**3.060**	**3.327**	**65,494.32**	**71,188.00**	**5,693.68**
Sep-18	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	2.540	2.712	25,650.00	27,394.00	1,744.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	2.502	2.753	23,270.40	25,600.00	2,329.60
	TOTAL		**1,940.0**	**0.0**	**1,940.0**	**2.522**	**2.732**	**48,920.40**	**52,994.00**	**4,073.60**
Oct-18	SEMINOLE	JURISD. SCH. - D	720.0	0.0	720.0	2.646	2.826	19,050.00	20,345.00	1,295.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	3.540	3.895	40,005.09	44,010.00	4,004.91
	TOTAL		**1,850.0**	**0.0**	**1,850.0**	**3.192**	**3.479**	**59,055.09**	**64,355.00**	**5,299.91**
Nov-18	SEMINOLE	JURISD. SCH. - D	650.0	0.0	650.0	2.566	2.741	16,680.00	17,814.00	1,134.00
	VARIOUS	JURISD. MKT. BASE	700.0	0.0	700.0	2.714	2.986	18,998.10	20,900.00	1,901.90
	TOTAL		**1,350.0**	**0.0**	**1,350.0**	**2.643**	**2.868**	**35,678.10**	**38,714.00**	**3,035.90**
Dec-18	SEMINOLE	JURISD. SCH. - D	590.0	0.0	590.0	2.512	2.683	14,820.00	15,828.00	1,008.00
	VARIOUS	JURISD. MKT. BASE	1,170.0	0.0	1,170.0	2.501	2.751	29,260.71	32,190.00	2,929.29
	TOTAL		**1,760.0**	**0.0**	**1,760.0**	**2.505**	**2.728**	**44,080.71**	**48,018.00**	**3,937.29**
TOTAL	SEMINOLE	JURISD. SCH. - D	10,340.0	0.0	10,340.0	2.613	2.790	270,150.00	288,517.00	18,367.00
Jan-18	VARIOUS	JURISD. MKT. BASE	11,990.0	0.0	11,990.0	3.018	3.320	361,827.45	398,050.00	36,222.55
THRU Dec-18	**TOTAL**		**22,330.0**	**0.0**	**22,330.0**	**2.830**	**3.075**	**631,977.45**	**686,567.00**	**54,589.55**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-18									
	PASCO COGEN	SCH. - D	730.0	0.0	0.0	730.0	4.908	4.908	35,830.00
	TOTAL		**730.0**	**0.0**	**0.0**	**730.0**	**4.908**	**4.908**	**35,830.00**
Feb-18									
	PASCO COGEN	SCH. - D	1,260.0	0.0	0.0	1,260.0	4.816	4.816	60,680.00
	TOTAL		**1,260.0**	**0.0**	**0.0**	**1,260.0**	**4.816**	**4.816**	**60,680.00**
Mar-18									
	PASCO COGEN	SCH. - D	3,640.0	0.0	0.0	3,640.0	4.452	4.452	162,060.00
	TOTAL		**3,640.0**	**0.0**	**0.0**	**3,640.0**	**4.452**	**4.452**	**162,060.00**
Apr-18									
	PASCO COGEN	SCH. - D	2,650.0	0.0	0.0	2,650.0	4.062	4.062	107,650.00
	TOTAL		**2,650.0**	**0.0**	**0.0**	**2,650.0**	**4.062**	**4.062**	**107,650.00**
May-18									
	PASCO COGEN	SCH. - D	3,780.0	0.0	0.0	3,780.0	3.913	3.913	147,910.00
	TOTAL		**3,780.0**	**0.0**	**0.0**	**3,780.0**	**3.913**	**3.913**	**147,910.00**
Jun-18									
	PASCO COGEN	SCH. - D	7,490.0	0.0	0.0	7,490.0	3.850	3.850	288,370.00
	TOTAL		**7,490.0**	**0.0**	**0.0**	**7,490.0**	**3.850**	**3.850**	**288,370.00**
Jul-18									
	PASCO COGEN	SCH. - D	10,130.0	0.0	0.0	10,130.0	3.860	3.860	391,020.00
	TOTAL		**10,130.0**	**0.0**	**0.0**	**10,130.0**	**3.860**	**3.860**	**391,020.00**
Aug-18									
	PASCO COGEN	SCH. - D	8,010.0	0.0	0.0	8,010.0	3.858	3.858	309,040.00
	TOTAL		**8,010.0**	**0.0**	**0.0**	**8,010.0**	**3.858**	**3.858**	**309,040.00**
Sep-18									
	PASCO COGEN	SCH. - D	6,670.0	0.0	0.0	6,670.0	3.819	3.819	254,740.00
	TOTAL		**6,670.0**	**0.0**	**0.0**	**6,670.0**	**3.819**	**3.819**	**254,740.00**
Oct-18									
	PASCO COGEN	SCH. - D	9,430.0	0.0	0.0	9,430.0	3.846	3.846	362,720.00
	TOTAL		**9,430.0**	**0.0**	**0.0**	**9,430.0**	**3.846**	**3.846**	**362,720.00**
Nov-18									
	PASCO COGEN	SCH. - D	10,470.0	0.0	0.0	10,470.0	4.047	4.047	423,770.00
	TOTAL		**10,470.0**	**0.0**	**0.0**	**10,470.0**	**4.047**	**4.047**	**423,770.00**
Dec-18									
	PASCO COGEN	SCH. - D	3,190.0	0.0	0.0	3,190.0	4.313	4.313	137,590.00
	TOTAL		**3,190.0**	**0.0**	**0.0**	**3,190.0**	**4.313**	**4.313**	**137,590.00**
TOTAL									
Jan-18	PASCO COGEN	SCH. - D	67,450.0	0.0	0.0	67,450.0	3.975	3.975	2,681,380.00
THRU	**TOTAL**		**67,450.0**	**0.0**	**0.0**	**67,450.0**	**3.975**	**3.975**	**2,681,380.00**
Dec-18									

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

SCHEDULE E8

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUST-MENT
Jan-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,680.0	0.0	0.0	7,680.0	3.695	3.695	283,760.00
	TOTAL		7,680.0	0.0	0.0	7,680.0	3.695	3.695	283,760.00
Feb-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,280.0	0.0	0.0	7,280.0	3.168	3.168	230,640.00
	TOTAL		7,280.0	0.0	0.0	7,280.0	3.168	3.168	230,640.00
Mar-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,600.0	0.0	0.0	7,600.0	2.444	2.444	185,740.00
	TOTAL		7,600.0	0.0	0.0	7,600.0	2.444	2.444	185,740.00
Apr-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,480.0	0.0	0.0	7,480.0	2.117	2.117	158,380.00
	TOTAL		7,480.0	0.0	0.0	7,480.0	2.117	2.117	158,380.00
May-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,540.0	0.0	0.0	7,540.0	2.910	2.910	219,420.00
	TOTAL		7,540.0	0.0	0.0	7,540.0	2.910	2.910	219,420.00
Jun-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,500.0	0.0	0.0	7,500.0	2.451	2.451	183,820.00
	TOTAL		7,500.0	0.0	0.0	7,500.0	2.451	2.451	183,820.00
Jul-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.962	2.962	220,950.00
	TOTAL		7,460.0	0.0	0.0	7,460.0	2.962	2.962	220,950.00
Aug-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,530.0	0.0	0.0	7,530.0	3.447	3.447	259,590.00
	TOTAL		7,530.0	0.0	0.0	7,530.0	3.447	3.447	259,590.00
Sep-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,520.0	0.0	0.0	7,520.0	2.459	2.459	184,910.00
	TOTAL		7,520.0	0.0	0.0	7,520.0	2.459	2.459	184,910.00
Oct-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,550.0	0.0	0.0	7,550.0	3.200	3.200	241,610.00
	TOTAL		7,550.0	0.0	0.0	7,550.0	3.200	3.200	241,610.00
Nov-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,400.0	0.0	0.0	7,400.0	2.984	2.984	220,790.00
	TOTAL		7,400.0	0.0	0.0	7,400.0	2.984	2.984	220,790.00
Dec-18	VARIOUS	CO-GEN.							
		AS AVAIL.	7,570.0	0.0	0.0	7,570.0	2.507	2.507	189,800.00
	TOTAL		7,570.0	0.0	0.0	7,570.0	2.507	2.507	189,800.00
TOTAL	VARIOUS	CO-GEN.							
Jan-18		AS AVAIL.	90,110.0	0.0	0.0	90,110.0	2.863	2.863	2,579,410.00
THRU	TOTAL		90,110.0	0.0	0.0	90,110.0	2.863	2.863	2,579,410.00
Dec-18									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

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-18	VARIOUS	ECONOMY	27,290.0	0.0	27,290.0	2.885	787,240.00	3.054	833,340.00	46,100.00
Feb-18	VARIOUS	ECONOMY	24,200.0	0.0	24,200.0	2.977	720,460.00	3.180	769,570.00	49,110.00
Mar-18	VARIOUS	ECONOMY	25,130.0	0.0	25,130.0	3.438	864,050.00	4.217	1,059,830.00	195,780.00
Apr-18	VARIOUS	ECONOMY	27,320.0	0.0	27,320.0	3.407	930,880.00	3.627	990,930.00	60,050.00
May-18	VARIOUS	ECONOMY	26,610.0	0.0	26,610.0	2.746	730,820.00	3.829	1,018,880.00	288,060.00
Jun-18	VARIOUS	ECONOMY	25,170.0	0.0	25,170.0	2.811	707,410.00	7.407	1,864,230.00	1,156,820.00
Jul-18	VARIOUS	ECONOMY	26,600.0	0.0	26,600.0	3.488	927,720.00	7.326	1,948,730.00	1,021,010.00
Aug-18	VARIOUS	ECONOMY	27,400.0	0.0	27,400.0	3.517	963,660.00	6.376	1,746,930.00	783,270.00
Sep-18	VARIOUS	ECONOMY	27,150.0	0.0	27,150.0	3.306	897,480.00	6.111	1,659,150.00	761,670.00
Oct-18	VARIOUS	ECONOMY	27,710.0	0.0	27,710.0	3.142	870,580.00	5.010	1,388,330.00	517,750.00
Nov-18	VARIOUS	ECONOMY	21,320.0	0.0	21,320.0	2.794	595,610.00	4.528	965,290.00	369,680.00
Dec-18	VARIOUS	ECONOMY	27,380.0	0.0	27,380.0	2.595	710,560.00	4.280	1,171,820.00	461,260.00
TOTAL	VARIOUS	ECONOMY	**313,280.0**	**0.0**	**313,280.0**	**3.098**	**9,706,470.00**	**4.921**	**15,417,030.00**	**5,710,560.00**

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

	Current Jan 17 - Dec 17	Projected Jan 18 - Dec 18	Difference $	Difference %
Base Rate Revenue	68.62	68.62	0.00	0.0%
Fuel Recovery Revenue	26.42	28.18	1.76	6.7%
Conservation Revenue	2.25	2.46	0.21	9.3%
Capacity Revenue	0.88	0.66	(0.22)	-25.0%
Environmental Revenue	3.89	3.43	(0.46)	-11.8%
Florida Gross Receipts Tax Revenue	2.62	2.65	0.03	1.1%
TOTAL REVENUE	**$104.68**	**$106.00**	**$1.32**	**1.3%**

SCHEDULE H1

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

		ACTUAL 2015	ACTUAL 2016	ACT/EST 2017	EST 2018	DIFFERENCE (%) 2016-2015	2017-2016	2018-2017
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2	LIGHT OIL [1]	100,149	1,889,022	341,655	688,409	1786.2%	-81.9%	101.5%
3	COAL	315,575,618	272,390,442	208,603,850	170,606,860	-13.7%	-23.4%	-18.2%
4	NATURAL GAS	331,614,300	302,563,572	421,089,560	435,698,316	-8.8%	39.2%	3.5%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**647,290,067**	**576,843,036**	**630,035,065**	**606,993,585**	**-10.9%**	**9.2%**	**-3.7%**
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9	LIGHT OIL [1]	264	182	1,460	2,920	-31.1%	702.2%	100.0%
10	COAL	9,118,709	7,754,354	6,761,453	5,456,970	-15.0%	-12.8%	-19.3%
11	NATURAL GAS	9,919,007	9,865,453	13,164,823	14,465,160	-0.5%	33.4%	9.9%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	3,316	44,871	142,110	0.0%	1253.2%	216.7%
14	**TOTAL (MWH)**	**19,037,980**	**17,623,305**	**19,972,607**	**20,067,160**	**-7.4%**	**13.3%**	**0.5%**
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16	LIGHT OIL (BBL) [1]	777	532	2,680	5,400	-31.5%	403.8%	101.5%
17	COAL (TON)	4,016,804	3,397,515	2,934,516	2,338,650	-15.4%	-13.6%	-20.3%
18	NATURAL GAS (MCF)	74,846,827	77,886,370	95,307,609	104,470,630	4.1%	22.4%	9.6%
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]	4,484	3,071	15,480	31,340	-31.5%	404.1%	102.5%
23	COAL	96,061,582	82,203,563	71,335,834	56,478,090	-14.4%	-13.2%	-20.8%
24	NATURAL GAS	76,630,631	79,678,589	97,552,965	107,036,360	4.0%	22.4%	9.7%
25	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26	OTHER	0	0	0	0	0.0%	0.0%	0.0%
27	**TOTAL (MMBTU)**	**172,696,697**	**161,885,222**	**168,904,278**	**163,545,790**	**-6.3%**	**4.3%**	**-3.2%**
	GENERATION MIX (% MWH)							
28	HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29	LIGHT OIL [1]	0.00	0.00	0.01	0.01	0.0%	0.0%	0.0%
30	COAL	47.90	44.00	33.86	27.20	-8.1%	-23.0%	-19.7%
31	NATURAL GAS	52.10	55.98	65.91	72.08	7.4%	17.7%	9.4%
32	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33	OTHER	0.00	0.02	0.22	0.71	0.0%	1000.0%	222.7%
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]	128.89	3,550.79	127.48	127.48	2654.9%	-96.4%	0.0%
37	COAL ($/TON)	78.56	80.17	71.09	72.95	2.0%	-11.3%	2.6%
38	NATURAL GAS ($/MCF)	4.43	3.88	4.42	4.17	-12.4%	13.9%	-5.7%
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]	22.34	615.12	22.07	21.97	2653.4%	-96.4%	-0.5%
43	COAL	3.29	3.31	2.92	3.02	0.6%	-11.8%	3.4%
44	NATURAL GAS	4.33	3.80	4.32	4.07	-12.2%	13.7%	-5.8%
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)**	**3.75**	**3.56**	**3.73**	**3.71**	**-5.1%**	**4.8%**	**-0.5%**
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49	LIGHT OIL [1]	16,984	16,874	10,603	10,733	-0.6%	-37.2%	1.2%
50	COAL	10,535	10,601	10,550	10,350	0.6%	-0.5%	-1.9%
51	NATURAL GAS	7,726	8,077	7,410	7,400	4.5%	-8.3%	-0.1%
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)**	**9,071**	**9,186**	**8,457**	**8,150**	**1.3%**	**-7.9%**	**-3.6%**
	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]	37.94	1,037.92	23.40	23.58	2635.7%	-97.7%	0.8%
57	COAL	3.46	3.51	3.09	3.13	1.4%	-12.0%	1.3%
58	NATURAL GAS	3.34	3.07	3.20	3.01	-8.1%	4.2%	-5.9%
59	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	**TOTAL (cents/KWH)**	**3.40**	**3.27**	**3.15**	**3.02**	**-3.8%**	**-3.7%**	**-4.1%**

[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 2018 - DECEMBER 2018

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2018 through December 2018

	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	6,288,857	3.132	196,967,001	2.818	177,219,990
TIER II (Over 1,000) kWh	2,878,573	3.132	90,156,907	3.818	109,903,918
Total	9,167,430		287,123,908		287,123,908

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2018 - DECEMBER 2018

POLK UNIT 1 IGNITION CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

	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%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	
9 DEPRECIATION EXPENSE	$269,225	$269,225	$269,225	$269,225	$269,225	$269,225	-	-	-	-	-	-	$1,615,350
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	$14,528,600	$14,797,825	$15,067,050	$15,336,276	$15,605,501	$15,874,726	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$14,528,600
12 ENDING BALANCE DEPRECIATION	$14,797,825	$15,067,050	$15,336,276	$15,605,501	$15,874,726	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951
13													
14													
15 ENDING NET INVESTMENT	$1,346,125	$1,076,900	$807,675	$538,450	$269,225	-	-	-	-	-	-	-	$ -
16													
17													
18 AVERAGE INVESTMENT	$1,480,738	$1,211,513	$942,288	$673,063	$403,838	$134,613	-	-	-	-	-	-	
19 ALLOWED EQUITY RETURN	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	
20 EQUITY COMPONENT AFTER-TAX	$5,295	$4,332	$3,370	$2,407	$1,444	$481	-	-	-	-	-	-	$17,329
21 CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
22 EQUITY COMPONENT PRE-TAX	$8,642	$7,071	$5,501	$3,929	$2,357	$785	-	-	-	-	-	-	$28,285
23													
24 ALLOWED DEBT RETURN	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	
25 DEBT COMPONENT	$2,216	$1,813	$1,410	$1,007	$604	$201	-	-	-	-	-	-	$7,251
26													
27 TOTAL RETURN REQUIREMENTS	$10,858	$8,884	$6,911	$4,936	$2,961	$986	-	-	-	-	-	-	$35,536
28													
29 TOTAL DEPRECIATION & RETURN	$280,083	$278,109	$276,136	$274,161	$272,186	$270,211	-	-	-	-	-	-	$1,650,886
30													
31 ESTIMATED FUEL SAVINGS	$0	$920,458	$2,245,737	$2,617,640	$1,660,877	$1,786,724	$547,726	$776,952	$0	$2,964,752	$2,305,888	$0	$15,826,754
32 TOTAL DEPRECIATION & RETURN	$280,083	$278,109	$276,136	$274,161	$272,186	$270,211	-	-	-	-	-	-	$1,650,886
33 NET BENEFIT (COST) TO RATEPAYER	($280,083)	$642,349	$1,969,601	$2,343,479	$1,388,691	$1,516,513	547,726	776,952	-	2,964,752	2,305,888	-	$14,175,868
34													

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 8.7999% (EQUITY 7.0040% , DEBT 1.7959%). RATES ARE BASED ON THE MAY 2017 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 8.7999% (EQUITY 7.0040% , DEBT 1.7959%). RATES ARE BASED ON THE MAY 2017 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
38 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
39 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 2018 THROUGH DECEMBER 2018

	PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1 BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
2 ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2a ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2b ADD INVESTMENT: Big Bend Unit 2 (June 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2c ADD INVESTMENT: Big Bend Unit 1 (November 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
5													
6													
7 AVERAGE BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8 DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9 DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$4,182,070
10 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11 BEGINNING BALANCE DEPRECIATION	$10,913,710	$11,262,216	$11,610,722	$11,959,228	$12,307,734	$12,656,239	$13,004,745	$13,353,251	$13,701,757	$14,050,263	$14,398,768	$14,747,274	$10,913,710
12 ENDING BALANCE DEPRECIATION	$11,262,216	$11,610,722	$11,959,228	$12,307,734	$12,656,239	$13,004,745	$13,353,251	$13,701,757	$14,050,263	$14,398,768	$14,747,274	$15,095,780	$15,095,780
13													
14													
15 ENDING NET INVESTMENT	$9,648,132	$9,299,626	$8,951,120	$8,602,615	$8,254,109	$7,905,603	$7,557,097	$7,208,591	$6,860,086	$6,511,580	$6,163,074	$5,814,568	$5,814,568
16													
17													
18 AVERAGE INVESTMENT	$9,822,385	$9,473,879	$9,125,373	$8,776,867	$8,428,362	$8,079,856	$7,731,350	$7,382,844	$7,034,338	$6,685,833	$6,337,327	$5,988,821	
19 ALLOWED EQUITY RETURN	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	
20 EQUITY COMPONENT AFTER-TAX	$35,125	$33,878	$32,632	$31,386	$30,140	$28,893	$27,647	$26,401	$25,155	$23,908	$22,662	$21,416	$339,243
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	$57,331	$55,296	$53,262	$51,228	$49,195	$47,159	$45,125	$43,092	$41,058	$39,023	$36,989	$34,955	$553,713
23													
24 ALLOWED DEBT RETURN	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	
25 DEBT COMPONENT	$14,700	$14,179	$13,657	$13,136	$12,614	$12,092	$11,571	$11,049	$10,528	$10,006	$9,485	$8,963	$141,980
26													
27 TOTAL RETURN REQUIREMENTS	$72,031	$69,475	$66,919	$64,364	$61,809	$59,251	$56,696	$54,141	$51,586	$49,029	$46,474	$43,918	$695,693
28 PRIOR MONTH TRUE-UP													
29 TOTAL DEPRECIATION & RETURN	$420,537	$417,981	$415,425	$412,870	$410,315	$407,757	$405,202	$402,647	$400,092	$397,535	$394,980	$392,426	$4,877,765
30													
31 ESTIMATED FUEL SAVINGS	$172,646	$167,237	$752,510	$369,412	$460,850	$643,236	$775,888	$416,697	$520,110	$730,802	$339,766	$364,317	$5,713,468
32 TOTAL DEPRECIATION & RETURN	$420,537	$417,981	$415,425	$412,870	$410,315	$407,757	$405,202	$402,647	$400,092	$397,535	$394,980	$392,426	$4,877,765
33 NET BENEFIT (COST) TO RATEPAYER	($247,891)	($250,744)	$337,085	($43,458)	$50,535	$235,479	$370,686	$14,050	$120,019	$333,267	($55,214)	($28,109)	$835,703

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 8.7999% (EQUITY 7.0040% , DEBT 1.7959%). RATES ARE BASED ON THE MAY 2017 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 8.7999% (EQUITY 7.0040% , DEBT 1.7959%). RATES ARE BASED ON THE MAY 2017 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
38 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2018 to December 2018

	(1) Jurisdictional Rate Base Actual May 2017 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,611,554	33.14%	5.12%	1.6968%
Short Term Debt	$ 118,708	2.44%	1.55%	0.0378%
Preferred Stock	$ -	0.00%	0.00%	0.0000%
Customer Deposits	$ 101,181	2.08%	2.55%	0.0531%
Common Equity	$ 2,031,177	41.77%	10.25%	4.2815%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	$ 988,845	20.34%	0.00%	0.0000%
Deferred ITC - Weighted Cost	$ 11,216	0.23%	7.78%	0.0179%
Total	$ 4,862,681	100.00%		6.09%

ITC split between Debt and Equity:

Long Term Debt	$ 1,611,554	Long Term Debt	42.84%
Short Term Debt	118,708	Short Term Debt	3.16%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,031,177	Equity - Common	54.00%
Total	$ 3,761,439	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0179% * 46.00%	0.0082%
Equity = 0.0179% * 54.00%	0.0097%
Weighted Cost	0.0179%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.2815%
Deferred ITC - Weighted Cost	0.0097%
	4.2912%
Times Tax Multiplier	1.632200
Total Equity Component	7.0040%

Total Debt Cost Rate:

Long Term Debt	1.6968%
Short Term Debt	0.0378%
Customer Deposits	0.0531%
Deferred ITC - Weighted Cost	0.0082%
Total Debt Component	1.7959%
	8.7999%

Notes:

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED: AUGUST 24, 2017

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

Q. Have you previously filed testimony in Docket No. 20170001-EI?

A. Yes, I submitted direct testimony on March 15, 2017.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 an exhibit to support your direct testimony?

A. Yes. Exhibit 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 2018 period.

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

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

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

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2018 through December 2018 represent the top 98 percent of the total forecasted system net generation for this period. Polk Unit 2 combined cycle entered commercial service in January 2017 and consists of 36 percent of the total forecasted system net generation for 2018. It is included in the GPIF calculation to meet the base load generation minimum. The company used one year of Polk Unit 2 combined cycle and three years of simple cycle historical operational data on which to base the unit targets.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. A Big Bend Unit 4 forced outage was identified as an outlying outage; 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 2 through 4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing operations.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2018 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 2018 period, the projected EUOF for Bayside Unit 1 is 2.7 percent, the POF is 14.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 82.5 percent or:

$$100\% - (2.7\% + 14.8\%) = 82.5\%$$

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 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. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (2.7\%) + 0.95\ (14.8\%)] = 83.8\%$$

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 using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.7) + 1.10\ (14.8)] = 80.0\%$$

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 2018 are shown on page 21 of Document No. 1. Three GPIF units have a major outage of 28 days or greater in 2018; therefore, three 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 April 6, 2018 to April 17, 2018 and October 18, 2018 to November 28, 2018. There are 1,297 planned outage hours scheduled for the 2018 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 14.8 percent or:

$$\frac{1{,}297}{8{,}760} \times 100\% = 14.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big

Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 17.3 percent. Polk Unit 2 has a POF of 5.8 percent. Bayside Unit 1 has a POF of 14.8 percent, and Bayside Unit 2 has a POF of 18.6 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 2.7 percent for Bayside Unit 1. The EUOF of 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

$$EUOF = \frac{(99 + 135)}{8,760} \times 100\% = 2.7\%$$

Relative to Bayside Unit 1, the EUOF of 2.7 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 2

The projected EUOF for this unit is 31.9 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 61.5 percent.

Big Bend Unit 3

The projected EUOF for this unit is 26.7 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 66.7 percent.

Big Bend Unit 4

The projected EUOF for this unit is 14.7 percent. The unit will have two planned outages in 2018, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 78.7 percent.

Polk Unit 1

The projected EUOF for this unit is 8.3 percent. The unit will have two planned outages in 2018, and the POF is 17.3 percent. Therefore, the target equivalent availability for this unit is 74.4 percent.

Polk Unit 2

The projected EUOF for this unit is 11.0 percent. The unit will have one planned outage in 2018, and the POF is 5.8 percent. Therefore, the target equivalent availability for this unit is 83.2 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.7 percent. The unit will have two planned outages in 2018, and the POF is 14.8 percent. Therefore, the target equivalent availability for this unit is 82.5 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.0 percent. The unit will have two planned outages in 2018, and the POF is 18.6 percent. Therefore, the target equivalent availability for this unit is 77.3 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 76.3 percent is shown on page 5 of Document No. 1.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 19 of Document No. 1. Except for the months of April, October and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of April, October and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the 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 unit metrics, which are subsequently converted to factors. Therefore,

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

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

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

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

Q. How were the targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis for 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 period 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 or 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 the 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 2018 period.

A. The heat rate target for Big Bend Unit 2 is 11,320 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 478 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,619 Btu/Net kWh with a range of ± 367 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,448 Btu/Net kWh, with a range of ± 382 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,978 Btu/Net kWh with a range of ± 334 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,382 Btu/Net kWh with a range of ± 555 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,489 Btu/Net kWh with a range of ± 130 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,676 Btu/Net kWh with a range of ± 229 Btu/Net kWh. A zone of tolerance of ± 75 Btu/Net kWh is included within a 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 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 $615,817,190 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 the individual savings are calculated, column

4 totals $29,174,790 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 4.66 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 1, page 12, if the unit operates at 7,360 average net operating heat rate, fuel savings would equal $1,359,627 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 $29,174,790. 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 2018 is \$2,508,779,992. This produces the maximum allowed jurisdictional incentive of \$10,237,065 shown on line 21.

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

A. Yes. As Order No. PSC-2013-0665-FOF-EI issued in Docket No. 20130001-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 \$10,237,065.

Q. Please summarize your direct 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).

$$
\begin{aligned}
GPIP = (0.0211\ EAP_{BB2} &+ 0.0370\ EAP_{BB3} \\
+ 0.0505\ EAP_{BB4} &+ 0.0073\ EAP_{PK1} \\
+ 0.0483\ EAP_{PK2} &+ 0.0264\ EAP_{BAY1}
\end{aligned}
$$

$$
\begin{aligned}
&+ 0.0516\ EAP_{BAY2} + 0.0267\ HRP_{BB2} \\
&+ 0.0496\ HRP_{BB3} + 0.0736\ HRP_{BB4} \\
&+ 0.0352\ HRP_{PK1} + 0.4539\ HRP_{PK2} \\
&+ 0.0466\ HRP_{BAY1} + 0.0722\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2018 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 direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY

OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2018 - DECEMBER 2018

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2018 - DECEMBER 2018
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2018 - DECEMBER 2018

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,174.8	10,237.1
+9	26,257.3	9,213.4
+8	23,339.8	8,189.7
+7	20,422.4	7,165.9
+6	17,504.9	6,142.2
+5	14,587.4	5,118.5
+4	11,669.9	4,094.8
+3	8,752.4	3,071.1
+2	5,835.0	2,047.4
+1	2,917.5	1,023.7
0	0.0	0.0
-1	(3,217.7)	(1,023.7)
-2	(6,435.4)	(2,047.4)
-3	(9,653.1)	(3,071.1)
-4	(12,870.8)	(4,094.8)
-5	(16,088.5)	(5,118.5)
-6	(19,306.2)	(6,142.2)
-7	(22,523.9)	(7,165.9)
-8	(25,741.6)	(8,189.7)
-9	(28,959.3)	(9,213.4)
-10	(32,177.0)	(10,237.1)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2018 - DECEMBER 2018

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,478,918,000	
Line 2	Month of January	2018	$	2,416,168,000	
Line 3	Month of February	2018	$	2,436,806,102	
Line 4	Month of March	2018	$	2,457,620,487	
Line 5	Month of April	2018	$	2,499,910,175	
Line 6	Month of May	2018	$	2,521,263,574	
Line 7	Month of June	2018	$	2,542,799,367	
Line 8	Month of July	2018	$	2,479,340,232	
Line 9	Month of August	2018	$	2,500,517,930	
Line 10	Month of September	2018	$	2,521,876,520	
Line 11	Month of October	2018	$	2,564,340,396	
Line 12	Month of November	2018	$	2,586,244,137	
Line 13	Month of December	2018	$	2,608,334,972	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,508,779,992	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.27%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,237,065	
Line 18	Jurisdictional Sales			19,544,119	MWH
Line 19	Total Sales			19,544,119	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)		$	10,237,065	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	14,587,395	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	10,237,065	

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 2018 - DECEMBER 2018

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 2	2.11%	61.5	68.2	48.1	615.6	(1,077.7)
BIG BEND 3	3.70%	66.7	72.4	55.4	1,079.4	(3,189.4)
BIG BEND 4	5.05%	78.7	82.0	72.1	1,473.1	(1,845.8)
POLK 1	0.73%	74.4	77.0	69.4	211.9	(380.9)
POLK 2	4.83%	83.2	85.7	78.2	1,408.9	(1,372.7)
BAYSIDE 1	2.64%	82.5	83.8	80.0	770.2	(385.1)
BAYSIDE 2	5.16%	77.3	79.1	73.9	1,505.7	(1,815.5)
GPIF SYSTEM	**24.22%**					

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 2	2.67%	11,320	60.3	10,843	11,798	778.3	(778.3)
BIG BEND 3	4.96%	10,619	80.8	10,252	10,987	1,448.4	(1,448.4)
BIG BEND 4	7.36%	10,448	86.4	10,066	10,830	2,146.5	(2,146.5)
POLK 1	3.52%	9,978	99.1	9,644	10,312	1,028.0	(1,028.0)
POLK 2	45.39%	7,382	76.4	6,827	7,936	13,242.8	(13,242.8)
BAYSIDE 1	4.66%	7,489	62.8	7,360	7,619	1,359.6	(1,359.6)
BAYSIDE 2	7.22%	7,676	52.3	7,447	7,905	2,106.5	(2,106.5)
GPIF SYSTEM	**75.78%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 18 - DEC 18 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 16 - DEC 16 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 15 - DEC 15 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 14 - DEC 14 POF	EUOF	EUOR
BIG BEND 2	2.11%	8.7%	6.6	31.9	34.2	22.5	22.5	29.5	7.5	46.8	50.5	8.4	10.6	11.6
BIG BEND 3	3.70%	15.3%	6.6	26.7	28.6	12.6	33.6	39.7	3.7	24.1	25.0	5.1	15.8	16.7
BIG BEND 4	5.05%	20.9%	6.6	14.7	15.8	6.7	18.8	21.9	3.8	15.1	15.7	20.7	11.2	14.2
POLK 1	0.73%	3.0%	17.3	8.3	10.0	13.3	7.5	11.4	13.5	16.0	19.0	5.0	8.7	10.6
POLK 2	4.83%	19.9%	5.8	11.0	11.7	9.7	9.4	29.1	3.6	3.5	19.2	11.2	0.9	25.1
BAYSIDE 1	2.64%	10.9%	14.8	2.7	3.1	20.0	1.3	1.8	11.8	2.3	2.7	6.2	11.5	14.1
BAYSIDE 2	5.16%	21.3%	18.6	4.0	5.0	7.1	2.9	5.0	7.2	3.7	4.1	5.0	5.4	5.7
GPIF SYSTEM	**24.22%**	**100.0%**	**10.2**	**13.5**	**14.7**	**11.3**	**13.9**	**20.6**	**6.0**	**13.1**	**17.1**	**10.0**	**8.5**	**14.6**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**76.3**			**74.8**			**80.9**			**81.5**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
9.1	**11.8**	**17.4**	**79.1**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 16 - DEC 16	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 14 - DEC 14
BIG BEND 2	2.67%	3.5%	11,320	10,952	10,765	10,810
BIG BEND 3	4.96%	6.6%	10,619	10,395	10,419	10,604
BIG BEND 4	7.36%	9.7%	10,448	10,329	10,331	10,293
POLK 1	3.52%	4.6%	9,978	9,944	10,351	10,207
POLK 2	45.39%	59.9%	7,382	8,604	11,576	12,297
BAYSIDE 1	4.66%	6.1%	7,489	7,521	7,443	7,347
BAYSIDE 2	7.22%	9.5%	7,676	7,723	7,610	7,488
GPIF SYSTEM	**75.78%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**8,185**	**8,883**	**10,662**	**11,079**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2018 - DECEMBER 2018
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 2	615,817.19	615,201.55	615.64	2.11%
EA_2 BIG BEND 3	615,817.19	614,737.82	1,079.37	3.70%
EA_3 BIG BEND 4	615,817.19	614,344.07	1,473.12	5.05%
EA_4 POLK 1	615,817.19	615,605.25	211.94	0.73%
EA_5 POLK 2	615,817.19	614,408.34	1,408.85	4.83%
EA_6 BAYSIDE 1	615,817.19	615,046.99	770.20	2.64%
EA_7 BAYSIDE 2	615,817.19	614,311.49	1,505.70	5.16%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 2	615,817.19	615,038.88	778.31	2.67%
AHR_2 BIG BEND 3	615,817.19	614,368.81	1,448.38	4.96%
AHR_3 BIG BEND 4	615,817.19	613,670.72	2,146.47	7.36%
AHR_4 POLK 1	615,817.19	614,789.23	1,027.96	3.52%
AHR_5 POLK 2	615,817.19	602,574.43	13,242.76	45.39%
AHR_6 BAYSIDE 1	615,817.19	614,457.56	1,359.63	4.66%
AHR_7 BAYSIDE 2	615,817.19	613,710.73	2,106.46	7.22%
TOTAL SAVINGS			**29,174.79**	**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 2018 - DECEMBER 2018

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	615.6	68.2	+10	778.3	10,843
+9	554.1	67.6	+9	700.5	10,883
+8	492.5	66.9	+8	622.6	10,923
+7	430.9	66.2	+7	544.8	10,963
+6	369.4	65.5	+6	467.0	11,004
+5	307.8	64.9	+5	389.2	11,044
+4	246.3	64.2	+4	311.3	11,084
+3	184.7	63.5	+3	233.5	11,124
+2	123.1	62.9	+2	155.7	11,165
+1	61.6	62.2	+1	77.8	11,205
					11,245
0	0.0	61.5	0	0.0	11,320
					11,395
-1	(107.8)	60.2	-1	(77.8)	11,436
-2	(215.5)	58.8	-2	(155.7)	11,476
-3	(323.3)	57.5	-3	(233.5)	11,516
-4	(431.1)	56.1	-4	(311.3)	11,556
-5	(538.9)	54.8	-5	(389.2)	11,597
-6	(646.6)	53.5	-6	(467.0)	11,637
-7	(754.4)	52.1	-7	(544.8)	11,677
-8	(862.2)	50.8	-8	(622.6)	11,717
-9	(970.0)	49.4	-9	(700.5)	11,758
-10	(1,077.7)	48.1	-10	(778.3)	11,798
	Weighting Factor =	2.11%		Weighting Factor =	2.67%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,079.4	72.4	+10	1,448.4	10,252
+9	971.4	71.8	+9	1,303.5	10,281
+8	863.5	71.3	+8	1,158.7	10,310
+7	755.6	70.7	+7	1,013.9	10,339
+6	647.6	70.1	+6	869.0	10,369
+5	539.7	69.6	+5	724.2	10,398
+4	431.7	69.0	+4	579.4	10,427
+3	323.8	68.4	+3	434.5	10,456
+2	215.9	67.9	+2	289.7	10,486
+1	107.9	67.3	+1	144.8	10,515
					10,544
0	0.0	66.7	0	0.0	10,619
					10,694
-1	(318.9)	65.6	-1	(144.8)	10,723
-2	(637.9)	64.5	-2	(289.7)	10,753
-3	(956.8)	63.3	-3	(434.5)	10,782
-4	(1,275.8)	62.2	-4	(579.4)	10,811
-5	(1,594.7)	61.0	-5	(724.2)	10,840
-6	(1,913.6)	59.9	-6	(869.0)	10,870
-7	(2,232.6)	58.8	-7	(1,013.9)	10,899
-8	(2,551.5)	57.6	-8	(1,158.7)	10,928
-9	(2,870.5)	56.5	-9	(1,303.5)	10,957
-10	(3,189.4)	55.4	-10	(1,448.4)	10,987
	Weighting Factor =	3.70%		Weighting Factor =	4.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,473.1	82.0	+10	2,146.5	10,066
+9	1,325.8	81.6	+9	1,931.8	10,097
+8	1,178.5	81.3	+8	1,717.2	10,128
+7	1,031.2	81.0	+7	1,502.5	10,159
+6	883.9	80.6	+6	1,287.9	10,189
+5	736.6	80.3	+5	1,073.2	10,220
+4	589.2	80.0	+4	858.6	10,251
+3	441.9	79.7	+3	643.9	10,281
+2	294.6	79.3	+2	429.3	10,312
+1	147.3	79.0	+1	214.6	10,343
					10,373
0	0.0	78.7	0	0.0	10,448
					10,523
-1	(184.6)	78.0	-1	(214.6)	10,554
-2	(369.2)	77.4	-2	(429.3)	10,585
-3	(553.7)	76.7	-3	(643.9)	10,615
-4	(738.3)	76.1	-4	(858.6)	10,646
-5	(922.9)	75.4	-5	(1,073.2)	10,677
-6	(1,107.5)	74.7	-6	(1,287.9)	10,708
-7	(1,292.0)	74.1	-7	(1,502.5)	10,738
-8	(1,476.6)	73.4	-8	(1,717.2)	10,769
-9	(1,661.2)	72.8	-9	(1,931.8)	10,800
-10	(1,845.8)	72.1	-10	(2,146.5)	10,830
	Weighting Factor =	5.05%		Weighting Factor =	7.36%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

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	211.9	77.0	+10	1,028.0	9,644
+9	190.7	76.7	+9	925.2	9,670
+8	169.6	76.4	+8	822.4	9,696
+7	148.4	76.2	+7	719.6	9,722
+6	127.2	75.9	+6	616.8	9,748
+5	106.0	75.7	+5	514.0	9,774
+4	84.8	75.4	+4	411.2	9,799
+3	63.6	75.2	+3	308.4	9,825
+2	42.4	74.9	+2	205.6	9,851
+1	21.2	74.7	+1	102.8	9,877
					9,903
0	0.0	74.4	0	0.0	9,978
					10,053
-1	(38.1)	73.9	-1	(102.8)	10,079
-2	(76.2)	73.4	-2	(205.6)	10,105
-3	(114.3)	72.9	-3	(308.4)	10,130
-4	(152.4)	72.4	-4	(411.2)	10,156
-5	(190.4)	71.9	-5	(514.0)	10,182
-6	(228.5)	71.4	-6	(616.8)	10,208
-7	(266.6)	70.9	-7	(719.6)	10,234
-8	(304.7)	70.4	-8	(822.4)	10,260
-9	(342.8)	69.9	-9	(925.2)	10,286
-10	(380.9)	69.4	-10	(1,028.0)	10,312
	Weighting Factor =	0.73%		Weighting Factor =	3.52%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

POLK 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	1,408.9	85.7	+10	13,242.8	6,827
+9	1,268.0	85.5	+9	11,918.5	6,875
+8	1,127.1	85.2	+8	10,594.2	6,923
+7	986.2	85.0	+7	9,269.9	6,971
+6	845.3	84.7	+6	7,945.7	7,019
+5	704.4	84.5	+5	6,621.4	7,067
+4	563.5	84.2	+4	5,297.1	7,115
+3	422.7	84.0	+3	3,972.8	7,163
+2	281.8	83.7	+2	2,648.6	7,211
+1	140.9	83.5	+1	1,324.3	7,259
					7,307
0	0.0	83.2	0	0.0	7,382
					7,457
-1	(137.3)	82.7	-1	(1,324.3)	7,505
-2	(274.5)	82.2	-2	(2,648.6)	7,553
-3	(411.8)	81.7	-3	(3,972.8)	7,601
-4	(549.1)	81.2	-4	(5,297.1)	7,648
-5	(686.3)	80.7	-5	(6,621.4)	7,696
-6	(823.6)	80.2	-6	(7,945.7)	7,744
-7	(960.9)	79.7	-7	(9,269.9)	7,792
-8	(1,098.2)	79.2	-8	(10,594.2)	7,840
-9	(1,235.4)	78.7	-9	(11,918.5)	7,888
-10	(1,372.7)	78.2	-10	(13,242.8)	7,936
	Weighting Factor =	4.83%		Weighting Factor =	45.39%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

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	770.2	83.8	+10	1,359.6	7,360
+9	693.2	83.7	+9	1,223.7	7,365
+8	616.2	83.5	+8	1,087.7	7,371
+7	539.1	83.4	+7	951.7	7,376
+6	462.1	83.3	+6	815.8	7,382
+5	385.1	83.2	+5	679.8	7,387
+4	308.1	83.0	+4	543.9	7,393
+3	231.1	82.9	+3	407.9	7,398
+2	154.0	82.8	+2	271.9	7,403
+1	77.0	82.7	+1	136.0	7,409
					7,414
0	0.0	82.5	0	0.0	7,489
					7,564
-1	(38.5)	82.3	-1	(136.0)	7,570
-2	(77.0)	82.0	-2	(271.9)	7,575
-3	(115.5)	81.8	-3	(407.9)	7,581
-4	(154.0)	81.5	-4	(543.9)	7,586
-5	(192.5)	81.3	-5	(679.8)	7,592
-6	(231.1)	81.0	-6	(815.8)	7,597
-7	(269.6)	80.7	-7	(951.7)	7,603
-8	(308.1)	80.5	-8	(1,087.7)	7,608
-9	(346.6)	80.2	-9	(1,223.7)	7,614
-10	(385.1)	80.0	-10	(1,359.6)	7,619
	Weighting Factor =	2.64%		Weighting Factor =	4.66%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2018 - DECEMBER 2018

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	1,505.7	79.1	+10	2,106.5	7,447
+9	1,355.1	78.9	+9	1,895.8	7,462
+8	1,204.6	78.7	+8	1,685.2	7,478
+7	1,054.0	78.6	+7	1,474.5	7,493
+6	903.4	78.4	+6	1,263.9	7,509
+5	752.9	78.2	+5	1,053.2	7,524
+4	602.3	78.0	+4	842.6	7,539
+3	451.7	77.9	+3	631.9	7,555
+2	301.1	77.7	+2	421.3	7,570
+1	150.6	77.5	+1	210.6	7,585
					7,601
0	0.0	77.3	0	0.0	7,676
					7,751
-1	(181.5)	77.0	-1	(210.6)	7,766
-2	(363.1)	76.6	-2	(421.3)	7,782
-3	(544.6)	76.3	-3	(631.9)	7,797
-4	(726.2)	75.9	-4	(842.6)	7,812
-5	(907.7)	75.6	-5	(1,053.2)	7,828
-6	(1,089.3)	75.3	-6	(1,263.9)	7,843
-7	(1,270.8)	74.9	-7	(1,474.5)	7,859
-8	(1,452.4)	74.6	-8	(1,685.2)	7,874
-9	(1,633.9)	74.2	-9	(1,895.8)	7,889
-10	(1,815.5)	73.9	-10	(2,106.5)	7,905
	Weighting Factor =	5.16%		Weighting Factor =	7.22%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

PLANT/UNIT BIG BEND 2	MONTH OF: Jan-18	MONTH OF: Feb-18	MONTH OF: Mar-18	MONTH OF: Apr-18	MONTH OF: May-18	MONTH OF: Jun-18	MONTH OF: Jul-18	MONTH OF: Aug-18	MONTH OF: Sep-18	MONTH OF: Oct-18	MONTH OF: Nov-18	MONTH OF: Dec-18	PERIOD 2018
1. EAF (%)	65.8	58.8	42.5	65.8	65.8	65.8	65.8	65.8	65.8	65.8	43.9	65.8	61.5
2. POF	0.0	10.7	35.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	34.2	30.5	22.1	34.2	34.2	34.2	34.2	34.2	34.2	34.2	22.8	34.2	31.9
4. EUOR	34.2	34.2	34.2	0.0	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	48	43	105	0	10	229	211	266	248	227	341	173	1,901
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	696	629	638	720	734	491	533	478	472	517	380	571	6,859
9. POH	0	72	263	0	0	0	0	0	0	0	240	0	575
10. EFOH	243	196	157	235	243	235	243	243	235	243	157	243	2,670
11. EMOH	12	9	7	11	12	11	12	12	11	12	7	12	127
12. OPER BTU (GBTU)	105	102	231	0	22	556	508	626	627	596	971	391	4,738
13. NET GEN (MWH)	9,120	8,920	20,200	0	1,960	48,990	44,750	54,950	55,490	52,900	87,060	34,220	418,560
14. ANOHR (Btu/kwh)	11,463	11,381	11,452	0	11,435	11,350	11,359	11,385	11,303	11,259	11,154	11,426	11,320
15. NOF (%)	52.1	56.8	52.7	0.0	53.7	58.6	58.1	56.6	61.3	63.8	69.9	54.2	60.3
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365
17. ANOHR EQUATION	ANOHR = NOF(		-17.276	) +	12,362								

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DOCKET NO. 20170001-EI
GPIF 2018 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.18E
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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	71.4	71.4	71.4	47.6	62.2	71.4	71.4	71.4	71.4	48.4	71.4	71.4	66.7
2. POF	0.0	0.0	0.0	33.3	12.9	0.0	0.0	0.0	0.0	32.3	0.0	0.0	6.6
3. EUOF	28.6	28.6	28.6	19.1	24.9	28.6	28.6	28.6	28.6	19.4	28.6	28.6	26.7
4. EUOR	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	539	540	603	206	525	439	523	419	450	283	438	474	5,439
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	205	132	140	514	219	281	221	325	270	461	283	270	3,321
9. POH	0	0	0	240	96	0	0	0	0	240	0	0	576
10. EFOH	201	181	200	129	175	194	201	201	194	136	194	201	2,206
11. EMOH	12	11	12	8	11	12	12	12	12	8	12	12	133
12. OPER BTU (GBTU)	1,981	1,870	2,168	653	1,723	1,454	1,610	1,362	1,574	954	1,427	1,731	18,515
13. NET GEN (MWH)	188,660	176,390	205,730	60,860	161,490	136,450	149,510	127,490	149,010	89,710	133,570	164,680	1,743,550
14. ANOHR (Btu/kwh)	10,500	10,604	10,539	10,727	10,672	10,657	10,770	10,687	10,565	10,629	10,684	10,512	10,619
15. NOF (%)	87.5	81.7	85.3	74.8	77.9	78.7	72.4	77.0	83.8	80.3	77.2	86.9	80.8
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397
17. ANOHR EQUATION	ANOHR = NOF(	-17.826	) +		12,060								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	84.2	84.2	46.1	84.2	84.2	84.2	84.2	84.2	84.2	84.2	84.2	57.0	78.7
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	15.8	15.8	8.6	15.8	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	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	522	672	362	546	624	584	622	608	672	666	522	257	6,657
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	222	0	381	174	120	136	122	136	48	78	199	487	2,103
9. POH	0	0	336	0	0	0	0	0	0	0	0	240	576
10. EFOH	89	81	49	86	89	86	89	89	86	89	86	60	981
11. EMOH	28	26	15	27	28	27	28	28	27	28	27	19	311
12. OPER BTU (GBTU)	2,178	2,721	1,586	2,122	2,366	2,230	2,514	2,389	2,654	2,548	2,050	1,012	26,375
13. NET GEN (MWH)	209,530	260,830	153,470	202,780	225,390	212,640	241,270	228,520	254,010	243,020	196,120	96,750	2,524,330
14. ANOHR (Btu/kwh)	10,394	10,431	10,331	10,466	10,495	10,487	10,420	10,454	10,448	10,485	10,454	10,464	10,448
15. NOF (%)	90.8	87.8	95.9	85.0	82.7	83.3	88.8	86.0	86.5	83.5	86.0	85.2	86.4
16. NPC (MW)	442	442	442	437	437	437	437	437	437	437	437	442	439
17. ANOHR EQUATION	ANOHR = NOF(	-12.371	) +		11,518								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	90.0	67.5	90.0	90.0	90.0	90.0	90.0	43.5	0.0	60.9	90.0	90.0	74.4
2. POF	0.0	25.0	0.0	0.0	0.0	0.0	0.0	51.6	100.0	32.3	0.0	0.0	17.3
3. EUOF	10.0	7.5	10.0	10.0	10.0	10.0	10.0	4.9	0.0	6.8	10.0	10.0	8.3
4. EUOR	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	0.0	10.0	10.0	10.0	10.0
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	688	510	659	658	696	608	678	348	0	497	651	671	6,664
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	56	162	84	62	48	112	66	396	720	247	70	73	2,096
9. POH	0	168	0	0	0	0	0	384	720	240	0	0	1,512
10. EFOH	64	44	64	62	64	62	64	31	0	44	62	64	627
11. EMOH	10	7	10	10	10	10	10	5	0	7	10	10	101
12. OPER BTU (GBTU)	1,504	1,100	1,436	1,433	1,504	1,321	1,476	760	0	1,080	1,422	1,462	14,498
13. NET GEN (MWH)	150,650	110,370	143,890	143,580	150,900	132,450	147,940	76,130	0	108,220	142,450	146,460	1,453,040
14. ANOHR (Btu/kwh)	9,985	9,966	9,980	9,979	9,969	9,976	9,979	9,983	0	9,976	9,984	9,980	9,978
15. NOF (%)	99.5	98.4	99.2	99.2	98.6	99.0	99.2	99.4	0.0	99.0	99.5	99.2	99.1
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220

17. ANOHR EQUATION   ANOHR = NOF(16.584) + 8,334

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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 2	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	88.3	88.3	88.3	88.3	88.3	88.3	88.3	88.3	88.3	71.2	44.1	88.3	83.2
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4	50.1	0.0	5.8
3. EUOF	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	9.4	5.8	11.7	11.0
4. EUOR	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	744	672	743	720	744	720	744	744	720	744	453	744	8,492
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	0	0	0	0	0	0	0	0	0	0	268	0	268
9. POH	0	0	0	0	0	0	0	0	0	144	361	0	505
10. EFOH	47	42	47	46	47	46	47	47	46	38	23	47	522
11. EMOH	40	36	40	39	40	39	40	40	39	32	19	40	443
12. OPER BTU (GBTU)	4,787	3,952	4,703	4,752	4,594	4,768	4,874	5,087	4,385	4,117	2,489	4,707	53,287
13. NET GEN (MWH)	642,410	523,710	629,610	654,830	625,340	657,390	670,600	705,820	595,590	550,740	332,710	630,080	7,218,830
14. ANOHR (Btu/kwh)	7,452	7,547	7,470	7,257	7,346	7,253	7,268	7,207	7,363	7,475	7,482	7,470	7,382
15. NOF (%)	71.2	64.3	69.9	85.5	79.0	85.8	84.7	89.2	77.7	69.6	69.0	69.9	76.4
16. NPC (MW)	1,212	1,212	1,212	1,064	1,064	1,064	1,064	1,064	1,064	1,064	1,064	1,212	1,113

17. ANOHR EQUATION ANOHR = NOF(-13.653) + 8,424

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DOCKET NO. 20170001-EI
GPIF 2018 PROJECTION
EXHIBIT NO. BSB-2, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.18E
PAGE 18 OF 40

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	96.9	96.9	96.9	58.1	96.9	96.9	96.9	96.9	96.9	53.1	6.4	96.9	82.5
2. POF	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	45.2	93.3	0.0	14.8
3. EUOF	3.1	3.1	3.1	1.9	3.1	3.1	3.1	3.1	3.1	1.7	0.2	3.1	2.7
4. EUOR	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	721	651	720	418	721	697	721	721	697	395	18	721	7,201
7. RSH	0	0	0	0	0	0	0	0	0	0	28	0	29
8. UH	23	21	23	302	23	23	23	23	23	349	675	23	1,530
9. POH	0	0	0	288	0	0	0	0	0	336	673	0	1,297
10. EFOH	10	9	10	6	10	10	10	10	10	5	1	10	99
11. EMOH	13	12	13	8	13	13	13	13	13	7	1	13	135
12. OPER BTU (GBTU)	2,160	1,879	2,182	1,323	2,469	2,665	2,645	2,795	2,779	1,384	55	2,354	24,760
13. NET GEN (MWH)	281,570	244,000	284,750	175,770	331,350	363,440	358,430	382,030	381,610	186,230	7,300	309,540	3,306,020
14. ANOHR (Btu/kwh)	7,672	7,699	7,663	7,528	7,452	7,333	7,379	7,316	7,283	7,429	7,556	7,606	7,489
15. NOF (%)	49.3	47.3	50.0	59.9	65.6	74.3	70.9	75.6	78.1	67.2	57.9	54.2	62.8
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(	-13.560	) +		8,341								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018
1. EAF (%)	95.0	10.2	0.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	58.2	77.3
2. POF	0.0	89.3	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.7	18.6
3. EUOF	5.0	0.5	0.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	3.0	4.0
4. EUOR	5.0	0.0	0.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	96	0	0	680	707	684	707	707	684	707	685	303	5,961
7. RSH	611	68	0	4	0	0	0	0	0	0	0	130	814
8. UH	37	604	743	36	37	36	37	37	36	37	36	311	1,985
9. POH	0	600	743	0	0	0	0	0	0	0	0	288	1,631
10. EFOH	19	2	0	18	19	18	19	19	18	19	18	11	180
11. EMOH	18	2	0	18	18	18	18	18	18	18	18	11	175
12. OPER BTU (GBTU)	169	0	0	2,425	2,521	2,871	2,666	2,871	2,822	2,802	3,156	741	23,158
13. NET GEN (MWH)	21,050	0	0	314,770	327,250	378,150	347,710	376,920	371,070	367,050	419,740	93,310	3,017,020
14. ANOHR (Btu/kwh)	8,034	0	0	7,704	7,704	7,593	7,668	7,618	7,606	7,635	7,520	7,937	7,676
15. NOF (%)	20.9	0.0	0.0	49.8	49.8	59.5	52.9	57.4	58.4	55.9	65.9	29.4	52.3
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(-11.437) + 8,274

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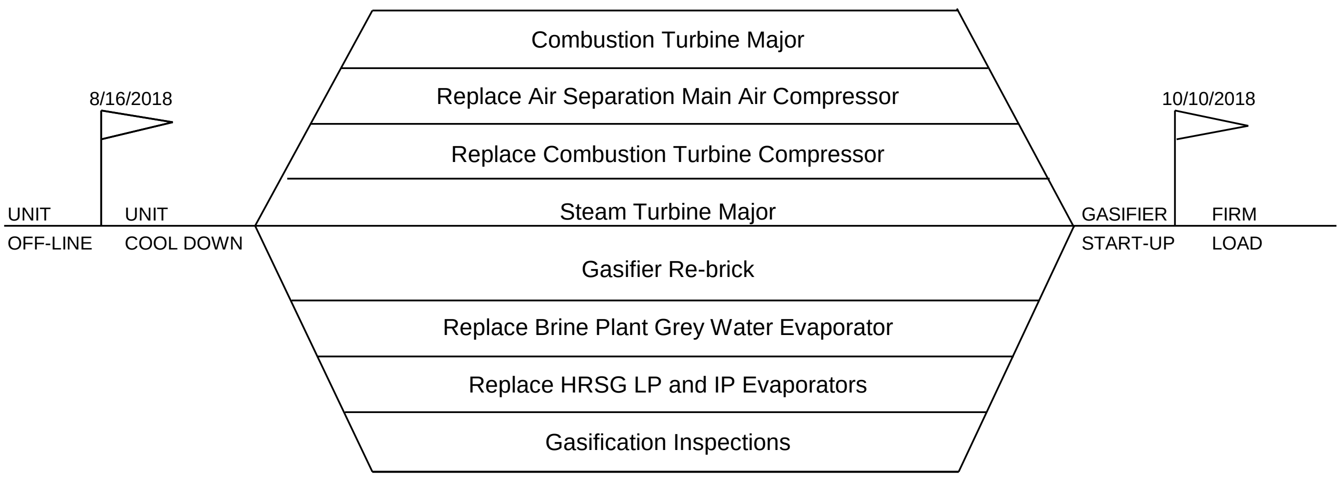
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2018 - DECEMBER 2018

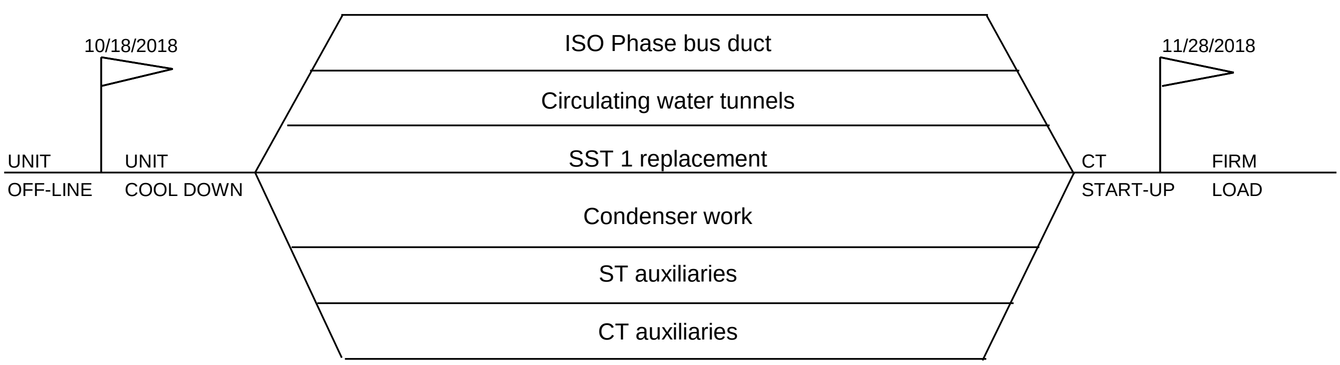
	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
	BIG BEND 2	Feb 26 - Mar 11	Fuel System Cleanup and FGD/SCR work
		Nov 19 - Nov 28	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Apr 21 - May 04	Fuel System Cleanup and FGD/SCR work
		Oct 06 - Oct 15	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Mar 13 - Mar 26	Fuel System Cleanup and FGD/SCR work
		Dec 04 - Dec 13	Fuel System Cleanup and FGD/SCR work
+	POLK 1	Feb 17 - Feb 23	Gasifier Outage
		Aug 16 - Oct 10	Combustion Turbine Major, Steam Turbine Major, Replace Combustion Turbine Compressor, Replace Air Separation Main Air Compressor Bull Gear, pinions, and impellers, Gasifier Re-brick, Replace Brine Plant Grey Water Evaporator, Replace HRSG LP and IP Evaporators, Gasification Inspections
	POLK 2	Oct 19 - Nov 15	Fuel System Cleanup
+	BAYSIDE 1	Apr 06 - Apr 17	Fuel System Cleanup
		Oct 18 - Nov 28	SST 1 replacement, ISO Phase bus duct, Condenser work, Circulating water tunnels, ST auxiliaries, CT auxiliaries
+	BAYSIDE 2	Feb 04 - Mar 31	HP/IP Curtis Stage upgrade, Centerline bearing & steam seals, SST 2 replacement, Reserve #3 replacement, Condensers, ZBL System, Circ. & condensate pumps, ST & CT auxiliaries
		Dec 09 - Dec 20	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 2018 - DECEMBER 2018

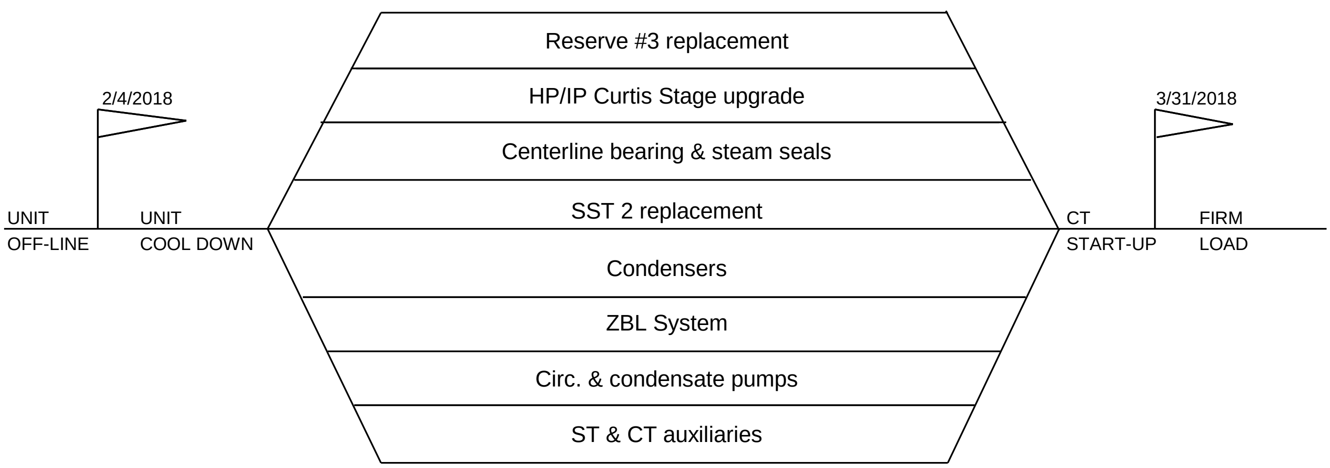


TAMPA ELECTRIC COMPANY
POLK 1
PLANNED OUTAGE 2018
PROJECTED CPM

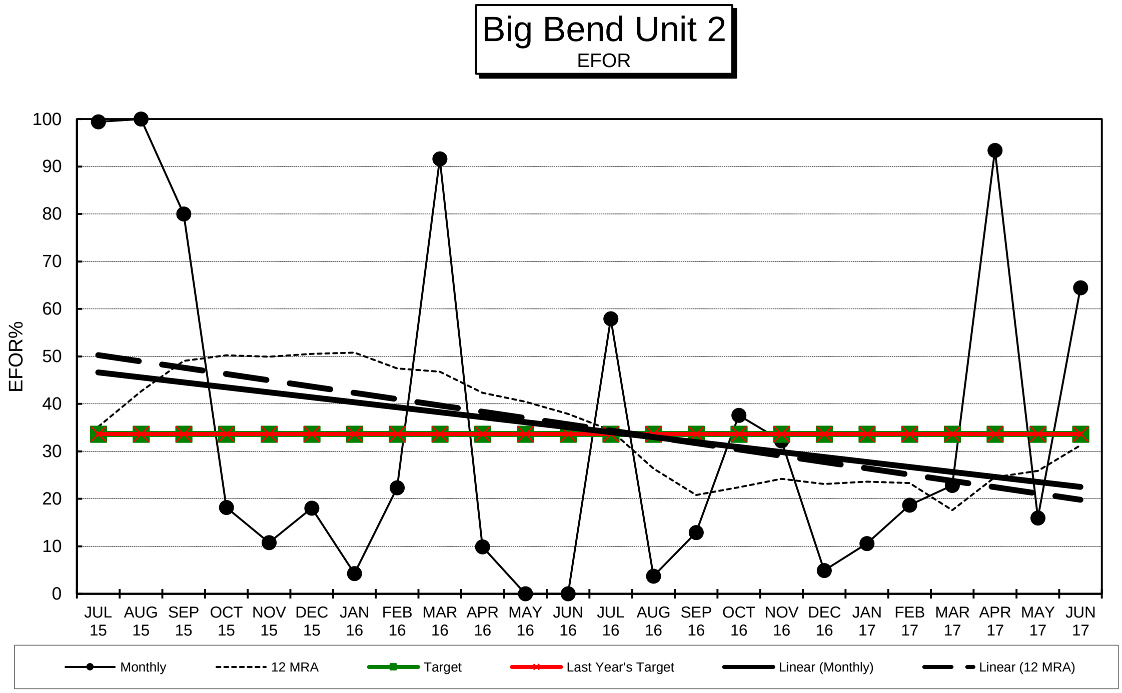


TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2018
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2018 - DECEMBER 2018



TAMPA ELECTRIC COMPANY
BAYSIDE 2
PLANNED OUTAGE 2018
PROJECTED CPM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JUL 15
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NOV 15
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JUN 16
JUL 16
AUG 16
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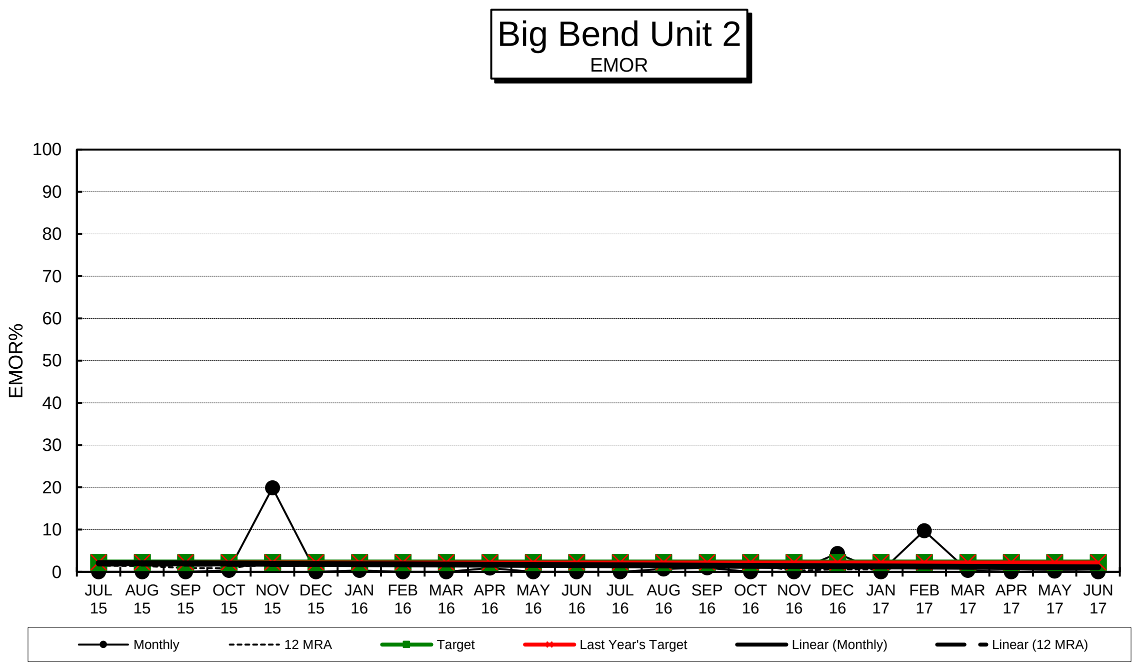
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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NOV 15
DEC 15
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NOV 16
DEC 16
JAN 17
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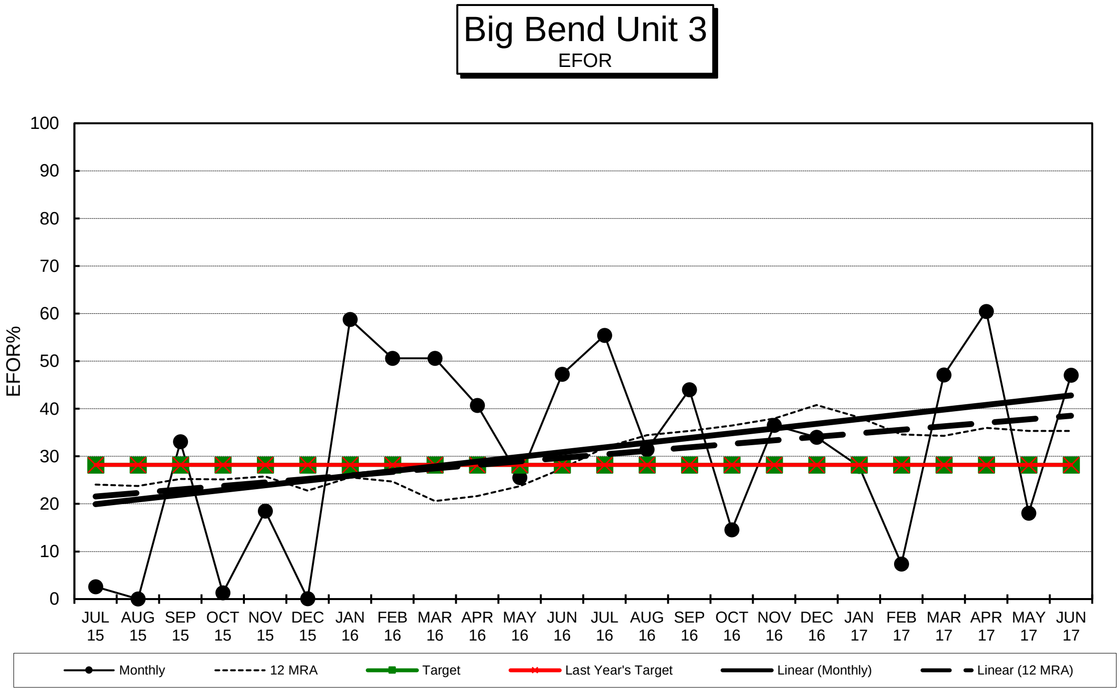
MAR 17
APR 17
MAY 17
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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DEC 16
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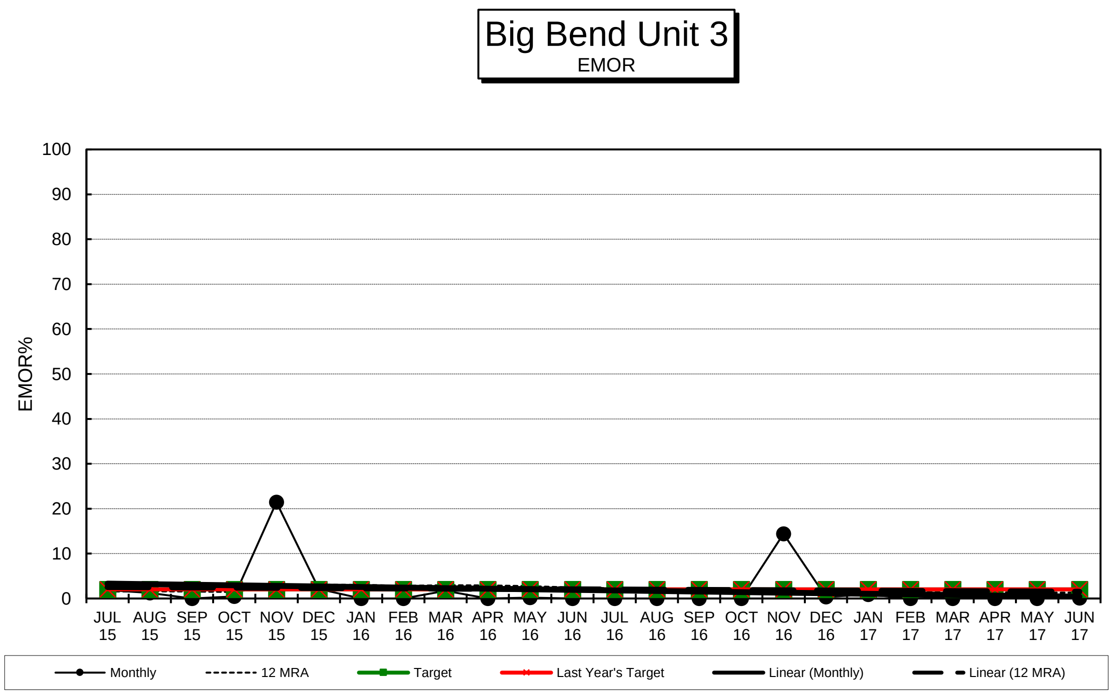
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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DEC 15
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MAY 16
JUN 16
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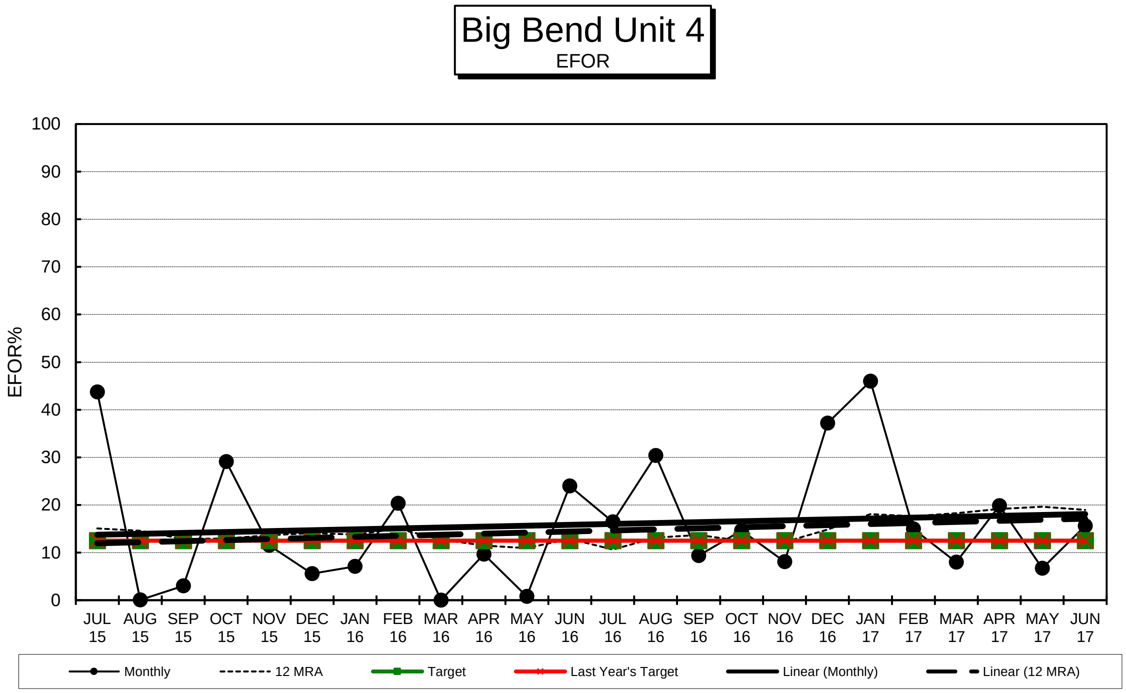
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR%
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MAY 17
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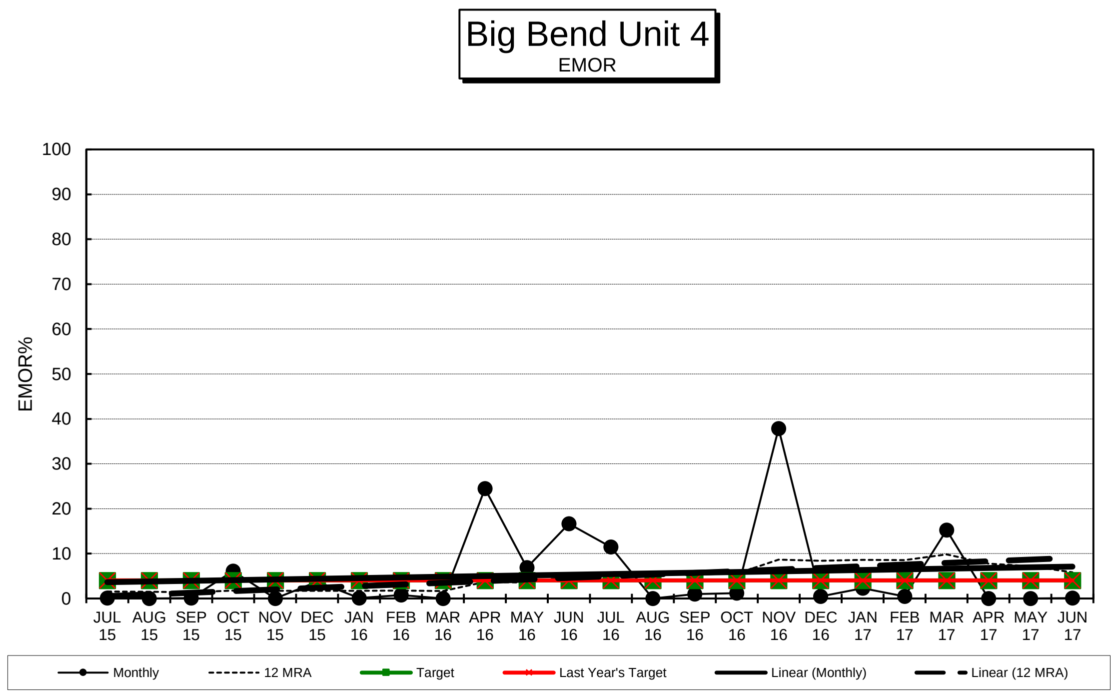
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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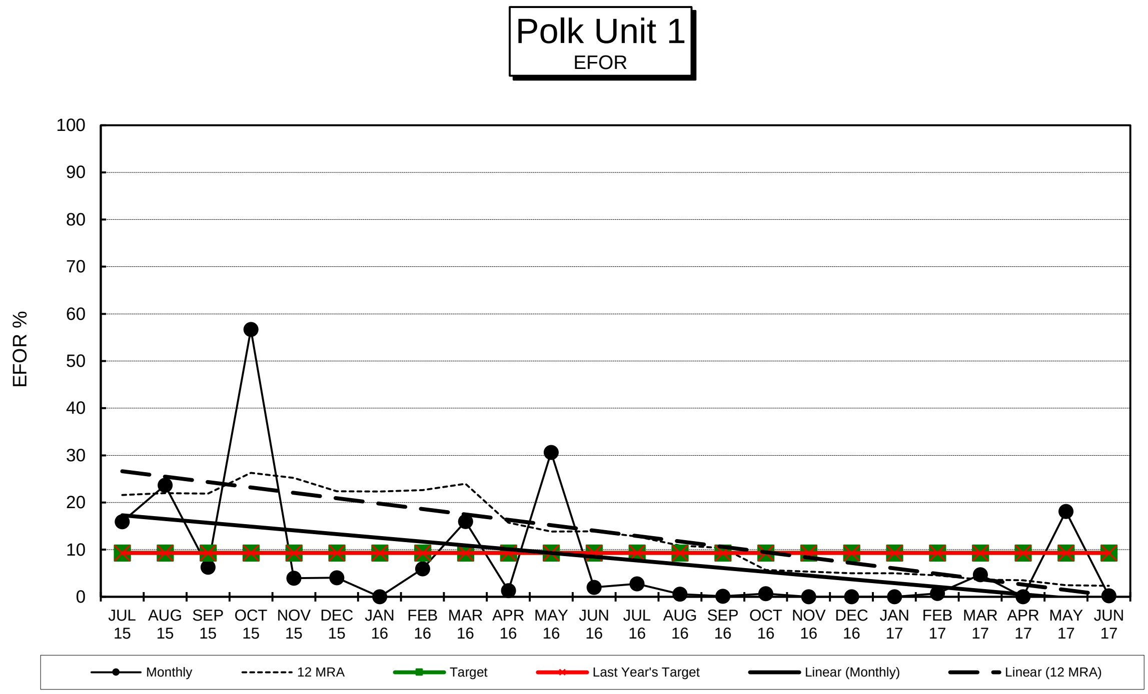
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR %
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DEC 15
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SEP 16
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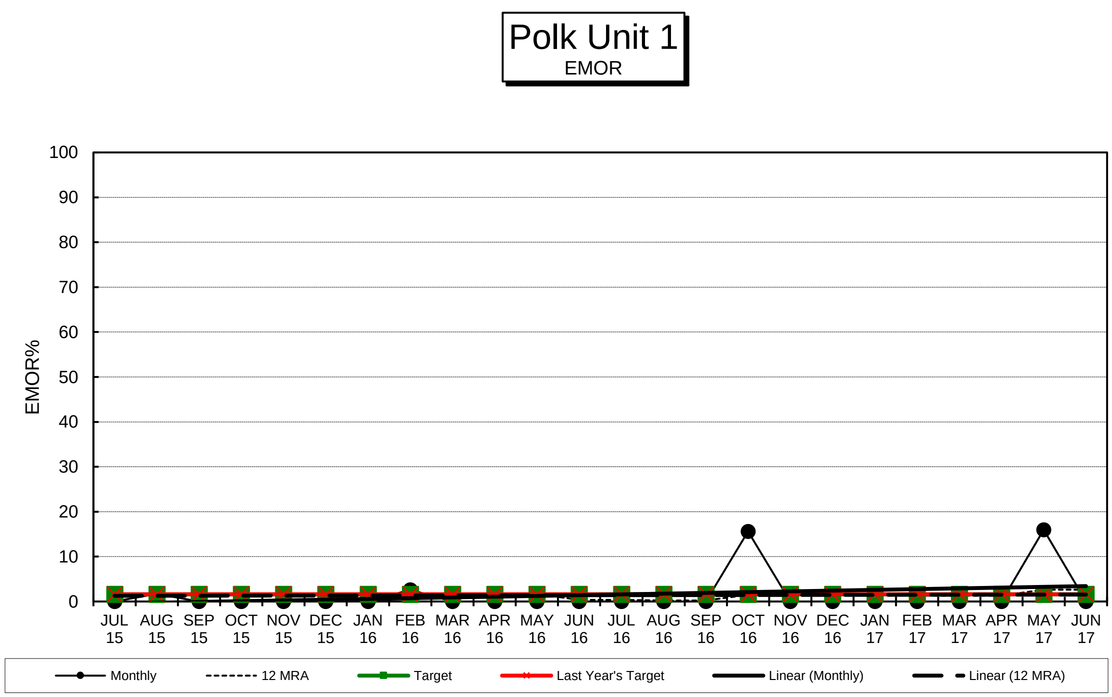
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
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EMOR%
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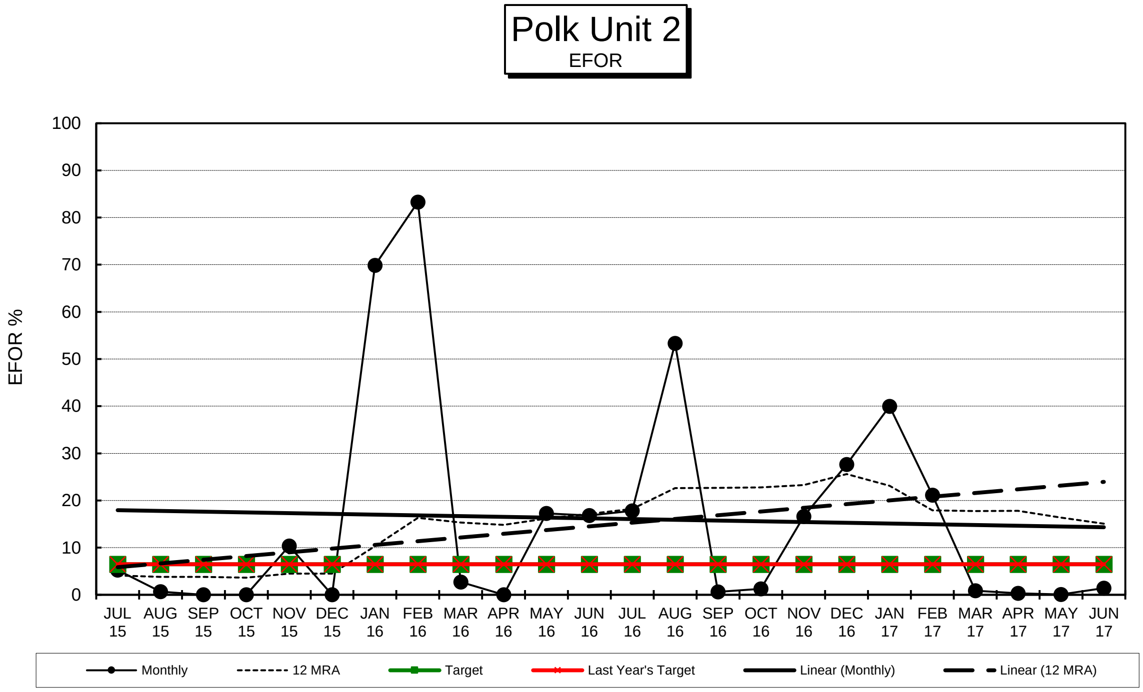
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR %
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DEC 15
JAN 16
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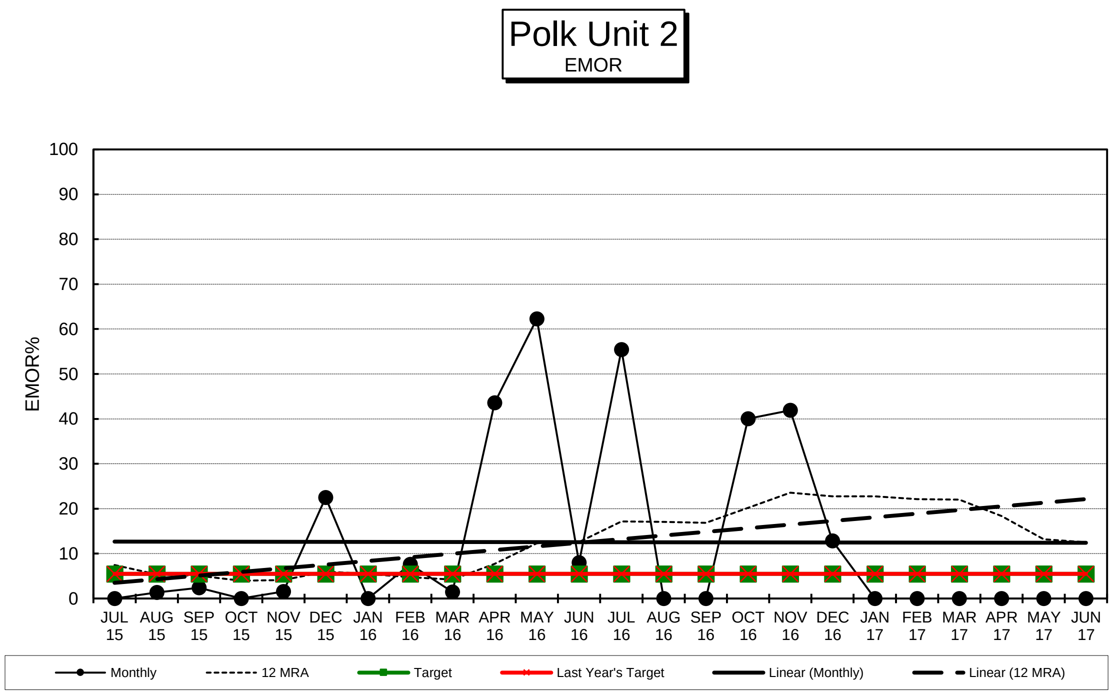
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 2
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EMOR%
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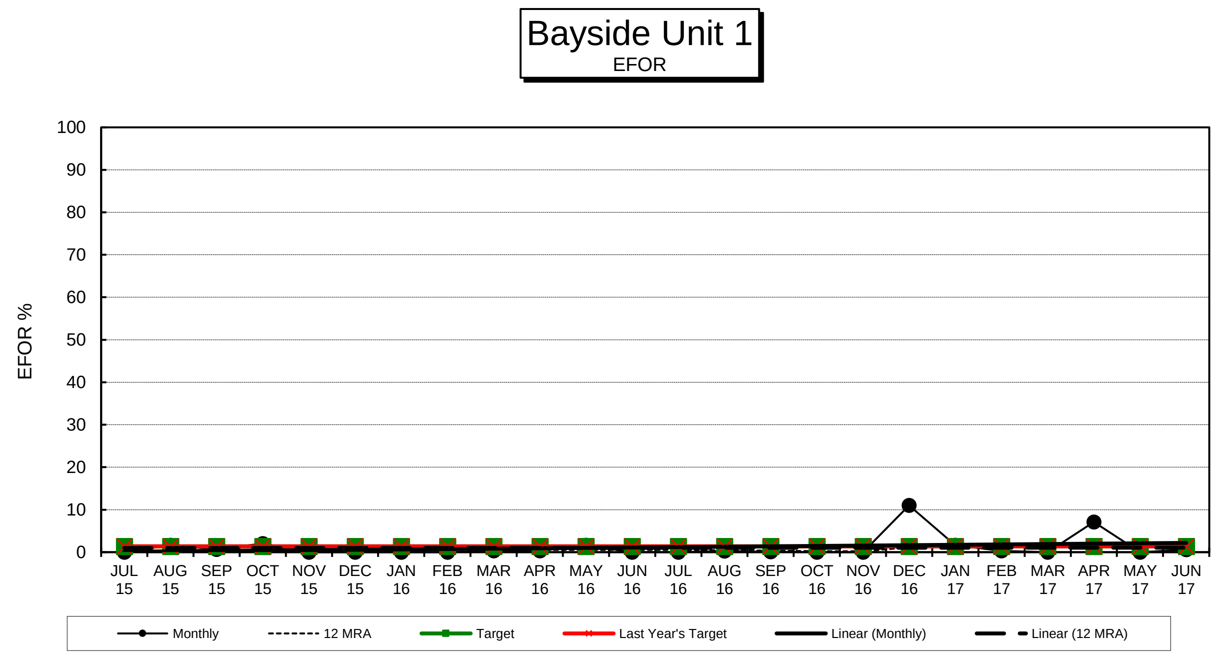
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
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EFOR %
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NOV 15
DEC 15
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DEC 16
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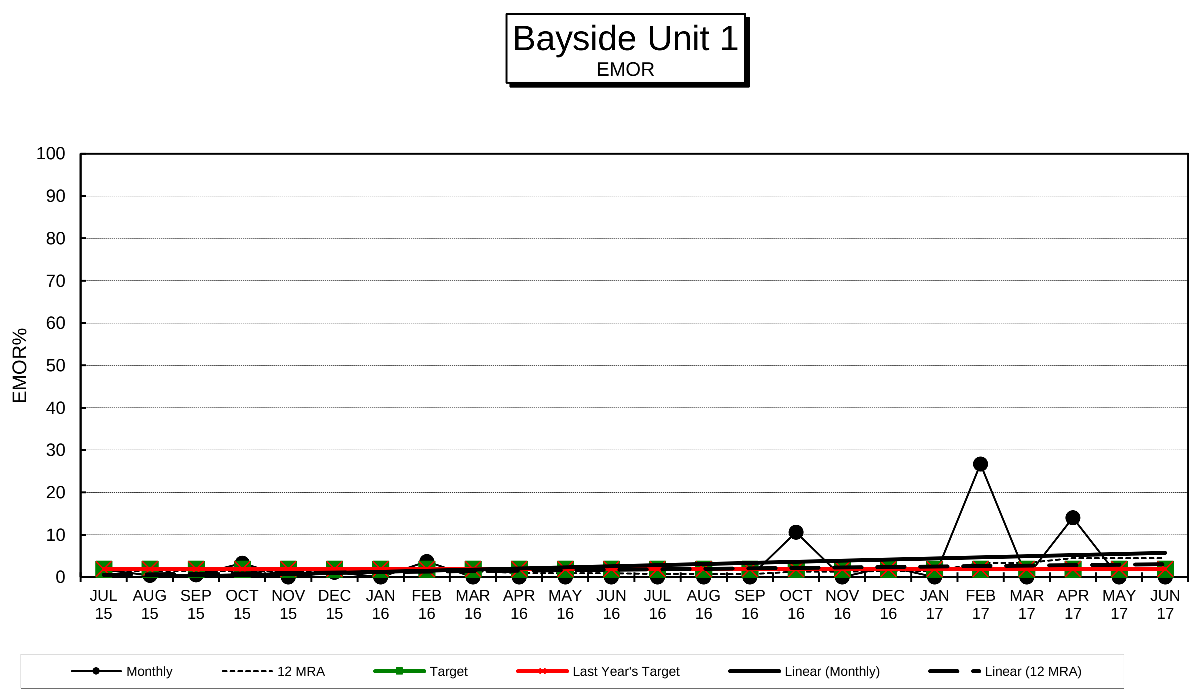
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


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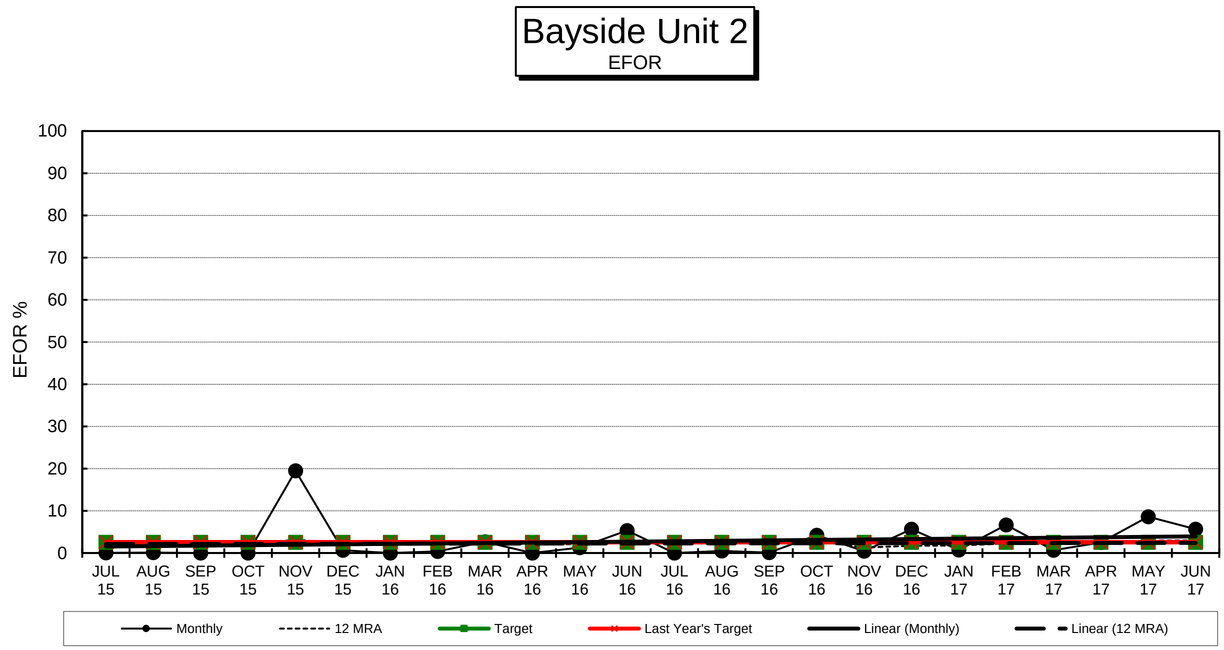
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
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EFOR %
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OCT 15
NOV 15
DEC 15
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FEB 16
MAR 16
APR 16
MAY 16
JUN 16
JUL 16
AUG 16
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OCT 16
NOV 16
DEC 16
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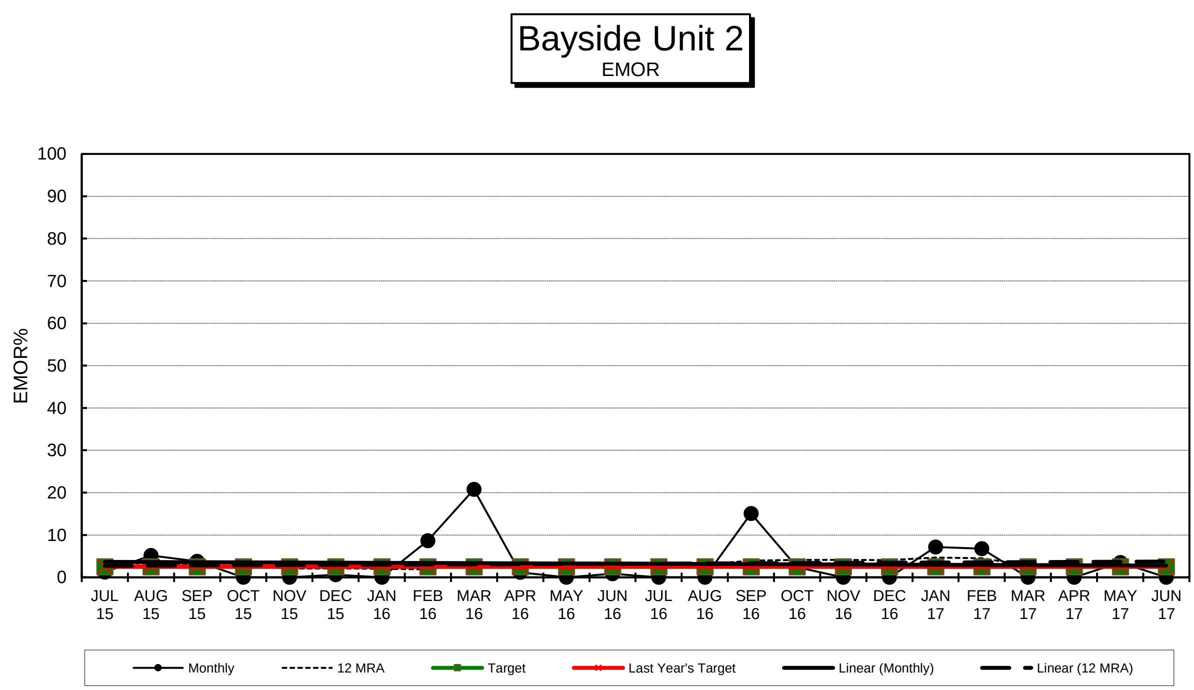
APR 17
MAY 17
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
100
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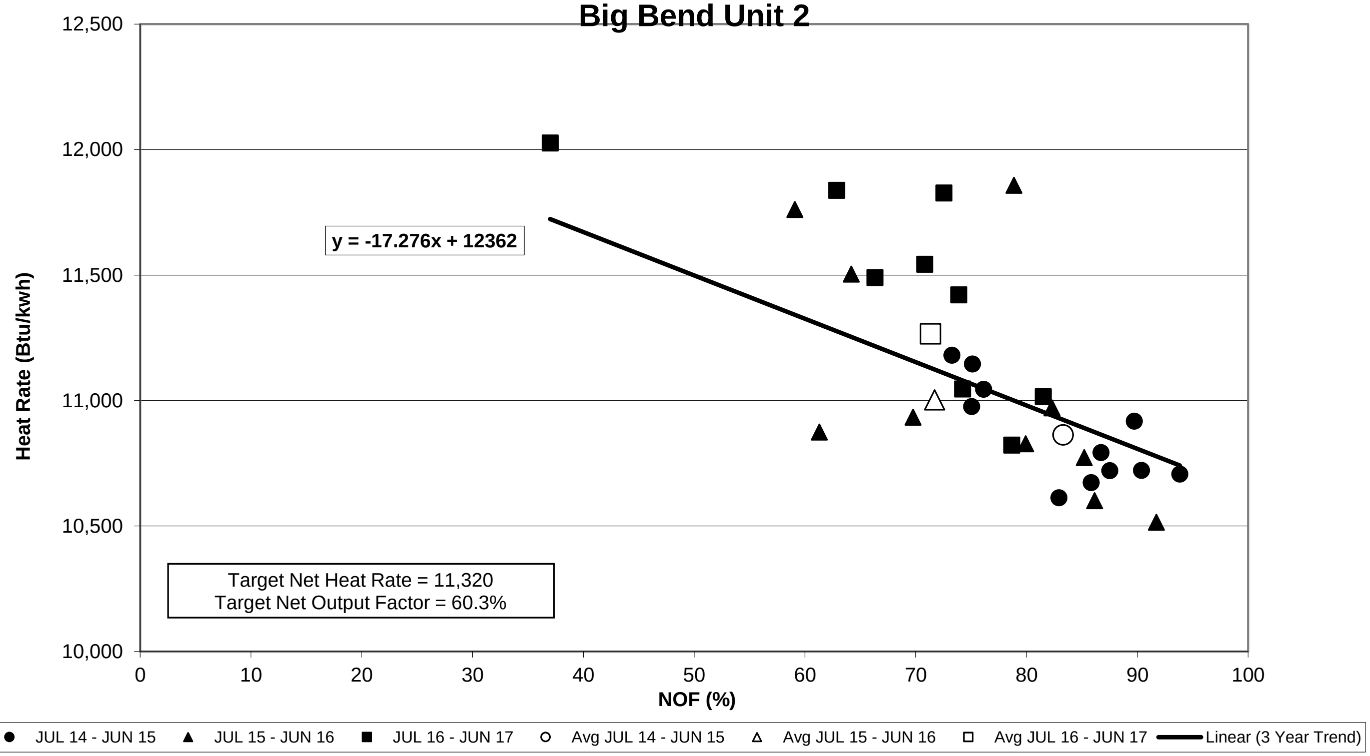
APR 17
MAY 17
JUN 17
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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



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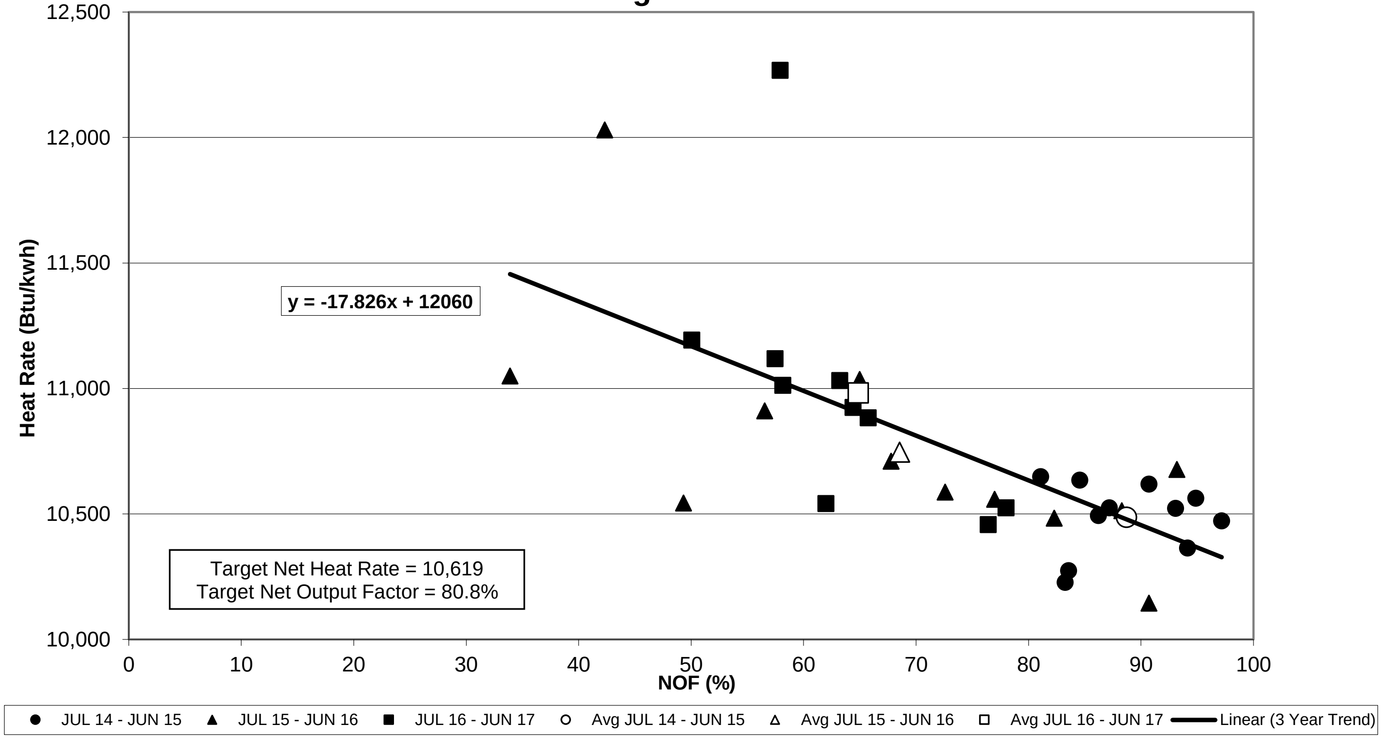
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3



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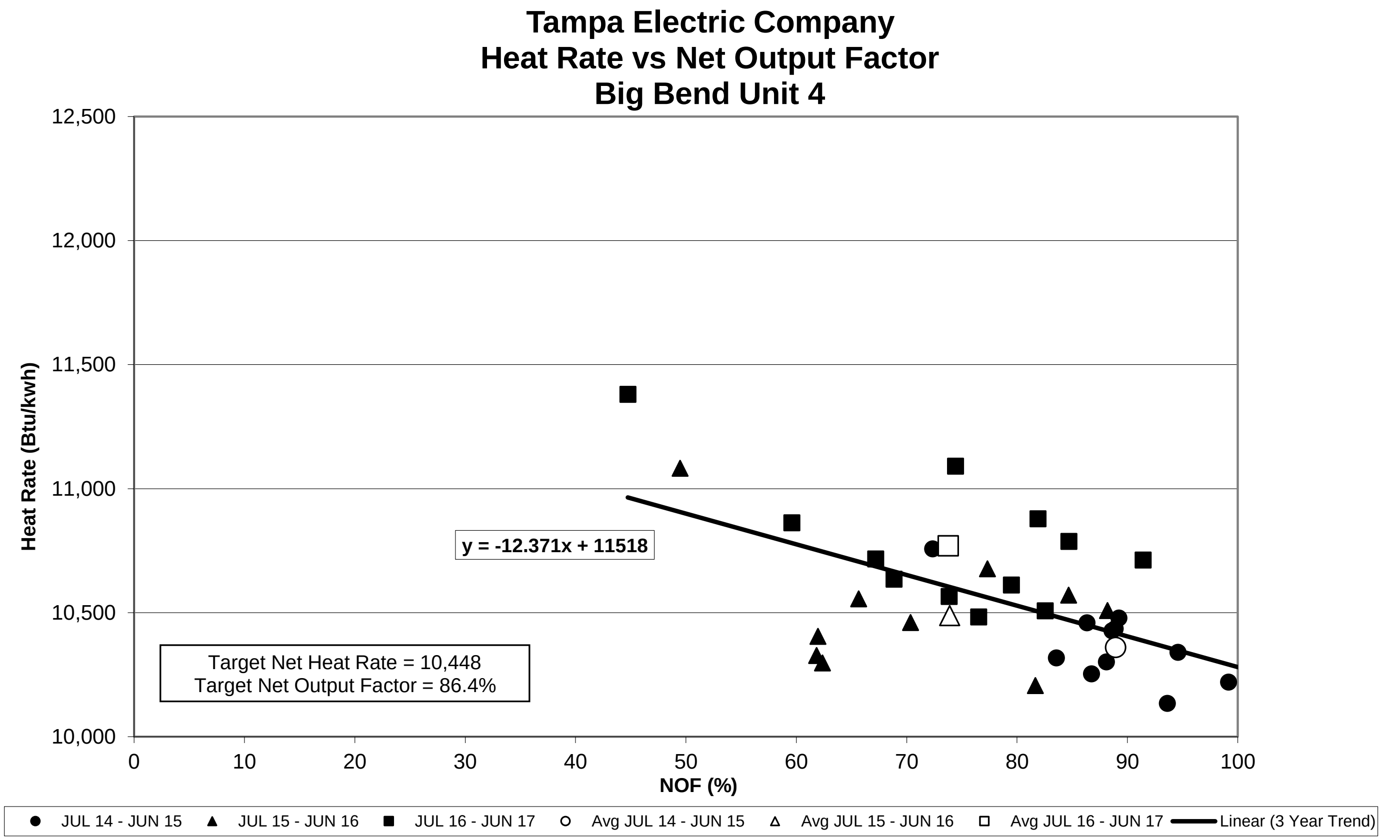

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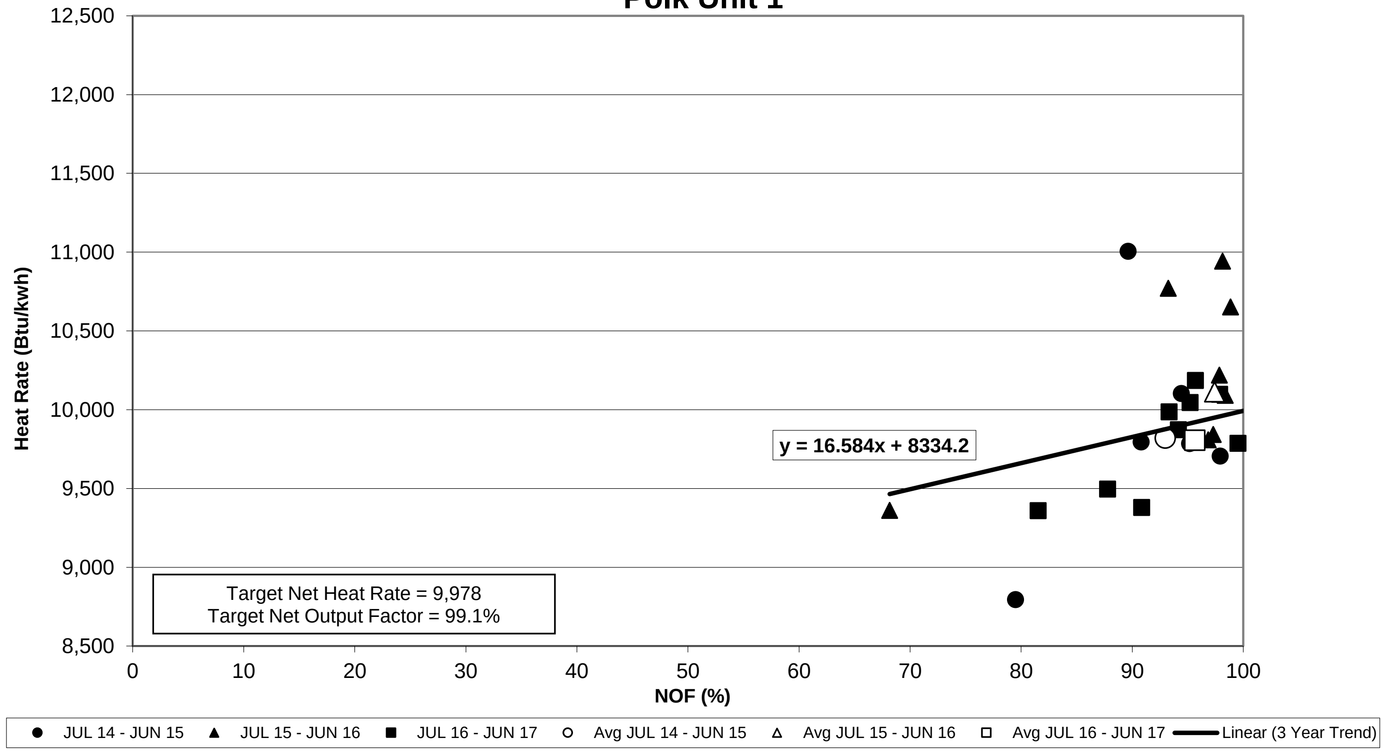
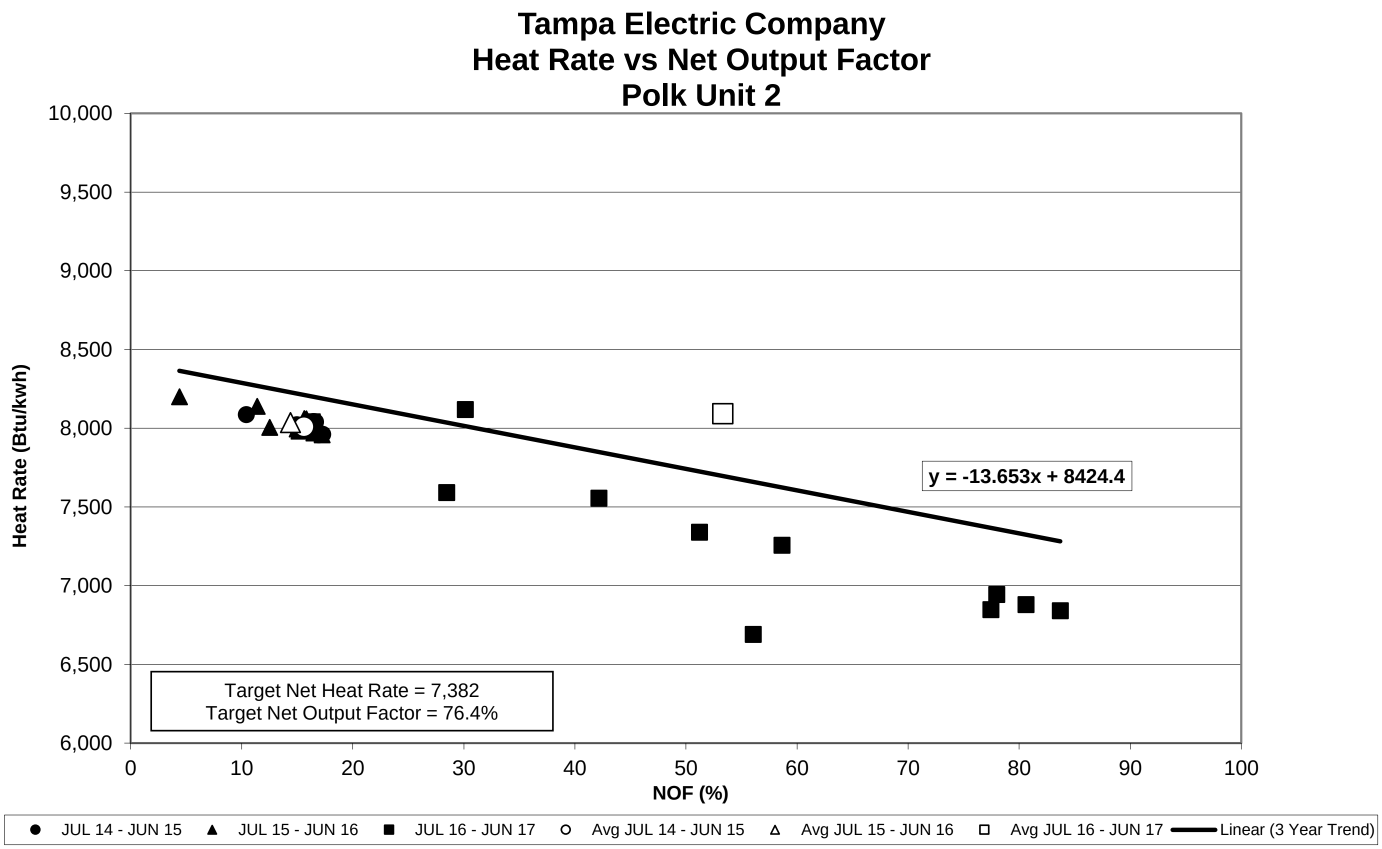
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1





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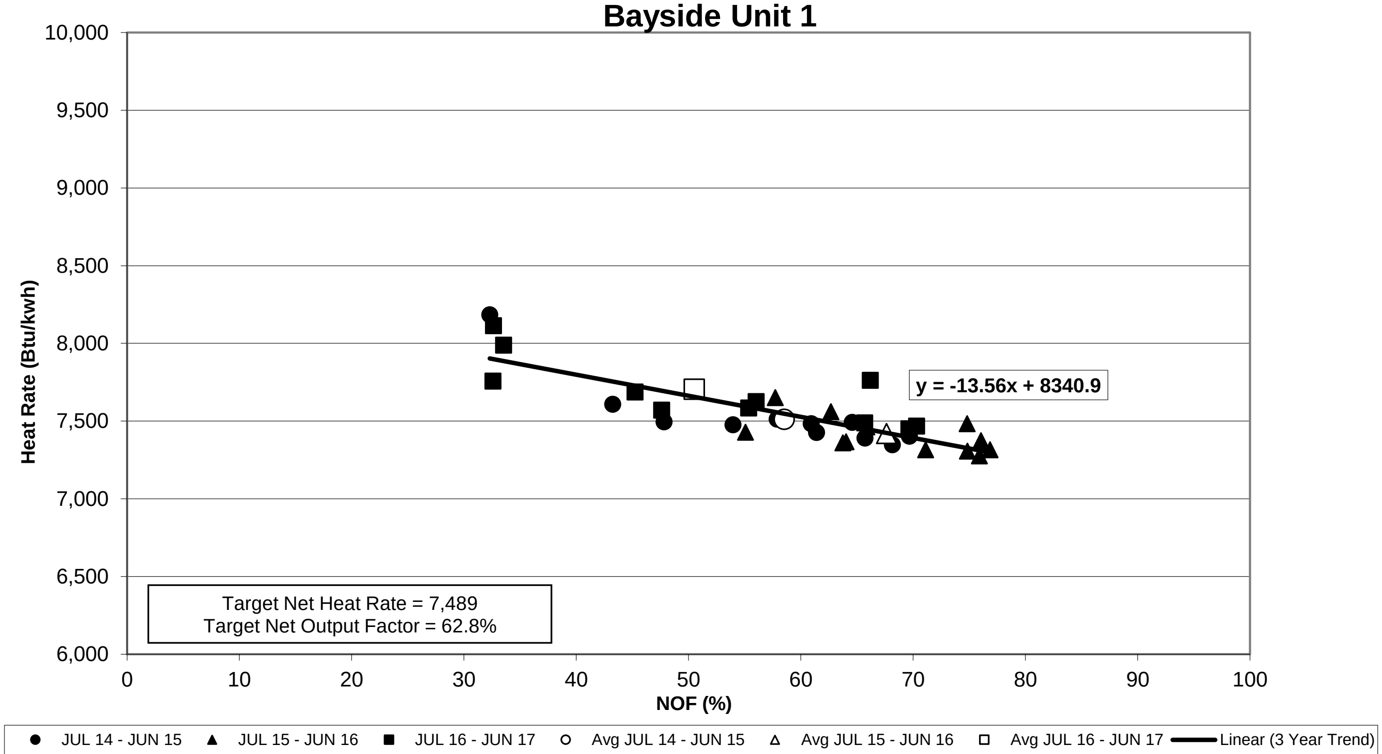
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1



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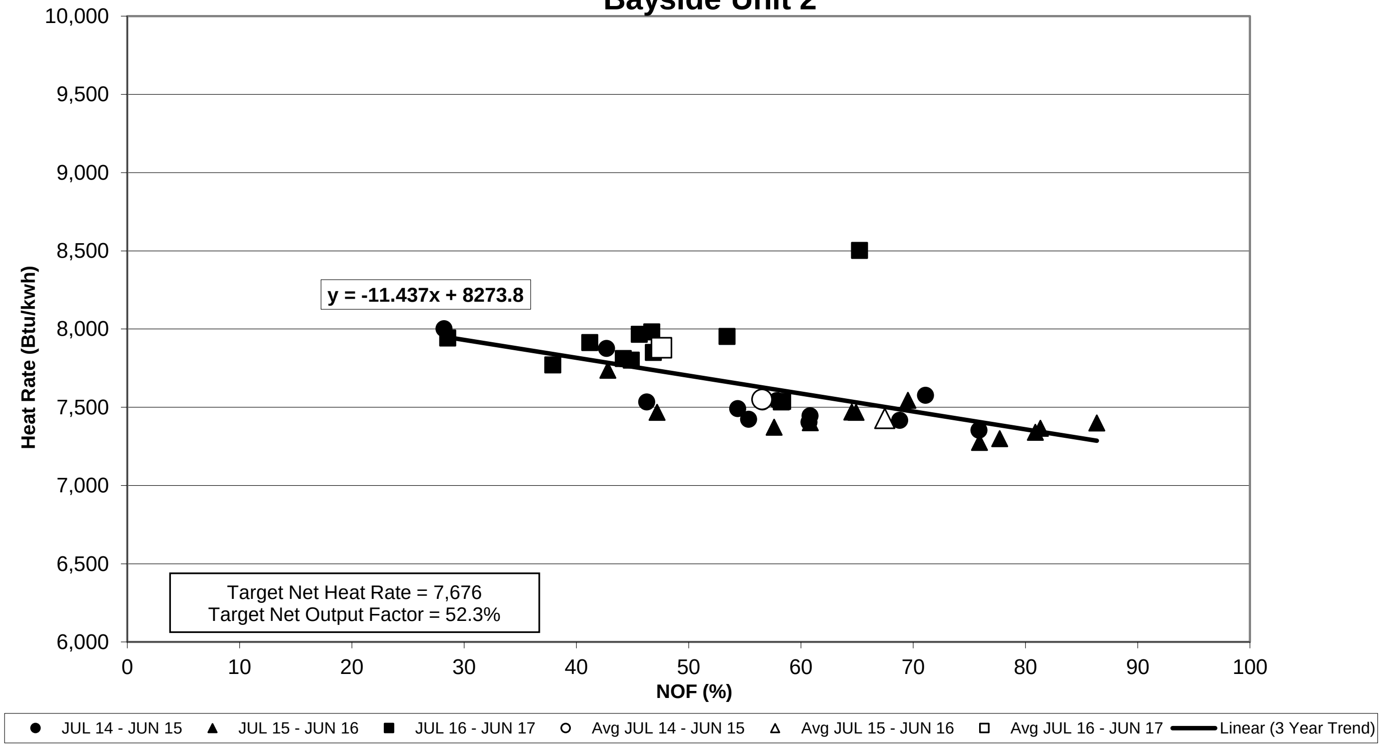
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



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TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2018 - DECEMBER 2018

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 2		380	365
BIG BEND 3		422	397
BIG BEND 4		472	439
POLK 1		290	220
POLK 2		1,137	1,113
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	4,420	4,233
	SYSTEM TOTAL	**5,065**	**4,858**
	% OF SYSTEM TOTAL	**87.3%**	**87.1%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2018 - DECEMBER 2018

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		330	315
BIG BEND 2		380	365
BIG BEND 3		422	397
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,662	1,573
POLK 1		290	220
POLK 2		1,137	1,113
	POLK TOTAL	1,427	1,333
SOLAR		21	21
	SOLAR TOTAL	21	21
	SYSTEM TOTAL	**5,065**	**4,858**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2018 - DECEMBER 2018

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	7,218,830	35.92%	35.92%
BAYSIDE	1	3,306,020	16.45%	52.37%
BAYSIDE	2	3,017,020	15.01%	67.39%
BIG BEND	4	2,524,330	12.56%	79.95%
BIG BEND	3	1,743,550	8.68%	88.62%
POLK	1	1,453,040	7.23%	95.85%
BIG BEND	2	418,560	2.08%	97.94%
BIG BEND	1	290,910	1.45%	99.38%
SOLAR		46,920	0.23%	99.62%
BIG BEND CT	4	28,380	0.14%	99.76%
BAYSIDE	5	18,540	0.09%	99.85%
BAYSIDE	6	14,140	0.07%	99.92%
BAYSIDE	3	9,470	0.05%	99.97%
BAYSIDE	4	6,430	0.03%	100.00%
TOTAL GENERATION		20,096,140	100.00%	

GENERATION BY COAL UNITS:	6,430,390 MWH	GENERATION BY NATURAL GAS UNITS:	13,618,830 MWH
% GENERATION BY COAL UNITS	32.00%	% GENERATION BY NATURAL GAS UNITS:	67.77%
GENERATION BY SOLAR UNITS:	46,920 MWH	GENERATION BY GPIF UNITS:	19,681,350 MWH
% GENERATION BY SOLAR UNIT	0.23%	% GENERATION BY GPIF UNITS:	97.94%

EXHIBIT TO THE TESTIMONY

OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2018 - DECEMBER 2018

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2018 - DECEMBER 2018

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 2[1]	61.5	6.6	31.9	11,320
Big Bend 3[2]	66.7	6.6	26.7	10,619
Big Bend 4[3]	78.7	6.6	14.7	10,448
Polk 1[4]	74.4	17.3	8.3	9,978
Polk 2[5]	83.2	5.8	11.0	7,382
Bayside 1[6]	82.5	14.8	2.7	7,489
Bayside 2[7]	77.3	18.6	4.0	7,676

1 Original Sheet 8.401.18E, Page 14

2 Original Sheet 8.401.18E, Page 15

3 Original Sheet 8.401.18E, Page 16

4 Original Sheet 8.401.18E, Page 17

5 Original Sheet 8.401.18E, Page 18

6 Original Sheet 8.401.18E, Page 19

7 Original Sheet 8.401.18E, Page 20

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TAMPA ELECTRIC

AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY

OF

J. BRENT CALDWELL

FILED: AUGUST 24, 2017

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, Portfolio Optimization.

Q. Have you previously filed testimony in Docket No. 20170001-EI?

A. Yes, I submitted direct testimony on April 3, 2017 and August 18, 2017.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, it has not.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2001. In 2015, I testified in docket No. 20150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 20120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle ("CC") Conversion project. Most recently, I submitted written testimony in Docket No. 201700057-EI regarding natural gas financial hedging.

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.

Fuel Mix and Procurement Strategies

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

A. Tampa Electric's fuel mix includes coal, natural gas, and oil. Coal is the primary fuel for Big Bend Station, and natural gas is a secondary fuel. The Polk Unit 1 integrated combined cycle unit utilizes coal as the primary fuel and natural gas as a secondary fuel; Polk

Unit 2 CC uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.,* aero-derivative combustion turbines) utilize natural gas. Since it serves as a backup fuel, oil consumption as a percentage of system generation is minute (*i.e.,* less than one percent). During 2017, continued low natural gas prices haves resulted in greater use of natural gas, compared to the original projection. Based upon the 2017 actual-estimate projections, the company expects 2017 total system generation to be 34 percent coal and 66 percent natural gas, with oil making up a fraction of a percentage point.

In 2018, coal-fired and natural gas-fired generation are expected to be approximately 27 percent and 72 percent of total generation, respectively. Generation from other fuel sources 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 its fuel needs. The company strives to maintain a large number of credit worthy 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 customers.

Coal Supply Strategy

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

A. Solid fuel is the primary fuel for the four pulverized-coal steam turbine units at Big Bend Station and the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel’s chemistry and contents vary based on many factors, including geography. The variability of the product dictates Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and credit worthiness 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 generation 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. This market intelligence also helps shape the company’s coal procurement strategy to reflect short and long-term market conditions. Tampa Electric’s strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric’s solid fuel, coal, and petroleum coke supply through 2018.

A. In general, Tampa Electric supplies Big Bend’s coal needs through a combination 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 2018 delivery?

A. No, Tampa Electric is in a unique position with respect to solid fuel supply. Tampa Electric has contracts with call options for tonnage in 2018 and 2019, but the price is higher than current market prices. Therefore, Tampa Electric is in the process of securing a portion of its projected need for solid fuel for 2018 through 2020 from lower cost suppliers, and negotiations with suppliers are expected to be complete before the end of the year. These market purchases, combined with projected inventory levels, will allow the company to cover its expected solid fuel supply need for 2018.

Tampa Electric expects to have contracted for, or will have available from inventory, about 85 percent of its 2018 expected coal needs through agreements with coal suppliers. This not only ensures reliability of supply, but also mitigates price volatility. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases in 2018. As I discuss later in my testimony, the company will use less coal and more natural gas in 2018, compared to previous years.

Coal Transportation

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

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

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

A. Transportation options provide benefits to customers. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal portfolio, 2) the opportunity to switch to either water or rail in the event of 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 2017 and 2018?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2017 and is evaluating how much coal to receive by rail in 2018. The evaluation depends in part on the results of the previously mentioned ongoing contract negotiations for solid fuel supply.

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

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

Q. Please describe the replacement for the Gulf of Mexico ("Gulf") transportation contract with a term ending in 2018.

A. Tampa Electric is in the process of securing waterborne solid fuel transportation across the Gulf of Mexico from the terminal to Big Bend Station through 2020. The company is in negotiations with a short-list of potential providers. A final contract will be in place by the end of 2017.

Q. Please describe the events that led to the need for execution of a new Gulf transportation agreement.

A. In 2014, Tampa Electric contracted with United Ocean Services ("UOS") to provide Gulf transportation for the following several years. Shortly thereafter, International Shipholding acquired United Ocean Services from United Maritime Group but Tampa Electric's arrangement with UOS was unaffected. Then, on August 1, 2016, International Shipholding and UOS filed for Chapter 11 protection under the bankruptcy laws of the United

States. In the bankruptcy process, UOS rejected Tampa Electric's agreement. Tampa Electric and UOS agreed to an amended agreement as part of the company's emergence from bankruptcy. The amended agreement includes an earlier termination, leading to the need to seek a replacement transportation agreement in 2018.

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

A. Tampa Electric's "open" position for solid fuel and Gulf transportation, along with other operational and market factors, allows the company to use more natural gas in Big Bend Units 1 and 2. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and Gulf transportation in the remainder of 2017 and 2018, than it would have otherwise. This change will allow Tampa Electric to utilize low-cost natural gas-fired generation and provides projected fuel savings to Tampa Electric's customers for the period July 2017 through December 2018.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2018 solid fuel supply portfolio.

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

Natural Gas Supply Strategy

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

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

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

Q. Please describe Tampa Electric’s diversified natural gas transportation agreements.

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 from Gulfstream to support the aero-derivative combustion turbines and natural gas co-firing in the coal units. Polk Station receives natural gas from FGT to support Polk Unit 2 CC and, as an alternate fuel, Polk Unit 1.

Q. Are there any significant changes to Tampa Electric’s expected natural gas usage?

A. Tampa Electric's Big Bend Station coal-fired units can be fueled with natural gas for ignition, reliability, emissions control, and power generation. As such, Tampa Electric is seeking to maximize its existing pipeline capacity and burning natural gas to the extent that there is available capacity. For the balance of 2017 and during 2018, Big Bend Units 1 and 2 are projected to be fueled by natural gas only. This opportunity has emerged as the result of continued low natural gas prices, the open coal supply and transportation portfolio positions, and available natural gas pipeline capacity to the station. The company projects that this change will result in fuel savings, as I stated earlier in my testimony.

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 Transco lateral give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2017 and 2018 due to greater use of natural gas at Big Bend Station?

A. No. Tampa Electric has not acquired additional long-term firm pipeline capacity for 2017 and 2018 due to greater use of natural gas at Big Bend Station. The company continues to supplement its existing transportation portfolio with near-term daily transportation to support the incremental natural gas burn on its system, including in Big Bend Units 1 and 2. Nonetheless, with its growing dependence on natural gas, the company continues to monitor the interstate pipeline market for attractive opportunities to secure long-term, firm pipeline capacity. While there is daily transportation capacity to support operation of Big Bend Units 1 and 2 on natural gas, there is not sufficient spare capacity to support additional gas usage at Big Bend Station.

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 2018 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), PIRA Energy, the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days in May 2017, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

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

Q. How do the 2018 projected fuel prices compare to the fuel prices projected for 2017?

A. The commodity price for natural gas during 2018 is projected to be slightly lower ($3.13 per MMBtu) than the 2017 projected price ($3.17 per MMBtu). The market price for natural gas in 2018 is expected to be similar to the prices projected in 2017.

The 2018 coal commodity price projection is slightly higher ($35.80 per ton) than the price projected for 2017 ($30.88 per ton) during preparation of the 2017 fuel clause factor. Production cuts and growing international demand for coal have put some upward pressure on coal prices.

Risk Management Activities

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

A. On October 24, 2016 electric investor-owned utilities Duke Energy Florida, Gulf Power and Tampa Electric (collectively the "IOUs"), Office of Public Counsel, the Florida Industrial Power Users Group, and the Florida Retail Federation jointly entered into a Stipulation and Agreement ("Agreement"). Under the terms of the

Agreement, the IOUs agreed to put in place a 100% moratorium on any new hedges, effective immediately upon the Commission's approval of the Agreement with that moratorium extending through calendar year 2017. The Agreement further called for a workshop or workshops, as soon as practicable to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether. The stated goal was either establishing a basis for the IOUs to present risk management plans for 2018 that all stakeholders could agree upon or not object to, or reaching some other mutually agreeable resolution of the hedging issues identified in Docket No. 20160001-EI. The Agreement was approved by the Commission on December 5, 2016, with the issuance of Order No. PSC-2016-0547-FOF-EI. The Commission, by Order No. PSC-2017-0134-PCO-EI, issued April 13, 2017 in Docket No. 20170001-EI, subsequently determined the IOUs would not have to file a Risk Management Plan for 2018 because an evidentiary hearing on hedging will be held September 27-28, 2017 in Docket No. 20170057-EI. This order effectively extended the hedging moratorium until a decision is reached in Docket

No. 20170057-EI. A low number of natural gas financial hedges equating to a relatively small volume remain from the hedging activities prior to the moratorium. Those financial hedges were placed in accordance with the company's Commission-approved Risk Management Plan.

Q. Were Tampa Electric's efforts through July 31, 2017 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes, Tampa Electric has executed hedges according to the Risk Management Plan approved by the company's Risk Authorizing Committee and filed with the Commission. On April 3, 2017, the company filed its 2016 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 31st 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 in this docket on August 18, 2017. The report shows the results of the company's prudent hedging activities from January through July 2017. The company executed hedges for a smaller volume of expected usage than stated in its Risk Management Plan for this period due to the 2016 agreement for a hedging moratorium, as I discussed above.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20170001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY
OF
BENJAMIN F. SMITH II

FILED: AUGUST 24, 2017

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 Wholesale Marketing Group within the Wholesale Marketing, Planning & Fuels 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, Wholesale Origination in the Wholesale Marketing, Planning and Fuels Department. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market and assist in wholesale origination and contract structures. 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. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

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

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

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

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

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

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-1997-0262-FOF-EI, issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs and improve reliability. The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company’s contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and 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 2017 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short and long-term purchases based on price and availability of supply. Approximately 2.3 percent of the company’s expected needs for 2017 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, pre-existing firm purchased power agreements with Pasco Cogen and Duke Energy Florida (“Duke”), and reliability purchases.

My testimony in previous years' dockets described the agreement with Pasco Cogen and Duke. However, in summary, the Pasco Cogen purchase is a call option with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase began January 2009, is for 121 MW of combined-cycle capacity and continues through 2018. The Duke purchase was for 250 MW of combined-cycle capacity with a term of February 2016 through February 2017. In addition to providing customers with efficient combined-cycle energy, the company secured the Duke purchase to support its reserve margin during the construction of Tampa Electric's Polk Unit 2-5 combined cycle conversion ("Polk Unit 2 CC") project. Both the Pasco Cogen and Duke purchases were previously approved by the Commission as being cost-effective for Tampa Electric customers.

Q. Has Tampa Electric entered into any other wholesale power purchases in 2017?

A. Other than the purchases previously described in my testimony, the company has not entered into any additional power purchases in 2017.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2018 and beyond?

A. Tampa Electric does not anticipate entering into other purchased power agreements at this time. However, the company will continue to evaluate its options in light of changing circumstances and new opportunities. This evaluation includes the review of short and long-term capacity and energy purchases to augment its own generation for the year 2018 and beyond. The company always assesses the merits of long-term purchase opportunities and will consider securing additional long-term purchases that bring value to customers. Also, Tampa Electric will continue to evaluate and utilize the short-term purchased power market as part of its purchasing strategy going forward. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2018 energy needs. This energy includes contributions from the previously mentioned Pasco Cogen firm purchase.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's Pasco Cogen power agreement is from a dual-fuel resource. This allows the resource 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 market place.

Q. Please describe Tampa Electric's wholesale energy sales for 2017 and 2018.

A. Tampa Electric entered into various non-separated wholesale sales in 2017, and the company anticipates making additional non-separated sales during the balance of 2017 and 2018. The gains from these sales are distributed amongst Tampa Electric and its customers in accordance with the company's current incentive mechanism established in Order No. PSC-2001-2371-FOF-EI, issued on

December 7, 2001 in Docket No. 20010283-EI. The current incentive mechanism provides that all gains from non-separated sales be returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2017, Tampa Electric projected the company's gains from non-separated sales to be below the threshold, based on six months actual and six months of projected data. However, due to favorable market conditions and results from July, the company now expects to exceed the 2017 threshold of $1,493,095. Therefore, Tampa Electric expects customers to receive 100 percent of the 2017 non-separated sales gains up to $1,493,095, and 80 percent of gains above the threshold. Based on seven months of actual and five months of projected data, the company is projected to retain approximately $15,700 in gains for the year. In 2018, the company projects gains to be $54,590, of which customers would receive 100 percent, since the amount is less than the 2018 projected three-year rolling average threshold of $881,855.

Q. Please summarize your direct 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 physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters into wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes, it does.