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August 24, 2018

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. 20180001-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-3) 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)

<u>CERTIFICATE OF SERVICE</u>

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 2018, 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. 20180001-EI FILED: August 24, 2018

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, and generating performance incentive factors set forth herein, and in support thereof, says:

Fuel and Purchased Power Factors

1. Tampa Electric projects its fuel and purchased power net true-up amount for the period January 1, 2019 through December 31, 2019 will be an over-recovery of $7,015,485. (See Exhibit No. PAR-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2019 through December 31, 2019, when adjusted for the proposed GPIF penalty and true-up over-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2019 through December 31, 2019, produce a fuel and purchased power factor for the new period of 2.719 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).

Capacity Cost Factor

4. Tampa Electric estimates that its net true-up amount applicable for the period January 1, 2019 through December 31, 2019 will be an under-recovery of $2,784,988, 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, 2019 through December 31, 2019, 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 0.088 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.32 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 penalty of $2,261,019 for performance during the period January 1, 2017 through December 31, 2017.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2019 through December 31, 2019 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.

DATED this 24th day of August 2018.

Respectfully submitted,

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 24th day of August 2018, to the following:

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ATTORNEY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2019 THROUGH DECEMBER 2019

TESTIMONY AND EXHIBIT
OF
PENELOPE A. RUSK

FILED: AUGUST 24, 2018

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. 20180001-EI?

A. Yes, I submitted direct testimony on March 2, 2018 and July 27, 2018.

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 for January 2019 through December 2019. 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 2019.

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 2019 through December 2019 as well as Schedule H1 for 2016 through 2019. 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 $17,124,796 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2019.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2019 through December 2019.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per Kw
RS Secondary	0.103	
GS and CS Secondary	0.086	
GSD, SBF Standard		
Secondary		0.32
Primary		0.32
Transmission		0.31
IS, IST, SBI		
Primary		0.24
Transmission		0.24
GSD Optional		
Secondary	0.075	
Primary	0.074	
Transmission	0.074	
LS1 Secondary	0.024	

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 0.088 cents per kWh compare to the factor for January 2018 through December 2018?

A. The proposed capacity cost recovery factor is 0.032 cents per kWh (or $0.32 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.056 cents per kWh for the January 2018 through December 2018 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 2019?

A. The appropriate amount for the 2019 period is 2.719 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 2019 through December 2019.

Q. Please describe the information provided on Schedule E1-

C.

A. The Generating Performance Incentive Factor (“GPIF”) and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF penalty of $2,261,019, 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 to be applied during the January 2019 through December 2019 period. The net true-up amount is an over-recovery of $7,015,485.

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 2019 through December 2019. 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 the information provided in Document No. 3.

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

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2019 through December 2019.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	2.719
Tier I (Up to 1,000 kWh)	2.405
Tier II (Over 1,000 kWh)	3.405
Distribution Primary	2.692
Transmission	2.665
Lighting Service	2.691
Distribution Secondary	2.874 (on-peak)
	2.653 (off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	2.845 (on-peak)
	2.626 (off-peak)
Transmission	2.817 (on-peak)
	2.600 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor 2.719 cents per kWh compare to the levelized fuel adjustment factor for the January 2018 through December 2018 period?

A. The proposed fuel charge factor is 0.413 cents per kWh (or $4.13 per 1,000 kWh) lower than the average fuel charge factor of 3.132 cents per kWh for the January 2018 through December 2018 period.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2019 through December 2019?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $4,462,045. 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 2019 through December 2019?

A. Yes, fuel savings exceed costs for the period January 2019 through December 2019. 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 2019 through December 2019 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 this project.

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 and Optimization Mechanism

Q. Will Tampa Electric project a 2019 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company’s Optimization Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no incentive benchmark is required for the 2019 projection. Under the new program, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $8.31 beginning January 2019, when compared to the September 2018 through December 2018 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 2019.

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 2019 - DECEMBER 2019

AND

SCHEDULE E12

CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2019 THROUGH DECEMBER 2019
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	53.88%	9,382,624	1,988	1.08036	1.05201	9,870,588	2,148	48.30%	57.04%	56.37%
GS, TS	65.19%	955,831	167	1.08036	1.05199	1,005,526	181	4.92%	4.81%	4.82%
GSD Optional	3.72%	401,209	60	1.07581	1.04842	420,635	65	2.06%	1.73%	1.76%
GSD, SBF	72.02%	7,769,102	1,171	1.07581	1.04842	8,145,268	1,260	39.85%	33.47%	33.96%
IS,SBI	90.33%	800,071	101	1.02952	1.01769	814,225	104	3.98%	2.76%	2.85%
LS1	305.67%	173,595	6	1.08036	1.05201	182,623	7	0.89%	0.19%	0.24%
TOTAL		19,482,432	3,494			20,438,865	3,765	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2018 projected calendar data.
(2) Projected MWH sales for the period January 2019 thru December 2019.
(3) Based on 12 months average CP at meter.
(4) Based on 2018 projected demand losses.
(5) Based on 2018 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

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2019 THROUGH DECEMBER 2019
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,126,500	1,126,500	1,126,500	751,000	2,112,500	2,112,500	2,112,500	2,112,500	2,112,500	2,112,500	0	0	16,805,500
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,501)	(206,502)	(2,478,013)
4	TOTAL CAPACITY DOLLARS	$919,999	$919,999	$919,999	$544,499	$1,905,999	$1,905,999	$1,905,999	$1,905,999	$1,905,999	$1,905,999	($206,501)	($206,502)	$14,327,487
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	$919,999	$919,999	$919,999	$544,499	$1,905,999	$1,905,999	$1,905,999	$1,905,999	$1,905,999	$1,905,999	($206,501)	($206,502)	$14,327,487
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2018 - DEC. 2018													2,784,988
8	TOTAL													$17,112,475
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$17,124,796

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2019 THROUGH DECEMBER 2019
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	48.30%	57.04%	636,062	9,016,825	9,652,887	9,382,624	9,382,624				0.00103
GS, CS	4.92%	4.81%	64,791	760,360	825,151	955,831	955,831				0.00086
GSD, SBF											
Secondary						6,344,187	6,344,187			0.32	
Primary						1,414,966	1,400,816			0.32	
Transmission						9,949	9,750			0.31	
GSD, SBF - Standard	39.85%	33.47%	524,783	5,290,904	5,815,687	7,769,102	7,754,753	58.81%	18,062,791		
GSD - Optional	2.06%	1.73%	27,128	273,477	300,605						
Secondary						388,398	388,398				0.00075
Primary						12,811	12,683				0.00074
Transmission						0	0				0.00074
IS, SBI											
Primary						156,328	154,765			0.24	
Transmission						643,743	630,868			0.24	
Total IS, SBI	3.98%	2.76%	52,413	436,298	488,711	800,071	785,633	52.26%	2,059,387		
LS1	0.89%	0.19%	11,720	30,035	41,755	173,595	173,595				0.00024
TOTAL	100.00%	100.00%	1,316,897	15,807,899	17,124,796	19,482,432	19,453,517				0.00088

(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 2019 through December 2019.
(7) Projected kWh sales at secondary for the period January 2019 through December 2019.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2019 through December 2019.
(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 2019 THROUGH DECEMBER 2019

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
SEMINOLE ELECTRIC **	6/1/1992	--------	LT

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
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 ($)
VARIOUS	[redacted]												
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	919,999	919,999	919,999	544,499	1,905,999	1,905,999	1,905,999	1,905,999	1,905,999	1,905,999	(206,501)	(206,502)	14,327,487
TOTAL CAPACITY	**$919,999**	**$919,999**	**$919,999**	**$544,499**	**$1,905,999**	**$1,905,999**	**$1,905,999**	**$1,905,999**	**$1,905,999**	**$1,905,999**	**($206,501)**	**($206,502)**	**$14,327,487**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2019 - DECEMBER 2019

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 2019 THROUGH DECEMBER 2019

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	496,918,382	18,789,550	2.64465
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	4,462,045	18,789,550 (1)	0.02375
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**501,380,427**	**18,789,550**	**2.66840**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	0	0	0.00000
7.	Energy Cost of Economy Purchases (E9)	34,396,960	1,589,960	2.16339
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,641,870	90,120	2.93150
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**37,038,830**	**1,680,080**	**2.20459**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,469,630	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	223,760	10,330	2.16612
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	285,826	11,990	2.38387
14.	Gains on Sales	37,918	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**547,504**	**22,320**	**2.45297**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		524	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**537,871,753**	**20,446,786**	**2.63059**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	978,579 (1)	37,200	0.00502
22.	T & D Losses	24,389,616 (1)	927,154	0.12519
23.	System MWH Sales	537,871,753	19,482,432	2.76080
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	537,871,753	19,482,432	2.76080
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	537,871,753	19,482,432	2.76080
28.	True-up (2)	(7,015,485)	19,482,432	(0.03601)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	530,856,268	19,482,432	2.72479
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	531,238,485	19,482,432	2.72675
32.	GPIF Adjusted for Taxes (2)	(2,261,019)	19,482,432	(0.01161)
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	528,977,466	19,482,432	2.71514
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**2.715**

(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 2019 THROUGH DECEMBER 2019

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2018 - December 2018 (6 months actual, 6 months estimated)	($184,422)
2.	FINAL TRUE-UP (January 2017 - December 2017) (Per True-Up filed March 2, 2018)	7,199,907
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2019 through December 2019 (Schedule E1, line 28)	$7,015,485
4.	JURISDICTIONAL MWH SALES (Projected January 2019 through December 2019)	19,482,432
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0360)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2019 through December 2019)	($2,261,019)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2019 through December 2019)	$7,015,485	
2.	TOTAL SALES (January 2019 through December 2019)	19,482,432	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0116)**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0360)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	29.77	$23.94
OFF PEAK	70.23	$22.10
	100.00	1.0833

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$537,871,753		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,482,432		
2a	Effective MWH Sales (Jurisd)		19,453,517		
3	Cost Per KWH Sold	(line 1 / line 2)	2.7608		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 28)	($7,015,485)		
7	TOTAL	(line 1 x line 4)+line 6	$530,856,268		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	2.7308		
10	GPIF Factor	(Sch E1-C line 3a)	(0.0116)		
11	Recovery Factor Including GPIF	(line 9 + line 10)	2.7192	2.8743	2.6534
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		2.719	2.874	2.653

13	Hours: ON PEAK	25.48%
14	OFF PEAK	74.52%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	17,244,635	17,244,635
Distribution Primary	1,584,105	1,568,264
Transmission	653,692	640,618
Total	19,482,432	19,453,517

	Standard	On-Peak	Off-Peak
Distribution Secondary	2.719	2.874	2.653
Distribution Primary	2.692	2.845	2.626
Transmission	2.665	2.817	2.600
RS 1st Tier	2.405		
RS 2nd Tier	3.405		
Lighting	2.691		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

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)		2.405	3.405
Distribution Secondary	2.719		
Distribution Primary	2.692		
Transmission	2.665		
Lighting Service (1)	2.691		
TIME-OF-USE			
Distribution Secondary - On-Peak	2.874		
Distribution Secondary - Off-Peak	2.653		
Distribution Primary - On-Peak	2.845		
Distribution Primary - Off-Peak	2.626		
Transmission - On-Peak	2.817		
Transmission - Off-Peak	2.600		

(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 2019 THROUGH DECEMBER 2019

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		ESTIMATED												TOTAL
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	PERIOD
1.	Fuel Cost of System Net Generation	41,958,073	36,073,386	40,155,844	35,953,752	42,124,305	44,821,262	47,004,083	48,260,417	43,681,292	40,877,758	35,599,897	40,408,313	496,918,382
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	51,654	40,748	48,694	47,717	43,810	45,172	45,859	52,038	45,983	45,746	33,305	46,778	547,504
4.	Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
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	290,630	236,240	189,240	163,260	224,660	187,380	226,500	266,490	188,810	248,690	225,080	194,890	2,641,870
7.	Energy Cost of Economy Purchases	1,297,380	1,673,580	1,854,620	2,778,930	2,403,530	3,663,800	4,230,490	3,928,210	4,022,310	3,520,280	2,787,990	2,235,840	34,396,960
8.	Big Bend Units 1-4 Igniters Conversion Project	383,847	381,664	379,479	377,296	375,113	372,930	370,745	368,562	366,378	364,194	362,010	359,827	4,462,045
9.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**43,878,276**	**38,324,122**	**42,530,489**	**39,225,521**	**45,083,798**	**49,000,200**	**51,785,959**	**52,771,641**	**48,212,807**	**44,965,176**	**38,941,672**	**43,152,092**	**537,871,753**
11.	Jurisdictional MWH Sold	1,499,964	1,343,529	1,338,308	1,424,660	1,566,247	1,825,998	1,906,515	1,897,443	1,960,452	1,781,369	1,486,481	1,451,466	19,482,432
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)	43,878,276	38,324,122	42,530,489	39,225,521	45,083,798	49,000,200	51,785,959	52,771,641	48,212,807	44,965,176	38,941,672	43,152,092	537,871,753
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)	**43,878,276**	**38,324,122**	**42,530,489**	**39,225,521**	**45,083,798**	**49,000,200**	**51,785,959**	**52,771,641**	**48,212,807**	**44,965,176**	**38,941,672**	**43,152,092**	**537,871,753**
16.	Cost Per kWh Sold (Cents/kWh)	2.9253	2.8525	3.1779	2.7533	2.8785	2.6835	2.7163	2.7812	2.4593	2.5242	2.6197	2.9730	2.7608
17.	True-up (Cents/kWh) [2]	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)	(0.0360)
18.	Total (Cents/kWh) (Line 16+17)	2.8893	2.8165	3.1419	2.7173	2.8425	2.6475	2.6803	2.7452	2.4233	2.4882	2.5837	2.9370	2.7248
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)	2.8914	2.8185	3.1442	2.7193	2.8445	2.6494	2.6822	2.7472	2.4250	2.4900	2.5856	2.9391	2.7268
21.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)
22.	**TOTAL RECOVERY FACTOR (LINE 20+21)**	**2.8798**	**2.8069**	**3.1326**	**2.7077**	**2.8329**	**2.6378**	**2.6706**	**2.7356**	**2.4134**	**2.4784**	**2.5740**	**2.9275**	**2.7152**
23.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**2.880**	**2.807**	**3.133**	**2.708**	**2.833**	**2.638**	**2.671**	**2.736**	**2.413**	**2.478**	**2.574**	**2.928**	**2.715**

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

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TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH JUNE 2019

SCHEDULE E3

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	0	0	0	142,781	0	0
3. COAL	6,527,543	5,952,831	5,338,152	2,002,090	3,905,065	3,907,170
4. NATURAL GAS	35,430,530	30,120,555	34,817,692	33,808,881	38,219,240	40,914,092
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**41,958,073**	**36,073,386**	**40,155,844**	**35,953,752**	**42,124,305**	**44,821,262**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	0	0	0	600	0	0
10. COAL	198,210	179,020	152,960	49,660	97,880	99,620
11. NATURAL GAS	1,193,910	1,007,060	1,129,820	1,268,980	1,478,470	1,573,150
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	64,330	70,400	100,680	107,700	113,000	97,040
14. TOTAL (MWH)	**1,456,450**	**1,256,480**	**1,383,460**	**1,426,940**	**1,689,350**	**1,769,810**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	0	0	0	1,120	0	0
17. COAL (TON)	92,490	83,560	75,300	28,060	54,960	55,070
18. NATURAL GAS (MCF)	8,199,120	6,954,080	7,716,930	8,923,340	10,283,060	11,051,680
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	0	0	0	6,460	0	0
23. COAL	2,081,050	1,880,160	1,694,170	631,240	1,236,660	1,239,120
24. NATURAL GAS	8,420,110	7,140,170	7,929,580	9,150,880	10,567,550	11,338,820
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,501,160**	**9,020,330**	**9,623,750**	**9,788,580**	**11,804,210**	**12,577,940**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.04	0.00	0.00
30. COAL	13.61	14.25	11.05	3.48	5.79	5.63
31. NATURAL GAS	81.97	80.15	81.67	88.93	87.52	88.89
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	4.42	5.60	7.28	7.55	6.69	5.48
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)	0.00	0.00	0.00	127.48	0.00	0.00
37. COAL ($/TON)	70.58	71.24	70.89	71.35	71.05	70.95
38. NATURAL GAS ($/MCF)	4.32	4.33	4.51	3.79	3.72	3.70
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	0.00	0.00	0.00	22.10	0.00	0.00
43. COAL	3.14	3.17	3.15	3.17	3.16	3.15
44. NATURAL GAS	4.21	4.22	4.39	3.69	3.62	3.61
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.00**	**4.00**	**4.17**	**3.67**	**3.57**	**3.56**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	0	0	0	10,767	0	0
50. COAL	10,499	10,503	11,076	12,711	12,634	12,438
51. NATURAL GAS	7,053	7,090	7,018	7,211	7,148	7,208
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,210**	**7,179**	**6,956**	**6,860**	**6,987**	**7,107**
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	0.00	0.00	0.00	23.80	0.00	0.00
57. COAL	3.29	3.33	3.49	4.03	3.99	3.92
58. NATURAL GAS	2.97	2.99	3.08	2.66	2.59	2.60
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)	**2.88**	**2.87**	**2.90**	**2.52**	**2.49**	**2.53**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2019 THROUGH DECEMBER 2019

SCHEDULE E3

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	0	0	0	0	0	0	142,781
3.	COAL	4,158,424	4,054,195	0	0	3,665,192	5,413,466	44,924,128
4.	NATURAL GAS	42,845,659	44,206,222	43,681,292	40,877,758	31,934,705	34,994,847	451,851,473
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**47,004,083**	**48,260,417**	**43,681,292**	**40,877,758**	**35,599,897**	**40,408,313**	**496,918,382**
	SYSTEM NET GENERATION (MWH)							
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	0	0	0	0	0	0	600
10.	COAL	105,400	103,640	0	0	105,160	158,400	1,249,950
11.	NATURAL GAS	1,637,370	1,669,380	1,659,750	1,518,310	1,139,750	1,240,420	16,516,370
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	91,800	97,780	75,510	77,270	67,420	59,700	1,022,630
14.	**TOTAL (MWH)**	**1,834,570**	**1,870,800**	**1,735,260**	**1,595,580**	**1,312,330**	**1,458,520**	**18,789,550**
	UNITS OF FUEL BURNED							
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	0	0	0	0	0	0	1,120
17.	COAL (TON)	57,850	57,160	0	0	52,010	77,360	633,820
18.	NATURAL GAS (MCF)	11,483,590	11,839,350	11,758,720	10,618,300	8,007,640	8,514,830	115,350,640
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	0	0	0	0	0	0	6,460
23.	COAL	1,301,540	1,286,120	0	0	1,170,140	1,740,640	14,260,840
24.	NATURAL GAS	11,791,390	12,136,490	12,072,500	10,905,240	8,218,110	8,744,610	118,415,450
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**13,092,930**	**13,422,610**	**12,072,500**	**10,905,240**	**9,388,250**	**10,485,250**	**132,682,750**
	GENERATION MIX (% MWH)							
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30.	COAL	5.75	5.54	0.00	0.00	8.01	10.86	6.66
31.	NATURAL GAS	89.25	89.23	95.65	95.16	86.85	85.05	87.90
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	5.00	5.23	4.35	4.84	5.14	4.09	5.44
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)	0.00	0.00	0.00	0.00	0.00	0.00	127.48
37.	COAL ($/TON)	71.88	70.93	0.00	0.00	70.47	69.98	70.88
38.	NATURAL GAS ($/MCF)	3.73	3.73	3.71	3.85	3.99	4.11	3.92
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	0.00	0.00	0.00	0.00	0.00	0.00	22.10
43.	COAL	3.20	3.15	0.00	0.00	3.13	3.11	3.15
44.	NATURAL GAS	3.63	3.64	3.62	3.75	3.89	4.00	3.82
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)**	**3.59**	**3.60**	**3.62**	**3.75**	**3.79**	**3.85**	**3.75**
	BTU BURNED PER KWH (BTU/KWH)							
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	0	0	0	0	0	0	10,767
50.	COAL	12,349	12,409	0	0	11,127	10,989	11,409
51.	NATURAL GAS	7,201	7,270	7,274	7,182	7,210	7,050	7,170
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,137**	**7,175**	**6,957**	**6,835**	**7,154**	**7,189**	**7,062**
	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	0.00	0.00	0.00	0.00	0.00	0.00	23.80
57.	COAL	3.95	3.91	0.00	0.00	3.49	3.42	3.59
58.	NATURAL GAS	2.62	2.65	2.63	2.69	2.80	2.82	2.74
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)**	**2.56**	**2.58**	**2.52**	**2.56**	**2.71**	**2.77**	**2.64**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2019

(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. BIG BEND SOLAR	19.4	2,600	18.0	-	18.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	170	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	61,330	20.4	-	20.4	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**64,330**	**20.2**	**-**	**20.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	315	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**315**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	350	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**350**	**0**	**0.0**	**88.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)	355	5,230	2.0	-	-	-	GAS	61,760	1,028,012	63,490.0	266,881	5.10	4.32
13. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**355**	**5,230**	**2.0**	**91.7**	**30.7**	**12,140**		**-**	**-**	**63,490.0**	**266,881**	**5.10**	**-**
15. B.B.#4 (GAS)	195	10,430	7.2	-	-	-	GAS	106,550	1,027,968	109,530.0	460,430	4.41	4.32
16. B.B.#4 (COAL)	442	198,210	60.3	-	-	-	COAL	92,490	22,500,270	2,081,050.0	6,527,543	3.29	70.58
17. TOTAL BIG BEND #4	**442**	**208,640**	**63.4**	**74.5**	**74.7**	**10,499**		**-**	**-**	**2,190,580.0**	**6,987,973**	**3.35**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	8,350	-	8,580.0	36,083	-	4.32
19. BIG BEND 1-4 COAL TOTAL	**842**	**198,210**	**31.6**	**-**	**-**	**10,499**	**COAL**	**92,490**	**22,500,270**	**2,081,050.0**	**6,527,543**	**3.29**	**70.58**
20. B.B.C.T.#4 (OIL)	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	210	0.5	-	86.1	12,000	GAS	2,460	1,024,390	2,520.0	10,630	5.06	4.32
22. B.B.C.T.#4 TOTAL	**61**	**210**	**0.5**	**98.2**	**86.1**	**12,000**	**-**	**-**	**-**	**2,520.0**	**10,630**	**5.06**	**-**
23. BIG BEND STATION TOTAL	**1,523**	**214,080**	**18.9**	**85.4**	**72.2**	**10,541**	**-**	**-**	**-**	**2,256,590.0**	**7,301,567**	**3.41**	**-**
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)	205	5,580	3.7	-	85.1	8,219	GAS	44,610	1,028,021	45,860.0	192,771	3.45	4.32
26. POLK #1 TOTAL	**220**	**5,580**	**3.4**	**93.5**	**85.1**	**8,219**	**-**	**-**	**-**	**45,860.0**	**192,771**	**3.45**	**-**
27. POLK #2 ST DUCT FIRING	120	880	1.0	-	66.7	8,193	GAS	7,010	1,028,531	7,210.0	30,292	3.44	4.32
28. POLK #2 ST W/O DUCT FIRING	360	642,690	-	-	-	-	GAS	4,223,530	1,028,000	4,341,790.0	18,250,972	2.84	4.32
29. POLK #2 ST TOTAL	**480**	**643,570**	**180.2**	**-**	**180.0**	**6,758**	**GAS**	**-**	**-**	**4,349,000.0**	**18,281,264**	**2.84**	**-**
30. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,200**	**643,570**	**72.1**	**93.2**	**180.0**	**6,758**	**-**	**-**	**-**	**4,349,000.0**	**18,281,264**	**2.84**	**-**
39. POLK STATION TOTAL	**1,420**	**649,150**	**61.4**	**93.2**	**176.1**	**6,770**	**-**	**-**	**-**	**4,394,860.0**	**18,474,035**	**2.85**	**-**
40. BAYSIDE #1	792	391,730	66.5	96.6	77.4	7,221	GAS	2,751,560	1,027,999	2,828,600.0	11,890,207	3.04	4.32
41. BAYSIDE #2	1,047	136,850	17.6	96.8	61.4	7,433	GAS	989,500	1,027,994	1,017,200.0	4,275,887	3.12	4.32
42. BAYSIDE #3	61	50	0.1	98.6	82.0	12,000	GAS	580	1,034,483	600.0	2,506	5.01	4.32
43. BAYSIDE #4	61	50	0.1	98.6	82.0	12,000	GAS	580	1,034,483	600.0	2,506	5.01	4.32
44. BAYSIDE #5	61	160	0.4	98.6	65.6	13,188	GAS	2,050	1,029,268	2,110.0	8,859	5.54	4.32
45. BAYSIDE #6	61	50	0.1	98.6	82.0	12,000	GAS	580	1,034,483	600.0	2,506	5.01	4.32
46. BAYSIDE TOTAL	**2,083**	**528,890**	**34.1**	**96.9**	**72.5**	**7,279**	**GAS**	**3,744,850**	**1,028,001**	**3,849,710.0**	**16,182,471**	**3.06**	**4.32**
47. SYSTEM	**5,454**	**1,456,450**	**35.9**	**85.1**	**112.1**	**7,210**	**-**	**-**	**-**	**10,501,160.0**	**41,958,073**	**2.88**	**-**

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

(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. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 10 OF 30

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2019

(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	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR		19.4	2,780	21.3	-	21.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.5	170	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR		405.0	67,230	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR	(3)	**427.5**	**70,400**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)		315	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1		**315**	**0**	**0.0**	**44.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)		350	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2		**350**	**0**	**0.0**	**44.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)		355	5,230	2.2	-	-	-	GAS	61,760	1,028,012	63,490.0	267,504	5.11	4.33
13. B.B.#3 (COAL)		400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3		**355**	**5,230**	**2.2**	**91.7**	**30.7**	**12,140**		**-**	**-**	**63,490.0**	**267,504**	**5.11**	**-**
15. B.B.#4 (GAS)		195	9,420	7.2	-	-	-	GAS	96,260	1,028,049	98,960.0	416,935	4.43	4.33
16. B.B.#4 (COAL)		442	179,020	60.3	-	-	-	COAL	83,560	22,500,718	1,880,160.0	5,952,831	3.33	71.24
17. TOTAL BIG BEND #4		**442**	**188,440**	**63.4**	**74.5**	**74.7**	**10,503**		**-**	**-**	**1,979,120.0**	**6,369,766**	**3.38**	**-**
18. B.B. IGNITION		-	-	-	-	-	-	GAS	8,350	-	8,580.0	36,167	-	4.33
19. BIG BEND 1-4 COAL TOTAL		**842**	**179,020**	**31.6**	**-**	**-**	**10,503**	**COAL**	**83,560**	**22,500,718**	**1,880,160.0**	**5,952,831**	**3.33**	**71.24**
20. B.B.C.T.#4 (OIL)		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	410	1.0	-	84.0	11,951	GAS	4,770	1,027,254	4,900.0	20,661	5.04	4.33
22. B.B.C.T.#4 TOTAL		**61**	**410**	**1.0**	**98.2**	**84.0**	**11,951**	**-**	**-**	**-**	**4,900.0**	**20,661**	**5.04**	**-**
23. BIG BEND STATION TOTAL		**1,523**	**194,080**	**19.0**	**66.2**	**71.9**	**10,550**	**-**	**-**	**-**	**2,047,510.0**	**6,694,098**	**3.45**	**-**
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)		205	6,060	4.4	-	92.4	8,038	GAS	47,380	1,028,071	48,710.0	205,219	3.39	4.33
26. POLK #1 TOTAL		**220**	**6,060**	**4.1**	**93.5**	**92.4**	**8,038**	**-**	**-**	**-**	**48,710.0**	**205,219**	**3.39**	**-**
27. POLK #2 ST DUCT FIRING		120	610	0.8	-	46.2	8,131	GAS	4,820	1,029,046	4,960.0	20,877	3.42	4.33
28. POLK #2 ST W/O DUCT FIRING		360	567,580	-	-	-	-	GAS	3,726,090	1,028,000	3,830,420.0	16,139,000	2.84	4.33
29. POLK #2 ST TOTAL		**480**	**568,190**	**176.2**	**-**	**175.6**	**6,750**	**GAS**	**-**	**-**	**3,835,380.0**	**16,159,877**	**2.84**	**-**
30. POLK #2 CT (GAS)		180	1,510	1.2	-	93.2	10,980	GAS	16,130	1,027,898	16,580.0	69,865	4.63	4.33
31. POLK #2 CT (OIL)		187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL	(4)	**180**	**1,510**	**1.2**	**-**	**93.2**	**10,980**	**-**	**-**	**-**	**16,580.0**	**69,865**	**4.63**	**-**
33. POLK #3 CT (GAS)		180	530	0.4	-	98.1	11,000	GAS	5,670	1,028,219	5,830.0	24,559	4.63	4.33
34. POLK #3 CT (OIL)		187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL	(4)	**180**	**530**	**0.4**	**-**	**98.1**	**11,000**	**-**	**-**	**-**	**5,830.0**	**24,559**	**4.63**	**-**
36. POLK #4 CT (GAS)	(4)	**180**	**530**	**0.4**	**-**	**98.1**	**10,981**	**GAS**	**5,670**	**1,026,455**	**5,820.0**	**24,559**	**4.63**	**4.33**
37. POLK #5 CT (GAS)	(4)	**180**	**170**	**0.1**	**-**	**94.4**	**11,176**	**GAS**	**1,850**	**1,027,027**	**1,900.0**	**8,013**	**4.71**	**4.33**
38. POLK #2 CC TOTAL		**1,200**	**570,930**	**70.8**	**86.0**	**173.8**	**6,771**	**-**	**-**	**-**	**3,865,510.0**	**16,286,873**	**2.85**	**-**
39. POLK STATION TOTAL		**1,420**	**576,990**	**60.5**	**87.1**	**170.2**	**6,784**	**-**	**-**	**-**	**3,914,220.0**	**16,492,092**	**2.86**	**-**
40. BAYSIDE #1		792	95,970	18.0	55.2	76.2	7,237	GAS	675,650	1,027,988	694,560.0	2,926,477	3.05	4.33
41. BAYSIDE #2		1,047	318,070	45.2	96.8	65.2	7,396	GAS	2,288,370	1,027,998	2,352,440.0	9,911,732	3.12	4.33
42. BAYSIDE #3		61	170	0.4	98.6	92.9	12,294	GAS	2,040	1,024,510	2,090.0	8,836	5.20	4.33
43. BAYSIDE #4		61	60	0.1	98.6	98.4	10,667	GAS	630	1,015,873	640.0	2,729	4.55	4.33
44. BAYSIDE #5		61	370	0.9	98.6	86.7	12,081	GAS	4,350	1,027,586	4,470.0	18,841	5.09	4.33
45. BAYSIDE #6		61	370	0.9	98.6	86.7	11,892	GAS	4,290	1,025,641	4,400.0	18,581	5.02	4.33
46. BAYSIDE TOTAL		**2,083**	**415,010**	**29.6**	**81.2**	**67.5**	**7,370**	**GAS**	**2,975,330**	**1,027,987**	**3,058,600.0**	**12,887,196**	**3.11**	**4.33**
47. SYSTEM		**5,454**	**1,256,480**	**34.3**	**72.2**	**110.7**	**7,179**	**-**	**-**	**-**	**9,020,330.0**	**36,073,386**	**2.87**	**-**

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

(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 E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2019

(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. BIG BEND SOLAR	19.4	3,840	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	230	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	96,330	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**100,680**	**31.7**	**-**	**31.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	315	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**315**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	350	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**350**	**0**	**0.0**	**88.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)	355	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
13. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**400**	**0**	**0.0**	**50.3**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. B.B.#4 (GAS)	195	8,050	5.5	-	-	-	GAS	86,740	1,028,015	89,170.0	391,358	4.86	4.51
16. B.B.#4 (COAL)	442	152,960	46.5	-	-	-	COAL	75,300	22,498,938	1,694,170.0	5,338,152	3.49	70.89
17. TOTAL BIG BEND #4	**442**	**161,010**	**49.0**	**74.5**	**57.6**	**11,076**		**-**	**-**	**1,783,340.0**	**5,729,510**	**3.56**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	3,340	-	3,430.0	15,070	-	4.51
19. BIG BEND 1-4 COAL TOTAL	**842**	**152,960**	**24.4**	**-**	**-**	**11,076**	**COAL**	**75,300**	**22,498,938**	**1,694,170.0**	**5,338,152**	**3.49**	**70.89**
20. B.B.C.T.#4 (OIL)	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	230	0.5	-	75.4	11,957	GAS	2,670	1,029,963	2,750.0	12,047	5.24	4.51
22. B.B.C.T.#4 TOTAL	**61**	**230**	**0.5**	**98.2**	**75.4**	**11,957**	**-**	**-**	**-**	**2,750.0**	**12,047**	**5.24**	**-**
23. BIG BEND STATION TOTAL	**1,568**	**161,240**	**13.8**	**75.0**	**57.7**	**11,077**	**-**	**-**	**-**	**1,786,090.0**	**5,756,627**	**3.57**	**-**
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)	205	2,810	1.8	-	85.7	8,107	GAS	22,150	1,028,442	22,780.0	99,938	3.56	4.51
26. POLK #1 TOTAL	**220**	**2,810**	**1.7**	**93.5**	**85.7**	**8,107**	**-**	**-**	**-**	**22,780.0**	**99,938**	**3.56**	**-**
27. POLK #2 ST DUCT FIRING	120	890	1.0	-	74.2	8,157	GAS	7,060	1,028,329	7,260.0	31,854	3.58	4.51
28. POLK #2 ST W/O DUCT FIRING	360	637,550	-	-	-	-	GAS	4,189,070	1,027,999	4,306,360.0	18,900,488	2.96	4.51
29. POLK #2 ST TOTAL	**480**	**638,440**	**178.8**	**-**	**178.8**	**6,757**	**GAS**	**-**	**-**	**4,313,620.0**	**18,932,342**	**2.97**	**-**
30. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,200**	**638,440**	**71.5**	**84.2**	**178.8**	**6,757**	**-**	**-**	**-**	**4,313,620.0**	**18,932,342**	**2.97**	**-**
39. POLK STATION TOTAL	**1,420**	**641,250**	**60.7**	**85.7**	**176.8**	**6,762**	**-**	**-**	**-**	**4,336,400.0**	**19,032,280**	**2.97**	**-**
40. BAYSIDE #1	792	292,630	49.7	96.6	80.3	7,211	GAS	2,052,820	1,027,996	2,110,290.0	9,262,032	3.17	4.51
41. BAYSIDE #2	1,047	187,410	24.1	59.3	64.2	7,406	GAS	1,350,090	1,028,006	1,387,900.0	6,091,414	3.25	4.51
42. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
44. BAYSIDE #5	61	150	0.3	98.6	82.0	12,067	GAS	1,760	1,028,409	1,810.0	7,941	5.29	4.51
45. BAYSIDE #6	61	100	0.2	98.6	82.0	12,600	GAS	1,230	1,024,390	1,260.0	5,550	5.55	4.51
46. BAYSIDE TOTAL	**2,083**	**480,290**	**31.0**	**72.3**	**73.1**	**7,290**	**GAS**	**3,405,900**	**1,027,998**	**3,501,260.0**	**15,366,937**	**3.20**	**4.51**
47. SYSTEM	**5,499**	**1,383,460**	**33.8**	**70.9**	**114.8**	**6,956**	**-**	**-**	**-**	**9,623,750.0**	**40,155,844**	**2.90**	**-**

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

(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. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 12 OF 30

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2019

(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. BIG BEND SOLAR		19.4	4,290	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.5	280	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR		405.0	102,860	35.3	-	35.3	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR	(3)	**427.5**	**107,700**	**35.0**	**-**	**35.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)		305	4,070	1.9	-	-	-	GAS	56,080	1,027,996	57,650.0	212,477	5.22	3.79
7. B.B.#1 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1		**305**	**4,070**	**1.9**	**88.1**	**39.2**	**14,165**		**-**	**-**	**57,650.0**	**212,477**	**5.22**	**-**
9. B.B.#2 (GAS)		340	5,460	2.2	-	-	-	GAS	70,620	1,028,037	72,600.0	267,566	4.90	3.79
10. B.B.#2 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2		**340**	**5,460**	**2.2**	**88.0**	**33.5**	**13,297**		**-**	**-**	**72,600.0**	**267,566**	**4.90**	**-**
12. B.B.#3 (GAS)		345	5,540	2.2	-	-	-	GAS	65,020	1,027,991	66,840.0	246,349	4.45	3.79
13. B.B.#3 (COAL)		395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3		**345**	**5,540**	**2.2**	**48.9**	**33.5**	**12,065**		**-**	**-**	**66,840.0**	**246,349**	**4.45**	**-**
15. B.B.#4 (GAS)		185	2,610	2.0	-	-	-	GAS	32,320	1,027,847	33,220.0	122,454	4.69	3.79
16. B.B.#4 (COAL)		437	49,660	15.8	-	-	-	COAL	28,060	22,496,080	631,240.0	2,002,090	4.03	71.35
17. TOTAL BIG BEND #4		**437**	**52,270**	**16.6**	**39.7**	**36.6**	**12,712**		**-**	**-**	**664,460.0**	**2,124,544**	**4.06**	**-**
18. B.B. IGNITION		-	-	-	-	-	-	GAS	21,710	-	22,320.0	82,255	-	3.79
19. BIG BEND 1-4 COAL TOTAL		**832**	**49,660**	**8.3**	**-**	**-**	**12,711**	**COAL**	**28,060**	**22,496,080**	**631,240.0**	**2,002,090**	**4.03**	**71.35**
20. B.B.C.T.#4 (OIL)		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	590	1.5	-	81.0	12,458	GAS	7,140	1,029,412	7,350.0	27,052	4.59	3.79
22. B.B.C.T.#4 TOTAL		**56**	**590**	**1.5**	**78.6**	**81.0**	**12,458**	**-**	**-**	**-**	**7,350.0**	**27,052**	**4.59**	**-**
23. BIG BEND STATION TOTAL		**1,483**	**67,930**	**6.4**	**64.4**	**36.4**	**12,791**	**-**	**-**	**-**	**868,900.0**	**2,960,243**	**4.36**	**-**
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	2,660	1.9	-	85.3	8,128	GAS	21,030	1,028,055	21,620.0	79,679	3.00	3.79
26. POLK #1 TOTAL		**220**	**2,660**	**1.7**	**62.3**	**85.3**	**8,128**	**-**	**-**	**-**	**21,620.0**	**79,679**	**3.00**	**-**
27. POLK #2 ST DUCT FIRING		120	1,530	1.8	-	75.0	8,268	GAS	12,310	1,027,620	12,650.0	46,640	3.05	3.79
28. POLK #2 ST W/O DUCT FIRING		341	510,320	-	-	-	-	GAS	3,349,550	1,028,001	3,443,340.0	12,690,824	2.49	3.79
29. POLK #2 ST TOTAL		**461**	**511,850**	**154.2**	**-**	**182.3**	**6,752**	**GAS**	**-**	**-**	**3,455,990.0**	**12,737,464**	**2.49**	**-**
30. POLK #2 CT (GAS)		150	730	0.7	-	97.3	11,384	GAS	8,080	1,028,465	8,310.0	30,613	4.19	3.79
31. POLK #2 CT (OIL)		159	300	0.3	-	94.3	10,767	LGT OIL	560	5,767,857	3,230.0	71,391	23.80	127.48
32. POLK #2 TOTAL	(4)	**150**	**1,030**	**1.0**	**-**	**96.4**	**11,204**	**-**	**-**	**-**	**11,540.0**	**102,004**	**9.90**	**-**
33. POLK #3 CT (GAS)		150	600	0.6	-	100.0	11,200	GAS	6,530	1,029,096	6,720.0	24,741	4.12	3.79
34. POLK #3 CT (OIL)		159	300	0.3	-	94.3	10,767	LGT OIL	560	5,767,857	3,230.0	71,390	23.80	127.48
35. POLK #3 TOTAL	(4)	**150**	**900**	**0.8**	**-**	**98.0**	**11,056**	**-**	**-**	**-**	**9,950.0**	**96,131**	**10.68**	**-**
36. POLK #4 CT (GAS)	(4)	**150**	**580**	**0.5**	**-**	**96.7**	**11,328**	**GAS**	**6,390**	**1,028,169**	**6,570.0**	**24,211**	**4.17**	**3.79**
37. POLK #5 CT (GAS)	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL		**1,061**	**514,360**	**67.3**	**88.4**	**180.0**	**6,774**	**-**	**-**	**-**	**3,484,050.0**	**12,959,810**	**2.52**	**-**
39. POLK STATION TOTAL		**1,281**	**517,020**	**56.1**	**83.9**	**177.6**	**6,781**	**-**	**-**	**-**	**3,505,670.0**	**13,039,489**	**2.52**	**-**
40. BAYSIDE #1		701	408,050	80.8	96.6	87.8	7,295	GAS	2,895,530	1,027,998	2,976,600.0	10,970,627	2.69	3.79
41. BAYSIDE #2		929	325,330	48.6	96.8	69.1	7,458	GAS	2,360,150	1,028,002	2,426,240.0	8,942,170	2.75	3.79
42. BAYSIDE #3		56	160	0.4	98.6	95.2	11,813	GAS	1,840	1,027,174	1,890.0	6,971	4.36	3.79
43. BAYSIDE #4		56	100	0.2	88.7	89.3	12,300	GAS	1,200	1,025,000	1,230.0	4,547	4.55	3.79
44. BAYSIDE #5		56	360	0.9	78.9	80.4	12,583	GAS	4,410	1,027,211	4,530.0	16,709	4.64	3.79
45. BAYSIDE #6		56	290	0.7	78.9	86.3	12,138	GAS	3,430	1,026,239	3,520.0	12,996	4.48	3.79
46. BAYSIDE TOTAL		**1,854**	**734,290**	**55.0**	**95.5**	**78.4**	**7,373**	**GAS**	**5,266,560**	**1,027,997**	**5,414,010.0**	**19,954,020**	**2.72**	**3.79**
47. SYSTEM		**5,046**	**1,426,940**	**39.3**	**75.3**	**107.0**	**6,860**	**-**	**-**	**-**	**9,788,580.0**	**35,953,752**	**2.52**	**-**

LEGEND:
B.B. = BIG BEND — CT = COMBUSTION TURBINE
CC = COMBINED CYCLE — ST = STEAM TURBINE

(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 E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2019

(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	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.4	4,540	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	290	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	107,880	35.8	-	35.8	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**113,000**	**35.5**	**-**	**35.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	305	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**305**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	340	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**340**	**0**	**0.0**	**88.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**395**	**0**	**0.0**	**91.7**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
15. B.B.#4 (GAS)	185	5,150	3.7	-	-	-	GAS	63,320	1,027,953	65,090.0	235,342	4.57	3.72
16. B.B.#4 (COAL)	437	97,880	30.1	-	-	-	COAL	54,960	22,501,092	1,236,660.0	3,905,065	3.99	71.05
17. TOTAL BIG BEND #4	**437**	**103,030**	**31.7**	**74.5**	**37.3**	**12,635**		**-**	**-**	**1,301,750.0**	**4,140,407**	**4.02**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	3,340	-	3,430.0	12,414	-	3.72
19. BIG BEND 1-4 COAL TOTAL	**832**	**97,880**	**15.8**	**-**	**-**	**12,634**	**COAL**	**54,960**	**22,501,092**	**1,236,660.0**	**3,905,065**	**3.99**	**71.05**
20. B.B.C.T.#4 (OIL)	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	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
22. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**98.2**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
23. BIG BEND STATION TOTAL	**1,533**	**103,030**	**9.0**	**85.5**	**37.3**	**12,635**	**-**	**-**	**-**	**1,301,750.0**	**4,152,821**	**4.03**	**-**
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	5,360	3.7	-	85.9	8,261	GAS	43,070	1,028,094	44,280.0	160,079	2.99	3.72
26. POLK #1 TOTAL	**220**	**5,360**	**3.3**	**93.5**	**85.9**	**8,261**	**-**	**-**	**-**	**44,280.0**	**160,079**	**2.99**	**-**
27. POLK #2 ST DUCT FIRING	120	980	1.1	-	62.8	8,255	GAS	7,870	1,027,954	8,090.0	29,251	2.98	3.72
28. POLK #2 ST W/O DUCT FIRING	341	627,440	-	-	-	-	GAS	4,116,420	1,028,000	4,231,680.0	15,299,574	2.44	3.72
29. POLK #2 ST TOTAL	**461**	**628,420**	**183.2**	**-**	**182.5**	**6,747**	**GAS**	**-**	**-**	**4,239,770.0**	**15,328,825**	**2.44**	**-**
30. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,061**	**628,420**	**79.6**	**95.9**	**182.5**	**6,747**	**-**	**-**	**-**	**4,239,770.0**	**15,328,825**	**2.44**	**-**
39. POLK STATION TOTAL	**1,281**	**633,780**	**66.5**	**95.5**	**178.5**	**6,760**	**-**	**-**	**-**	**4,284,050.0**	**15,488,904**	**2.44**	**-**
40. BAYSIDE #1	701	419,930	80.5	96.6	84.1	7,309	GAS	2,985,840	1,028,002	3,069,450.0	11,097,527	2.64	3.72
41. BAYSIDE #2	929	419,610	60.7	96.8	63.4	7,504	GAS	3,063,200	1,027,997	3,148,960.0	11,385,053	2.71	3.72
42. BAYSIDE #3	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
44. BAYSIDE #5	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. BAYSIDE #6	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. BAYSIDE TOTAL	**1,854**	**839,540**	**60.9**	**85.0**	**72.3**	**7,407**	**GAS**	**6,049,040**	**1,027,999**	**6,218,410.0**	**22,482,580**	**2.68**	**3.72**
47. SYSTEM	**5,096**	**1,689,350**	**44.6**	**80.7**	**99.6**	**6,987**	**-**	**-**	**-**	**11,804,210.0**	**42,124,305**	**2.49**	**-**

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

(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 2019

(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. BIG BEND SOLAR		19.4	3,990	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR		1.5	270	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR		405.0	92,530	31.7	-	31.7	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR	(3)	**427.5**	**97,040**	**31.5**	**-**	**31.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)		305	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1		**305**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)		340	5,240	2.1	-	-	-	GAS	68,610	1,027,984	70,530.0	253,999	4.85	3.70
10. B.B.#2 (COAL)		0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2		**340**	**5,240**	**2.1**	**88.0**	**32.1**	**13,460**		**-**	**-**	**70,530.0**	**253,999**	**4.85**	**-**
12. B.B.#3 (GAS)		345	10,600	4.3	-	-	-	GAS	125,570	1,028,032	129,090.0	464,869	4.39	3.70
13. B.B.#3 (COAL)		395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3		**345**	**10,600**	**4.3**	**91.7**	**32.0**	**12,178**		**-**	**-**	**129,090.0**	**464,869**	**4.39**	**-**
15. B.B.#4 (GAS)		185	5,240	3.9	-	-	-	GAS	63,440	1,028,058	65,220.0	234,859	4.48	3.70
16. B.B.#4 (COAL)		437	99,620	31.7	-	-	-	COAL	55,070	22,500,817	1,239,120.0	3,907,170	3.92	70.95
17. TOTAL BIG BEND #4		**437**	**104,860**	**33.3**	**74.5**	**39.2**	**12,439**		**-**	**-**	**1,304,340.0**	**4,142,029**	**3.95**	**-**
18. B.B. IGNITION		-	-	-	-	-	-	GAS	21,710	-	22,320.0	80,372	-	3.70
19. BIG BEND 1-4 COAL TOTAL		**832**	**99,620**	**16.6**	**-**	**-**	**12,438**	**COAL**	**55,070**	**22,500,817**	**1,239,120.0**	**3,907,170**	**3.92**	**70.95**
20. B.B.C.T.#4 (OIL)		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	850	2.1	-	84.3	12,094	GAS	9,990	1,029,029	10,280.0	36,984	4.35	3.70
22. B.B.C.T.#4 TOTAL		**56**	**850**	**2.1**	**98.2**	**84.3**	**12,094**	**-**	**-**	**-**	**10,280.0**	**36,984**	**4.35**	**-**
23. BIG BEND STATION TOTAL		**1,483**	**121,550**	**11.4**	**85.3**	**38.2**	**12,458**	**-**	**-**	**-**	**1,514,240.0**	**4,978,253**	**4.10**	**-**
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	20,890	14.9	-	88.5	8,178	GAS	166,160	1,028,105	170,830.0	615,136	2.94	3.70
26. POLK #1 TOTAL		**220**	**20,890**	**13.2**	**93.5**	**88.5**	**8,178**	**-**	**-**	**-**	**170,830.0**	**615,136**	**2.94**	**-**
27. POLK #2 ST DUCT FIRING		120	3,900	4.5	-	66.3	8,279	GAS	31,420	1,027,689	32,290.0	116,319	2.98	3.70
28. POLK #2 ST W/O DUCT FIRING		341	617,240	-	-	-	-	GAS	4,051,430	1,027,998	4,164,860.0	14,998,677	2.43	3.70
29. POLK #2 ST TOTAL		**461**	**621,140**	**187.1**	**-**	**177.5**	**6,757**	**GAS**	**-**	**-**	**4,197,150.0**	**15,114,996**	**2.43**	**-**
30. POLK #2 CT (GAS)		150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)		159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)		150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)		159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS)	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS)	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL		**1,061**	**621,140**	**81.3**	**95.7**	**177.5**	**6,757**	**-**	**-**	**-**	**4,197,150.0**	**15,114,996**	**2.43**	**-**
39. POLK STATION TOTAL		**1,281**	**642,030**	**69.6**	**95.3**	**165.3**	**6,803**	**-**	**-**	**-**	**4,367,980.0**	**15,730,132**	**2.45**	**-**
40. BAYSIDE #1		701	425,890	84.4	96.6	87.9	7,293	GAS	3,021,480	1,028,000	3,106,080.0	11,185,730	2.63	3.70
41. BAYSIDE #2		929	481,900	72.0	96.8	74.5	7,413	GAS	3,475,110	1,027,996	3,572,400.0	12,865,100	2.67	3.70
42. BAYSIDE #3		56	320	0.8	98.6	81.6	12,656	GAS	3,940	1,027,919	4,050.0	14,586	4.56	3.70
43. BAYSIDE #4		56	270	0.7	98.6	80.4	12,000	GAS	3,150	1,028,571	3,240.0	11,662	4.32	3.70
44. BAYSIDE #5		56	400	1.0	98.6	79.4	12,350	GAS	4,800	1,029,167	4,940.0	17,770	4.44	3.70
45. BAYSIDE #6		56	410	1.0	98.6	81.3	12,220	GAS	4,870	1,028,747	5,010.0	18,029	4.40	3.70
46. BAYSIDE TOTAL		**1,854**	**909,190**	**68.1**	**96.9**	**80.3**	**7,364**	**GAS**	**6,513,350**	**1,027,999**	**6,695,720.0**	**24,112,877**	**2.65**	**3.70**
47. SYSTEM		**5,046**	**1,769,810**	**48.7**	**84.9**	**102.6**	**7,107**	**-**	**-**	**-**	**12,577,940.0**	**44,821,262**	**2.53**	**-**

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

(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 2019

(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. BIG BEND SOLAR	19.4	3,880	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	270	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	87,400	29.0	-	29.0	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**91,800**	**28.9**	**-**	**28.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	305	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**305**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	340	7,950	3.1	-	-	-	GAS	94,840	1,028,047	97,500.0	353,851	4.45	3.73
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**340**	**7,950**	**3.1**	**88.0**	**43.3**	**12,264**		**-**	**-**	**97,500.0**	**353,851**	**4.45**	**-**
12. B.B.#3 (GAS)	345	5,500	2.1	-	-	-	GAS	64,990	1,028,004	66,810.0	242,480	4.41	3.73
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**345**	**5,500**	**2.1**	**91.7**	**32.5**	**12,147**		**-**	**-**	**66,810.0**	**242,480**	**4.41**	**-**
15. B.B.#4 (GAS)	185	5,550	4.0	-	-	-	GAS	66,640	1,027,911	68,500.0	248,636	4.48	3.73
16. B.B.#4 (COAL)	437	105,400	32.4	-	-	-	COAL	57,850	22,498,531	1,301,540.0	4,158,424	3.95	71.88
17. TOTAL BIG BEND #4	**437**	**110,950**	**34.1**	**74.5**	**40.2**	**12,348**		**-**	**-**	**1,370,040.0**	**4,407,060**	**3.97**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	13,360	-	13,730.0	49,847	-	3.73
19. BIG BEND 1-4 COAL TOTAL	**832**	**105,400**	**17.0**	**-**	**-**	**12,349**	**COAL**	**57,850**	**22,498,531**	**1,301,540.0**	**4,158,424**	**3.95**	**71.88**
20. B.B.C.T.#4 (OIL)	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	560	1.3	-	76.9	12,661	GAS	6,900	1,027,536	7,090.0	25,744	4.60	3.73
22. B.B.C.T.#4 TOTAL	**56**	**560**	**1.3**	**98.2**	**76.9**	**12,661**	**-**	**-**	**-**	**7,090.0**	**25,744**	**4.60**	**-**
23. BIG BEND STATION TOTAL	**1,483**	**124,960**	**11.3**	**85.3**	**40.0**	**12,335**	**-**	**-**	**-**	**1,541,440.0**	**5,078,982**	**4.06**	**-**
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	28,500	19.6	-	88.6	8,207	GAS	227,530	1,027,996	233,900.0	848,922	2.98	3.73
26. POLK #1 TOTAL	**220**	**28,500**	**17.4**	**93.5**	**88.6**	**8,207**	**-**	**-**	**-**	**233,900.0**	**848,922**	**2.98**	**-**
27. POLK #2 ST DUCT FIRING	120	4,220	4.7	-	59.6	8,273	GAS	33,950	1,028,277	34,910.0	126,669	3.00	3.73
28. POLK #2 ST W/O DUCT FIRING	341	639,150	-	-	-	-	GAS	4,195,550	1,027,999	4,313,020.0	15,653,738	2.45	3.73
29. POLK #2 ST TOTAL	**461**	**643,370**	**187.6**	**-**	**176.0**	**6,758**	**GAS**	**-**	**-**	**4,347,930.0**	**15,780,407**	**2.45**	**-**
30. POLK #2 CT (GAS)	150	750	0.7	-	100.0	11,293	GAS	8,240	1,027,913	8,470.0	30,743	4.10	3.73
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**150**	**750**	**0.7**	**-**	**100.0**	**11,293**	**-**	**-**	**-**	**8,470.0**	**30,743**	**4.10**	**-**
33. POLK #3 CT (GAS)	150	600	0.5	-	100.0	11,333	GAS	6,610	1,028,744	6,800.0	24,662	4.11	3.73
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**150**	**600**	**0.5**	**-**	**100.0**	**11,333**	**-**	**-**	**-**	**6,800.0**	**24,662**	**4.11**	**-**
36. POLK #4 CT (GAS) (4)	**150**	**450**	**0.4**	**-**	**100.0**	**11,378**	**GAS**	**4,990**	**1,026,052**	**5,120.0**	**18,618**	**4.14**	**3.73**
37. POLK #5 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,061**	**645,170**	**81.7**	**95.9**	**174.9**	**6,771**	**-**	**-**	**-**	**4,368,320.0**	**15,854,430**	**2.46**	**-**
39. POLK STATION TOTAL	**1,281**	**673,670**	**70.7**	**95.5**	**160.2**	**6,832**	**-**	**-**	**-**	**4,602,220.0**	**16,703,352**	**2.48**	**-**
40. BAYSIDE #1	701	444,170	85.2	96.6	88.1	7,293	GAS	3,151,170	1,027,999	3,239,400.0	11,757,121	2.65	3.73
41. BAYSIDE #2	929	499,160	72.2	96.8	74.8	7,412	GAS	3,598,870	1,028,000	3,699,640.0	13,427,504	2.69	3.73
42. BAYSIDE #3	56	90	0.2	98.6	80.4	13,667	GAS	1,200	1,025,000	1,230.0	4,477	4.97	3.73
43. BAYSIDE #4	56	50	0.1	98.6	89.3	12,200	GAS	590	1,033,898	610.0	2,201	4.40	3.73
44. BAYSIDE #5	56	370	0.9	98.6	82.6	12,405	GAS	4,470	1,026,846	4,590.0	16,678	4.51	3.73
45. BAYSIDE #6	56	300	0.7	98.6	76.5	12,667	GAS	3,690	1,029,810	3,800.0	13,768	4.59	3.73
46. BAYSIDE TOTAL	**1,854**	**944,140**	**68.4**	**96.9**	**80.6**	**7,360**	**GAS**	**6,759,990**	**1,028,000**	**6,949,270.0**	**25,221,749**	**2.67**	**3.73**
47. SYSTEM	**5,046**	**1,834,570**	**48.9**	**84.9**	**103.1**	**7,137**	**-**	**-**	**-**	**13,092,930.0**	**47,004,083**	**2.56**	**-**

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

(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 2019

(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. BIG BEND SOLAR	19.4	3,740	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	250	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	93,540	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**97,780**	**30.7**	**-**	**30.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	305	12,770	5.6	-	-	-	GAS	170,520	1,028,032	175,300.0	636,694	4.99	3.73
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**305**	**12,770**	**5.6**	**88.1**	**42.7**	**13,727**		**-**	**-**	**175,300.0**	**636,694**	**4.99**	**-**
9. B.B.#2 (GAS)	340	11,560	4.6	-	-	-	GAS	147,640	1,027,973	151,770.0	551,264	4.77	3.73
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**340**	**11,560**	**4.6**	**88.0**	**34.7**	**13,129**		**-**	**-**	**151,770.0**	**551,264**	**4.77**	**-**
12. B.B.#3 (GAS)	345	9,870	3.8	-	-	-	GAS	116,570	1,027,966	119,830.0	435,254	4.41	3.73
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**345**	**9,870**	**3.8**	**91.7**	**32.5**	**12,141**		**-**	**-**	**119,830.0**	**435,254**	**4.41**	**-**
15. B.B.#4 (GAS)	185	5,450	4.0	-	-	-	GAS	65,850	1,027,942	67,690.0	245,873	4.51	3.73
16. B.B.#4 (COAL)	437	103,640	31.9	-	-	-	COAL	57,160	22,500,350	1,286,120.0	4,054,195	3.91	70.93
17. TOTAL BIG BEND #4	**437**	**109,090**	**33.6**	**74.5**	**39.5**	**12,410**		**-**	**-**	**1,353,810.0**	**4,300,068**	**3.94**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	33,400	-	34,330.0	124,710	-	3.73
19. BIG BEND 1-4 COAL TOTAL	**832**	**103,640**	**16.7**	**-**	**-**	**12,409**	**COAL**	**57,160**	**22,500,350**	**1,286,120.0**	**4,054,195**	**3.91**	**70.93**
20. B.B.C.T.#4 (OIL)	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	700	1.7	-	89.3	12,129	GAS	8,260	1,027,845	8,490.0	30,842	4.41	3.73
22. B.B.C.T.#4 TOTAL	**56**	**700**	**1.7**	**98.2**	**89.3**	**12,129**	**-**	**-**	**-**	**8,490.0**	**30,842**	**4.41**	**-**
23. BIG BEND STATION TOTAL	**1,483**	**143,990**	**13.1**	**85.3**	**38.9**	**12,565**	**-**	**-**	**-**	**1,809,200.0**	**6,078,832**	**4.22**	**-**
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	21,760	15.0	-	91.5	8,129	GAS	172,070	1,027,954	176,880.0	642,482	2.95	3.73
26. POLK #1 TOTAL	**220**	**21,760**	**13.3**	**93.5**	**91.5**	**8,129**	**-**	**-**	**-**	**176,880.0**	**642,482**	**2.95**	**-**
27. POLK #2 ST DUCT FIRING	120	4,500	5.0	-	68.2	8,267	GAS	36,190	1,027,908	37,200.0	135,128	3.00	3.73
28. POLK #2 ST W/O DUCT FIRING	341	640,340	-	-	-	-	GAS	4,203,520	1,027,998	4,321,210.0	15,695,264	2.45	3.73
29. POLK #2 ST TOTAL	**461**	**644,840**	**188.0**	**-**	**177.3**	**6,759**	**GAS**	**-**	**-**	**4,358,410.0**	**15,830,392**	**2.45**	**-**
30. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,061**	**644,840**	**81.7**	**95.7**	**177.3**	**6,759**	**-**	**-**	**-**	**4,358,410.0**	**15,830,392**	**2.45**	**-**
39. POLK STATION TOTAL	**1,281**	**666,600**	**69.9**	**95.3**	**165.8**	**6,804**	**-**	**-**	**-**	**4,535,290.0**	**16,472,874**	**2.47**	**-**
40. BAYSIDE #1	701	445,490	85.4	96.6	89.0	7,289	GAS	3,158,550	1,028,000	3,246,990.0	11,793,516	2.65	3.73
41. BAYSIDE #2	929	515,190	74.5	96.8	77.2	7,395	GAS	3,706,050	1,027,997	3,809,810.0	13,837,793	2.69	3.73
42. BAYSIDE #3	56	350	0.8	98.6	89.3	12,029	GAS	4,090	1,029,340	4,210.0	15,271	4.36	3.73
43. BAYSIDE #4	56	340	0.8	98.6	86.7	12,235	GAS	4,050	1,027,160	4,160.0	15,122	4.45	3.73
44. BAYSIDE #5	56	560	1.3	98.6	83.3	12,321	GAS	6,710	1,028,316	6,900.0	25,054	4.47	3.73
45. BAYSIDE #6	56	500	1.2	98.6	89.3	12,100	GAS	5,880	1,028,912	6,050.0	21,955	4.39	3.73
46. BAYSIDE TOTAL	**1,854**	**962,430**	**69.8**	**96.9**	**82.3**	**7,354**	**GAS**	**6,885,330**	**1,028,000**	**7,078,120.0**	**25,708,711**	**2.67**	**3.73**
47. SYSTEM	**5,046**	**1,870,800**	**49.8**	**84.9**	**102.6**	**7,175**	**-**	**-**	**-**	**13,422,610.0**	**48,260,417**	**2.58**	**-**

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

(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. 20180001-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 2019

(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. BIG BEND SOLAR	19.4	3,090	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	210	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	71,990	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**75,510**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	305	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**305**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	340	29,470	12.0	-	-	-	GAS	371,980	1,027,985	382,390.0	1,381,832	4.69	3.71
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**340**	**29,470**	**12.0**	**88.0**	**36.1**	**12,976**		**-**	**-**	**382,390.0**	**1,381,832**	**4.69**	**-**
12. B.B.#3 (GAS)	345	10,810	4.4	-	-	-	GAS	127,510	1,027,998	131,080.0	473,674	4.38	3.71
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**345**	**10,810**	**4.4**	**91.7**	**32.6**	**12,126**		**-**	**-**	**131,080.0**	**473,674**	**4.38**	**-**
15. B.B.#4 (GAS)	185	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
16. B.B.#4 (COAL)	437	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
17. TOTAL BIG BEND #4	**437**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	15,030	-	15,450.0	55,833	-	3.71
19. BIG BEND 1-4 COAL TOTAL	**832**	**0**	**0.0**	**-**	**-**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. B.B.C.T.#4 (OIL)	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	970	2.4	-	78.7	12,649	GAS	11,940	1,027,638	12,270.0	44,355	4.57	3.71
22. B.B.C.T.#4 TOTAL	**56**	**970**	**2.4**	**98.2**	**78.7**	**12,649**	**-**	**-**	**-**	**12,270.0**	**44,355**	**4.57**	**-**
23. BIG BEND STATION TOTAL	**1,483**	**41,250**	**3.9**	**63.4**	**35.6**	**12,745**	**-**	**-**	**-**	**525,740.0**	**1,955,694**	**4.74**	**-**
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	29,320	20.9	-	89.0	8,186	GAS	233,470	1,028,012	240,010.0	867,294	2.96	3.71
26. POLK #1 TOTAL	**220**	**29,320**	**18.5**	**93.5**	**89.0**	**8,186**	**-**	**-**	**-**	**240,010.0**	**867,294**	**2.96**	**-**
27. POLK #2 ST DUCT FIRING	120	6,420	7.4	-	78.7	8,271	GAS	51,650	1,028,074	53,100.0	191,869	2.99	3.71
28. POLK #2 ST W/O DUCT FIRING	341	623,990	-	-	-	-	GAS	4,097,070	1,028,000	4,211,790.0	15,219,796	2.44	3.71
29. POLK #2 ST TOTAL	**461**	**630,410**	**189.9**	**-**	**175.8**	**6,765**	**GAS**	**-**	**-**	**4,264,890.0**	**15,411,665**	**2.44**	**-**
30. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,061**	**630,410**	**82.5**	**95.9**	**175.8**	**6,765**	**-**	**-**	**-**	**4,264,890.0**	**15,411,665**	**2.44**	**-**
39. POLK STATION TOTAL	**1,281**	**659,730**	**71.5**	**95.5**	**160.3**	**6,828**	**-**	**-**	**-**	**4,504,900.0**	**16,278,959**	**2.47**	**-**
40. BAYSIDE #1	701	437,520	86.7	96.6	90.3	7,283	GAS	3,099,860	1,027,998	3,186,650.0	11,515,359	2.63	3.71
41. BAYSIDE #2	929	519,000	77.6	96.8	80.2	7,375	GAS	3,723,480	1,027,998	3,827,730.0	13,831,984	2.67	3.71
42. BAYSIDE #3	56	450	1.1	98.6	89.3	12,356	GAS	5,410	1,027,726	5,560.0	20,097	4.47	3.71
43. BAYSIDE #4	56	340	0.8	98.6	86.7	12,147	GAS	4,010	1,029,925	4,130.0	14,896	4.38	3.71
44. BAYSIDE #5	56	810	2.0	98.6	85.1	12,358	GAS	9,740	1,027,721	10,010.0	36,182	4.47	3.71
45. BAYSIDE #6	56	650	1.6	98.6	89.3	11,969	GAS	7,570	1,027,741	7,780.0	28,121	4.33	3.71
46. BAYSIDE TOTAL	**1,854**	**958,770**	**71.8**	**96.9**	**84.5**	**7,345**	**GAS**	**6,850,070**	**1,027,998**	**7,041,860.0**	**25,446,639**	**2.65**	**3.71**
47. SYSTEM	**5,046**	**1,735,260**	**47.8**	**78.5**	**112.8**	**6,957**	**-**	**-**	**-**	**12,072,500.0**	**43,681,292**	**2.52**	**-**

LEGEND:
B.B. = BIG BEND — CT = COMBUSTION TURBINE
CC = COMBINED CYCLE — ST = STEAM TURBINE

(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. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 18 OF 30

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2019

(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. BIG BEND SOLAR	19.4	3,180	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	200	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	73,640	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	427.5	77,270	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
6. B.B.#1 (GAS)	305	6,010	2.6	-	-	-	GAS	81,620	1,027,934	83,900.0	314,216	5.23	3.85
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	305	6,010	2.6	88.1	41.1	13,960		-	-	83,900.0	314,216	5.23	-
9. B.B.#2 (GAS)	340	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	340	0	0.0	88.0	0.0	0		-	-	0.0	0	0.00	-
12. B.B.#3 (GAS)	345	6,630	2.6	-	-	-	GAS	78,010	1,027,945	80,190.0	300,319	4.53	3.85
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	345	6,630	2.6	91.7	33.1	12,095		-	-	80,190.0	300,319	4.53	-
15. B.B.#4 (GAS)	185	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
16. B.B.#4 (COAL)	437	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
17. TOTAL BIG BEND #4	437	0	0.0	0.0	0.0	0		-	-	0.0	0	0.00	-
18. B.B. IGNITION	-	-	-	-	-	-	GAS	10,020	-	10,300.0	38,574	-	3.85
19. BIG BEND 1-4 COAL TOTAL	832	0	0.0	-	-	0	COAL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 (OIL)	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	1,000	2.4	-	85.0	12,250	GAS	11,920	1,027,685	12,250.0	45,889	4.59	3.85
22. B.B.C.T.#4 TOTAL	56	1,000	2.4	98.2	85.0	12,250	-	-	-	12,250.0	45,889	4.59	-
23. BIG BEND STATION TOTAL	1,483	13,640	1.2	63.4	38.1	12,928	-	-	-	176,340.0	698,998	5.12	-
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	12,870	8.9	-	89.2	8,200	GAS	102,670	1,027,954	105,540.0	395,253	3.07	3.85
26. POLK #1 TOTAL	220	12,870	7.9	51.3	89.2	8,200	-	-	-	105,540.0	395,253	3.07	-
27. POLK #2 ST DUCT FIRING	120	3,150	3.5	-	72.9	8,283	GAS	25,390	1,027,570	26,090.0	97,745	3.10	3.85
28. POLK #2 ST W/O DUCT FIRING	341	625,730	-	-	-	-	GAS	4,105,840	1,027,999	4,220,800.0	15,806,442	2.53	3.85
29. POLK #2 ST TOTAL	461	628,880	183.4	-	177.2	6,753	GAS	-	-	4,246,890.0	15,904,187	2.53	-
30. POLK #2 CT (GAS)	150	1,130	1.0	-	94.2	11,442	GAS	12,580	1,027,822	12,930.0	48,429	4.29	3.85
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	150	1,130	1.0	-	94.2	11,442	-	-	-	12,930.0	48,429	4.29	-
33. POLK #3 CT (GAS)	150	1,000	0.9	-	95.2	11,460	GAS	11,150	1,027,803	11,460.0	42,925	4.29	3.85
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	150	1,000	0.9	-	95.2	11,460	-	-	-	11,460.0	42,925	4.29	-
36. POLK #4 CT (GAS) (4)	150	850	0.8	-	94.4	11,506	GAS	9,520	1,027,311	9,780.0	36,650	4.31	3.85
37. POLK #5 CT (GAS) (4)	150	580	0.5	-	96.7	11,500	GAS	6,490	1,027,735	6,670.0	24,985	4.31	3.85
38. POLK #2 CC TOTAL	1,061	632,440	80.1	93.5	174.6	6,780	-	-	-	4,287,730.0	16,057,176	2.54	-
39. POLK STATION TOTAL	1,281	645,310	67.7	86.2	167.3	6,808	-	-	-	4,393,270.0	16,452,429	2.55	-
40. BAYSIDE #1	701	408,280	78.3	96.6	87.6	7,295	GAS	2,897,340	1,027,998	2,978,460.0	11,154,023	2.73	3.85
41. BAYSIDE #2	929	449,300	65.0	96.8	73.3	7,423	GAS	3,244,500	1,027,998	3,335,340.0	12,490,500	2.78	3.85
42. BAYSIDE #3	56	350	0.8	98.6	89.3	12,200	GAS	4,160	1,026,442	4,270.0	16,015	4.58	3.85
43. BAYSIDE #4	56	250	0.6	98.6	89.3	12,280	GAS	2,990	1,026,756	3,070.0	11,511	4.60	3.85
44. BAYSIDE #5	56	730	1.8	98.6	81.5	12,329	GAS	8,760	1,027,397	9,000.0	33,724	4.62	3.85
45. BAYSIDE #6	56	450	1.1	98.6	89.3	12,200	GAS	5,340	1,028,090	5,490.0	20,558	4.57	3.85
46. BAYSIDE TOTAL	1,854	859,360	62.3	96.9	79.5	7,372	GAS	6,163,090	1,027,996	6,335,630.0	23,726,331	2.76	3.85
47. SYSTEM	5,046	1,595,580	42.5	76.1	114.6	6,835	-	-	-	10,905,240.0	40,877,758	2.56	-

LEGEND:
B.B. = BIG BEND — CT = COMBUSTION TURBINE
CC = COMBINED CYCLE — ST = STEAM TURBINE

(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. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 19 OF 30

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2019

(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. BIG BEND SOLAR	19.4	2,690	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	170	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	64,330	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**67,420**	**21.9**	**-**	**21.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	305	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**305**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	340	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**340**	**0**	**0.0**	**88.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)	345	10,970	4.4	-	-	-	GAS	121,560	1,027,970	124,960.0	484,785	4.42	3.99
13. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**345**	**10,970**	**4.4**	**61.2**	**45.4**	**11,391**		**-**	**-**	**124,960.0**	**484,785**	**4.42**	**-**
15. B.B.#4 (GAS)	185	5,530	4.2	-	-	-	GAS	59,910	1,028,042	61,590.0	238,923	4.32	3.99
16. B.B.#4 (COAL)	437	105,160	33.4	-	-	-	COAL	52,010	22,498,366	1,170,140.0	3,665,192	3.49	70.47
17. TOTAL BIG BEND #4	**437**	**110,690**	**35.2**	**52.2**	**59.2**	**11,128**		**-**	**-**	**1,231,730.0**	**3,904,115**	**3.53**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	13,360	-	13,730.0	53,280	-	3.99
19. BIG BEND 1-4 COAL TOTAL	**832**	**105,160**	**17.6**	**-**	**-**	**11,127**	**COAL**	**52,010**	**22,498,366**	**1,170,140.0**	**3,665,192**	**3.49**	**70.47**
20. B.B.C.T.#4 (OIL)	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	1,010	2.5	-	90.2	12,030	GAS	11,820	1,027,919	12,150.0	47,138	4.67	3.99
22. B.B.C.T.#4 TOTAL	**56**	**1,010**	**2.5**	**98.2**	**90.2**	**12,030**	**-**	**-**	**-**	**12,150.0**	**47,138**	**4.67**	**-**
23. BIG BEND STATION TOTAL	**1,483**	**122,670**	**11.5**	**71.6**	**57.8**	**11,159**	**-**	**-**	**-**	**1,368,840.0**	**4,489,318**	**3.66**	**-**
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	12,950	9.2	-	96.2	8,059	GAS	101,530	1,027,972	104,370.0	404,905	3.13	3.99
26. POLK #1 TOTAL	**220**	**12,950**	**8.2**	**93.5**	**96.2**	**8,059**	**-**	**-**	**-**	**104,370.0**	**404,905**	**3.13**	**-**
27. POLK #2 ST DUCT FIRING	120	140	0.2	-	38.9	8,000	GAS	1,090	1,027,523	1,120.0	4,347	3.11	3.99
28. POLK #2 ST W/O DUCT FIRING	341	436,200	-	-	-	-	GAS	2,855,060	1,027,999	2,935,000.0	11,386,064	2.61	3.99
29. POLK #2 ST TOTAL	**461**	**436,340**	**131.5**	**-**	**159.1**	**6,729**	**GAS**	**-**	**-**	**2,936,120.0**	**11,390,411**	**2.61**	**-**
30. POLK #2 CT (GAS)	150	1,050	1.0	-	100.0	11,257	GAS	11,500	1,027,826	11,820.0	45,862	4.37	3.99
31. POLK #2 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**150**	**1,050**	**1.0**	**-**	**100.0**	**11,257**	**-**	**-**	**-**	**11,820.0**	**45,862**	**4.37**	**-**
33. POLK #3 CT (GAS)	150	750	0.7	-	100.0	11,187	GAS	8,160	1,028,186	8,390.0	32,542	4.34	3.99
34. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**150**	**750**	**0.7**	**-**	**100.0**	**11,187**	**-**	**-**	**-**	**8,390.0**	**32,542**	**4.34**	**-**
36. POLK #4 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,061**	**438,140**	**57.4**	**73.0**	**157.9**	**6,747**	**-**	**-**	**-**	**2,956,330.0**	**11,468,815**	**2.62**	**-**
39. POLK STATION TOTAL	**1,281**	**451,090**	**48.9**	**76.6**	**151.6**	**6,785**	**-**	**-**	**-**	**3,060,700.0**	**11,873,720**	**2.63**	**-**
40. BAYSIDE #1	701	175,340	34.7	58.0	83.4	7,309	GAS	1,246,640	1,027,995	1,281,540.0	4,971,637	2.84	3.99
41. BAYSIDE #2	929	494,100	73.9	96.8	76.3	7,400	GAS	3,556,800	1,028,003	3,656,400.0	14,184,624	2.87	3.99
42. BAYSIDE #3	56	350	0.9	98.6	89.3	12,200	GAS	4,160	1,026,442	4,270.0	16,590	4.74	3.99
43. BAYSIDE #4	56	50	0.1	98.6	89.3	12,200	GAS	590	1,033,898	610.0	2,353	4.71	3.99
44. BAYSIDE #5	56	760	1.9	98.6	84.8	12,184	GAS	9,010	1,027,747	9,260.0	35,932	4.73	3.99
45. BAYSIDE #6	56	550	1.4	98.6	89.3	12,055	GAS	6,450	1,027,907	6,630.0	25,723	4.68	3.99
46. BAYSIDE TOTAL	**1,854**	**671,150**	**50.3**	**82.3**	**78.1**	**7,388**	**GAS**	**4,823,650**	**1,028,000**	**4,958,710.0**	**19,236,859**	**2.87**	**3.99**
47. SYSTEM	**5,046**	**1,312,330**	**36.1**	**70.7**	**101.6**	**7,154**	**-**	**-**	**-**	**9,388,250.0**	**35,599,897**	**2.71**	**-**

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

(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. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 20 OF 30

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2019

(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. BIG BEND SOLAR	19.4	2,400	16.6	-	16.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	150	13.4	-	13.4	-	SOLAR	-	-	-	-	-	-
4. FUTURE SOLAR	405.0	56,930	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
5. TOTAL SOLAR (3)	**427.5**	**59,700**	**18.8**	**-**	**18.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
6. B.B.#1 (GAS)	315	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
7. B.B.#1 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
8. TOTAL BIG BEND #1	**315**	**0**	**0.0**	**88.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
9. B.B.#2 (GAS)	350	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
10. B.B.#2 (COAL)	0	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
11. TOTAL BIG BEND #2	**350**	**0**	**0.0**	**88.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
12. B.B.#3 (GAS)	355	5,870	2.2	-	-	-	GAS	68,580	1,027,997	70,500.0	281,855	4.80	4.11
13. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
14. TOTAL BIG BEND #3	**355**	**5,870**	**2.2**	**91.7**	**32.4**	**12,010**		**-**	**-**	**70,500.0**	**281,855**	**4.80**	**-**
15. B.B.#4 (GAS)	195	8,340	5.7	-	-	-	GAS	89,120	1,027,940	91,610.0	366,272	4.39	4.11
16. B.B.#4 (COAL)	442	158,400	48.2	-	-	-	COAL	77,360	22,500,517	1,740,640.0	5,413,466	3.42	69.98
17. TOTAL BIG BEND #4	**442**	**166,740**	**50.7**	**74.5**	**59.7**	**10,989**		**-**	**-**	**1,832,250.0**	**5,779,738**	**3.47**	**-**
18. B.B. IGNITION	-	-	-	-	-	-	GAS	8,350	-	8,580.0	34,317	-	4.11
19. BIG BEND 1-4 COAL TOTAL	**842**	**158,400**	**25.3**	**-**	**-**	**10,989**	**COAL**	**77,360**	**22,500,517**	**1,740,640.0**	**5,413,466**	**3.42**	**69.98**
20. B.B.C.T.#4 (OIL)	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	230	0.5	-	75.4	12,304	GAS	2,750	1,029,091	2,830.0	11,302	4.91	4.11
22. B.B.C.T.#4 TOTAL	**61**	**230**	**0.5**	**98.2**	**75.4**	**12,304**	**-**	**-**	**-**	**2,830.0**	**11,302**	**4.91**	**-**
23. BIG BEND STATION TOTAL	**1,523**	**172,840**	**15.3**	**85.4**	**58.0**	**11,025**	**-**	**-**	**-**	**1,905,580.0**	**6,107,212**	**3.53**	**-**
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)	205	15,600	10.2	-	83.6	8,197	GAS	124,390	1,028,057	127,880.0	511,227	3.28	4.11
26. POLK #1 TOTAL	**220**	**15,600**	**9.5**	**93.5**	**83.6**	**8,197**	**-**	**-**	**-**	**127,880.0**	**511,227**	**3.28**	**-**
27. POLK #2 ST DUCT FIRING	120	2,620	2.9	-	70.4	8,176	GAS	20,840	1,027,831	21,420.0	85,650	3.27	4.11
28. POLK #2 ST W/O DUCT FIRING	360	665,870	-	-	-	-	GAS	4,381,990	1,028,001	4,504,690.0	18,009,410	2.70	4.11
29. POLK #2 ST TOTAL	**480**	**668,490**	**187.2**	**-**	**182.1**	**6,771**	**GAS**	**-**	**-**	**4,526,110.0**	**18,095,060**	**2.71**	**-**
30. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. POLK #2 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. POLK #2 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
33. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #3 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
35. POLK #3 TOTAL (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #4 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #5 CT (GAS) (4)	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #2 CC TOTAL	**1,200**	**668,490**	**74.9**	**93.2**	**182.1**	**6,771**	**-**	**-**	**-**	**4,526,110.0**	**18,095,060**	**2.71**	**-**
39. POLK STATION TOTAL	**1,420**	**684,090**	**64.8**	**93.2**	**171.6**	**6,803**	**-**	**-**	**-**	**4,653,990.0**	**18,606,287**	**2.72**	**-**
40. BAYSIDE #1	792	408,100	69.3	96.6	82.6	7,204	GAS	2,859,820	1,027,995	2,939,880.0	11,753,489	2.88	4.11
41. BAYSIDE #2	1,047	133,390	17.1	59.3	72.4	7,353	GAS	954,170	1,027,993	980,880.0	3,921,515	2.94	4.11
42. BAYSIDE #3	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	2,795	4.66	4.11
43. BAYSIDE #4	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	2,795	4.66	4.11
44. BAYSIDE #5	61	170	0.4	98.6	69.7	13,000	GAS	2,160	1,023,148	2,210.0	8,877	5.22	4.11
45. BAYSIDE #6	61	110	0.2	98.6	90.2	12,091	GAS	1,300	1,023,077	1,330.0	5,343	4.86	4.11
46. BAYSIDE TOTAL	**2,083**	**541,890**	**35.0**	**78.1**	**79.8**	**7,244**	**GAS**	**3,818,810**	**1,027,985**	**3,925,680.0**	**15,694,814**	**2.90**	**4.11**
47. SYSTEM	**5,454**	**1,458,520**	**35.9**	**78.0**	**115.3**	**7,189**	**-**	**-**	**-**	**10,485,250.0**	**40,408,313**	**2.77**	**-**

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

(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 2019 THROUGH JUNE 2019

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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)	0	0	0	1,120	0	0
20. UNIT COST ($/BBL)	0.00	0.00	0.00	127.48	0.00	0.00
21. AMOUNT ($)	0	0	0	142,781	0	0
22. ENDING INVENTORY:						
23. UNITS (BBL)	44,403	44,403	44,403	43,283	43,283	43,283
24. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48
25. AMOUNT ($)	5,660,639	5,660,639	5,660,639	5,517,858	5,517,858	5,517,858
26. DAYS SUPPLY: NORMAL	14,471	14,471	14,510	14,144	14,144	14,144
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	22,000	22,000	22,000	22,000	22,000	22,000
30. UNIT COST ($/TON)	55.82	75.23	75.63	75.16	74.96	74.98
31. AMOUNT ($)	1,228,102	1,655,059	1,663,932	1,653,485	1,649,229	1,649,541
32. BURNED:						
33. UNITS (TONS)	92,490	83,560	75,300	28,060	54,960	55,070
34. UNIT COST ($/TON)	70.58	71.24	70.89	71.35	71.05	70.95
35. AMOUNT ($)	6,527,543	5,952,831	5,338,152	2,002,090	3,905,065	3,907,170
36. ENDING INVENTORY:						
37. UNITS (TONS)	489,726	428,166	374,866	368,806	335,846	302,776
38. UNIT COST ($/TON)	74.09	74.86	75.77	76.12	76.95	77.96
39. AMOUNT ($)	36,285,360	32,053,042	28,402,276	28,074,125	25,841,743	23,604,568
40. DAYS SUPPLY:	175	204	218	243	184	164
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	8,199,120	6,954,080	7,716,930	8,923,340	10,672,165	11,051,680
43. UNIT COST ($/MCF)	4.33	4.33	4.50	3.75	3.68	3.71
44. AMOUNT ($)	35,533,490	30,079,995	34,691,692	33,501,441	39,239,000	40,957,292
45. BURNED:						
46. UNITS (MCF)	8,199,120	6,954,080	7,716,930	8,923,340	10,283,060	11,051,680
47. UNIT COST ($/MCF)	4.32	4.33	4.51	3.79	3.72	3.70
48. AMOUNT ($)	35,430,530	30,120,555	34,817,692	33,808,881	38,219,240	40,914,092
49. ENDING INVENTORY:						
50. UNITS (MCF)	1,167,315	1,167,315	1,167,315	1,167,315	1,556,420	1,556,420
51. UNIT COST ($/MCF)	3.15	3.11	3.01	2.74	2.71	2.74
52. AMOUNT ($)	3,675,360	3,634,800	3,508,800	3,201,360	4,221,120	4,264,320
53. DAYS SUPPLY:	4	4	4	4	5	5
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 2019 THROUGH DECEMBER 2019

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	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)	0	0	0	0	0	0	1,120
20.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	127.48
21.	AMOUNT ($)	0	0	0	0	0	0	142,781
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	43,283	43,283	43,283	43,283	43,283	43,283	43,283
24.	UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48	127.48
25.	AMOUNT ($)	5,517,858	5,517,858	5,517,858	5,517,858	5,517,858	5,517,858	5,517,858
26.	DAYS SUPPLY: NORMAL	14,144	14,144	14,144	14,144	14,144	14,144	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	22,000	22,000	22,000	22,000	22,000	28,000	270,000
30.	UNIT COST ($/TON)	75.05	74.91	74.69	74.59	74.32	72.70	73.16
31.	AMOUNT ($)	1,651,152	1,647,913	1,643,207	1,640,968	1,635,058	2,035,667	19,753,313
32.	BURNED:							
33.	UNITS (TONS)	57,850	57,160	0	0	52,010	77,360	633,820
34.	UNIT COST ($/TON)	71.88	70.93	0.00	0.00	70.47	69.98	70.88
35.	AMOUNT ($)	4,158,424	4,054,195	0	0	3,665,192	5,413,466	44,924,128
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	266,926	231,766	253,766	275,766	245,756	196,396	196,396
38.	UNIT COST ($/TON)	79.34	81.13	80.57	80.10	81.75	85.26	85.26
39.	AMOUNT ($)	21,177,477	18,803,376	20,446,583	22,087,551	20,091,098	16,743,980	16,743,980
40.	DAYS SUPPLY:	214	373	444	196	102	71	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	11,483,590	11,839,350	11,758,720	10,618,300	7,618,535	8,514,830	115,350,640
43.	UNIT COST ($/MCF)	3.74	3.73	3.71	3.85	4.06	4.13	3.92
44.	AMOUNT ($)	42,893,979	44,214,542	43,661,132	40,921,918	30,916,865	35,151,567	451,762,913
45.	BURNED:							
46.	UNITS (MCF)	11,483,590	11,839,350	11,758,720	10,618,300	8,007,640	8,514,830	115,350,640
47.	UNIT COST ($/MCF)	3.73	3.73	3.71	3.85	3.99	4.11	3.92
48.	AMOUNT ($)	42,845,659	44,206,222	43,681,292	40,877,758	31,934,705	34,994,847	451,851,473
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,556,420	1,556,420	1,556,420	1,556,420	1,167,315	1,167,315	1,167,315
51.	UNIT COST ($/MCF)	2.77	2.78	2.76	2.79	2.85	2.98	2.98
52.	AMOUNT ($)	4,312,640	4,320,960	4,300,800	4,344,960	3,327,120	3,483,840	3,483,840
53.	DAYS SUPPLY:	5	5	5	5	4	4	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

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

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH JUNE 2019

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		CENTS/KWH				
		TYPE	TOTAL	WHEELED FROM	MWH	(A)	(B)	TOTAL $		
		&	MWH	OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST	GAINS ON
MONTH	SOLD TO	SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$	SALES
Jan-19	SEMINOLE	JURISD. SCH. - D	820.0	0.0	820.0	2.388	2.487	19,580.00	20,394.00	814.00
	VARIOUS	JURISD. MKT. BASE	1,110.0	0.0	1,110.0	2.560	2.816	28,415.34	31,260.00	2,844.66
	TOTAL		**1,930.0**	**0.0**	**1,930.0**	**2.487**	**2.676**	**47,995.34**	**51,654.00**	**3,658.66**
Feb-19	SEMINOLE	JURISD. SCH. - D	660.0	0.0	660.0	2.397	2.497	15,820.00	16,478.00	658.00
	VARIOUS	JURISD. MKT. BASE	880.0	0.0	880.0	2.507	2.758	22,061.43	24,270.00	2,208.57
	TOTAL		**1,540.0**	**0.0**	**1,540.0**	**2.460**	**2.646**	**37,881.43**	**40,748.00**	**2,866.57**
Mar-19	SEMINOLE	JURISD. SCH. - D	870.0	0.0	870.0	2.306	2.402	20,060.00	20,894.00	834.00
	VARIOUS	JURISD. MKT. BASE	1,010.0	0.0	1,010.0	2.502	2.752	25,270.20	27,800.00	2,529.80
	TOTAL		**1,880.0**	**0.0**	**1,880.0**	**2.411**	**2.590**	**45,330.20**	**48,694.00**	**3,363.80**
Apr-19	SEMINOLE	JURISD. SCH. - D	1,090.0	0.0	1,090.0	2.045	2.130	22,290.00	23,217.00	927.00
	VARIOUS	JURISD. MKT. BASE	1,020.0	0.0	1,020.0	2.183	2.402	22,270.50	24,500.00	2,229.50
	TOTAL		**2,110.0**	**0.0**	**2,110.0**	**2.112**	**2.261**	**44,560.50**	**47,717.00**	**3,156.50**
May-19	SEMINOLE	JURISD. SCH. - D	930.0	0.0	930.0	1.992	2.075	18,530.00	19,300.00	770.00
	VARIOUS	JURISD. MKT. BASE	1,050.0	0.0	1,050.0	2.122	2.334	22,279.59	24,510.00	2,230.41
	TOTAL		**1,980.0**	**0.0**	**1,980.0**	**2.061**	**2.213**	**40,809.59**	**43,810.00**	**3,000.41**
Jun-19	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	2.044	2.129	20,240.00	21,082.00	842.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	2.355	2.590	21,897.81	24,090.00	2,192.19
	TOTAL		**1,920.0**	**0.0**	**1,920.0**	**2.195**	**2.353**	**42,137.81**	**45,172.00**	**3,034.19**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2019 THROUGH DECEMBER 2019

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
Jul-19	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	2.090	2.177	20,900.00	21,769.00	869.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	2.433	2.677	21,897.81	24,090.00	2,192.19
	TOTAL		**1,900.0**	**0.0**	**1,900.0**	**2.253**	**2.414**	**42,797.81**	**45,859.00**	**3,061.19**
Aug-19	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	2.115	2.203	21,360.00	22,248.00	888.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	2.396	2.636	27,079.11	29,790.00	2,710.89
	TOTAL		**2,140.0**	**0.0**	**2,140.0**	**2.264**	**2.432**	**48,439.11**	**52,038.00**	**3,598.89**
Sep-19	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	2.100	2.187	21,000.00	21,873.00	873.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	2.357	2.592	21,915.99	24,110.00	2,194.01
	TOTAL		**1,930.0**	**0.0**	**1,930.0**	**2.224**	**2.383**	**42,915.99**	**45,983.00**	**3,067.01**
Oct-19	SEMINOLE	JURISD. SCH. - D	730.0	0.0	730.0	2.195	2.286	16,020.00	16,686.00	666.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	2.338	2.572	26,415.54	29,060.00	2,644.46
	TOTAL		**1,860.0**	**0.0**	**1,860.0**	**2.281**	**2.459**	**42,435.54**	**45,746.00**	**3,310.46**
Nov-19	SEMINOLE	JURISD. SCH. - D	640.0	0.0	640.0	2.234	2.327	14,300.00	14,895.00	595.00
	VARIOUS	JURISD. MKT. BASE	700.0	0.0	700.0	2.391	2.630	16,734.69	18,410.00	1,675.31
	TOTAL		**1,340.0**	**0.0**	**1,340.0**	**2.316**	**2.485**	**31,034.69**	**33,305.00**	**2,270.31**
Dec-19	SEMINOLE	JURISD. SCH. - D	590.0	0.0	590.0	2.315	2.412	13,660.00	14,228.00	568.00
	VARIOUS	JURISD. MKT. BASE	1,200.0	0.0	1,200.0	2.466	2.713	29,587.95	32,550.00	2,962.05
	TOTAL		**1,790.0**	**0.0**	**1,790.0**	**2.416**	**2.613**	**43,247.95**	**46,778.00**	**3,530.05**
TOTAL	SEMINOLE	JURISD. SCH. - D	10,330.0	0.0	10,330.0	2.166	2.256	223,760.00	233,064.00	9,304.00
Jan-19	VARIOUS	JURISD. MKT. BASE	11,990.0	0.0	11,990.0	2.384	2.623	285,825.96	314,440.00	28,614.04
THRU	**TOTAL**		**22,320.0**	**0.0**	**22,320.0**	**2.283**	**2.453**	**509,585.96**	**547,504.00**	**37,918.04**
Dec-19										

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TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

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-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Feb-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Mar-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Apr-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
May-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Jun-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Jul-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Aug-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Sep-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Oct-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Nov-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
Dec-19									
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**
TOTAL Jan-19			0.0	0.0	0.0	0.0	0.000	0.000	0.00
THRU Dec-19	**TOTAL**		**0.0**	**0.0**	**0.0**	**0.0**	**0.000**	**0.000**	**0.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUST-
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	MENT
Jan-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,690.0	0.0	0.0	7,690.0	3.779	3.779	290,630.00
	TOTAL		7,690.0	0.0	0.0	7,690.0	3.779	3.779	290,630.00
Feb-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,290.0	0.0	0.0	7,290.0	3.241	3.241	236,240.00
	TOTAL		7,290.0	0.0	0.0	7,290.0	3.241	3.241	236,240.00
Mar-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,550.0	0.0	0.0	7,550.0	2.506	2.506	189,240.00
	TOTAL		7,550.0	0.0	0.0	7,550.0	2.506	2.506	189,240.00
Apr-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,530.0	0.0	0.0	7,530.0	2.168	2.168	163,260.00
	TOTAL		7,530.0	0.0	0.0	7,530.0	2.168	2.168	163,260.00
May-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,540.0	0.0	0.0	7,540.0	2.980	2.980	224,660.00
	TOTAL		7,540.0	0.0	0.0	7,540.0	2.980	2.980	224,660.00
Jun-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.512	2.512	187,380.00
	TOTAL		7,460.0	0.0	0.0	7,460.0	2.512	2.512	187,380.00
Jul-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,460.0	0.0	0.0	7,460.0	3.036	3.036	226,500.00
	TOTAL		7,460.0	0.0	0.0	7,460.0	3.036	3.036	226,500.00
Aug-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,540.0	0.0	0.0	7,540.0	3.534	3.534	266,490.00
	TOTAL		7,540.0	0.0	0.0	7,540.0	3.534	3.534	266,490.00
Sep-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,500.0	0.0	0.0	7,500.0	2.517	2.517	188,810.00
	TOTAL		7,500.0	0.0	0.0	7,500.0	2.517	2.517	188,810.00
Oct-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,600.0	0.0	0.0	7,600.0	3.272	3.272	248,690.00
	TOTAL		7,600.0	0.0	0.0	7,600.0	3.272	3.272	248,690.00
Nov-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,370.0	0.0	0.0	7,370.0	3.054	3.054	225,080.00
	TOTAL		7,370.0	0.0	0.0	7,370.0	3.054	3.054	225,080.00
Dec-19	VARIOUS	CO-GEN.							
		AS AVAIL.	7,590.0	0.0	0.0	7,590.0	2.568	2.568	194,890.00
	TOTAL		7,590.0	0.0	0.0	7,590.0	2.568	2.568	194,890.00
TOTAL	VARIOUS	CO-GEN.							
Jan-19		AS AVAIL.	90,120.0	0.0	0.0	90,120.0	2.932	2.932	2,641,870.00
THRU	TOTAL		90,120.0	0.0	0.0	90,120.0	2.932	2.932	2,641,870.00
Dec-19									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
Jan-19	VARIOUS	ECONOMY	52,780.0	0.0	52,780.0	2.458	1,297,380.00	4.874	2,572,390.00	1,275,010.00
Feb-19	VARIOUS	ECONOMY	68,810.0	0.0	68,810.0	2.432	1,673,580.00	3.539	2,435,110.00	761,530.00
Mar-19	VARIOUS	ECONOMY	78,890.0	0.0	78,890.0	2.351	1,854,620.00	3.303	2,605,420.00	750,800.00
Apr-19	VARIOUS	ECONOMY	133,800.0	0.0	133,800.0	2.077	2,778,930.00	2.987	3,996,190.00	1,217,260.00
May-19	VARIOUS	ECONOMY	117,020.0	0.0	117,020.0	2.054	2,403,530.00	3.800	4,446,880.00	2,043,350.00
Jun-19	VARIOUS	ECONOMY	176,570.0	0.0	176,570.0	2.075	3,663,800.00	4.056	7,161,460.00	3,497,660.00
Jul-19	VARIOUS	ECONOMY	201,640.0	0.0	201,640.0	2.098	4,230,490.00	3.915	7,894,990.00	3,664,500.00
Aug-19	VARIOUS	ECONOMY	186,880.0	0.0	186,880.0	2.102	3,928,210.00	3.621	6,766,250.00	2,838,040.00
Sep-19	VARIOUS	ECONOMY	192,270.0	0.0	192,270.0	2.092	4,022,310.00	4.401	8,461,470.00	4,439,160.00
Oct-19	VARIOUS	ECONOMY	160,750.0	0.0	160,750.0	2.190	3,520,280.00	4.131	6,640,570.00	3,120,290.00
Nov-19	VARIOUS	ECONOMY	124,800.0	0.0	124,800.0	2.234	2,787,990.00	3.742	4,670,470.00	1,882,480.00
Dec-19	VARIOUS	ECONOMY	95,750.0	0.0	95,750.0	2.335	2,235,840.00	4.654	4,456,360.00	2,220,520.00
TOTAL	VARIOUS	ECONOMY	**1,589,960.0**	**0.0**	**1,589,960.0**	**2.163**	**34,396,960.00**	**3.906**	**62,107,560.00**	**27,710,600.00**

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

	Current Sept 18 - Dec 18	Projected Jan 19 - Dec 19	Difference $	Difference %
Base Rate Revenue	70.43	66.55	(3.88)	-5.5%
Fuel Recovery Revenue	28.18	24.05	(4.13)	-14.7%
Conservation Revenue	2.46	3.21	0.75	30.5%
Capacity Revenue	0.66	1.03	0.37	56.1%
Environmental Revenue	3.43	2.22	(1.21)	-35.3%
Florida Gross Receipts Tax Revenue	2.70	2.49	(0.21)	-7.8%
TOTAL REVENUE	**$107.86**	**$99.55**	**($8.31)**	**-7.7%**

SCHEDULE H1

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

		ACTUAL 2016	ACTUAL 2017	ACT/EST 2018	EST 2019	DIFFERENCE (%) 2017-2016	2018-2017	2019-2018
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2	LIGHT OIL [1]	1,889,022	10,825	0	142,781	-99.4%	-100.0%	0.0%
3	COAL	272,390,442	198,469,769	108,794,918	44,924,128	-27.1%	-45.2%	-58.7%
4	NATURAL GAS	302,563,572	412,107,824	459,450,124	451,851,473	36.2%	11.5%	-1.7%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**576,843,036**	**610,588,418**	**568,245,042**	**496,918,382**	**5.9%**	**-6.9%**	**-12.6%**
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9	LIGHT OIL [1]	182	36	81	600	-80.2%	125.0%	640.7%
10	COAL	7,754,354	6,013,495	2,980,984	1,249,950	-22.5%	-50.4%	-58.1%
11	NATURAL GAS	9,865,453	13,685,288	15,818,664	16,516,370	38.7%	15.6%	4.4%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	3,316	44,594	137,856	1,022,630	1244.8%	209.1%	641.8%
14	**TOTAL (MWH)**	**17,623,305**	**19,743,413**	**18,937,585**	**18,789,550**	**12.0%**	**-4.1%**	**-0.8%**
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16	LIGHT OIL (BBL) [1]	532	85	0	1,120	-84.0%	-100.0%	0.0%
17	COAL (TON)	3,397,515	2,655,830	1,409,927	633,820	-21.8%	-46.9%	-55.0%
18	NATURAL GAS (MCF)	77,886,370	100,512,457	115,173,325	115,350,640	29.1%	14.6%	0.2%
19	NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20	OTHER	0	0	0	0	0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)							
21	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22	LIGHT OIL [1]	3,071	495	1,349	6,460	-83.9%	172.5%	378.9%
23	COAL	82,203,563	64,801,532	33,200,233	14,260,840	-21.2%	-48.8%	-57.0%
24	NATURAL GAS	79,678,589	102,771,003	117,903,382	118,415,450	29.0%	14.7%	0.4%
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)**	**161,885,222**	**167,573,029**	**151,104,964**	**132,682,750**	**3.5%**	**-9.8%**	**-12.2%**
	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	0.00	0.00	0.0%	0.0%	0.0%
30	COAL	44.00	30.45	15.74	6.66	-30.8%	-48.3%	-57.7%
31	NATURAL GAS	55.98	69.32	83.53	87.90	23.8%	20.5%	5.2%
32	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33	OTHER	0.02	0.23	0.73	5.44	1050.0%	217.4%	645.2%
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]	3,550.79	127.35	0.00	127.48	-96.4%	-100.0%	0.0%
37	COAL ($/TON)	80.17	74.73	77.16	70.88	-6.8%	3.3%	-8.1%
38	NATURAL GAS ($/MCF)	3.88	4.10	3.99	3.92	5.7%	-2.7%	-1.8%
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]	615.12	21.87	0.00	22.10	-96.4%	-100.0%	0.0%
43	COAL	3.31	3.06	3.28	3.15	-7.6%	7.2%	-4.0%
44	NATURAL GAS	3.80	4.01	3.90	3.82	5.5%	-2.7%	-2.1%
45	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	**TOTAL ($/MMBTU)**	**3.56**	**3.64**	**3.76**	**3.75**	**2.2%**	**3.3%**	**-0.3%**
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49	LIGHT OIL [1]	16,874	13,750	16,654	10,767	-18.5%	21.1%	-35.3%
50	COAL	10,601	10,776	11,137	11,409	1.7%	3.4%	2.4%
51	NATURAL GAS	8,077	7,510	7,453	7,170	-7.0%	-0.8%	-3.8%
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)**	**9,186**	**8,488**	**7,979**	**7,062**	**-7.6%**	**-6.0%**	**-11.5%**
	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]	1,037.92	30.07	0.00	23.80	-97.1%	-100.0%	0.0%
57	COAL	3.51	3.30	3.65	3.59	-6.0%	10.6%	-1.6%
58	NATURAL GAS	3.07	3.01	2.90	2.74	-2.0%	-3.7%	-5.5%
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)**	**3.27**	**3.09**	**3.00**	**2.64**	**-5.5%**	**-2.9%**	**-12.0%**

[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 2019 - DECEMBER 2019

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2019 through December 2019

	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	6,379,602	2.719	173,461,390	2.405	153,429,438
TIER II (Over 1,000) kWh	2,920,110	2.719	79,397,779	3.405	99,429,731
Total	9,299,712		252,859,169		252,859,169

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DOCKET NO. 20180001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 3, PAGE 1 OF 1

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2019 - DECEMBER 2019

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

		ESTIMATED JANUARY	ESTIMATED FEBRUARY	ESTIMATED MARCH	ESTIMATED APRIL	ESTIMATED MAY	ESTIMATED JUNE	ESTIMATED JULY	ESTIMATED AUGUST	ESTIMATED SEPTEMBER	ESTIMATED OCTOBER	ESTIMATED NOVEMBER	ESTIMATED 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	$ 15,095,780	$ 15,444,286	$ 15,792,792	$ 16,141,297	$ 16,489,803	$ 16,838,309	$ 17,186,815	$ 17,535,321	$ 17,883,826	$ 18,232,332	$ 18,580,838	$ 18,929,344	$ 15,095,780
12	ENDING BALANCE DEPRECIATION	$ 15,444,286	$ 15,792,792	$ 16,141,297	$ 16,489,803	$ 16,838,309	$ 17,186,815	$ 17,535,321	$ 17,883,826	$ 18,232,332	$ 18,580,838	$ 18,929,344	$ 19,277,850	$ 19,277,850
13														
14														
15	ENDING NET INVESTMENT	$ 5,466,062	$ 5,117,557	$ 4,769,051	$ 4,420,545	$ 4,072,039	$ 3,723,533	$ 3,375,028	$ 3,026,522	$ 2,678,016	$ 2,329,510	$ 1,981,004	$ 1,632,499	$ 1,632,499
16														
17														
18	AVERAGE INVESTMENT	$ 5,640,315	$ 5,291,809	$ 4,943,304	$ 4,594,798	$ 4,246,292	$ 3,897,786	$ 3,549,280	$ 3,200,775	$ 2,852,269	$ 2,503,763	$ 2,155,257	$ 1,806,751	
19	ALLOWED EQUITY RETURN	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	
20	EQUITY COMPONENT AFTER-TAX	$ 20,316	$ 19,061	$ 17,805	$ 16,550	$ 15,295	$ 14,040	$ 12,784	$ 11,529	$ 10,274	$ 9,018	$ 7,763	$ 6,508	$ 160,943
21	CONVERSION TO PRE-TAX	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	
22	EQUITY COMPONENT PRE-TAX	$ 27,283	$ 25,598	$ 23,911	$ 22,226	$ 20,540	$ 18,855	$ 17,168	$ 15,483	$ 13,797	$ 12,111	$ 10,425	$ 8,740	$ 216,137
23														
24	ALLOWED DEBT RETURN	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	
25	DEBT COMPONENT	$ 8,058	$ 7,560	$ 7,062	$ 6,564	$ 6,067	$ 5,569	$ 5,071	$ 4,573	$ 4,075	$ 3,577	$ 3,079	$ 2,581	$ 63,836
26														
27	TOTAL RETURN REQUIREMENTS	$ 35,341	$ 33,158	$ 30,973	$ 28,790	$ 26,607	$ 24,424	$ 22,239	$ 20,056	$ 17,872	$ 15,688	$ 13,504	$ 11,321	$ 279,973
28	PRIOR MONTH TRUE-UP													
29	TOTAL DEPRECIATION & RETURN	$ 383,847	$ 381,664	$ 379,479	$ 377,296	$ 375,113	$ 372,930	$ 370,745	$ 368,562	$ 366,378	$ 364,194	$ 362,010	$ 359,827	$ 4,462,045
30														
31	ESTIMATED FUEL SAVINGS	$ 363,871	$ 363,582	$ 270,249	$ 854,096	$ 341,622	$ 667,331	$ 475,885	$ 856,445	$ 381,004	$ 472,949	$ 281,679	$ 279,931	$ 5,608,643
32	TOTAL DEPRECIATION & RETURN	$ 383,847	$ 381,664	$ 379,479	$ 377,296	$ 375,113	$ 372,930	$ 370,745	$ 368,562	$ 366,378	$ 364,194	$ 362,010	$ 359,827	$ 4,462,045
33	NET BENEFIT (COST) TO RATEPAYER	$ (19,976)	$ (18,082)	$ (109,230)	$ 476,800	$ (33,491)	$ 294,401	$ 105,141	$ 487,883	$ 14,626	$ 108,756	$ (80,331)	$ (79,896)	$ 1,146,599

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - DECEMBER USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046%, DEBT 1.7144%). RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2019 to December 2019

	(1) Jurisdictional Rate Base Actual May 2018 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0289% * 46.00%	0.0133%
Equity = 0.0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.34295
Total Equity Component	5.8046%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.5190%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2019 THROUGH DECEMBER 2019

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

FILED AUGUST 24, 2018

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. 20180001-EI?

A. Yes, I submitted direct testimony on March 15, 2018.

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-3, 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 2019 period.

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

A. Four natural gas combined cycle units are included. These are 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 2019 through

December 2019 represent 83 percent of the total forecasted system net generation for this period.

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. No.

Q. Did Tampa Electric make any other adjustments?

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

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2019 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 four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2019 period, the projected EUOF for Bayside Unit 1 is 1.9 percent, and the POF is 7.1 percent. Therefore, the target EAF for Bayside Unit 1 equals 91.0 percent or:

$$100\% - (1.9\% + 7.1\%) = 91.0\%$$

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

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

A. Maximum equivalent availability is derived 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:

$$EAF_{MAX} = 1 – [0.80\ (1.9\%) + 0.95\ (7.1\%)] = 91.7\%$$

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,

$$EAF_{MIN} = 1 – [1.40 (1.9\%) + 1.10 (7.1\%)] = 89.5\%$$

The equivalent availability maximum and minimum for the other three 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 2019 are shown on page 15 of Document No. 1. There are not any major outages of 28 days or greater planned for the GPIF units during 2019; therefore, no Critical Path Method diagrams are provided. However, Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from February 1, 2019 to February 13, 2019 and November 14, 2019 to November 23, 2019. There are 624 planned outage hours scheduled for the 2019 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 7.1 percent or:

$$\frac{624}{8,760} \times 100\% = 7.1\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Polk Unit 1 has a POF of 8.2 percent. Polk Unit 2 has a POF of 6.6 percent. Bayside Unit 1 has a POF of 7.1 percent, and Bayside Unit 2 has a POF of 7.7 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 1.9 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 13, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(84 + 83)}{8{,}760} \times 100\% = 1.9\%$$

Relative to Bayside Unit 1, the EUOF of 1.9 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 8.5 percent. The unit will have two planned outages in 2019, and the POF is 8.2 percent. Therefore, the target equivalent availability for this unit is 83.3 percent.

Polk Unit 2

The projected EUOF for this unit is 2.5 percent. The unit will have two planned outages in 2019, and the POF is 6.6

percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.9 percent. The unit will have two planned outages in 2019, and the POF is 7.1 percent. Therefore, the target equivalent availability for this unit is 91.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.9 percent. The unit will have two planned outages in 2019, and the POF is 7.7 percent. Therefore, the target equivalent availability for this unit is 87.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 86.5 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 13 of Document No. 1. Except for the months of February 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 February 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 are the targets determined?

A. Net heat rate data for the three most recent July through June annual periods form 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 21 through 24 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 2019 period.

A. The heat rate target for Polk Unit 1 is 10,170 Btu/Net kWh with a range of ± 937 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,930 Btu/Net kWh with a range of ± 173 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,400 Btu/Net kWh with a range of ± 116 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,561 Btu/Net kWh with a range of ± 228 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 10 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 10. 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 $446,098,430 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 $10,838,700 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 14.0 percent as shown in the right-hand column on page 6. Pages 7 through 10 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 9, if the unit operates at 7,284 average net operating heat rate, fuel savings would equal $1,517,065 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 10. 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 $10,838,700. 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 2019 is $2,999,881,612. This produces the maximum allowed jurisdictional incentive of $10,071,700 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 $5,419,348.

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).

$$
\begin{aligned}
GPIP = (&0.0507\ EAP_{PK1} + 0.0190\ EAP_{PK2} \\
&+ 0.0111\ EAP_{BAY1} + 0.0312\ EAP_{BAY2} \\
&+ 0.1057\ HRP_{PK1} + 0.3689\ HRP_{PK2} \\
&+ 0.1400\ HRP_{BAY1} + 0.2735\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2019 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 2019 – DECEMBER 2019

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2019 - DECEMBER 2019
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2019 - DECEMBER 2019

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	10,838.7	5,419.3
+9	9,754.8	4,877.4
+8	8,671.0	4,335.5
+7	7,587.1	3,793.5
+6	6,503.2	3,251.6
+5	5,419.3	2,709.7
+4	4,335.5	2,167.7
+3	3,251.6	1,625.8
+2	2,167.7	1,083.9
+1	1,083.9	541.9
0	0.0	0.0
-1	(1,256.1)	(541.9)
-2	(2,512.1)	(1,083.9)
-3	(3,768.2)	(1,625.8)
-4	(5,024.3)	(2,167.7)
-5	(6,280.3)	(2,709.7)
-6	(7,536.4)	(3,251.6)
-7	(8,792.4)	(3,793.5)
-8	(10,048.5)	(4,335.5)
-9	(11,304.6)	(4,877.4)
-10	(12,560.6)	(5,419.3)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2019 - DECEMBER 2019

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,962,129,480	
Line 2	Month of January	2019	$	2,891,498,066	
Line 3	Month of February	2019	$	2,916,196,278	
Line 4	Month of March	2019	$	2,941,105,455	
Line 5	Month of April	2019	$	2,987,251,423	
Line 6	Month of May	2019	$	3,012,767,528	
Line 7	Month of June	2019	$	3,038,501,584	
Line 8	Month of July	2019	$	2,967,059,323	
Line 9	Month of August	2019	$	2,992,402,954	
Line 10	Month of September	2019	$	3,017,963,063	
Line 11	Month of October	2019	$	3,064,280,019	
Line 12	Month of November	2019	$	3,090,454,077	
Line 13	Month of December	2019	$	3,116,851,706	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,999,881,612	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.46%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,071,700	
Line 18	Jurisdictional Sales			19,482,432	MWH
Line 19	Total Sales			19,482,432	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)		$	10,071,700	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	5,419,348	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	5,419,348	

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 2019 - DECEMBER 2019

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
POLK 1	5.07%	83.3	85.4	79.1	549.8	(342.2)
POLK 2	1.90%	90.9	91.7	89.2	205.7	(1,759.2)
BAYSIDE 1	1.11%	91.0	91.7	89.5	120.0	(60.0)
BAYSIDE 2	3.12%	87.4	88.8	84.7	337.7	(773.7)
GPIF SYSTEM	**11.19%**					

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)
POLK 1	10.57%	10,170	86.4	9,233	11,107	1,145.8	(1,145.8)
POLK 2	36.89%	6,930	80.5	6,757	7,103	3,998.7	(3,998.7)
BAYSIDE 1	14.00%	7,400	80.6	7,284	7,516	1,517.1	(1,517.1)
BAYSIDE 2	27.35%	7,561	60.5	7,334	7,789	2,964.0	(2,964.0)
GPIF SYSTEM	**88.81%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 19 - DEC 19 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 17 - DEC 17 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 16 - DEC 16 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 15 - DEC 15 POF	EUOF	EUOR
POLK 1	5.07%	45.3%	8.2	8.5	9.2	4.4	9.6	10.4	13.3	7.5	11.4	13.5	16.0	19.0
POLK 2	1.90%	17.0%	6.6	2.5	2.7	1.8	6.9	7.8	9.7	9.4	29.1	3.6	3.5	19.2
BAYSIDE 1	1.11%	9.9%	7.1	1.9	2.0	11.6	2.0	2.4	20.0	1.3	1.8	11.8	2.3	2.7
BAYSIDE 2	3.12%	27.8%	7.7	4.9	5.3	9.4	5.1	5.7	7.1	2.9	5.0	7.2	3.7	4.1
GPIF SYSTEM	**11.19%**	**100.0%**	**7.7**	**5.8**	**6.3**	**6.1**	**7.1**	**7.8**	**11.6**	**5.9**	**11.7**	**9.9**	**9.1**	**13.3**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**86.5**			**86.8**			**82.4**			**81.0**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
9.2	**7.4**	**10.9**	**83.4**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 17 - DEC 17	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 16 - DEC 16	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 15 - DEC 15
POLK 1	10.57%	11.9%	10,170	10,085	9,915	10,330
POLK 2	36.89%	41.5%	6,930	6,826	7,806	11,436
BAYSIDE 1	14.00%	15.8%	7,400	7,332	7,455	7,340
BAYSIDE 2	27.35%	30.8%	7,561	7,513	7,643	7,467
GPIF SYSTEM	**88.81%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**7,584**	**7,505**	**7,951**	**9,437**

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TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2019 - DECEMBER 2019
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 POLK 1	446,098.4	445,548.6	549.79	5.07%
EA_2 POLK 2	446,098.4	445,892.7	205.73	1.90%
EA_3 BAYSIDE 1	446,098.4	445,978.4	120.00	1.11%
EA_4 BAYSIDE 2	446,098.4	445,760.8	337.68	3.12%
AVERAGE HEAT RATE				
AHR_1 POLK 1	446,098.43	444,952.64	1,145.79	10.57%
AHR_2 POLK 2	446,098.43	442,099.77	3,998.66	36.89%
AHR_3 BAYSIDE 1	446,098.43	444,581.37	1,517.06	14.00%
AHR_4 BAYSIDE 2	446,098.43	443,134.45	2,963.98	27.35%
TOTAL SAVINGS			**10,838.70**	**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 2019 - DECEMBER 2019

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	549.8	85.4	+10	1,145.8	9,233
+9	494.8	85.2	+9	1,031.2	9,319
+8	439.8	85.0	+8	916.6	9,405
+7	384.9	84.8	+7	802.1	9,492
+6	329.9	84.6	+6	687.5	9,578
+5	274.9	84.4	+5	572.9	9,664
+4	219.9	84.1	+4	458.3	9,750
+3	164.9	83.9	+3	343.7	9,836
+2	110.0	83.7	+2	229.2	9,922
+1	55.0	83.5	+1	114.6	10,009
					10,095
0	0.0	83.3	0	0.0	10,170
					10,245
-1	(34.2)	82.9	-1	(114.6)	10,331
-2	(68.4)	82.5	-2	(229.2)	10,417
-3	(102.7)	82.0	-3	(343.7)	10,503
-4	(136.9)	81.6	-4	(458.3)	10,590
-5	(171.1)	81.2	-5	(572.9)	10,676
-6	(205.3)	80.8	-6	(687.5)	10,762
-7	(239.6)	80.4	-7	(802.1)	10,848
-8	(273.8)	79.9	-8	(916.6)	10,934
-9	(308.0)	79.5	-9	(1,031.2)	11,020
-10	(342.2)	79.1	-10	(1,145.8)	11,107
	Weighting Factor =	5.07%		Weighting Factor =	10.57%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2019 - DECEMBER 2019

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	205.7	91.7	+10	3,998.7	6,757
+9	185.2	91.6	+9	3,598.8	6,767
+8	164.6	91.6	+8	3,198.9	6,776
+7	144.0	91.5	+7	2,799.1	6,786
+6	123.4	91.4	+6	2,399.2	6,796
+5	102.9	91.3	+5	1,999.3	6,806
+4	82.3	91.2	+4	1,599.5	6,816
+3	61.7	91.1	+3	1,199.6	6,825
+2	41.1	91.1	+2	799.7	6,835
+1	20.6	91.0	+1	399.9	6,845
					6,855
0	0.0	90.9	0	0.0	6,930
					7,005
-1	(175.9)	90.7	-1	(399.9)	7,015
-2	(351.8)	90.6	-2	(799.7)	7,024
-3	(527.8)	90.4	-3	(1,199.6)	7,034
-4	(703.7)	90.2	-4	(1,599.5)	7,044
-5	(879.6)	90.1	-5	(1,999.3)	7,054
-6	(1,055.5)	89.9	-6	(2,399.2)	7,064
-7	(1,231.5)	89.7	-7	(2,799.1)	7,073
-8	(1,407.4)	89.6	-8	(3,198.9)	7,083
-9	(1,583.3)	89.4	-9	(3,598.8)	7,093
-10	(1,759.2)	89.2	-10	(3,998.7)	7,103
	Weighting Factor =	1.90%		Weighting Factor =	36.89%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2019 - DECEMBER 2019

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	120.0	91.7	+10	1,517.1	7,284
+9	108.0	91.6	+9	1,365.4	7,288
+8	96.0	91.6	+8	1,213.7	7,292
+7	84.0	91.5	+7	1,061.9	7,296
+6	72.0	91.4	+6	910.2	7,300
+5	60.0	91.3	+5	758.5	7,305
+4	48.0	91.3	+4	606.8	7,309
+3	36.0	91.2	+3	455.1	7,313
+2	24.0	91.1	+2	303.4	7,317
+1	12.0	91.0	+1	151.7	7,321
					7,325
0	0.0	91.0	0	0.0	7,400
					7,475
-1	(6.0)	90.8	-1	(151.7)	7,479
-2	(12.0)	90.7	-2	(303.4)	7,483
-3	(18.0)	90.5	-3	(455.1)	7,487
-4	(24.0)	90.4	-4	(606.8)	7,491
-5	(30.0)	90.2	-5	(758.5)	7,495
-6	(36.0)	90.1	-6	(910.2)	7,500
-7	(42.0)	89.9	-7	(1,061.9)	7,504
-8	(48.0)	89.8	-8	(1,213.7)	7,508
-9	(54.0)	89.6	-9	(1,365.4)	7,512
-10	(60.0)	89.5	-10	(1,517.1)	7,516
	Weighting Factor =	1.11%		Weighting Factor =	14.00%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2019 - DECEMBER 2019

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	337.7	88.8	+10	2,964.0	7,334
+9	303.9	88.7	+9	2,667.6	7,349
+8	270.1	88.5	+8	2,371.2	7,364
+7	236.4	88.4	+7	2,074.8	7,379
+6	202.6	88.3	+6	1,778.4	7,395
+5	168.8	88.1	+5	1,482.0	7,410
+4	135.1	88.0	+4	1,185.6	7,425
+3	101.3	87.9	+3	889.2	7,441
+2	67.5	87.7	+2	592.8	7,456
+1	33.8	87.6	+1	296.4	7,471
					7,486
0	0.0	87.4	0	0.0	7,561
					7,636
-1	(77.4)	87.2	-1	(296.4)	7,652
-2	(154.7)	86.9	-2	(592.8)	7,667
-3	(232.1)	86.6	-3	(889.2)	7,682
-4	(309.5)	86.4	-4	(1,185.6)	7,698
-5	(386.8)	86.1	-5	(1,482.0)	7,713
-6	(464.2)	85.8	-6	(1,778.4)	7,728
-7	(541.6)	85.5	-7	(2,074.8)	7,743
-8	(618.9)	85.3	-8	(2,371.2)	7,759
-9	(696.3)	85.0	-9	(2,667.6)	7,774
-10	(773.7)	84.7	-10	(2,964.0)	7,789
	Weighting Factor =	3.12%		Weighting Factor =	27.35%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

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-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019
1. EAF (%)	90.8	90.8	90.8	60.5	90.8	90.8	90.8	90.8	90.8	32.2	90.8	90.8	83.3
2. POF	0.0	0.0	0.0	33.3	0.0	0.0	0.0	0.0	0.0	64.5	0.0	0.0	8.2
3. EUOF	9.2	9.2	9.2	6.2	9.2	9.2	9.2	9.2	9.2	3.3	9.2	9.2	8.5
4. EUOR	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	66	98	48	141	244	321	310	342	439	195	251	220	2,675
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	678	574	695	579	500	399	434	402	281	549	470	524	6,085
9. POH	0	0	0	240	0	0	0	0	0	480	0	0	720
10. EFOH	55	50	55	36	55	54	55	55	54	20	54	55	599
11. EMOH	13	12	13	9	13	13	13	13	13	5	13	13	143
12. OPER BTU (GBTU)	111	165	76	244	415	567	549	596	779	333	447	374	4,660
13. NET GEN (MWH)	10,890	16,140	7,400	24,050	40,740	55,880	54,140	58,710	76,790	32,710	44,110	36,680	458,240
14. ANOHR (Btu/kwh)	10,216	10,217	10,257	10,161	10,176	10,147	10,145	10,157	10,144	10,173	10,141	10,209	10,170
15. NOF (%)	80.5	80.3	75.2	87.5	85.6	89.3	89.6	88.0	89.7	86.0	90.1	81.3	86.4
16. NPC (MW)	205	205	205	195	195	195	195	195	195	195	195	205	198
17. ANOHR EQUATION	ANOHR = NOF(	-7.778	) +		10,842								

DOCKET NO. 20180001-EI
GPIF 2019 PROJECTION
EXHIBIT NO. BSB-3, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.19E
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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

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-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019
1. EAF (%)	97.3	83.4	87.9	81.1	97.3	97.3	97.3	97.3	97.3	97.3	58.4	97.3	90.9
2. POF	0.0	14.3	9.7	16.7	0.0	0.0	0.0	0.0	0.0	0.0	39.9	0.0	6.6
3. EUOF	2.7	2.3	2.4	2.3	2.7	2.7	2.7	2.7	2.7	2.7	1.6	2.7	2.5
4. EUOR	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	731	661	732	590	732	708	732	732	708	732	590	732	8,380
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	13	11	11	130	12	12	12	12	12	12	131	12	380
9. POH	0	96	72	120	0	0	0	0	0	0	288	0	576
10. EFOH	10	8	9	8	10	10	10	10	10	10	6	10	108
11. EMOH	10	8	9	8	10	10	10	10	10	10	6	10	113
12. OPER BTU (GBTU)	4,622	4,338	4,727	3,537	4,398	4,295	4,450	4,445	4,327	4,417	3,543	4,775	52,039
13. NET GEN (MWH)	613,020	599,550	641,010	519,460	648,670	646,610	673,300	670,740	663,110	656,860	522,000	655,170	7,509,500
14. ANOHR (Btu/kwh)	7,539	7,235	7,375	6,809	6,780	6,643	6,610	6,628	6,525	6,724	6,787	7,289	6,930
15. NOF (%)	69.2	74.8	72.3	82.7	83.3	85.8	86.4	86.1	88.0	84.3	83.2	73.8	80.5
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(	-53.862	) +		11,266								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

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-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019
1. EAF (%)	98.0	52.5	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	55.6	98.0	91.0
2. POF	0.0	46.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.3	0.0	7.1
3. EUOF	2.0	1.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.2	2.0	1.9
4. EUOR	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	729	102	728	705	729	705	729	729	705	729	355	729	7,673
7. RSH	0	251	0	0	0	0	0	0	0	0	46	0	297
8. UH	15	319	15	15	15	15	15	15	15	15	320	15	791
9. POH	0	312	0	0	0	0	0	0	0	0	312	0	624
10. EFOH	8	4	8	7	8	7	8	8	7	8	4	8	84
11. EMOH	8	4	8	7	8	7	8	8	7	8	4	8	83
12. OPER BTU (GBTU)	2,812	414	3,131	2,987	3,128	3,193	3,333	3,309	3,273	3,173	1,442	3,241	33,449
13. NET GEN (MWH)	377,820	55,700	421,850	403,850	423,070	432,590	451,830	448,360	443,870	429,350	194,630	437,190	4,520,110
14. ANOHR (Btu/kwh)	7,443	7,433	7,421	7,397	7,394	7,380	7,378	7,380	7,374	7,390	7,407	7,414	7,400
15. NOF (%)	65.5	68.9	73.2	81.7	82.8	87.5	88.5	87.8	89.8	84.1	78.2	75.8	80.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(	-2.852	) +		7,630								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

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-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019
1. EAF (%)	94.7	94.7	52.0	94.7	94.7	94.7	94.7	94.7	94.7	94.7	94.7	51.9	87.4
2. POF	0.0	0.0	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.2	7.7
3. EUOF	5.3	5.3	2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	2.9	4.9
4. EUOR	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	643	636	386	682	705	682	705	705	682	692	683	386	7,586
7. RSH	62	0	0	0	0	0	0	0	0	13	0	0	74
8. UH	39	36	357	38	39	38	39	39	38	39	38	358	1,100
9. POH	0	0	335	0	0	0	0	0	0	0	0	336	671
10. EFOH	19	17	10	18	19	18	19	19	18	19	18	10	204
11. EMOH	21	19	11	20	21	20	21	21	20	21	20	11	224
12. OPER BTU (GBTU)	1,430	2,820	1,062	2,861	3,017	3,474	3,609	3,601	3,784	3,119	3,297	1,373	33,580
13. NET GEN (MWH)	183,800	371,360	137,260	378,060	399,190	464,790	482,990	481,760	509,460	413,880	439,390	179,070	4,441,010
14. ANOHR (Btu/kwh)	7,783	7,593	7,739	7,567	7,558	7,475	7,473	7,474	7,428	7,535	7,503	7,670	7,561
15. NOF (%)	27.3	55.7	33.9	59.7	61.0	73.4	73.8	73.6	80.4	64.4	69.3	44.3	60.5
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF(		-6.673	) +	7,965								

DOCKET NO. 20180001-EI
GPIF 2019 PROJECTION
EXHIBIT NO. BSB-3, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.19E
PAGE 14 OF 27

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
POLK 1	Apr 20 - Apr 29	Combined Cycle & Gasifier Planned Outage
	Oct 07 - Oct 26	Combined Cycle & Gasifier Planned Outage
POLK 2	Apr 01 - Apr 05	Combined Cycle Planned Outage
	Nov 21 - Nov 25	Combined Cycle Planned Outage
BAYSIDE 1	Feb 01 - Feb 13	Combined Cycle Planned Outage
	Nov 14 - Nov 23	Combined Cycle Planned Outage
BAYSIDE 2	Mar 02 - Mar 15	Combined Cycle Planned Outage
	Dec 02 - Dec 15	Combined Cycle Planned Outage

+ 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 2019 - DECEMBER 2019

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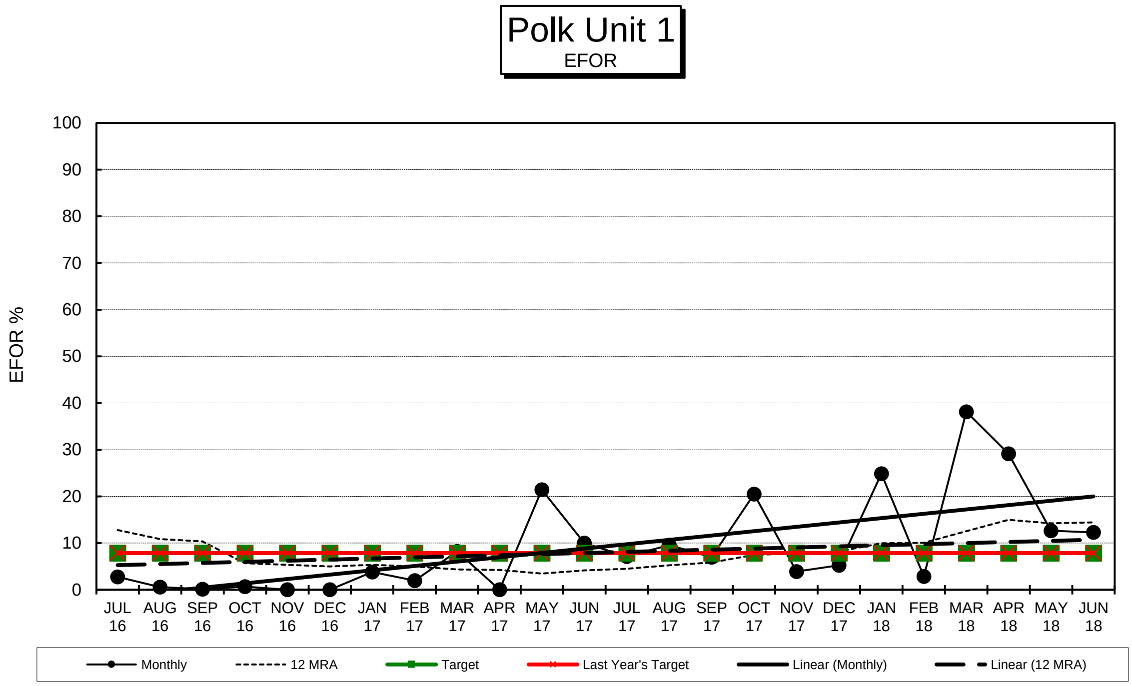
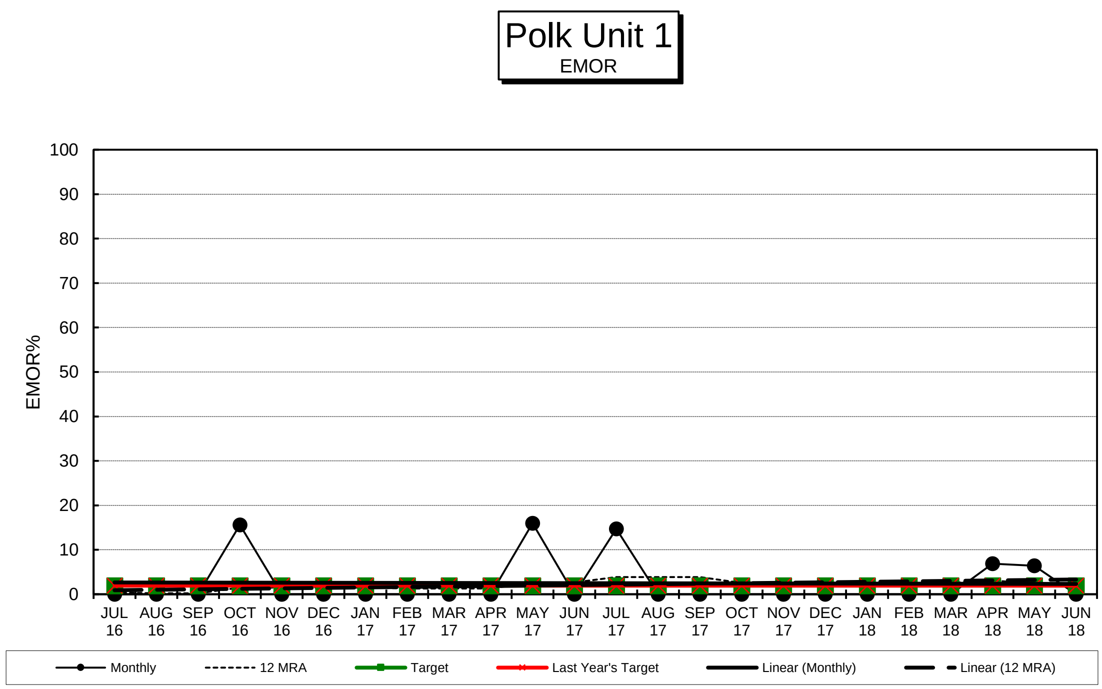
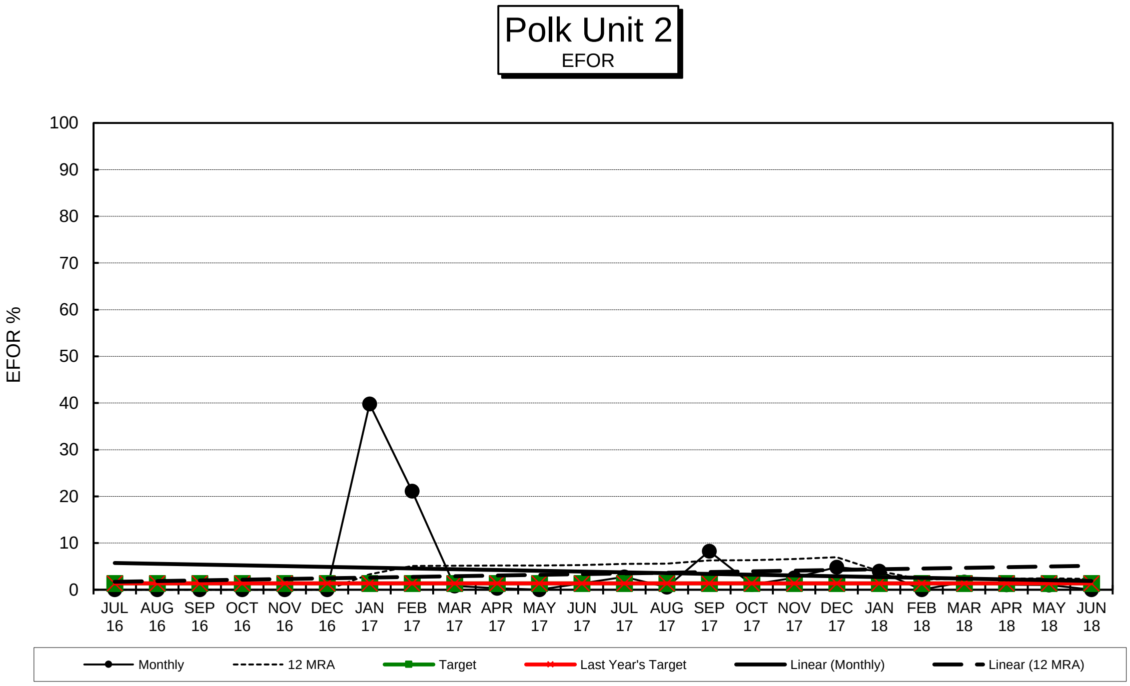
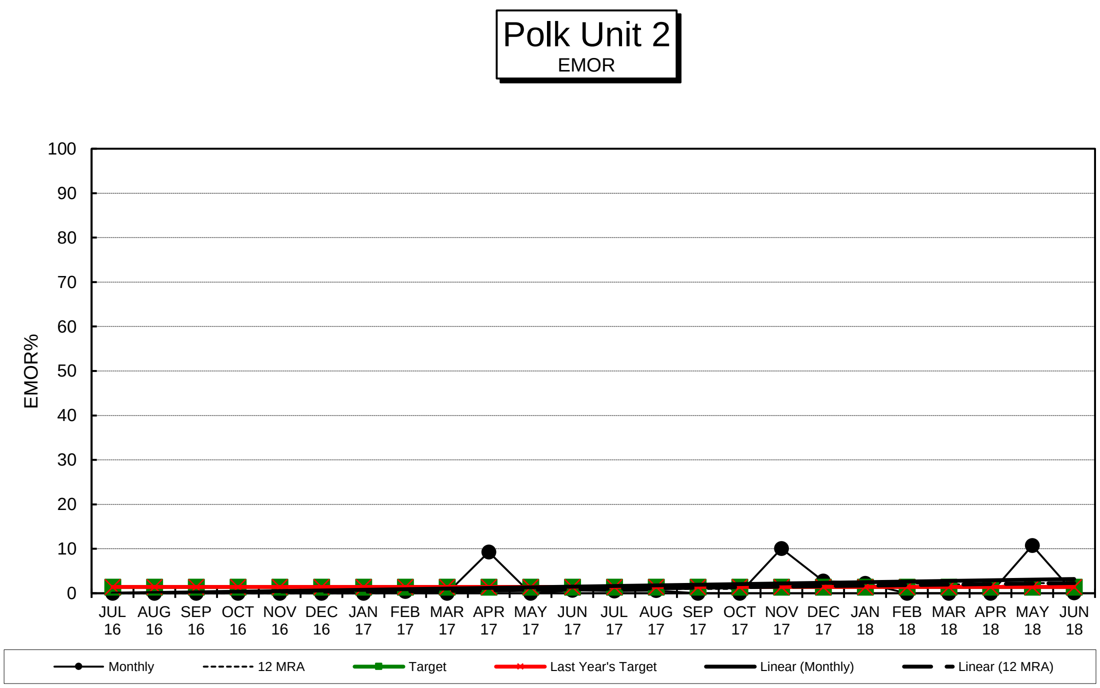
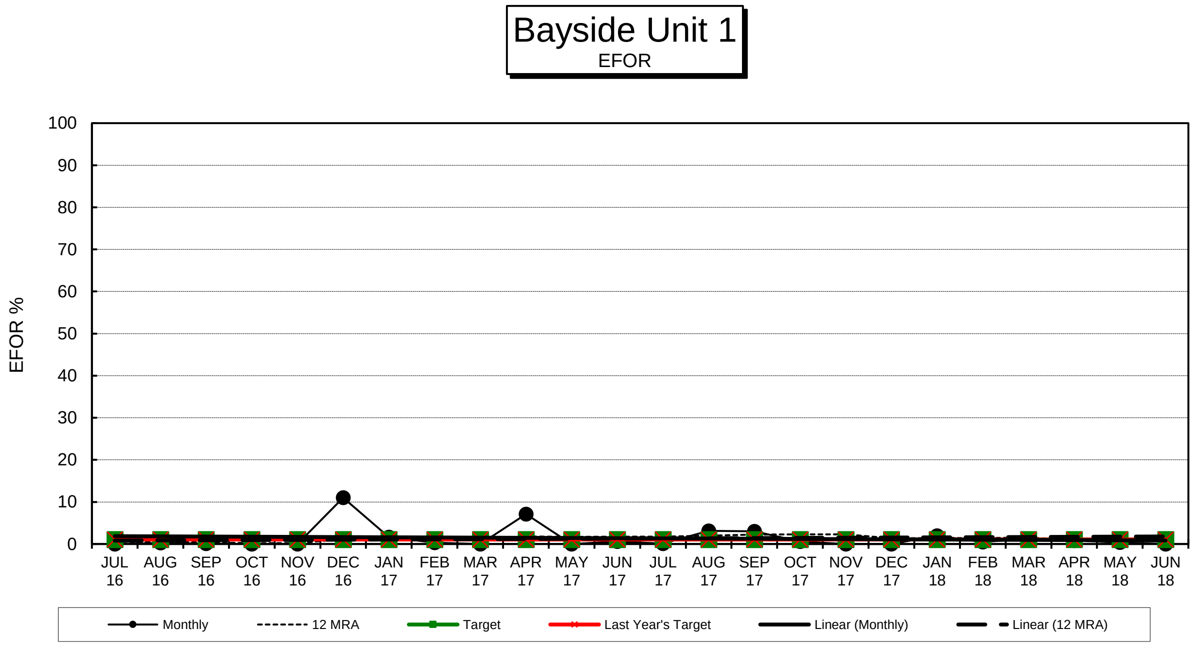
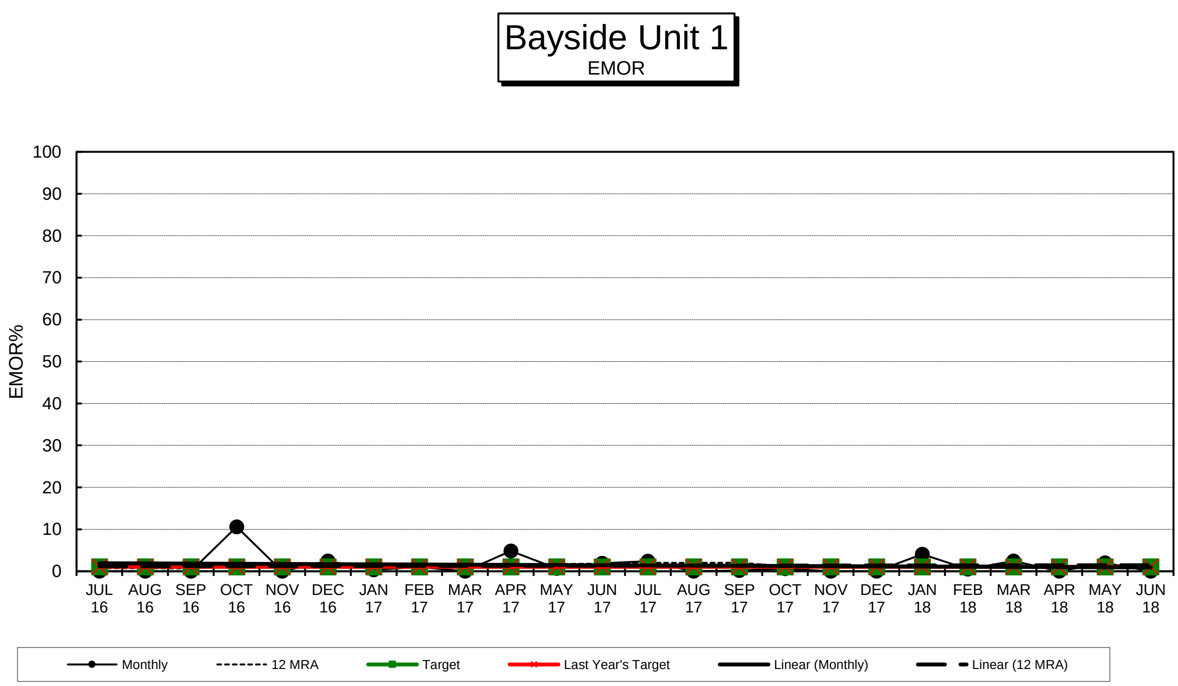

Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

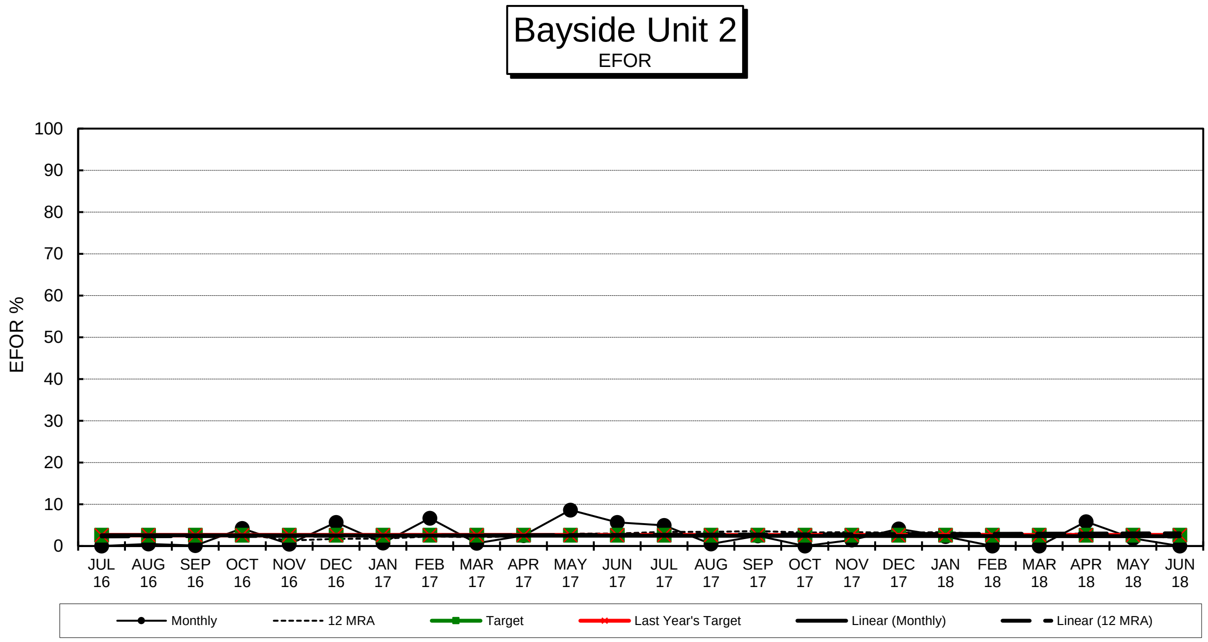

Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

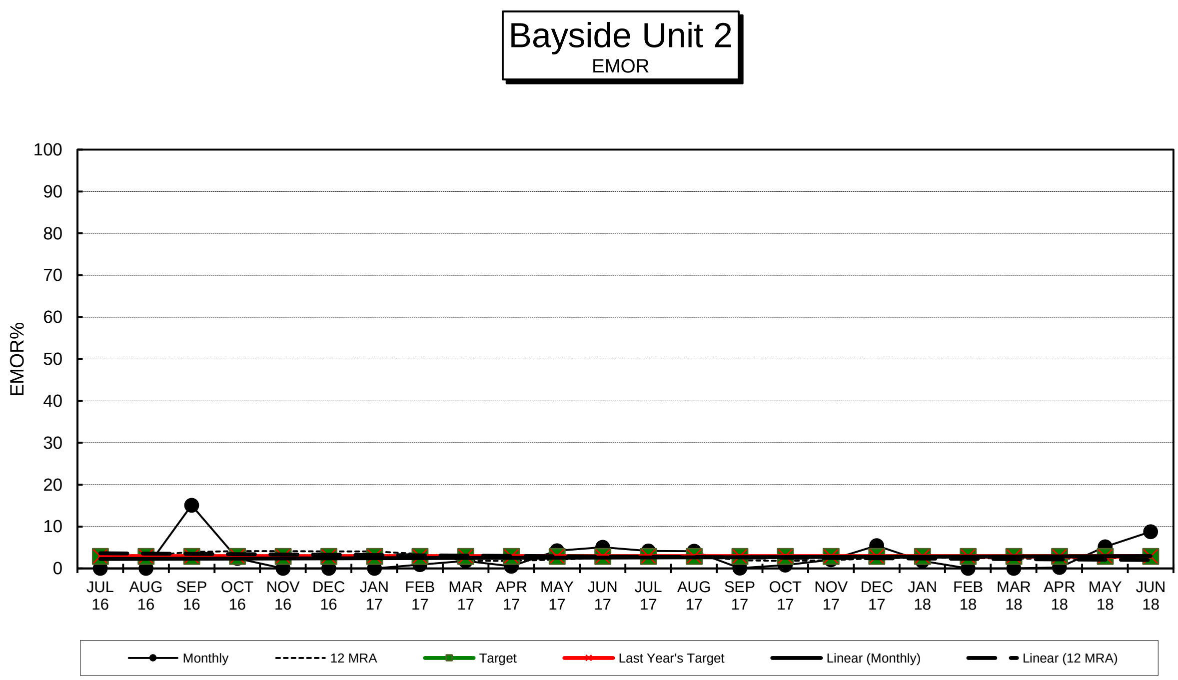

Polk Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

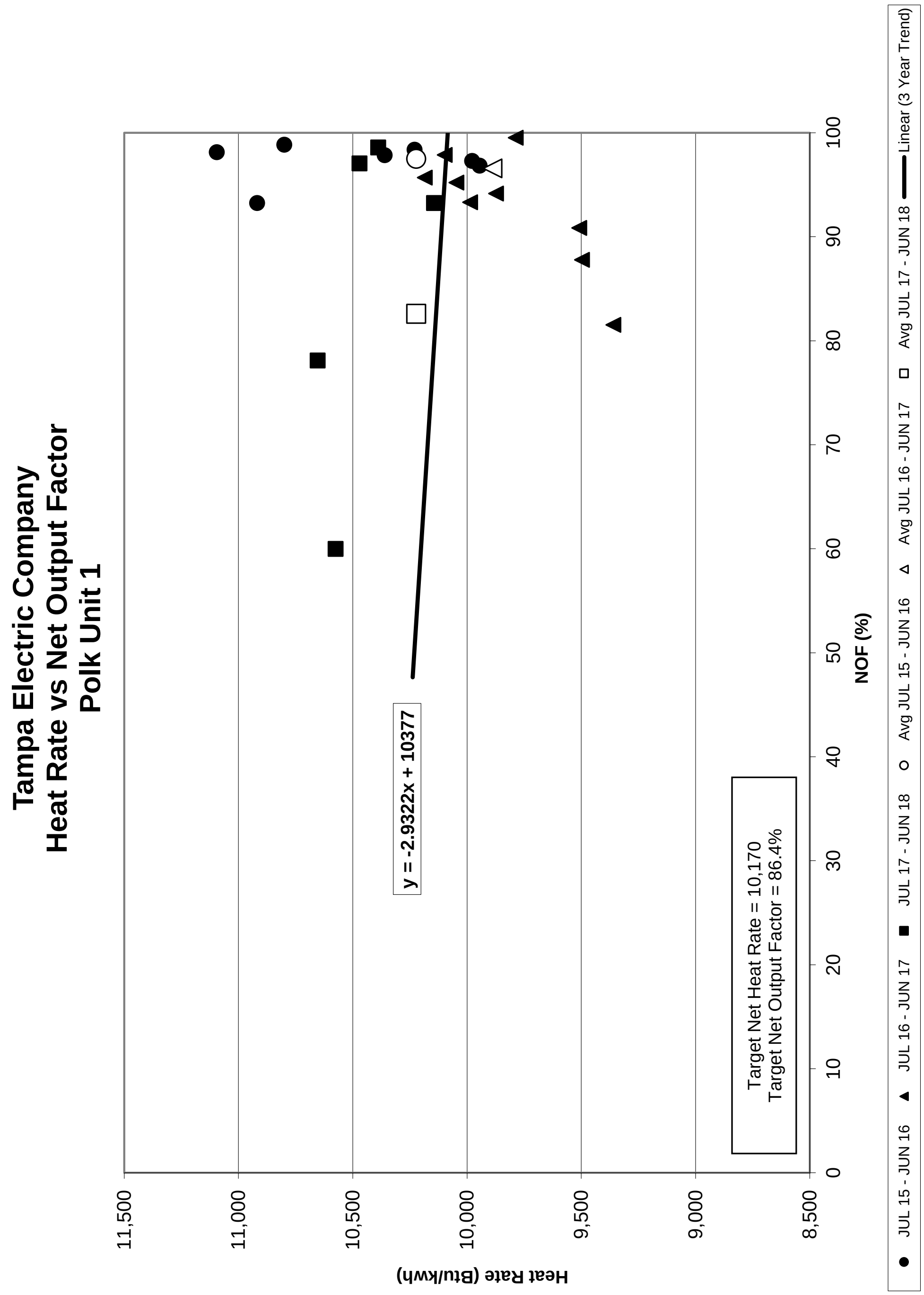

Polk Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

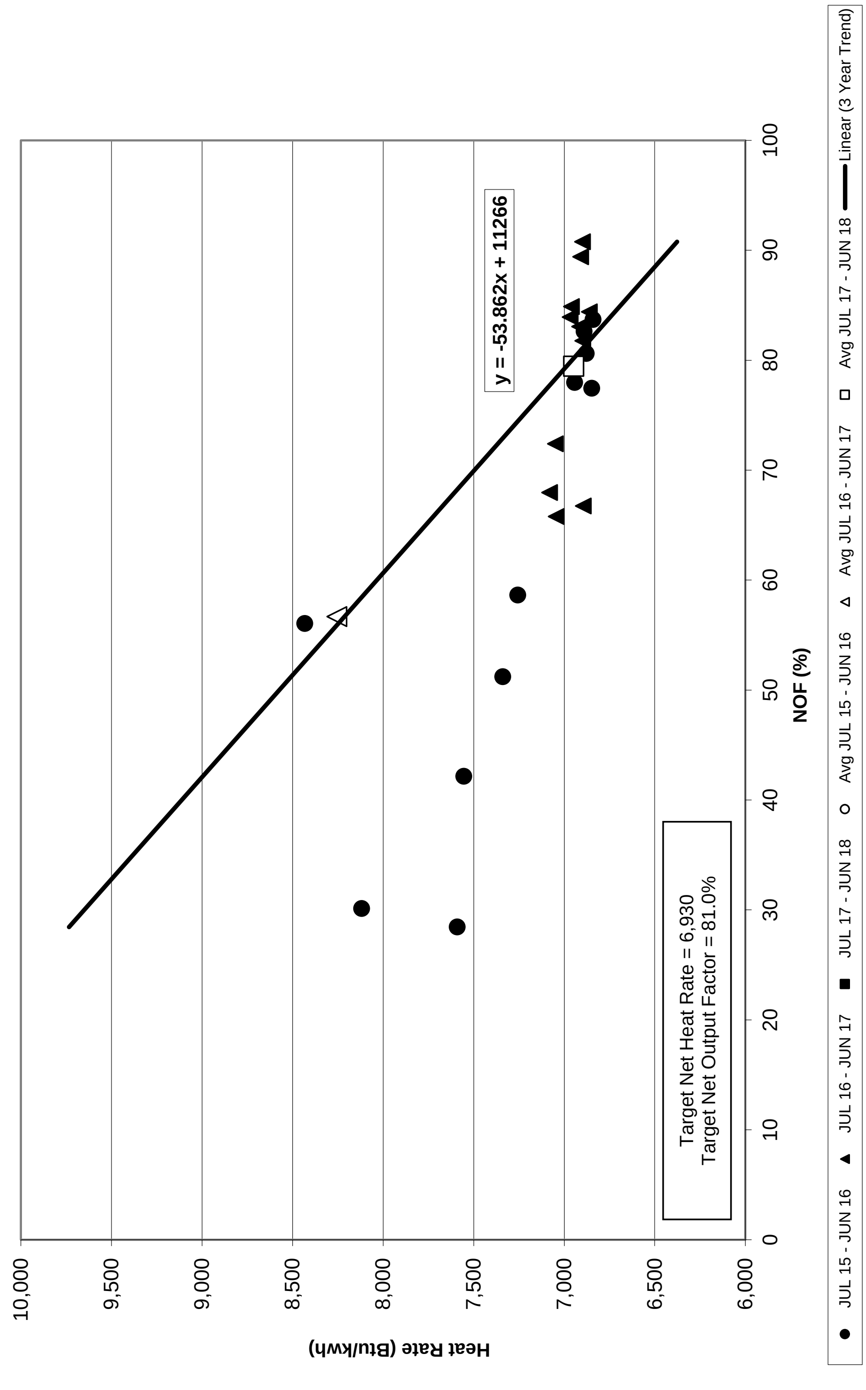

Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

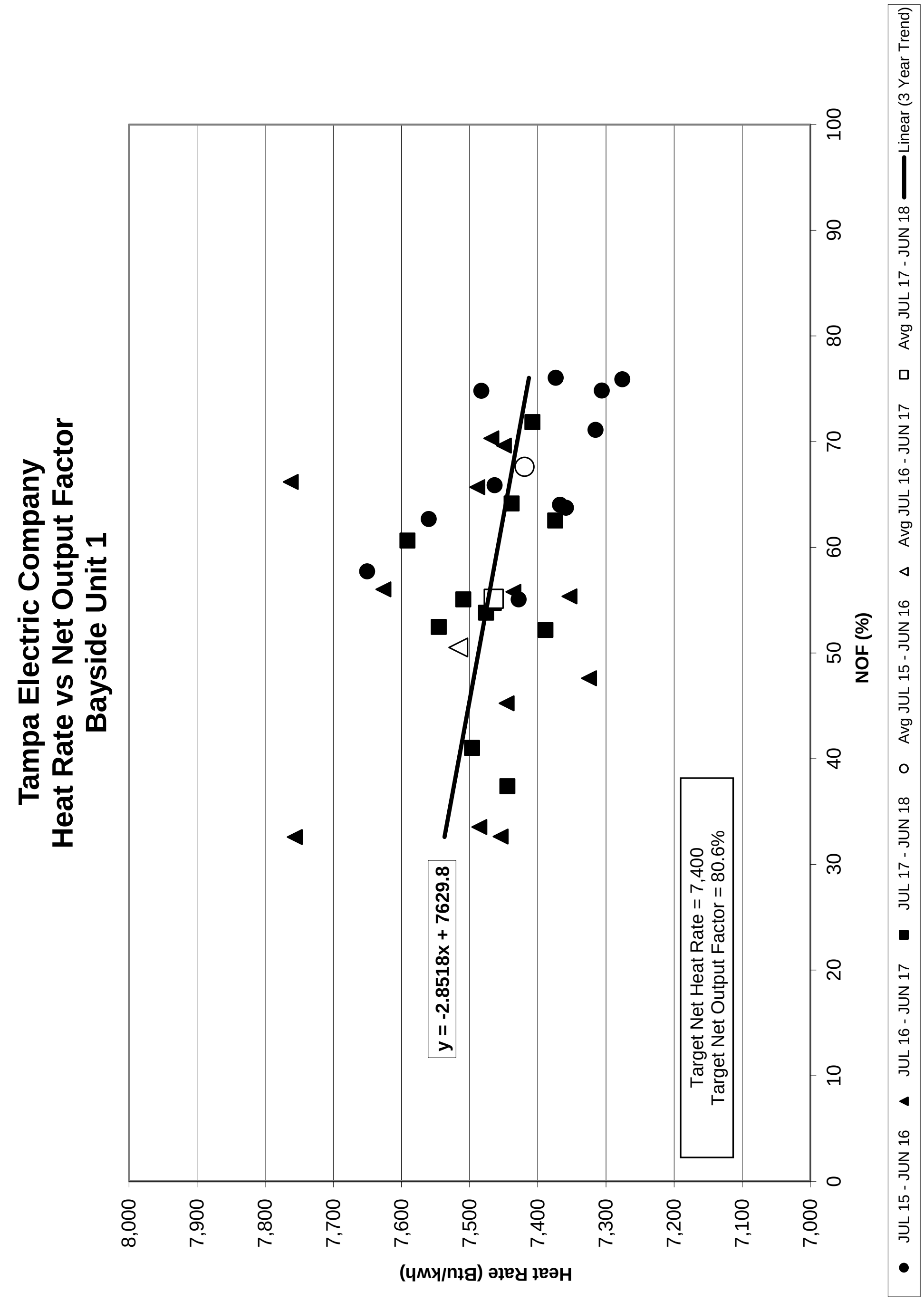

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

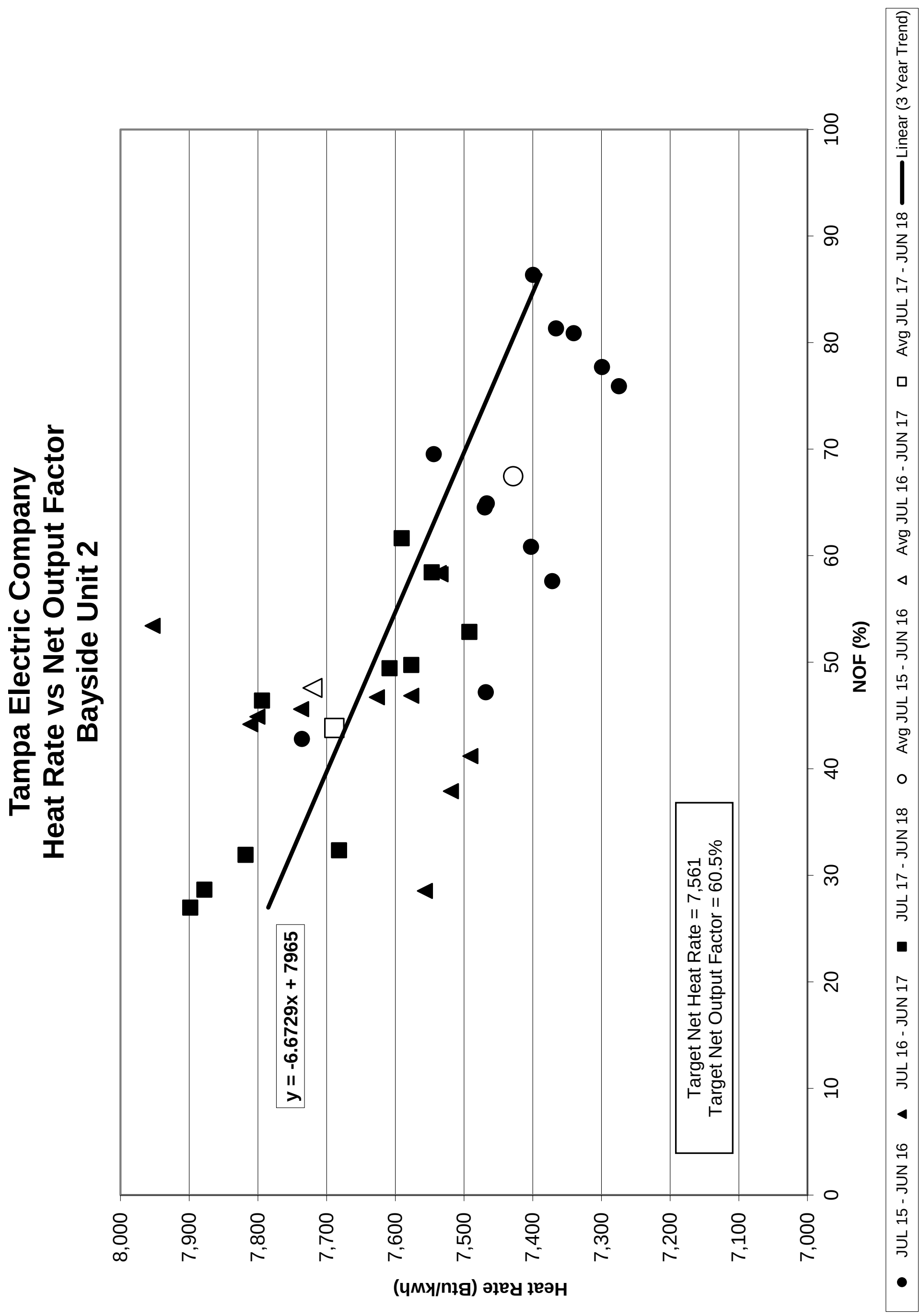

Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 16
AUG 16
SEP 16
OCT 16
NOV 16
DEC 16
JAN 17
FEB 17
MAR 17
APR 17
MAY 17
JUN 17
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1
Heat Rate (Btu/kwh)
11,500
11,000
10,500
10,000
9,500
9,000
8,500
NOF (%)
0
10
20
30
40
50
60
70
80
90
100
y = -2.9322x + 10377
Target Net Heat Rate = 10,170
Target Net Output Factor = 86.4%
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
Avg JUL 15 - JUN 16
Avg JUL 16 - JUN 17
Avg JUL 17 - JUN 18
Linear (3 Year Trend)

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




Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
Heat Rate (Btu/kwh)
8,000
7,900
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
0
10
20
30
40
50
60
70
80
90
100
NOF (%)
y = -2.8518x + 7629.8
Target Net Heat Rate = 7,400
Target Net Output Factor = 80.6%
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
Avg JUL 15 - JUN 16
Avg JUL 16 - JUN 17
Avg JUL 17 - JUN 18
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
Heat Rate (Btu/kwh)
8,000
7,900
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
0
10
20
30
40
50
60
70
80
90
100
NOF (%)
y = -6.6729x + 7965
Target Net Heat Rate = 7,561
Target Net Output Factor = 60.5%
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
Avg JUL 15 - JUN 16
Avg JUL 16 - JUN 17
Avg JUL 17 - JUN 18
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
POLK 1		203	198
POLK 2		1,130	1,113
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,053	3,011
	SYSTEM TOTAL	**5,300**	**5,170**
	% OF SYSTEM TOTAL	**57.6%**	**58.2%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2019 - DECEMBER 2019

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		323	308
BIG BEND 2		363	343
BIG BEND 3		368	352
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,585	1,500
POLK 1		203	198
POLK 2		1,130	1,113
	POLK TOTAL	1,333	1,312
SOLAR		428	428
	SOLAR TOTAL	428	428
	SYSTEM TOTAL	**5,300**	**5,170**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2019 - DECEMBER 2019

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	7,509,500	36.88%	36.88%
BAYSIDE	1	4,520,110	22.20%	59.08%
BAYSIDE	2	4,441,010	21.81%	80.90%
BIG BEND	4	1,421,090	6.98%	87.87%
SOLAR		1,022,630	5.02%	92.90%
POLK	1	458,240	2.25%	95.15%
BIG BEND	2	365,520	1.80%	96.94%
BIG BEND	3	305,750	1.50%	98.45%
BIG BEND	1	233,310	1.15%	99.59%
BIG BEND CT	4	27,760	0.14%	99.73%
BAYSIDE	5	20,740	0.10%	99.83%
BAYSIDE	6	15,880	0.08%	99.91%
BAYSIDE	3	11,420	0.06%	99.96%
BAYSIDE	4	7,470	0.04%	100.00%
TOTAL GENERATION		20,360,430	100.00%	

GENERATION BY COAL UNITS: 1,421,090 MWH

% GENERATION BY COAL UNITS 6.98%

GENERATION BY NATURAL GAS UNITS: 17,916,710 MWH

% GENERATION BY NATURAL GAS UNITS: 88.00%

GENERATION BY SOLAR UNITS: 1,022,630 MWH

% GENERATION BY SOLAR UNIT 5.02%

GENERATION BY GPIF UNITS: 16,928,860 MWH

% GENERATION BY GPIF UNITS: 83.15%

EXHIBIT TO THE TESTIMONY

OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2019 – DECEMBER 2019

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2019 - DECEMBER 2019

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Polk 1[1]	83.3	8.2	8.5	10,170
Polk 2[2]	90.9	6.6	2.5	6,930
Bayside 1[3]	91.0	7.1	1.9	7,400
Bayside 2[4]	87.4	7.7	4.9	7,561

1 Original Sheet 8.401.19E, Page 11

2 Original Sheet 8.401.19E, Page 12

3 Original Sheet 8.401.19E, Page 13

4 Original Sheet 8.401.19E, Page 14

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2019 THROUGH DECEMBER 2019

TESTIMONY

OF

J. BRENT CALDWELL

FILED: AUGUST 24, 2018

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. 20180001-EI?

A. Yes, I submitted direct testimony on April 3, 2018 and August 10, 2018.

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 2011. 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.

Fuel Mix and Procurement Strategies

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

A. Tampa Electric's fuel mix includes natural gas, coal, solar, and oil as a backup fuel. The Big Bend units can operate on coal or natural gas. 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) all utilize natural gas. Since it serves as a backup fuel, oil consumption as a percentage of system generation is negligible. During 2018, continued low natural gas prices haves resulted in greater use of natural gas, compared to the original projection. Based upon the 2018 actual-estimate projections, the company expects 2018 total system generation to be 83 percent natural gas and 16 percent coal. The remainder of the 2018 projected generation will be from solar facilities, at approximately 1 percent.

In 2019, natural gas-fired and coal-fired generation are expected to be approximately 88 percent and 7 percent of total generation, respectively. The remaining 5 percent of 2019 projected generation will be from solar facilities.

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 flexibility to pursue lower cost options for Tampa Electric customers.

Coal Supply Strategy

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

A. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have been upgraded to operate on natural gas. Polk Unit 1 can burn a mix of petroleum coke, low sulfur coal or natural gas. Each plant has varying operational and environmental restrictions and requires solid 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 how Tampa Electric will manage its solid fuel supply contracts through 2019.

A. Since the company will use less coal and more natural gas in 2019 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, 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.

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

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2018 and 2019?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2018 and is evaluating how much coal to receive by rail in 2019.

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

A. Tampa Electric's "open" positions for solid fuel, rail and Gulf transportation, along with other operational and market factors, allows the company to use more natural gas in the dual-fueled Big Bend and Polk units, when economical. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and Gulf transportation in the remainder of 2018 and 2019 than it would have otherwise.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2019 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. 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 supplies 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 and seasonal 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.

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

A. Tampa Electric currently receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric has added the ability to receive a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline. The ability to deliver natural gas directly from three 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 and Sabal Trail (via Gulfstream backhaul) to support the aero-derivative combustion turbines and steam generating units. Polk Station receives natural gas from FGT to support Polk Unit 2 CC and, as an alternate fuel, Polk Unit 1. The addition of Sabal Trail to the list of delivery options enhances reliability and supply price diversity.

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 utilize its existing pipeline capacity and is burning natural gas to the extent that there is available capacity and it is the more economic option. Over the past few years, Tampa Electric’s natural gas usage has increased, and that trend is expected to continue in 2019 due to expected low natural gas prices. The low natural gas prices along with the flexibility the company has built into its units, coal supply and transportation portfolio positions, and available natural gas pipeline capacity has allowed the company to take advantage of alternate fuel opportunities. This strategy lowers overall costs.

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. In alignment with this objective, effective April 1, 2018, the company has reserved 2,000,000 MMBtu of long-term storage capacity from two salt-dome storage caverns that replaced the previous storage capacity at a single location.

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 capacity 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 2018 and 2019 due to greater use of natural gas?

A. Yes, with the continued low price of natural gas and the company's growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal and, recently, longer-term pipeline capacity to support the company's portfolio of gas-fired generation assets. In particular, in 2018 Tampa Electric acquired 20,000 MMBtu per day of pipeline capacity on Sabal Trail. This capacity provides additional diversification of pipelines and gas supply receipt points.

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-term, 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.

Q. Have there been other changes in the management of Tampa Electric's fuel supply portfolio?

A. Yes, as part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, and utilization of natural gas storage and transportation assets.

Q. Are additional activities envisioned to generate additional benefits through the Optimization Mechanism?

A. Yes, Tampa Electric expects to generate additional benefits through an Asset Management Agreement ("AMA") for the natural gas storage capacity assets.

Q. Please describe what an AMA is.

A. In general, an AMA is an agreement between an entity that has the contractual rights to an asset and a market participant that optimizes the use of that asset to serve the entity's needs and to use that asset for market activity. The entity with the contractual right and the Asset Manager share in the benefit derived from the optimization activity. The AMA supports the extraction of additional value for an entity by utilizing the expertise of the Asset Manager to combine its asset portfolio and market access with the use of the AMA assets.

Q. Please describe the AMA Tampa Electric is implementing.

A. As previously mentioned, Tampa Electric has 2,000,000 MMBtu of natural gas storage capacity contracted between two storage facilities. Tampa Electric is contracting with Emera Energy Services ("EES") to optimize 1,500,000 MMBtu of that capacity. Tampa Electric is retaining all of its rights to store and withdraw natural gas in that capacity, and EES has the right to utilize the portion that is not being used by Tampa Electric. EES has guaranteed a minimum level of benefit and then will share transactional benefits above that amount with Tampa Electric. The AMA is effective from September 1, 2018.

Q. How was EES chosen to be the Asset Manager?

A. Tampa Electric conducted a request for proposals to manage the storage assets. Two entities were short-listed and offered the opportunity to refine their offer. Ultimately, EES provided the greatest guaranteed benefits for customers.

Projected 2019 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 April 2018, 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 2019 projected fuel prices compare to the fuel prices projected for 2018?

A. The commodity price for natural gas during 2019 is projected to be lower ($2.79 per MMBtu) than the 2018 price ($3.13 per MMBtu) projected when setting the 2018 fuel cost recovery clause factors. The 2019 coal commodity price projection is slightly higher ($37.57 per ton) than the price projected for 2018 ($35.80 per ton) during preparation of the 2018 fuel clause factors. The significant volume of natural gas produced in association with crude oil production from shale continues to keep natural gas prices low. While low natural gas prices are keeping downward pressure on coal prices, access to the higher valued international market is putting upward pressure on coal prices.

Risk Management Activities

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

A. The ongoing Tampa Electric moratorium on natural gas financial hedges was continued in 2018 by Commission approval of the company's 2017 Amended and Restated Stipulation and Settlement Agreement memorialized in Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI. The agreement states that Tampa Electric will not enter into any new natural gas financial hedging contracts for fuel from January 1, 2018 through December 31, 2022.

Tampa Electric continues to report on the natural gas financial hedging contracts entered prior to Commission approval of the hedging moratorium, and the company has not entered any new financial hedging contracts since the moratorium began.

Q. Were Tampa Electric's efforts through July 31, 2018 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. On April 3, 2018, the company filed its 2017 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 10, 2018. The report shows the results of the company's prudent hedging activities, for hedges in place prior to the start of the hedging moratorium, from January through July 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2019 THROUGH DECEMBER 2019

TESTIMONY
OF
BENJAMIN F. SMITH II

FILED: AUGUST 24, 2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing Group within the Wholesale Marketing & 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, Gas and Power Origination in the Wholesale Marketing, Planning and Fuels Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion by-product contract administration and market opportunities. 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 2018 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 nine percent of the company’s expected needs for 2018 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, pre-existing firm purchased power agreement with Pasco Cogen and reliability purchases.

My testimony in previous years' dockets described the agreement with Pasco Cogen. 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 Pasco Cogen purchase agreement was 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 2018?

A. Yes. Tampa Electric purchased forward up to 250 MW of economic energy for the period May through October. The purchases are on-peak, must-take products from Florida Power & Light ("FPL") and ExGen. The FPL purchase volume is for 50 MW in May and 150 MW from June through October. The ExGen purchase is 100 MW during the period of May through October. These purchases are expected to result in $1.25 million of total savings to customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2019 and beyond?

A. Yes, the company anticipates entering into new short-term power purchases for 2019. Tampa Electric 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 2019 and beyond with purchases that bring value to customers. Currently, Tampa Electric expects purchased power to meet approximately eight percent of its 2019 energy needs.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company’s 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 2018 and 2019.

A. Tampa Electric entered into various non-separated wholesale sales in 2018, and the company anticipates making additional non-separated sales during the balance of 2018 and 2019. The gains from these sales are distributed amongst Tampa Electric and its customers in accordance with the company’s current optimization mechanism, which is described in the testimony of Tampa Electric witness J. Brent Caldwell, submitted concurrently in this docket.

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.