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September 3, 2020

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
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. 20200001-EI

Dear Mr. Teitzman:

Document No. 05902, filed earlier today, was filed in this docket by mistake. This cover letter and the attached filing should have been filed instead of Document No. 05902.

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 (MAS-3) of M. Ashley Sizemore;

3. Prepared Direct Testimony and Exhibit of Jeremy B. Cain (JC-1);

4. Prepared Direct Testimony of John C. Heisey; and

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

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

Attachments
cc: All Parties of Record (w/attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 20200001-EI FILED: September 3, 2020

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, 2020 through December 31, 2020 will be an under-recovery of $25,479,055 (See Exhibit No. MAS-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2021 through December 31, 2021, when adjusted for the proposed GPIF reward and true-up under-recovery amount and spread over projected kilowatt-hour sales for the period January 1, 2021 through December 31, 2021, produce a fuel and purchased power factor for the new period of 3.167 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. (See Exhibit No. MAS-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, 2020 through December 31, 2020 will be an under-recovery of $353,890, as shown in Exhibit No. MAS-3, Document No. 1, page 2 of 4.

5. The company's projected expenditures for the period January 1, 2021 through December 31, 2021, 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 0.002 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.01 per billed kW as set forth in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

GPIF

6. Tampa Electric has calculated that it is subject to a GPIF reward of $2,858,056 for performance during the period January 1, 2019 through December 31, 2019, included in Exhibit No. MAS-3, Document No. 2, Schedule E1-C.

7. The company is also proposing GPIF targets and ranges for the period January 1, 2021 through December 31, 2021 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Jeremy B. Cain filed herewith.

Optimization Mechanism

8. Tampa Electric has calculated that it is subject to an Optimization Mechanism sharing amount of $1,180,820, included in Exhibit No. MAS-3, Document No. 2, Schedule E1-C.

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 3rd day of September 2020.

Respectfully submitted,

Malcolm N. Means

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition, Testimonies and Exhibits, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 3rd day of September 2020, to the following:

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Malcolm N. Means

ATTORNEY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2021 THROUGH DECEMBER 2021

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: SEPTEMBER 3, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. 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. 20200001-EI?

A. Yes, I submitted direct testimony on June 3, 2020, July 27, 2020 and revised the July 27, 2020 testimony on August 12, 2020.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

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, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2021 through December 2021. 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 2021.

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

A. Yes. Exhibit No. MAS-3, consisting of three 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 2021 through December 2021 as well as Schedule H1 for 2018 through 2021. 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.

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. MAS-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. MAS-3, Document No. 1, page 2 of 4. Tampa Electric requests recovery of $353,890 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2021.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.002	
GS and CS Secondary	0.002	
GSD, SBF Standard		
Secondary		0.01
Primary		0.01
Transmission		0.01
IS, IST, SBI		
Primary		0.00
Transmission		0.00
GSD Optional		
Secondary	0.002	
Primary	0.002	
Transmission	0.002	
LS1 Secondary	0.000	

These factors are shown in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.002 cents per kWh compare to the factor for June 2020 through December 2020?

A. The proposed capacity cost recovery factor of .002 cents per kWh for the January 2021 through December 2021 period is 0.014 cents per kWh (or $0.14 per 1,000 kWh) greater than the average capacity cost recovery factor credit of .012 cents per kWh for the June 2020 through December 2020 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 2021?

A. The appropriate amount for the 2021 period is 3.167 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. MAS-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 2021 through December 2021.

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

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $2,858,056, 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 2021 through December 2021 period. The net true-up amount is an under-recovery of $25,479,055. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,180,820.

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 2021 through December 2021. 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. MAS-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 levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.167
Tier I (Up to 1,000 kWh)	2.856
Tier II (Over 1,000 kWh)	3.856
Distribution Primary	3.135
Transmission	3.104
Lighting Service	3.136
Distribution Secondary	3.335(on-peak)
	3.095(off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	3.302(on-peak)
	3.064(off-peak)
Transmission	3.268(on-peak)
	3.033(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.167 cents per kWh compare to the levelized fuel adjustment factor for the June 2020 through December 2020 period?

A. The proposed fuel charge factor of 3.167 cents per kWh is 0.529 cents per kWh (or $5.29 per 1,000 kWh) higher than the average fuel charge factor of 2.638 cents per kWh for the June 2020 through December 2020 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2021 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 wholesale incentive benchmark is required for the 2021 projection.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is an increase of $8.14 beginning January 2021, when compared to the September 2020 through December 2020 charges. These amounts are shown in Exhibit No. MAS-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2021 - DECEMBER 2021

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
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	53.49%	9,684,803	2,067	1.08051	1.05263	10,194,472	2,233	49.67%	58.72%	58.02%
GS, CS	56.42%	902,049	182	1.08051	1.05261	949,504	197	4.63%	5.18%	5.14%
GSD Optional	3.42%	360,212	55	1.07583	1.04913	377,910	59	1.84%	1.55%	1.57%
GSD, SBF	71.57%	7,544,170	1,148	1.07583	1.04913	7,914,823	1,236	38.57%	32.50%	32.97%
IS,SBI	145.94%	927,861	73	1.02893	1.01716	943,787	75	4.60%	1.97%	2.17%
LS1	578.30%	134,246	3	1.08051	1.05263	141,311	3	0.69%	0.08%	0.13%
TOTAL		19,553,341	3,528			20,521,807	3,803	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2020 projected calendar data.
(2) Projected MWH sales for the period January 2021 thru December 2021.
(3) Based on 12 months average CP at meter.
(4) Based on 2020 projected demand losses.
(5) Based on 2020 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,473,600	1,473,600	0	0	0	0	0	0	0	0	0	0	2,947,200
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,508)	(822,085)
4	TOTAL CAPACITY DOLLARS	$1,405,093	$1,405,093	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,508)	$2,125,115
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$1,405,093	$1,405,093	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,507)	($68,508)	$2,125,115
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2020 - DEC. 2020													(1,771,480)
8	TOTAL													$353,635
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$353,890

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
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	49.67%	58.72%	13,517	191,824	205,341	9,684,803	9,684,803				0.00002
GS, CS	4.63%	5.18%	1,260	16,922	18,182	902,049	902,049				0.00002
GSD, SBF											
Secondary						6,132,121	6,132,121			0.01	
Primary						1,405,148	1,391,097			0.01	
Transmission						6,901	6,763			0.01	
GSD, SBF - Standard	38.57%	32.50%	10,496	106,170	116,666	7,544,170	7,529,981	58.85%	17,528,483		
GSD - Optional	1.84%	1.55%	501	5,063	5,564						
Secondary						352,605	352,605				0.00002
Primary						7,607	7,531				0.00002
Transmission						0	0				0.00002
IS, SBI											
Primary						184,855	183,006			0.00	
Transmission						743,006	728,146			0.00	
Total IS, SBI	4.60%	1.97%	1,252	6,436	7,688	927,861	911,152	62.85%	1,986,004		
LS1	0.69%	0.08%	188	261	449	134,246	134,246				0.00000
TOTAL	100.00%	100.00%	27,214	326,676	353,890	19,553,341	19,522,367				0.00002

(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 2021 through December 2021.
(7) Projected kWh sales at secondary for the period January 2021 through December 2021.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2021 through December 2021.
(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 2021 THROUGH DECEMBER 2021

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
SEMINOLE ELECTRIC **	6/1/1992	-----------	LT
FLORIDA MUNICIPAL POWER AGENCY	12/1/2020	2/28/2021	ST
ORLANDO UTILITIES COMMISSION	12/1/2020	2/28/2021	ST
FLORIDA POWER & LIGHT	12/1/2020	2/28/2021	ST

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	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
FLORIDA MUNICIPAL POWER AGENCY	150.0	150.0	-	-	-	-	-	-	-	-	-	-
ORLANDO UTILITIES COMMISSION	100.0	100.0	-	-	-	-	-	-	-	-	-	-
FLORIDA POWER & LIGHT	160.0	160.0	-	-	-	-	-	-	-	-	-	-

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
FLORIDA MUNICIPAL POWER AGENCY	[redacted]												
ORLANDO UTILITIES COMMISSION													
FLORIDA POWER & LIGHT													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,405,093	1,405,093	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,507)	(68,508)	2,125,115
TOTAL CAPACITY	**$1,405,093**	**$1,405,093**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,507)**	**($68,508)**	**$2,125,115**

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2021 - DECEMBER 2021

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 2021 THROUGH DECEMBER 2021

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	575,218,013	20,177,369	2.85081
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustment	0	0	0.00000
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**575,218,013**	**20,177,369**	**2.85081**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	104,253	2,394	4.35476
7.	Energy Cost of Economy Purchases (E9)	10,935,277	297,946	3.67022
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,933,490	108,020	2.71569
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**13,973,020**	**408,360**	**3.42174**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**20,585,729**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	973,880	35,040	2.77934
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	73,807	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**1,047,687**	**35,040**	**2.98997**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		0	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**588,143,346**	**20,550,689**	**2.86192**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,064,634 [1]	37,200	0.00545
22.	T & D Losses	27,714,830 [1]	968,400	0.14180
23.	System MWH Sales	588,143,346	19,545,089	3.00916
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	588,143,346	19,545,089	3.00916
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	588,143,346	19,545,089	3.00916
28.	Optimization Mechanism [2]	1,180,820	19,545,089	0.00604
29.	True-up [2]	25,479,055	19,545,089	0.13036
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	614,803,221	19,545,089	3.14556
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	615,245,879	19,545,089	3.14782
33.	GPIF Adjusted for Taxes [2]	2,858,056	19,545,089	0.01462
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	618,103,935	19,545,089	3.16244
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.162**

[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 2021 THROUGH DECEMBER 2021

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2020 - December 2020 (6 months actual, 6 months estimated)	($43,367,307)
2.	PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN JUNE - DECEMBER 2020 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	$0
3.	DIFFERENCE IN 2019 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2020 RATES AND AMOUNT COLLECTED IN 2020 ($30,742,026 under-recovery less ($2,561,836) refunded each month January through May 2020)	($17,932,846)
4.	ACTUAL-ESTIMATED 2020 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	($61,300,153)
5.	FINAL TRUE-UP (January 2019 - December 2019) (Per True-Up filed March 2, 2020)	35,821,098
6.	TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2021 (Line 4 + Line 5) To be included in the 12-month projected period January 2021 through December 2021 (2021 Schedule E1, line 29)	($25,479,055)
7.	JURISDICTIONAL MWH SALES (Projected January 2021 through December 2021)	19,545,089
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,514,116)	**0.1306**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
A.	GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2021 through December 2021)	$2,858,056	
B.	TRUE-UP OVER / (UNDER) RECOVERED (January 2021 through December 2021)	($25,479,055)	
C.	OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2021 through December 2021)	$1,180,820	
2.	TOTAL SALES (January 2021 through December 2021)	19,545,089	MWh
3.	ADJUSTMENT FACTORS		
A.	GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,514,116)	**0.0146**	Cents/kWh
B.	TRUE-UP FACTOR (Using Effective MWh Sales of 19,514,116)	**0.1306**	Cents/kWh
C.	OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,514,116)	**0.0061**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.06	$23.79
OFF PEAK	69.94	$22.08
	100.00	1.0774

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$588,143,346		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,545,089		
2a	Effective MWH Sales (Jurisd)		19,514,116		
3	Cost Per KWH Sold	(line 1 / line 2)	3.0092		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 29)	$25,479,055		
7	Optimization Mechanism	(Sch E1 line 28)	$1,180,820		
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$614,803,221		
9	Revenue Tax Factor		1.00072		
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	3.1528		
11	GPIF Factor	(Sch E1-C line 3A)	0.0146		
12	Recovery Factor Including GPIF	(line 10 + line 11)	3.1674	3.3350	3.0953
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.167	3.335	3.095

14	Hours: ON PEAK	25.51%
15	OFF PEAK	74.49%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,197,572		17,197,572
Distribution Primary	1,597,611	0.99	1,581,635
Transmission	749,907	0.98	734,909
Total	19,545,089		19,514,116

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.167	3.335	3.095
Distribution Primary	3.135	3.302	3.064
Transmission	3.104	3.268	3.033
RS 1st Tier	2.856		
RS 2nd Tier	3.856		
Lighting	3.136		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

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)		2.856	3.856
Distribution Secondary	3.167		
Distribution Primary	3.135		
Transmission	3.104		
Lighting Service [(1)]	3.136		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.335		
Distribution Secondary - Off-Peak	3.095		
Distribution Primary - On-Peak	3.302		
Distribution Primary - Off-Peak	3.064		
Transmission - On-Peak	3.268		
Transmission - Off-Peak	3.033		

(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 2021 THROUGH DECEMBER 2021

	(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(g)	(h)	(i)	(j)	(k)	(l)	(m) TOTAL
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	PERIOD
1. Fuel Cost of System Net Generation	42,503,342	39,868,097	42,920,541	41,640,728	49,408,392	54,031,615	56,408,656	57,134,359	54,626,784	51,096,137	40,083,748	45,495,614	575,218,013
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	82,717	78,758	89,538	86,590	95,573	100,683	88,656	89,247	94,357	80,587	80,125	80,856	1,047,687
4. Fuel Cost of Purchased Power	28,164	76,089	0	0	0	0	0	0	0	0	0	0	104,253
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	217,090	252,980	197,130	229,010	232,390	247,890	251,500	249,360	248,330	290,630	275,890	241,290	2,933,490
7. Energy Cost of Economy Purchases	2,886,796	1,438,741	461,410	330,920	599,060	743,490	374,170	464,070	202,680	3,322,110	106,180	5,650	10,935,277
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	**45,552,675**	**41,557,149**	**43,489,543**	**42,114,068**	**50,144,269**	**54,922,312**	**56,945,670**	**57,758,542**	**54,983,437**	**54,628,290**	**40,385,693**	**45,661,698**	**588,143,346**
11. Jurisdictional MWH Sold	1,471,672	1,355,362	1,336,932	1,416,998	1,572,691	1,830,995	1,913,414	1,902,089	1,992,078	1,802,624	1,511,740	1,438,493	19,545,089
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)	45,552,675	41,557,149	43,489,543	42,114,068	50,144,269	54,922,312	56,945,670	57,758,542	54,983,437	54,628,290	40,385,693	45,661,698	588,143,346
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)	**45,552,675**	**41,557,149**	**43,489,543**	**42,114,068**	**50,144,269**	**54,922,312**	**56,945,670**	**57,758,542**	**54,983,437**	**54,628,290**	**40,385,693**	**45,661,698**	**588,143,346**
16. Cost Per kWh Sold (Cents/kWh)	3.0953	3.0661	3.2529	2.9721	3.1884	2.9996	2.9761	3.0366	2.7601	3.0305	2.6715	3.1743	3.0092
17. Optimization Mechanism (Cents/kWh) [2]	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061	0.0061
18. True-up (Cents/kWh) [2]	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306	0.1306
19. Total (Cents/kWh) (Line 16+17+18)	3.2320	3.2028	3.3896	3.1088	3.3251	3.1363	3.1128	3.1733	2.8968	3.1672	2.8082	3.3110	3.1459
20. 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
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.2343	3.2051	3.3920	3.1110	3.3275	3.1386	3.1150	3.1756	2.8989	3.1695	2.8102	3.3134	3.1482
22. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**3.2489**	**3.2197**	**3.4066**	**3.1256**	**3.3421**	**3.1532**	**3.1296**	**3.1902**	**2.9135**	**3.1841**	**2.8248**	**3.3280**	**3.1628**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.249**	**3.220**	**3.407**	**3.126**	**3.342**	**3.153**	**3.130**	**3.190**	**2.914**	**3.184**	**2.825**	**3.328**	**3.163**

[1] Includes Gains
[2] Based on Effective MWh Sales shown on Schedule E1-C

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E3

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	487,933	0	470,965	340,852	445,648	419,916
3. COAL	4,387,675	4,136,102	2,316,287	3,167,903	5,971,387	5,734,099
4. NATURAL GAS	37,627,734	35,731,995	40,133,289	38,131,973	42,991,357	47,877,600
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**42,503,342**	**39,868,097**	**42,920,541**	**41,640,728**	**49,408,392**	**54,031,615**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	2,658	0	2,658	1,972	2,658	2,572
10. COAL	106,900	97,280	57,210	73,730	147,030	137,100
11. NATURAL GAS	1,164,793	1,074,920	1,245,613	1,320,839	1,480,223	1,653,809
12. SOLAR	97,450	107,360	134,250	163,800	179,270	154,170
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,371,801**	**1,279,560**	**1,439,731**	**1,560,341**	**1,809,181**	**1,947,651**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	4,986	0	4,986	3,698	4,986	4,824
17. COAL (TON)	61,050	55,390	30,780	40,910	77,080	72,580
18. NATURAL GAS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,190,315	12,398,004
19. SOLAR	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	29,229	0	29,229	21,686	29,229	28,286
23. COAL	1,373,610	1,246,200	692,540	920,490	1,734,280	1,632,960
24. NATURAL GAS	8,616,341	8,493,510	9,884,201	10,085,514	11,462,561	12,706,964
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,019,180**	**9,739,710**	**10,605,970**	**11,027,690**	**13,226,070**	**14,368,210**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.19	0.00	0.18	0.13	0.15	0.13
30. COAL	7.80	7.60	3.98	4.72	8.12	7.04
31. NATURAL GAS	84.91	84.01	86.52	84.65	81.82	84.91
32. SOLAR	7.10	8.39	9.32	10.50	9.91	7.92
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	97.86	0.00	94.46	92.17	89.38	87.05
37. COAL ($/TON)	71.87	74.67	75.25	77.44	77.47	79.00
38. NATURAL GAS ($/MCF)	4.48	4.32	4.16	3.87	3.84	3.86
39. SOLAR	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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	16.69	0.00	16.11	15.72	15.25	14.85
43. COAL	3.19	3.32	3.34	3.44	3.44	3.51
44. NATURAL GAS	4.37	4.21	4.06	3.78	3.75	3.77
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.24**	**4.09**	**4.05**	**3.78**	**3.74**	**3.76**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,996	0	10,996	10,997	10,996	10,998
50. COAL	12,849	12,810	12,105	12,485	11,795	11,911
51. NATURAL GAS	7,397	7,902	7,935	7,636	7,744	7,683
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,304**	**7,612**	**7,367**	**7,067**	**7,311**	**7,377**
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	18.36	0.00	17.72	17.28	16.77	16.33
57. COAL	4.10	4.25	4.05	4.30	4.06	4.18
58. NATURAL GAS	3.23	3.32	3.22	2.89	2.90	2.89
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.10**	**3.12**	**2.98**	**2.67**	**2.73**	**2.77**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E3

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	423,442	414,405	393,706	381,030	312,743	390,597	4,481,237
3.	COAL	5,559,374	5,769,559	5,461,415	3,123,824	0	1,825,597	47,453,222
4.	NATURAL GAS	50,425,840	50,950,395	48,771,663	47,591,283	39,771,005	43,279,420	523,283,554
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**56,408,656**	**57,134,359**	**54,626,784**	**51,096,137**	**40,083,748**	**45,495,614**	**575,218,013**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	2,658	2,658	2,572	2,529	2,100	2,658	27,693
10.	COAL	127,660	134,920	126,580	71,810	0	39,460	1,119,680
11.	NATURAL GAS	1,753,893	1,780,653	1,690,579	1,538,631	1,343,880	1,396,893	17,444,726
12.	SOLAR	150,450	145,640	125,760	125,370	99,020	102,730	1,585,270
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,034,661**	**2,063,871**	**1,945,491**	**1,738,340**	**1,445,000**	**1,541,741**	**20,177,369**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	51,946
17.	COAL (TON)	69,620	72,400	68,500	39,200	0	22,900	610,410
18.	NATURAL GAS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	10,004,504	10,476,895	131,115,049
19.	SOLAR	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	29,229	29,229	28,286	27,814	23,100	29,229	304,543
23.	COAL	1,566,500	1,628,890	1,541,230	881,930	0	515,150	13,733,780
24.	NATURAL GAS	13,272,901	13,397,591	12,863,054	12,597,076	10,281,630	10,751,851	134,413,197
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**14,868,630**	**15,055,710**	**14,432,570**	**13,506,820**	**10,304,730**	**11,296,230**	**148,451,520**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.13	0.13	0.13	0.15	0.15	0.17	0.14
30.	COAL	6.28	6.53	6.51	4.13	0.00	2.57	5.54
31.	NATURAL GAS	86.20	86.28	86.90	88.51	93.00	90.60	86.46
32.	SOLAR	7.39	7.06	6.46	7.21	6.85	6.66	7.86
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	84.93	83.11	81.61	80.32	79.38	78.34	86.27
37.	COAL ($/TON)	79.85	79.69	79.73	79.69	0.00	79.72	77.74
38.	NATURAL GAS ($/MCF)	3.89	3.90	3.89	3.87	3.98	4.13	3.99
39.	SOLAR	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 ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	14.49	14.18	13.92	13.70	13.54	13.36	14.71
43.	COAL	3.55	3.54	3.54	3.54	0.00	3.54	3.46
44.	NATURAL GAS	3.80	3.80	3.79	3.78	3.87	4.03	3.89
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.79**	**3.79**	**3.78**	**3.78**	**3.89**	**4.03**	**3.87**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,996	10,996	10,998	10,998	11,000	10,996	10,997
50.	COAL	12,271	12,073	12,176	12,281	0	13,055	12,266
51.	NATURAL GAS	7,568	7,524	7,609	8,187	7,651	7,697	7,705
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,308**	**7,295**	**7,418**	**7,770**	**7,131**	**7,327**	**7,357**
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	15.93	15.59	15.31	15.07	14.89	14.70	16.18
57.	COAL	4.35	4.28	4.31	4.35	0.00	4.63	4.24
58.	NATURAL GAS	2.88	2.86	2.88	3.09	2.96	3.10	3.00
59.	SOLAR	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)**	**2.77**	**2.77**	**2.81**	**2.94**	**2.77**	**2.95**	**2.85**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2021

(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	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,880	258.1	-	258.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,810	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,160	18.4	-	18.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,360	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,710	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,460	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,500	17.7	-	17.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,530	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,290	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,870	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	(3) **652.2**	**97,450**	**20.1**	**-**	**20.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**10,510**	**4.0**	**79.5**	**31.3**	**14,473**	**GAS**	**147,970**	**1,027,979**	**152,110.0**	**662,536**	**6.30**	**4.48**
19. B.B.#3 (GAS)	355	26,940	10.2	-	-	-	GAS	310,060	1,027,995	318,740.0	1,388,294	5.15	4.48
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**26,940**	**10.2**	**83.2**	**52.7**	**11,831**		**-**	**-**	**318,740.0**	**1,388,294**	**5.15**	**-**
22. B.B.#4 (GAS)	160	5,630	4.7	-	-	-	GAS	70,330	1,027,869	72,290.0	314,903	5.59	4.48
23. B.B.#4 (COAL)	432	106,900	33.3	-	-	-	COAL	61,050	22,499,754	1,373,610.0	4,387,675	4.10	71.87
24. BIG BEND #4 TOTAL	**432**	**112,530**	**35.0**	**89.8**	**38.0**	**12,849**		**-**	**-**	**1,445,900.0**	**4,702,578**	**4.18**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	22,130	1,028,016	22,750.0	99,087	-	4.48
26. B.B.C.T.#4 TOTAL	**61**	**130**	**0.3**	**98.3**	**53.3**	**13,462**	**GAS**	**1,710**	**1,023,392**	**1,750.0**	**7,657**	**5.89**	**4.48**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,198**	**150,110**	**16.8**	**85.3**	**39.4**	**12,781**	**-**	**-**	**-**	**1,918,500.0**	**6,860,151**	**4.57**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	13,280	9.3	-	85.4	8,974	GAS	115,920	1,028,037	119,170.0	519,032	3.91	4.48
32. POLK #1 TOTAL	**220**	**13,280**	**8.1**	**93.4**	**85.4**	**8,974**	**-**	**-**	**-**	**119,170.0**	**519,032**	**3.91**	**-**
33. POLK #2 ST DUCT FIRING	120	1,700	1.9	-	74.6	8,194	GAS	13,550	1,028,044	13,930.0	60,670	3.57	4.48
34. POLK #2 ST W/O DUCT FIRING	360	629,243	-	-	-	-		4,228,075	1,028,019	4,346,541.4	18,931,211	3.01	4.48
35. POLK #2 ST TOTAL	**480**	**630,943**	**176.7**	**-**	**179.1**	**6,911**	**GAS**	**-**	**-**	**4,360,471.4**	**18,991,881**	**3.01**	**-**
36. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.9	10,996	LGT OIL	2,493	5,862,134	14,614.3	243,966	18.36	97.86
38. POLK #2 TOTAL	(4) **180**	**1,329**	**1.0**	**-**	**5.9**	**10,996**	**-**	**-**	**-**	**14,614.3**	**243,966**	**18.36**	**-**
39. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	243,967	18.36	97.86
41. POLK #3 TOTAL	(4) **180**	**1,329**	**1.0**	**-**	**80.2**	**10,996**	**-**	**-**	**-**	**14,614.3**	**243,967**	**18.36**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,200**	**633,601**	**71.0**	**97.0**	**153.9**	**6,928**	**-**	**-**	**-**	**4,389,700.0**	**19,479,814**	**3.07**	**-**
45. POLK STATION TOTAL	**1,420**	**646,881**	**61.2**	**96.5**	**148.0**	**6,970**	**-**	**-**	**-**	**4,508,870.0**	**19,998,846**	**3.09**	**-**
46. BAYSIDE #1	792	310,320	52.7	97.3	55.7	7,357	GAS	2,220,870	1,027,998	2,283,050.0	9,943,948	3.20	4.48
47. BAYSIDE #2	1,047	166,480	21.4	97.4	34.5	7,819	GAS	1,266,250	1,027,996	1,301,700.0	5,669,637	3.41	4.48
48. BAYSIDE #3	61	140	0.3	98.6	57.4	12,214	GAS	1,670	1,023,952	1,710.0	7,477	5.34	4.48
49. BAYSIDE #4	61	140	0.3	98.6	57.4	12,643	GAS	1,720	1,029,070	1,770.0	7,701	5.50	4.48
50. BAYSIDE #5	61	140	0.3	98.6	57.4	12,571	GAS	1,710	1,029,240	1,760.0	7,657	5.47	4.48
51. BAYSIDE #6	61	140	0.3	98.6	57.4	13,000	GAS	1,770	1,028,249	1,820.0	7,925	5.66	4.48
52. BAYSIDE STATION TOTAL	**2,083**	**477,360**	**30.8**	**97.5**	**45.9**	**7,524**	**GAS**	**3,493,990**	**1,027,997**	**3,591,810.0**	**15,644,345**	**3.28**	**4.48**
53. SYSTEM TOTAL	**5,353**	**1,371,801**	**34.4**	**82.6**	**79.6**	**7,304**	**-**	**-**	**-**	**10,019,180.0**	**42,503,342**	**3.10**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
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: FEBRUARY 2021

(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	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,040	301.6	-	301.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,330	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,750	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,120	26.3	-	26.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	9,350	22.9	-	22.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	8,560	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,820	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	7,500	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	12,170	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	13,010	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,260	28.0	-	28.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**107,360**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**4,140**	**1.8**	**79.5**	**38.2**	**13,415**	**GAS**	**54,020**	**1,028,138**	**55,540.0**	**233,342**	**5.64**	**4.32**
19. B.B.#3 (GAS)	355	14,300	6.0	-	-	-	GAS	163,050	1,028,028	167,620.0	704,303	4.93	4.32
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**14,300**	**6.0**	**62.2**	**54.4**	**11,722**		**-**	**-**	**167,620.0**	**704,303**	**4.93**	**-**
22. B.B.#4 (GAS)	160	5,120	4.8	-	-	-	GAS	63,800	1,028,056	65,590.0	275,588	5.38	4.32
23. B.B.#4 (COAL)	432	97,280	33.5	-	-	-	COAL	55,390	22,498,646	1,246,200.0	4,136,102	4.25	74.67
24. BIG BEND #4 TOTAL	**432**	**102,400**	**35.3**	**89.8**	**38.3**	**12,810**		**-**	**-**	**1,311,790.0**	**4,411,690**	**4.31**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	10,020	1,027,944	10,300.0	43,282	-	4.32
26. B.B.C.T.#4 TOTAL	**61**	**640**	**1.6**	**98.3**	**52.5**	**12,781**	**GAS**	**7,950**	**1,028,931**	**8,180.0**	**34,340**	**5.37**	**4.32**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,198**	**121,480**	**15.1**	**79.0**	**39.7**	**12,703**	**-**	**-**	**-**	**1,543,130.0**	**5,426,957**	**4.47**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	85,450	66.2	-	85.9	8,870	GAS	737,320	1,028,007	757,970.0	3,184,893	3.73	4.32
32. POLK #1 TOTAL	**220**	**85,450**	**57.8**	**93.4**	**85.9**	**8,870**	**-**	**-**	**-**	**757,970.0**	**3,184,893**	**3.73**	**-**
33. POLK #2 ST DUCT FIRING	120	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #2 ST W/O DUCT FIRING	360	0	-	-	-	-		0	0	0.0	0	0.00	0.00
35. POLK #2 ST TOTAL	**480**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
36. POLK #2 CT (GAS)	180	37,830	31.3	-	66.9	11,520	GAS	423,940	1,028,023	435,820.0	1,831,232	4.84	4.32
37. POLK #2 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
38. POLK #2 TOTAL (4)	**180**	**37,830**	**31.3**	**-**	**66.9**	**11,520**	**-**	**-**	**-**	**435,820.0**	**1,831,232**	**4.84**	**-**
39. POLK #3 CT (GAS)	180	23,620	19.5	-	71.3	11,282	GAS	259,230	1,028,006	266,490.0	1,119,758	4.74	4.32
40. POLK #3 CT (OIL)	187	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
41. POLK #3 TOTAL (4)	**180**	**23,620**	**19.5**	**-**	**68.2**	**11,282**	**-**	**-**	**-**	**266,490.0**	**1,119,758**	**4.74**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**180**	**16,600**	**13.7**	**-**	**73.2**	**11,175**	**GAS**	**180,450**	**1,027,986**	**185,500.0**	**779,463**	**4.70**	**4.32**
43. POLK #5 CT (GAS) TOTAL [4]	**180**	**14,580**	**12.1**	**-**	**73.6**	**11,169**	**GAS**	**158,410**	**1,027,965**	**162,840.0**	**684,261**	**4.69**	**4.32**
44. POLK #2 CC TOTAL	**1,200**	**92,630**	**11.5**	**0.0**	**69.3**	**11,342**	**-**	**-**	**-**	**1,050,650.0**	**4,414,714**	**4.77**	**-**
45. POLK STATION TOTAL	**1,420**	**178,080**	**18.7**	**14.5**	**76.1**	**10,156**	**-**	**-**	**-**	**1,808,620.0**	**7,599,607**	**4.27**	**-**
46. BAYSIDE #1	792	344,120	64.7	97.3	66.4	7,263	GAS	2,431,210	1,027,998	2,499,280.0	10,501,742	3.05	4.32
47. BAYSIDE #2	1,047	526,190	74.8	97.4	76.8	7,334	GAS	3,754,040	1,027,999	3,859,150.0	16,215,777	3.08	4.32
48. BAYSIDE #3	61	690	1.7	98.6	56.6	12,507	GAS	8,400	1,027,381	8,630.0	36,284	5.26	4.32
49. BAYSIDE #4	61	220	0.5	98.6	45.1	13,864	GAS	2,960	1,030,405	3,050.0	12,786	5.81	4.32
50. BAYSIDE #5	61	690	1.7	98.6	53.9	12,667	GAS	8,490	1,029,446	8,740.0	36,673	5.31	4.32
51. BAYSIDE #6	61	730	1.8	98.6	57.0	12,479	GAS	8,860	1,028,217	9,110.0	38,271	5.24	4.32
52. BAYSIDE STATION TOTAL	**2,083**	**872,640**	**62.3**	**97.5**	**72.3**	**7,320**	**GAS**	**6,213,960**	**1,028,001**	**6,387,960.0**	**26,841,533**	**3.08**	**4.32**
53. SYSTEM TOTAL	**5,353**	**1,279,560**	**35.6**	**59.5**	**72.7**	**7,612**	**-**	**-**	**-**	**9,739,710.0**	**39,868,097**	**3.12**	**-**

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 2021

(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	330	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	250	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,070	365.2	-	365.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,310	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,800	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,100	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,160	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,310	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,810	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,550	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,460	31.6	-	31.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	12,740	28.7	-	28.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**134,250**	**27.7**	**-**	**27.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**24,620**	**9.5**	**79.5**	**48.8**	**12,375**	**GAS**	**296,360**	**1,028,040**	**304,670.0**	**1,231,894**	**5.00**	**4.16**
19. B.B.#3 (GAS)	355	41,630	15.8	-	-	-	GAS	464,470	1,027,989	477,470.0	1,930,684	4.64	4.16
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**400**	**41,630**	**14.0**	**83.2**	**52.8**	**11,469**		**-**	**-**	**477,470.0**	**1,930,684**	**4.64**	**-**
22. B.B.#4 (GAS)	160	3,010	2.5	-	-	-	GAS	35,460	1,027,919	36,450.0	147,398	4.90	4.16
23. B.B.#4 (COAL)	432	57,210	17.8	-	-	-	COAL	30,780	22,499,675	692,540.0	2,316,287	4.05	75.25
24. BIG BEND #4 TOTAL	**432**	**60,220**	**18.8**	**84.0**	**46.0**	**12,105**		**-**	**-**	**728,990.0**	**2,463,685**	**4.09**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,080	1,027,695	41,190.0	166,602	-	4.16
26. B.B.C.T.#4 TOTAL	**61**	**3,680**	**8.1**	**98.3**	**79.4**	**11,639**	**GAS**	**41,670**	**1,027,838**	**42,830.0**	**173,212**	**4.71**	**4.16**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,243**	**130,150**	**14.1**	**83.2**	**49.2**	**11,940**	**-**	**-**	**-**	**1,553,960.0**	**5,966,077**	**4.58**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	86,620	60.7	-	88.3	8,788	GAS	740,490	1,028,008	761,230.0	3,078,030	3.55	4.16
32. POLK #1 TOTAL	**220**	**86,620**	**53.0**	**93.4**	**88.3**	**8,788**	**-**	**-**	**-**	**761,230.0**	**3,078,030**	**3.55**	**-**
33. POLK #2 ST DUCT FIRING	120	10,320	11.6	-	82.7	8,171	GAS	82,030	1,027,917	84,320.0	340,978	3.30	4.16
34. POLK #2 ST W/O DUCT FIRING	360	265,933	-	-	-	-		1,780,235	1,028,050	1,830,171.4	7,399,987	2.78	4.16
35. POLK #2 ST TOTAL	**480**	**276,253**	**77.5**	**-**	**132.3**	**6,930**	**GAS**	**-**	**-**	**1,914,491.4**	**7,740,965**	**2.80**	**-**
36. POLK #2 CT (GAS)	180	32,760	24.5	-	76.5	11,028	GAS	351,430	1,028,028	361,280.0	1,460,805	4.46	4.16
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.8	10,996	LGT OIL	2,493	5,862,134	14,614.3	235,482	17.72	94.46
38. POLK #2 TOTAL (4)	**180**	**34,089**	**25.5**	**-**	**51.8**	**11,027**	**-**	**-**	**-**	**375,894.3**	**1,696,287**	**4.98**	**-**
39. POLK #3 CT (GAS)	180	21,650	16.2	-	78.1	10,998	GAS	231,630	1,027,976	238,110.0	962,827	4.45	4.16
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	235,483	17.72	94.46
41. POLK #3 TOTAL (4)	**180**	**22,979**	**17.2**	**-**	**78.2**	**10,998**	**-**	**-**	**-**	**252,724.3**	**1,198,310**	**5.21**	**-**

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EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 14 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**180**	**22,020**	**16.5**	**-**	**79.4**	**10,930**	**GAS**	**234,120**	**1,027,977**	**240,670.0**	**973,178**	**4.42**	**4.16**
43. POLK #5 CT (GAS) TOTAL [4]	**180**	**12,440**	**9.3**	**-**	**84.3**	**10,765**	**GAS**	**130,270**	**1,028,019**	**133,920.0**	**541,499**	**4.35**	**4.16**
44. POLK #2 CC TOTAL	**1,200**	**367,781**	**41.2**	**43.8**	**90.5**	**7,933**	**-**	**-**	**-**	**2,917,700.0**	**12,150,239**	**3.30**	**-**
45. POLK STATION TOTAL	**1,420**	**454,401**	**43.1**	**51.5**	**89.8**	**8,096**	**-**	**-**	**-**	**3,678,930.0**	**15,228,269**	**3.35**	**-**
46. BAYSIDE #1	792	196,880	33.5	53.4	64.2	7,281	GAS	1,394,520	1,028,002	1,433,570.0	5,796,667	2.94	4.16
47. BAYSIDE #2	1,047	508,400	65.4	97.4	68.2	7,392	GAS	3,655,630	1,027,998	3,757,980.0	15,195,529	2.99	4.16
48. BAYSIDE #3	61	2,290	5.1	79.5	81.6	11,563	GAS	25,760	1,027,950	26,480.0	107,078	4.68	4.16
49. BAYSIDE #4	61	4,160	9.2	89.1	85.2	11,397	GAS	46,110	1,028,193	47,410.0	191,668	4.61	4.16
50. BAYSIDE #5	61	4,390	9.7	98.6	76.6	11,713	GAS	50,010	1,028,194	51,420.0	207,879	4.74	4.16
51. BAYSIDE #6	61	4,810	10.6	98.6	77.3	11,688	GAS	54,700	1,027,788	56,220.0	227,374	4.73	4.16
52. BAYSIDE STATION TOTAL	**2,083**	**720,930**	**46.6**	**80.0**	**67.3**	**7,453**	**GAS**	**5,226,730**	**1,028,000**	**5,373,080.0**	**21,726,195**	**3.01**	**4.16**
53. SYSTEM TOTAL	**5,398**	**1,439,731**	**35.9**	**63.6**	**83.8**	**7,367**	**-**	**-**	**-**	**10,605,970.0**	**42,920,541**	**2.98**	**-**

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. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 15 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2021

(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	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	300	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,630	428.7	-	428.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,360	34.4	-	34.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	18,090	33.9	-	33.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,590	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,580	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	13,310	33.7	-	33.7	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,230	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,590	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	18,770	34.9	-	34.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,680	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	16,350	38.0	-	38.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**163,800**	**34.9**	**-**	**34.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**13,080**	**5.3**	**45.1**	**38.9**	**13,578**	**GAS**	**172,760**	**1,028,016**	**177,600.0**	**668,882**	**5.11**	**3.87**
19. B.B.#3 (GAS)	345	50,680	20.4	-	-	-	GAS	582,600	1,027,995	598,910.0	2,255,678	4.45	3.87
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**50,680**	**20.4**	**83.2**	**56.3**	**11,817**		**-**	**-**	**598,910.0**	**2,255,678**	**4.45**	**-**
22. B.B.#4 (GAS)	155	3,880	3.5	-	-	-	GAS	47,120	1,028,014	48,440.0	182,437	4.70	3.87
23. B.B.#4 (COAL)	422	73,730	24.3	-	-	-	COAL	40,910	22,500,367	920,490.0	3,167,903	4.30	77.44
24. BIG BEND #4 TOTAL	**422**	**77,610**	**25.5**	**53.9**	**43.8**	**12,485**		**-**	**-**	**968,930.0**	**3,350,340**	**4.32**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	37,990	1,027,639	39,040.0	147,088	-	3.87
26. B.B.C.T.#4 TOTAL	**56**	**1,270**	**3.1**	**78.6**	**63.0**	**13,039**	**GAS**	**16,110**	**1,027,933**	**16,560.0**	**62,374**	**4.91**	**3.87**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**142,640**	**17.0**	**61.2**	**47.1**	**12,353**	**-**	**-**	**-**	**1,762,000.0**	**6,484,362**	**4.55**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	56,260	40.7	-	89.1	8,870	GAS	485,420	1,027,996	499,010.0	1,879,422	3.34	3.87
32. POLK #1 TOTAL	**220**	**56,260**	**35.5**	**93.4**	**89.1**	**8,870**	**-**	**-**	**-**	**499,010.0**	**1,879,422**	**3.34**	**-**
33. POLK #2 ST DUCT FIRING	120	16,580	19.2	-	59.6	8,273	GAS	133,420	1,028,032	137,160.0	516,568	3.12	3.87
34. POLK #2 ST W/O DUCT FIRING	341	495,129	-	-	-	-		3,320,823	1,028,021	3,413,874.3	12,857,379	2.60	3.87
35. POLK #2 ST TOTAL	**461**	**511,709**	**154.2**	**-**	**118.3**	**6,940**	**GAS**	**-**	**-**	**3,551,034.3**	**13,373,947**	**2.61**	**-**
36. POLK #2 CT (GAS)	150	270	0.3	-	90.0	11,333	GAS	2,980	1,026,846	3,060.0	11,538	4.27	3.87
37. POLK #2 CT (OIL)	159	986	0.9	-	5.0	10,997	LGT OIL	1,849	5,864,197	10,842.9	170,426	17.28	92.17
38. POLK #2 TOTAL (4)	**150**	**1,256**	**1.2**	**-**	**6.3**	**11,069**	**-**	**-**	**-**	**13,902.9**	**181,964**	**14.49**	**-**
39. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	159	986	0.9	-	94.4	10,997	LGT OIL	1,849	5,864,197	10,842.9	170,426	17.28	92.17
41. POLK #3 TOTAL (4)	**150**	**986**	**0.9**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**10,842.9**	**170,426**	**17.28**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2021

(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)
42. POLK #4 CT (GAS) TOTAL	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL	(4)	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL		**1,061**	**513,951**	**67.3**	**97.0**	**105.1**	**6,957**	**-**	**-**	**-**	**3,575,780.1**	**13,726,337**	**2.67**	**-**
45. POLK STATION TOTAL		**1,281**	**570,211**	**61.8**	**96.4**	**101.3**	**7,146**	**-**	**-**	**-**	**4,074,790.1**	**15,605,759**	**2.74**	**-**
46. BAYSIDE #1		720	306,890	59.2	97.3	60.9	7,453	GAS	2,224,950	1,027,992	2,287,230.0	8,614,438	2.81	3.87
47. BAYSIDE #2		954	367,430	53.5	97.4	55.7	7,579	GAS	2,708,750	1,027,998	2,784,590.0	10,487,589	2.85	3.87
48. BAYSIDE #3		56	2,730	6.8	98.6	66.8	12,784	GAS	33,940	1,028,285	34,900.0	131,407	4.81	3.87
49. BAYSIDE #4		56	2,030	5.0	88.7	64.7	12,936	GAS	25,550	1,027,789	26,260.0	98,923	4.87	3.87
50. BAYSIDE #5		56	2,230	5.5	78.9	76.6	12,184	GAS	26,440	1,027,610	27,170.0	102,369	4.59	3.87
51. BAYSIDE #6		56	2,380	5.9	78.9	64.4	12,920	GAS	29,930	1,027,397	30,750.0	115,881	4.87	3.87
52. BAYSIDE STATION TOTAL		**1,898**	**683,690**	**50.0**	**96.1**	**58.0**	**7,592**	**GAS**	**5,049,560**	**1,027,991**	**5,190,900.0**	**19,550,607**	**2.86**	**3.87**
53. SYSTEM TOTAL		**4,994**	**1,560,341**	**43.4**	**75.5**	**84.7**	**7,067**	**-**	**-**	**-**	**11,027,690.1**	**41,640,728**	**2.67**	**-**

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 2021

(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	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	5,000	448.0	-	448.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,500	37.4	-	37.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,300	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,410	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	16,320	36.1	-	36.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	14,880	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	10,050	36.1	-	36.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	12,960	35.3	-	35.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	20,250	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,490	37.1	-	37.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	18,450	41.5	-	41.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL [(3)]	**652.2**	**179,270**	**36.9**	**-**	**36.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**35,260**	**13.9**	**77.0**	**50.6**	**12,455**	**GAS**	**427,190**	**1,028,020**	**439,160.0**	**1,641,194**	**4.65**	**3.84**
19. B.B.#3 (GAS)	345	58,500	22.8	-	-	-	GAS	658,410	1,027,992	676,840.0	2,529,503	4.32	3.84
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**395**	**58,500**	**19.9**	**83.2**	**53.3**	**11,570**		**-**	**-**	**676,840.0**	**2,529,503**	**4.32**	**-**
22. B.B.#4 (GAS)	155	7,740	6.7	-	-	-	GAS	88,790	1,028,044	91,280.0	341,117	4.41	3.84
23. B.B.#4 (COAL)	422	147,030	46.8	-	-	-	COAL	77,080	22,499,741	1,734,280.0	5,971,387	4.06	77.47
24. BIG BEND #4 TOTAL	**422**	**154,770**	**49.3**	**89.8**	**53.5**	**11,795**		**-**	**-**	**1,825,560.0**	**6,312,504**	**4.08**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,080	1,027,944	41,200.0	153,981	-	3.84
26. B.B.C.T.#4 TOTAL	**56**	**3,960**	**9.5**	**98.3**	**88.4**	**11,646**	**GAS**	**44,870**	**1,027,858**	**46,120.0**	**172,383**	**4.35**	**3.84**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,213**	**252,490**	**28.0**	**84.4**	**53.3**	**11,833**	**-**	**-**	**-**	**2,987,680.0**	**10,809,565**	**4.28**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	46,790	32.8	-	92.0	8,827	GAS	401,760	1,028,002	413,010.0	1,543,496	3.30	3.84
32. POLK #1 TOTAL	**220**	**46,790**	**28.6**	**51.2**	**92.0**	**8,827**	**-**	**-**	**-**	**413,010.0**	**1,543,496**	**3.30**	**-**
33. POLK #2 ST DUCT FIRING	120	32,620	36.5	-	79.7	8,276	GAS	262,610	1,028,026	269,970.0	1,008,905	3.09	3.84
34. POLK #2 ST W/O DUCT FIRING	341	589,513	-	-	-	-		3,953,635	1,028,021	4,064,421.4	15,189,218	2.58	3.84
35. POLK #2 ST TOTAL	**461**	**622,133**	**181.4**	**-**	**125.8**	**6,967**	**GAS**	**-**	**-**	**4,334,391.4**	**16,198,123**	**2.60**	**-**
36. POLK #2 CT (GAS)	150	1,730	1.6	-	96.1	10,786	GAS	18,150	1,028,099	18,660.0	69,729	4.03	3.84
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.8	10,996	LGT OIL	2,493	5,862,134	14,614.3	222,824	16.77	89.38
38. POLK #2 TOTAL [(4)]	**150**	**3,059**	**2.7**	**-**	**14.2**	**10,878**	**-**	**-**	**-**	**33,274.3**	**292,553**	**9.56**	**-**
39. POLK #3 CT (GAS)	150	1,740	1.6	-	96.7	10,782	GAS	18,250	1,027,945	18,760.0	70,114	4.03	3.84
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	222,824	16.77	89.38
41. POLK #3 TOTAL [(4)]	**150**	**3,069**	**2.8**	**-**	**95.7**	**10,875**	**-**	**-**	**-**	**33,374.3**	**292,938**	**9.55**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,440**	**1.3**	**-**	**96.0**	**10,806**	**GAS**	**15,140**	**1,027,741**	**15,560.0**	**58,165**	**4.04**	**3.84**
44. POLK #2 CC TOTAL	**1,061**	**629,701**	**79.8**	**97.0**	**112.8**	**7,014**	**-**	**-**	**-**	**4,416,600.0**	**16,841,779**	**2.67**	**-**
45. POLK STATION TOTAL	**1,281**	**676,491**	**71.0**	**89.1**	**109.1**	**7,139**	**-**	**-**	**-**	**4,829,610.0**	**18,385,275**	**2.72**	**-**
46. BAYSIDE #1	720	317,050	59.2	97.3	61.7	7,444	GAS	2,295,850	1,028,007	2,360,150.0	8,820,280	2.78	3.84
47. BAYSIDE #2	954	350,300	49.4	97.4	51.0	7,607	GAS	2,592,180	1,028,003	2,664,770.0	9,958,731	2.84	3.84
48. BAYSIDE #3	56	7,690	18.5	98.6	96.7	11,446	GAS	85,630	1,027,911	88,020.0	328,976	4.28	3.84
49. BAYSIDE #4	56	6,370	15.3	98.6	97.2	11,419	GAS	70,750	1,028,127	72,740.0	271,810	4.27	3.84
50. BAYSIDE #5	56	10,620	25.5	98.6	96.3	11,414	GAS	117,910	1,028,072	121,220.0	452,991	4.27	3.84
51. BAYSIDE #6	56	8,900	21.4	79.5	96.3	11,447	GAS	99,110	1,027,949	101,880.0	380,764	4.28	3.84
52. BAYSIDE STATION TOTAL	**1,898**	**700,930**	**49.6**	**97.0**	**56.7**	**7,717**	**GAS**	**5,261,430**	**1,028,006**	**5,408,780.0**	**20,213,552**	**2.88**	**3.84**
53. SYSTEM TOTAL	**5,044**	**1,809,181**	**48.2**	**79.4**	**86.9**	**7,311**	**-**	**-**	**-**	**13,226,070.0**	**49,408,392**	**2.73**	**-**

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 2021

(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	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.1	-	2.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,430	410.2	-	410.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,850	33.4	-	33.4	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,490	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,510	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,070	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,850	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,720	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,160	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,630	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,580	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	16,300	37.9	-	37.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**154,170**	**32.8**	**-**	**32.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**24,930**	**10.2**	**79.5**	**49.9**	**12,500**	**GAS**	**303,150**	**1,027,973**	**311,630.0**	**1,170,680**	**4.70**	**3.86**
19. B.B.#3 (GAS)	345	70,120	28.2	-	-	-	GAS	791,310	1,027,992	813,460.0	3,055,817	4.36	3.86
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**70,120**	**28.2**	**83.2**	**60.3**	**11,601**		**-**	**-**	**813,460.0**	**3,055,817**	**4.36**	**-**
22. B.B.#4 (GAS)	155	7,220	6.5	-	-	-	GAS	83,610	1,027,867	85,940.0	322,878	4.47	3.86
23. B.B.#4 (COAL)	422	137,100	45.1	-	-	-	COAL	72,580	22,498,760	1,632,960.0	5,734,099	4.18	79.00
24. BIG BEND #4 TOTAL	**422**	**144,320**	**47.5**	**89.8**	**51.5**	**11,910**		**-**	**-**	**1,718,900.0**	**6,056,977**	**4.20**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	37,160	1,027,987	38,200.0	143,501	-	3.86
26. B.B.C.T.#4 TOTAL	**56**	**4,080**	**10.1**	**98.3**	**85.7**	**11,708**	**GAS**	**46,480**	**1,027,754**	**47,770.0**	**179,493**	**4.40**	**3.86**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**243,450**	**29.1**	**85.2**	**54.0**	**11,878**	**-**	**-**	**-**	**2,891,760.0**	**10,606,468**	**4.36**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	81,120	58.7	-	92.5	8,813	GAS	695,460	1,028,010	714,940.0	2,685,671	3.31	3.86
32. POLK #1 TOTAL	**220**	**81,120**	**51.2**	**93.4**	**92.5**	**8,813**	**-**	**-**	**-**	**714,940.0**	**2,685,671**	**3.31**	**-**
33. POLK #2 ST DUCT FIRING	120	37,820	43.8	-	91.1	8,274	GAS	304,400	1,028,022	312,930.0	1,175,507	3.11	3.86
34. POLK #2 ST W/O DUCT FIRING	341	639,929	-	-	-	-		4,294,634	1,028,019	4,414,964.3	16,584,667	2.59	3.86
35. POLK #2 ST TOTAL	**461**	**677,749**	**204.2**	**-**	**139.4**	**6,976**	**GAS**	**-**	**-**	**4,727,894.3**	**17,760,174**	**2.62**	**-**
36. POLK #2 CT (GAS)	150	1,630	1.5	-	98.8	10,755	GAS	17,050	1,028,152	17,530.0	65,842	4.04	3.86
37. POLK #2 CT (OIL)	159	1,286	1.1	-	6.5	10,998	LGT OIL	2,412	5,863,557	14,142.9	209,958	16.33	87.05
38. POLK #2 TOTAL (4)	**150**	**2,916**	**2.7**	**-**	**13.6**	**10,862**	**-**	**-**	**-**	**31,672.9**	**275,800**	**9.46**	**-**
39. POLK #3 CT (GAS)	150	1,630	1.5	-	98.8	10,779	GAS	17,090	1,028,087	17,570.0	65,997	4.05	3.86
40. POLK #3 CT (OIL)	159	1,286	1.1	-	94.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	209,958	16.33	87.05
41. POLK #3 TOTAL (4)	**150**	**2,916**	**2.7**	**-**	**96.8**	**10,875**	**-**	**-**	**-**	**31,712.9**	**275,955**	**9.46**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,630**	**1.5**	**-**	**98.8**	**10,755**	**GAS**	**17,050**	**1,028,152**	**17,530.0**	**65,842**	**4.04**	**3.86**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,500**	**1.4**	**-**	**100.0**	**10,673**	**GAS**	**15,580**	**1,027,599**	**16,010.0**	**60,166**	**4.01**	**3.86**
44. POLK #2 CC TOTAL	**1,061**	**686,711**	**89.9**	**97.0**	**124.1**	**7,026**	**-**	**-**	**-**	**4,824,820.1**	**18,437,937**	**2.68**	**-**
45. POLK STATION TOTAL	**1,281**	**767,831**	**83.2**	**96.4**	**115.6**	**7,215**	**-**	**-**	**-**	**5,539,760.1**	**21,123,608**	**2.75**	**-**
46. BAYSIDE #1	720	309,650	59.7	97.3	62.8	7,434	GAS	2,239,190	1,027,997	2,301,880.0	8,647,121	2.79	3.86
47. BAYSIDE #2	954	446,860	65.1	97.4	67.0	7,473	GAS	3,248,430	1,027,998	3,339,380.0	12,544,523	2.81	3.86
48. BAYSIDE #3	56	5,720	14.2	98.6	92.9	11,523	GAS	64,120	1,027,916	65,910.0	247,613	4.33	3.86
49. BAYSIDE #4	56	5,150	12.8	98.6	92.9	11,505	GAS	57,640	1,027,932	59,250.0	222,589	4.32	3.86
50. BAYSIDE #5	56	8,230	20.4	98.6	93.6	11,467	GAS	91,810	1,027,884	94,370.0	354,544	4.31	3.86
51. BAYSIDE #6	56	6,590	16.3	98.6	92.7	11,517	GAS	73,840	1,027,898	75,900.0	285,149	4.33	3.86
52. BAYSIDE STATION TOTAL	**1,898**	**782,200**	**57.2**	**97.5**	**65.9**	**7,590**	**GAS**	**5,775,030**	**1,027,993**	**5,936,690.0**	**22,301,539**	**2.85**	**3.86**
53. SYSTEM TOTAL	**4,994**	**1,947,651**	**54.2**	**81.6**	**95.0**	**7,377**	**-**	**-**	**-**	**14,368,210.1**	**54,031,615**	**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**

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(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	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,280	383.5	-	383.5	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,340	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,950	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,310	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,640	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,450	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,490	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,810	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,390	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,850	35.6	-	35.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL [3]	**652.2**	**150,450**	**31.0**	**-**	**31.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**29,110**	**11.5**	**79.5**	**48.1**	**12,647**	**GAS**	**358,120**	**1,027,979**	**368,140.0**	**1,394,869**	**4.79**	**3.89**
19. B.B.#3 (GAS)	345	59,490	23.2	-	-	-	GAS	676,860	1,027,997	695,810.0	2,636,354	4.43	3.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**59,490**	**23.2**	**83.2**	**58.5**	**11,696**		**-**	**-**	**695,810.0**	**2,636,354**	**4.43**	**-**
22. B.B.#4 (GAS)	155	6,710	5.8	-	-	-	GAS	80,200	1,028,055	82,450.0	312,377	4.66	3.89
23. B.B.#4 (COAL)	422	127,660	40.7	-	-	-	COAL	69,620	22,500,718	1,566,500.0	5,559,374	4.35	79.85
24. BIG BEND #4 TOTAL	**422**	**134,370**	**42.8**	**89.8**	**46.4**	**12,272**		**-**	**-**	**1,648,950.0**	**5,871,751**	**4.37**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	35,070	1,027,944	36,050.0	136,597	-	3.89
26. B.B.C.T.#4 TOTAL	**56**	**3,140**	**7.5**	**98.3**	**83.7**	**11,815**	**GAS**	**36,090**	**1,027,986**	**37,100.0**	**140,570**	**4.48**	**3.89**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**226,110**	**26.1**	**85.2**	**49.6**	**12,162**	**-**	**-**	**-**	**2,750,000.0**	**10,180,142**	**4.50**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	53,670	37.6	-	92.0	8,840	GAS	461,500	1,027,996	474,420.0	1,797,532	3.35	3.89
32. POLK #1 TOTAL	**220**	**53,670**	**32.8**	**93.4**	**92.0**	**8,840**	**-**	**-**	**-**	**474,420.0**	**1,797,532**	**3.35**	**-**
33. POLK #2 ST DUCT FIRING	120	30,060	33.7	-	91.8	8,276	GAS	242,000	1,027,975	248,770.0	942,585	3.14	3.89
34. POLK #2 ST W/O DUCT FIRING	341	660,143	-	-	-	-		4,430,135	1,028,019	4,554,261.4	17,255,276	2.61	3.89
35. POLK #2 ST TOTAL	**461**	**690,203**	**201.2**	**-**	**149.0**	**6,959**	**GAS**	**-**	**-**	**4,803,031.4**	**18,197,861**	**2.64**	**-**
36. POLK #2 CT (GAS)	150	750	0.7	-	100.0	10,933	GAS	7,980	1,027,569	8,200.0	31,082	4.14	3.89
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	211,721	15.93	84.93
38. POLK #2 TOTAL [4]	**150**	**2,079**	**1.9**	**-**	**10.0**	**10,974**	**-**	**-**	**-**	**22,814.3**	**242,803**	**11.68**	**-**
39. POLK #3 CT (GAS)	150	750	0.7	-	100.0	10,693	GAS	7,800	1,028,205	8,020.0	30,381	4.05	3.90
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	211,721	15.93	84.93
41. POLK #3 TOTAL [4]	**150**	**2,079**	**1.9**	**-**	**96.3**	**10,887**	**-**	**-**	**-**	**22,634.3**	**242,102**	**11.65**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**450**	**0.4**	**-**	**100.0**	**10,889**	**GAS**	**4,770**	**1,027,254**	**4,900.0**	**18,579**	**4.13**	**3.89**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**450**	**0.4**	**-**	**100.0**	**10,711**	**GAS**	**4,690**	**1,027,719**	**4,820.0**	**18,267**	**4.06**	**3.89**
44. POLK #2 CC TOTAL	**1,061**	**695,261**	**88.1**	**97.0**	**132.3**	**6,988**	**-**	**-**	**-**	**4,858,200.0**	**18,719,612**	**2.69**	**-**
45. POLK STATION TOTAL	**1,281**	**748,931**	**78.6**	**96.4**	**123.9**	**7,120**	**-**	**-**	**-**	**5,332,620.0**	**20,517,144**	**2.74**	**-**
46. BAYSIDE #1	720	429,780	80.2	97.3	82.9	7,307	GAS	3,054,720	1,028,003	3,140,260.0	11,898,066	2.77	3.89
47. BAYSIDE #2	954	463,520	65.3	97.4	67.1	7,466	GAS	3,366,230	1,027,999	3,460,480.0	13,111,391	2.83	3.89
48. BAYSIDE #3	56	3,760	9.0	98.6	88.3	11,705	GAS	42,810	1,028,031	44,010.0	166,744	4.43	3.89
49. BAYSIDE #4	56	3,240	7.8	98.6	91.8	11,608	GAS	36,590	1,027,876	37,610.0	142,517	4.40	3.89
50. BAYSIDE #5	56	4,470	10.7	98.6	84.9	11,707	GAS	50,900	1,028,094	52,330.0	198,254	4.44	3.89
51. BAYSIDE #6	56	4,400	10.6	98.6	87.3	11,664	GAS	49,910	1,028,251	51,320.0	194,398	4.42	3.89
52. BAYSIDE STATION TOTAL	**1,898**	**909,170**	**64.4**	**97.5**	**74.1**	**7,464**	**GAS**	**6,601,160**	**1,028,003**	**6,786,010.0**	**25,711,370**	**2.83**	**3.89**
53. SYSTEM TOTAL	**4,994**	**2,034,661**	**54.8**	**81.6**	**99.0**	**7,308**	**-**	**-**	**-**	**14,868,630.0**	**56,408,656**	**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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(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	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,200	376.3	-	376.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,770	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,350	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,170	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,040	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,360	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,430	28.4	-	28.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	15,880	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,780	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,370	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**145,640**	**30.0**	**-**	**30.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**24,310**	**9.6**	**79.5**	**50.0**	**12,492**	**GAS**	**295,410**	**1,028,029**	**303,690.0**	**1,152,050**	**4.74**	**3.90**
19. B.B.#3 (GAS)	345	53,240	20.7	-	-	-	GAS	598,140	1,027,987	614,880.0	2,332,647	4.38	3.90
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**53,240**	**20.7**	**83.2**	**61.5**	**11,549**		**-**	**-**	**614,880.0**	**2,332,647**	**4.38**	**-**
22. B.B.#4 (GAS)	155	7,100	6.2	-	-	-	GAS	83,390	1,028,061	85,730.0	325,207	4.58	3.90
23. B.B.#4 (COAL)	422	134,920	43.0	-	-	-	COAL	72,400	22,498,481	1,628,890.0	5,769,559	4.28	79.69
24. BIG BEND #4 TOTAL	**422**	**142,020**	**45.2**	**89.8**	**49.1**	**12,073**		**-**	**-**	**1,714,620.0**	**6,094,766**	**4.29**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	32,150	1,027,994	33,050.0	125,380	-	3.90
26. B.B.C.T.#4 TOTAL	**56**	**4,230**	**10.2**	**98.3**	**87.8**	**11,636**	**GAS**	**47,870**	**1,028,201**	**49,220.0**	**186,685**	**4.41**	**3.90**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**223,800**	**25.9**	**85.2**	**52.1**	**11,986**	**-**	**-**	**-**	**2,682,410.0**	**9,891,529**	**4.42**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	51,990	36.4	-	92.1	8,831	GAS	446,620	1,028,010	459,130.0	1,741,745	3.35	3.90
32. POLK #1 TOTAL	**220**	**51,990**	**31.8**	**93.4**	**92.1**	**8,831**	**-**	**-**	**-**	**459,130.0**	**1,741,745**	**3.35**	**-**
33. POLK #2 ST DUCT FIRING	120	33,210	37.2	-	92.3	8,274	GAS	267,300	1,027,984	274,780.0	1,042,426	3.14	3.90
34. POLK #2 ST W/O DUCT FIRING	341	662,953	-	-	-	-		4,449,515	1,028,020	4,574,191.4	17,352,377	2.62	3.90
35. POLK #2 ST TOTAL	**461**	**696,163**	**203.0**	**-**	**146.3**	**6,965**	**GAS**	**-**	**-**	**4,848,971.4**	**18,394,803**	**2.64**	**-**
36. POLK #2 CT (GAS)	150	1,620	1.5	-	90.0	11,025	GAS	17,370	1,028,210	17,860.0	67,740	4.18	3.90
37. POLK #2 CT (OIL)	159	1,329	1.1	-	6.6	10,996	LGT OIL	2,493	5,862,134	14,614.3	207,203	15.59	83.11
38. POLK #2 TOTAL (4)	**150**	**2,949**	**2.6**	**-**	**13.4**	**11,012**	**-**	**-**	**-**	**32,474.3**	**274,943**	**9.32**	**-**
39. POLK #3 CT (GAS)	150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	12,518	4.17	3.90
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	207,202	15.59	83.11
41. POLK #3 TOTAL (4)	**150**	**1,629**	**1.5**	**-**	**95.4**	**10,997**	**-**	**-**	**-**	**17,914.3**	**219,720**	**13.49**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(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)
42. POLK #4 CT (GAS) TOTAL (4)	**150**	**300**	**0.3**	**-**	**100.0**	**10,733**	**GAS**	**3,130**	**1,028,754**	**3,220.0**	**12,206**	**4.07**	**3.90**
43. POLK #5 CT (GAS) TOTAL (4)	**150**	**150**	**0.1**	**-**	**100.0**	**11,333**	**GAS**	**1,660**	**1,024,096**	**1,700.0**	**6,474**	**4.32**	**3.90**
44. POLK #2 CC TOTAL	**1,061**	**701,191**	**88.8**	**97.0**	**130.1**	**6,994**	**-**	**-**	**-**	**4,904,280.0**	**18,908,146**	**2.70**	**-**
45. POLK STATION TOTAL	**1,281**	**753,181**	**79.0**	**96.4**	**122.6**	**7,121**	**-**	**-**	**-**	**5,363,410.0**	**20,649,891**	**2.74**	**-**
46. BAYSIDE #1	720	444,350	83.0	97.3	85.2	7,295	GAS	3,153,270	1,028,000	3,241,560.0	12,297,234	2.77	3.90
47. BAYSIDE #2	954	478,130	67.4	97.4	71.8	7,427	GAS	3,454,270	1,028,000	3,550,990.0	13,471,085	2.82	3.90
48. BAYSIDE #3	56	4,330	10.4	98.6	92.0	11,605	GAS	48,890	1,027,818	50,250.0	190,663	4.40	3.90
49. BAYSIDE #4	56	3,120	7.5	98.6	94.4	11,567	GAS	35,110	1,027,912	36,090.0	136,923	4.39	3.90
50. BAYSIDE #5	56	6,320	15.2	98.6	88.9	11,582	GAS	71,230	1,027,657	73,200.0	277,785	4.40	3.90
51. BAYSIDE #6	56	5,000	12.0	98.6	92.0	11,560	GAS	56,220	1,028,104	57,800.0	219,249	4.38	3.90
52. BAYSIDE STATION TOTAL	**1,898**	**941,250**	**66.7**	**97.5**	**77.9**	**7,447**	**GAS**	**6,818,990**	**1,027,995**	**7,009,890.0**	**26,592,939**	**2.83**	**3.90**
53. SYSTEM TOTAL	**4,994**	**2,063,871**	**55.5**	**81.6**	**102.7**	**7,295**	**-**	**-**	**-**	**15,055,710.0**	**57,134,359**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
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: SEPTEMBER 2021

(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	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,480	322.2	-	322.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,710	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,200	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,400	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,450	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,760	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,070	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,730	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,420	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,580	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**125,760**	**26.8**	**-**	**26.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**33,570**	**13.7**	**79.5**	**49.9**	**12,498**	**GAS**	**408,130**	**1,028,006**	**419,560.0**	**1,585,730**	**4.72**	**3.89**
19. B.B.#3 (GAS)	345	56,220	22.6	-	-	-	GAS	636,290	1,027,990	654,100.0	2,472,212	4.40	3.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**56,220**	**22.6**	**83.2**	**59.7**	**11,635**		**-**	**-**	**654,100.0**	**2,472,212**	**4.40**	**-**
22. B.B.#4 (GAS)	155	6,670	6.0	-	-	-	GAS	78,910	1,028,007	81,120.0	306,593	4.60	3.89
23. B.B.#4 (COAL)	422	126,580	41.7	-	-	-	COAL	68,500	22,499,708	1,541,230.0	5,461,415	4.31	79.73
24. BIG BEND #4 TOTAL	**422**	**133,250**	**43.9**	**89.8**	**47.6**	**12,175**		**-**	**-**	**1,622,350.0**	**5,768,008**	**4.33**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	40,070	1,027,951	41,190.0	155,686	-	3.89
26. B.B.C.T.#4 TOTAL	**56**	**3,420**	**8.5**	**98.3**	**81.4**	**11,918**	**GAS**	**39,650**	**1,027,995**	**40,760.0**	**154,054**	**4.50**	**3.89**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**226,460**	**27.0**	**85.2**	**50.8**	**12,085**	**-**	**-**	**-**	**2,736,770.0**	**10,135,690**	**4.48**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	67,360	48.7	-	91.8	8,810	GAS	577,250	1,028,012	593,420.0	2,242,821	3.33	3.89
32. POLK #1 TOTAL	**220**	**67,360**	**42.5**	**93.4**	**91.8**	**8,810**	**-**	**-**	**-**	**593,420.0**	**2,242,821**	**3.33**	**-**
33. POLK #2 ST DUCT FIRING	120	27,110	31.4	-	77.1	8,274	GAS	218,210	1,028,001	224,320.0	847,823	3.13	3.89
34. POLK #2 ST W/O DUCT FIRING	341	557,129	-	-	-	-		3,736,534	1,028,023	3,841,244.3	14,517,758	2.61	3.89
35. POLK #2 ST TOTAL	**461**	**584,239**	**176.0**	**-**	**126.5**	**6,959**	**GAS**	**-**	**-**	**4,065,564.3**	**15,365,581**	**2.63**	**-**
36. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	159	1,286	1.1	-	6.3	10,998	LGT OIL	2,412	5,863,557	14,142.9	196,853	15.31	81.61
38. POLK #2 TOTAL (4)	**150**	**1,286**	**1.2**	**-**	**6.3**	**10,998**	**-**	**-**	**-**	**14,142.9**	**196,853**	**15.31**	**-**
39. POLK #3 CT (GAS)	150	1,420	1.3	-	86.1	11,183	GAS	15,450	1,027,832	15,880.0	60,029	4.23	3.89
40. POLK #3 CT (OIL)	159	1,286	1.1	-	94.4	10,998	LGT OIL	2,412	5,863,557	14,142.9	196,853	15.31	81.61
41. POLK #3 TOTAL (4)	**150**	**2,706**	**2.5**	**-**	**89.8**	**11,095**	**-**	**-**	**-**	**30,022.9**	**256,882**	**9.49**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,061**	**588,231**	**77.0**	**97.0**	**112.4**	**6,987**	**-**	**-**	**-**	**4,109,730.1**	**15,819,316**	**2.69**	**-**
45. POLK STATION TOTAL	**1,281**	**655,591**	**71.1**	**96.4**	**107.3**	**7,174**	**-**	**-**	**-**	**4,703,150.1**	**18,062,137**	**2.76**	**-**
46. BAYSIDE #1	720	430,040	83.0	97.3	85.2	7,295	GAS	3,051,570	1,028,002	3,137,020.0	11,856,431	2.76	3.89
47. BAYSIDE #2	954	486,520	70.8	97.4	72.8	7,419	GAS	3,511,300	1,027,995	3,609,600.0	13,642,644	2.80	3.89
48. BAYSIDE #3	56	4,320	10.7	98.6	87.7	11,725	GAS	49,280	1,027,800	50,650.0	191,470	4.43	3.89
49. BAYSIDE #4	56	3,950	9.8	98.6	89.3	11,737	GAS	45,100	1,027,938	46,360.0	175,229	4.44	3.89
50. BAYSIDE #5	56	6,910	17.1	98.6	90.7	11,564	GAS	77,730	1,028,046	79,910.0	302,009	4.37	3.89
51. BAYSIDE #6	56	5,940	14.7	98.6	89.9	11,635	GAS	67,220	1,028,117	69,110.0	261,174	4.40	3.89
52. BAYSIDE STATION TOTAL	**1,898**	**937,680**	**68.6**	**97.5**	**78.3**	**7,457**	**GAS**	**6,802,200**	**1,027,998**	**6,992,650.0**	**26,428,957**	**2.82**	**3.89**
53. SYSTEM TOTAL	**4,994**	**1,945,491**	**54.1**	**81.6**	**96.0**	**7,418**	**-**	**-**	**-**	**14,432,570.1**	**54,626,784**	**2.81**	**-**

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. 20200001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 27 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(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	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,600	322.6	-	322.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,550	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,050	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,300	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,340	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,140	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,970	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,260	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,090	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,520	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL [(3)]	**652.2**	**125,370**	**25.8**	**-**	**25.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**52,810**	**20.9**	**79.5**	**52.1**	**12,354**	**GAS**	**634,640**	**1,028,000**	**652,410.0**	**2,455,183**	**4.65**	**3.87**
19. B.B.#3 (GAS)	345	52,530	20.5	-	-	-	GAS	580,580	1,028,006	596,840.0	2,246,045	4.28	3.87
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**52,530**	**20.5**	**59.0**	**66.2**	**11,362**		**-**	**-**	**596,840.0**	**2,246,045**	**4.28**	**-**
22. B.B.#4 (GAS)	155	3,780	3.3	-	-	-	GAS	45,150	1,028,128	46,420.0	174,668	4.62	3.87
23. B.B.#4 (COAL)	422	71,810	22.9	-	-	-	COAL	39,200	22,498,214	881,930.0	3,123,824	4.35	79.69
24. BIG BEND #4 TOTAL	**422**	**75,590**	**24.1**	**89.8**	**46.3**	**12,281**		**-**	**-**	**928,350.0**	**3,298,492**	**4.36**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	48,010	1,027,703	49,340.0	185,733	-	3.87
26. B.B.C.T.#4 TOTAL	**56**	**8,700**	**20.9**	**98.3**	**81.8**	**11,840**	**GAS**	**100,200**	**1,028,044**	**103,010.0**	**387,636**	**4.46**	**3.87**
27. B.B.C.T.#5 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
28. B.B.C.T.#6 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. BIG BEND STATION TOTAL	**1,163**	**189,630**	**21.9**	**78.1**	**53.5**	**12,027**	**-**	**-**	**-**	**2,280,610.0**	**8,573,090**	**4.52**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	102,590	71.8	-	92.3	8,743	GAS	872,540	1,028,010	896,980.0	3,375,529	3.29	3.87
32. POLK #1 TOTAL	**220**	**102,590**	**62.7**	**93.4**	**92.3**	**8,743**	**-**	**-**	**-**	**896,980.0**	**3,375,529**	**3.29**	**-**
33. POLK #2 ST DUCT FIRING	120	15,630	17.5	-	65.1	8,276	GAS	125,830	1,027,974	129,350.0	486,789	3.11	3.87
34. POLK #2 ST W/O DUCT FIRING	341	279,661	-	-	-	-		1,870,654	1,028,045	1,923,115.7	7,236,856	2.59	3.87
35. POLK #2 ST TOTAL	**461**	**295,291**	**86.1**	**-**	**106.4**	**6,951**	**GAS**	**-**	**-**	**2,052,465.7**	**7,723,645**	**2.62**	**-**
36. POLK #2 CT (GAS)	150	43,590	39.1	-	86.7	11,111	GAS	471,130	1,027,997	484,320.0	1,822,625	4.18	3.87
37. POLK #2 CT (OIL)	159	1,200	1.0	-	5.8	11,000	LGT OIL	2,251	5,864,060	13,200.0	180,796	15.07	80.32
38. POLK #2 TOTAL [(4)]	**150**	**44,790**	**40.1**	**-**	**63.2**	**11,108**	**-**	**-**	**-**	**497,520.0**	**2,003,421**	**4.47**	**-**
39. POLK #3 CT (GAS)	150	43,550	39.0	-	86.7	11,112	GAS	470,770	1,027,975	483,940.0	1,821,232	4.18	3.87
40. POLK #3 CT (OIL)	159	1,329	1.1	-	94.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	200,234	15.07	80.32
41. POLK #3 TOTAL [(4)]	**150**	**44,879**	**40.2**	**-**	**86.9**	**11,109**	**-**	**-**	**-**	**498,554.3**	**2,021,466**	**4.50**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(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)
42. POLK #4 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL	[4]	**150**	**35,700**	**32.0**	**-**	**88.8**	**11,040**	**GAS**	**383,410**	**1,027,986**	**394,140.0**	**1,483,269**	**4.15**	**3.87**
44. POLK #2 CC TOTAL		**1,061**	**420,660**	**53.3**	**53.2**	**87.6**	**8,184**	**-**	**-**	**-**	**3,442,680.0**	**13,231,801**	**3.15**	**-**
45. POLK STATION TOTAL		**1,281**	**523,250**	**54.9**	**60.1**	**88.8**	**8,294**	**-**	**-**	**-**	**4,339,660.0**	**16,607,330**	**3.17**	**-**
46. BAYSIDE #1		720	327,680	61.2	97.3	63.7	7,426	GAS	2,367,220	1,028,003	2,433,510.0	9,157,883	2.79	3.87
47. BAYSIDE #2		954	523,080	73.7	97.4	75.7	7,408	GAS	3,769,330	1,028,002	3,874,880.0	14,582,121	2.79	3.87
48. BAYSIDE #3		56	12,430	29.8	98.6	84.7	11,705	GAS	141,530	1,027,980	145,490.0	547,526	4.40	3.87
49. BAYSIDE #4		56	11,200	26.9	98.6	84.4	11,727	GAS	127,760	1,028,021	131,340.0	494,255	4.41	3.87
50. BAYSIDE #5		56	13,190	31.7	98.6	84.4	11,724	GAS	150,430	1,027,986	154,640.0	581,957	4.41	3.87
51. BAYSIDE #6		56	12,510	30.0	98.6	84.9	11,726	GAS	142,680	1,028,105	146,690.0	551,975	4.41	3.87
52. BAYSIDE STATION TOTAL		**1,898**	**900,090**	**63.7**	**97.5**	**71.2**	**7,651**	**GAS**	**6,698,950**	**1,028,004**	**6,886,550.0**	**25,915,717**	**2.88**	**3.87**
53. SYSTEM TOTAL		**4,994**	**1,738,340**	**46.8**	**70.7**	**84.0**	**7,770**	**-**	**-**	**-**	**13,506,820.0**	**51,096,137**	**2.94**	**-**

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

44

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

(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	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,970	274.6	-	274.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,130	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,500	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,720	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,040	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,700	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,780	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,070	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	10,210	23.7	-	23.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL (3)	**652.2**	**99,020**	**21.1**	**-**	**21.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. B.B.#3 (GAS)	345	13,890	5.6	-	-	-	GAS	161,170	1,027,983	165,680.0	640,701	4.61	3.98
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**345**	**13,890**	**5.6**	**80.4**	**54.4**	**11,928**		**-**	**-**	**165,680.0**	**640,701**	**4.61**	**-**
22. B.B.#4 (GAS)	155	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
23. B.B.#4 (COAL)	422	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
24. BIG BEND #4 TOTAL	**422**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	2,920	1,027,397	3,000.0	11,608	-	3.98
26. B.B.C.T.#4 TOTAL	**56**	**380**	**0.9**	**98.3**	**39.9**	**15,553**	**GAS**	**5,750**	**1,027,826**	**5,910.0**	**22,858**	**6.02**	**3.98**
27. B.B.C.T.#5 TOTAL	**330**	**73,810**	**31.0**	**98.0**	**64.5**	**10,371**	**GAS**	**744,630**	**1,027,974**	**765,460.0**	**2,960,135**	**4.01**	**3.98**
28. B.B.C.T.#6 TOTAL	**330**	**54,680**	**23.0**	**98.0**	**69.0**	**10,131**	**GAS**	**538,900**	**1,028,001**	**553,990.0**	**2,142,294**	**3.92**	**3.98**
29. BIG BEND STATION TOTAL	**1,823**	**142,760**	**10.9**	**53.7**	**64.8**	**10,444**	**-**	**-**	**-**	**1,491,040.0**	**5,777,596**	**4.05**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	57,630	41.6	-	88.8	8,887	GAS	498,200	1,028,001	512,150.0	1,980,499	3.44	3.98
32. POLK #1 TOTAL	**220**	**57,630**	**36.3**	**87.2**	**88.8**	**8,887**	**-**	**-**	**-**	**512,150.0**	**1,980,499**	**3.44**	**-**
33. POLK #2 ST DUCT FIRING	120	24,650	28.5	-	74.2	8,273	GAS	198,370	1,027,978	203,920.0	788,582	3.20	3.98
34. POLK #2 ST W/O DUCT FIRING	341	594,930	-	-	-	-		3,992,494	1,028,017	4,104,350.0	15,871,402	2.67	3.98
35. POLK #2 ST TOTAL	**461**	**619,580**	**186.4**	**-**	**136.3**	**6,954**	**GAS**	**-**	**-**	**4,308,270.0**	**16,659,984**	**2.69**	**-**
36. POLK #2 CT (GAS)	150	750	0.7	-	100.0	10,800	GAS	7,880	1,027,919	8,100.0	31,326	4.18	3.98
37. POLK #2 CT (OIL)	159	1,114	1.0	-	5.4	11,003	LGT OIL	2,091	5,861,836	12,257.1	165,976	14.90	79.38
38. POLK #2 TOTAL (4)	**150**	**1,864**	**1.7**	**-**	**8.7**	**10,921**	**-**	**-**	**-**	**20,357.1**	**197,302**	**10.58**	**-**
39. POLK #3 CT (GAS)	150	450	0.4	-	100.0	10,889	GAS	4,770	1,027,254	4,900.0	18,962	4.21	3.98
40. POLK #3 CT (OIL)	159	986	0.9	-	94.4	10,997	LGT OIL	1,849	5,864,197	10,842.9	146,767	14.89	79.38
41. POLK #3 TOTAL (4)	**150**	**1,436**	**1.3**	**-**	**96.1**	**10,963**	**-**	**-**	**-**	**15,742.9**	**165,729**	**11.54**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

(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)
42. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL	**1,061**	**622,880**	**81.4**	**97.0**	**120.7**	**6,975**	**-**	**-**	**-**	**4,344,370.0**	**17,023,015**	**2.73**	**-**
45. POLK STATION TOTAL	**1,281**	**680,510**	**73.7**	**95.3**	**113.3**	**7,137**	**-**	**-**	**-**	**4,856,520.0**	**19,003,514**	**2.79**	**-**
46. BAYSIDE #1	720	315,180	60.7	97.3	62.4	7,438	GAS	2,280,380	1,027,987	2,344,200.0	9,065,218	2.88	3.98
47. BAYSIDE #2	954	198,180	28.8	52.0	55.5	7,575	GAS	1,460,280	1,027,995	1,501,160.0	5,805,065	2.93	3.98
48. BAYSIDE #3	56	2,050	5.1	98.6	79.6	12,059	GAS	24,060	1,027,431	24,720.0	95,646	4.67	3.98
49. BAYSIDE #4	56	1,620	4.0	98.6	78.2	12,093	GAS	19,050	1,028,346	19,590.0	75,730	4.67	3.98
50. BAYSIDE #5	56	3,210	8.0	98.6	85.6	11,838	GAS	36,960	1,028,139	38,000.0	146,927	4.58	3.98
51. BAYSIDE #6	56	2,470	6.1	98.6	83.2	11,943	GAS	28,690	1,028,233	29,500.0	114,052	4.62	3.98
52. BAYSIDE STATION TOTAL	**1,898**	**522,710**	**38.2**	**74.7**	**59.9**	**7,570**	**GAS**	**3,849,420**	**1,027,991**	**3,957,170.0**	**15,302,638**	**2.93**	**3.98**
53. SYSTEM TOTAL	**5,654**	**1,445,000**	**35.4**	**64.0**	**98.7**	**7,131**	**-**	**-**	**-**	**10,304,730.0**	**40,083,748**	**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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,700	241.9	-	241.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,500	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,800	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,420	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,070	15.6	-	15.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,480	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,050	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,620	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,490	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,460	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,580	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	74.5	9,070	16.4	-	16.4	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.5	9,070	16.4	-	16.4	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL [3]	**801.2**	**102,730**	**17.2**	**-**	**17.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
17. BIG BEND #1 TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
18. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
19. B.B.#3 (GAS)	355	123,910	46.9	-	-	-	GAS	1,419,150	1,028,003	1,458,890.0	5,862,424	4.73	4.13
20. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	**355**	**123,910**	**46.9**	**83.2**	**53.8**	**11,774**		**-**	**-**	**1,458,890.0**	**5,862,424**	**4.73**	**-**
22. B.B.#4 (GAS)	160	2,080	1.7	-	-	-	GAS	26,380	1,027,672	27,110.0	108,974	5.24	4.13
23. B.B.#4 (COAL)	432	39,460	12.3	-	-	-	COAL	22,900	22,495,633	515,150.0	1,825,597	4.63	79.72
24. BIG BEND #4 TOTAL	**432**	**41,540**	**12.9**	**46.3**	**36.1**	**13,054**		**-**	**-**	**542,260.0**	**1,934,571**	**4.66**	**-**
25. B.B. IGNITION	-	-	-	-	-	-	GAS	17,950	1,027,855	18,450.0	74,150	-	4.13
26. B.B.C.T.#4 TOTAL	**61**	**0**	**0.0**	**98.3**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
27. B.B.C.T.#5 TOTAL	**350**	**14,540**	**5.6**	**98.0**	**62.0**	**10,534**	**GAS**	**148,980**	**1,028,057**	**153,160.0**	**615,427**	**4.23**	**4.13**
28. B.B.C.T.#6 TOTAL	**350**	**6,730**	**2.6**	**98.0**	**68.7**	**10,223**	**GAS**	**66,930**	**1,027,940**	**68,800.0**	**276,484**	**4.11**	**4.13**
29. BIG BEND STATION TOTAL	**1,898**	**186,720**	**13.2**	**65.4**	**49.3**	**11,906**	**-**	**-**	**-**	**2,223,110.0**	**8,763,056**	**4.69**	**-**
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	10,620	7.4	-	86.4	8,986	GAS	92,840	1,027,897	95,430.0	383,516	3.61	4.13
32. POLK #1 TOTAL	**220**	**10,620**	**6.5**	**57.3**	**86.4**	**8,986**	**-**	**-**	**-**	**95,430.0**	**383,516**	**3.61**	**-**
33. POLK #2 ST DUCT FIRING	120	4,550	5.1	-	72.9	8,178	GAS	36,200	1,027,901	37,210.0	149,540	3.29	4.13
34. POLK #2 ST W/O DUCT FIRING	360	684,803	-	-	-	-		4,605,135	1,028,018	4,734,161.4	19,023,535	2.78	4.13
35. POLK #2 ST TOTAL	**480**	**689,353**	**193.0**	**-**	**183.2**	**6,922**	**GAS**	**-**	**-**	**4,771,371.4**	**19,173,075**	**2.78**	**-**
36. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
37. POLK #2 CT (OIL)	187	1,329	1.0	-	5.4	10,996	LGT OIL	2,493	5,862,134	14,614.3	195,299	14.70	78.34
38. POLK #2 TOTAL [4]	**180**	**1,329**	**1.0**	**-**	**5.4**	**10,996**	**-**	**-**	**-**	**14,614.3**	**195,299**	**14.70**	**-**
39. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	187	1,329	1.0	-	80.2	10,996	LGT OIL	2,493	5,862,134	14,614.3	195,298	14.70	78.34
41. POLK #3 TOTAL [4]	**180**	**1,329**	**1.0**	**-**	**80.2**	**10,996**	**-**	**-**	**-**	**14,614.3**	**195,298**	**14.70**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(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)
42. POLK #4 CT (GAS) TOTAL	[4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
43. POLK #5 CT (GAS) TOTAL	[4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
44. POLK #2 CC TOTAL		**1,200**	**692,011**	**77.5**	**97.0**	**157.0**	**6,937**	**-**	**-**	**-**	**4,800,600.0**	**19,563,672**	**2.83**	**-**
45. POLK STATION TOTAL		**1,420**	**702,631**	**66.5**	**90.8**	**152.4**	**6,968**	**-**	**-**	**-**	**4,896,030.0**	**19,947,188**	**2.84**	**-**
46. BAYSIDE #1		792	292,400	49.6	97.3	51.6	7,390	GAS	2,101,920	1,028,008	2,160,790.0	8,682,904	2.97	4.13
47. BAYSIDE #2		1,047	257,040	33.0	97.4	34.1	7,833	GAS	1,958,690	1,027,993	2,013,520.0	8,091,231	3.15	4.13
48. BAYSIDE #3		61	70	0.2	98.6	57.4	13,857	GAS	950	1,021,053	970.0	3,924	5.61	4.13
49. BAYSIDE #4		61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
50. BAYSIDE #5		61	60	0.1	98.6	98.4	11,333	GAS	660	1,030,303	680.0	2,726	4.54	4.13
51. BAYSIDE #6		61	90	0.2	98.6	73.8	12,556	GAS	1,110	1,018,018	1,130.0	4,585	5.09	4.13
52. BAYSIDE STATION TOTAL		**2,083**	**549,660**	**35.5**	**94.6**	**41.6**	**7,599**	**GAS**	**4,063,330**	**1,027,997**	**4,177,090.0**	**16,785,370**	**3.05**	**4.13**
53. SYSTEM TOTAL		**6,202**	**1,541,741**	**33.4**	**72.6**	**76.7**	**7,327**	**-**	**-**	**-**	**11,296,230.0**	**45,495,614**	**2.95**	**-**

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 2021 THROUGH JUNE 2021

		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
	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)	4,985	0	4,985	3,699	4,985	4,824
16.	UNIT COST ($/BBL)	63.73	0.00	65.07	65.16	65.55	66.03
17.	AMOUNT ($)	317,672	0	324,370	241,017	326,762	318,537
18.	BURNED:						
19.	UNITS (BBL)	4,986	0	4,986	3,698	4,986	4,824
20.	UNIT COST ($/BBL)	97.86	0.00	94.46	92.17	89.38	87.05
21.	AMOUNT ($)	487,933	0	470,965	340,852	445,648	419,916
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	43,068	43,068	43,068	43,068	43,068	43,068
24.	UNIT COST ($/BBL)	97.88	97.88	94.47	92.16	89.40	87.04
25.	AMOUNT ($)	4,215,395	4,215,395	4,068,801	3,968,966	3,850,080	3,748,701
26.	DAYS SUPPLY: NORMAL	302,643	302,645	277,711	277,711	277,317	278,900
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	30,000	30,000	30,000	30,000	30,000	42,857
30.	UNIT COST ($/TON)	71.94	71.94	71.94	71.94	71.94	71.94
31.	AMOUNT ($)	2,158,194	2,158,194	2,158,194	2,158,194	2,158,194	3,083,135
32.	BURNED:						
33.	UNITS (TONS)	61,050	55,390	30,780	40,910	77,080	72,580
34.	UNIT COST ($/TON)	71.87	74.67	75.25	77.44	77.47	79.00
35.	AMOUNT ($)	4,387,675	4,136,102	2,316,287	3,167,903	5,971,387	5,734,099
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	176,794	151,404	150,624	139,714	92,634	62,911
38.	UNIT COST ($/TON)	67.84	69.04	69.74	70.23	70.42	69.41
39.	AMOUNT ($)	11,993,245	10,452,488	10,503,957	9,811,913	6,523,509	4,366,696
40.	DAYS SUPPLY:	108	106	93	67	39	27
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,287,592	12,398,004
43.	UNIT COST ($/MCF)	4.49	4.32	4.15	3.86	3.83	3.86
44.	AMOUNT ($)	37,705,734	35,716,395	40,093,689	38,044,373	43,248,757	47,888,000
45.	BURNED:						
46.	UNITS (MCF)	8,403,735	8,272,150	9,654,975	9,848,783	11,190,315	12,398,004
47.	UNIT COST ($/MCF)	4.48	4.32	4.16	3.87	3.84	3.86
48.	AMOUNT ($)	37,627,734	35,731,995	40,133,289	38,131,973	42,991,357	47,877,600
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	291,829	291,829	291,829	291,829	389,105	389,105
51.	UNIT COST ($/MCF)	3.32	3.27	3.14	2.84	2.79	2.81
52.	AMOUNT ($)	970,200	954,600	915,000	827,400	1,084,800	1,095,200
53.	DAYS SUPPLY:	1	1	1	1	1	1
	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 ADJUSTMENT (3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	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)	4,985	4,985	4,824	4,744	3,940	4,985	51,941
16.	UNIT COST ($/BBL)	66.80	67.47	68.05	68.62	69.10	69.48	66.81
17.	AMOUNT ($)	332,982	336,331	328,259	325,520	272,238	346,378	3,470,066
18.	BURNED:							
19.	UNITS (BBL)	4,986	4,986	4,824	4,744	3,940	4,986	51,946
20.	UNIT COST ($/BBL)	84.93	83.11	81.61	80.32	79.38	78.34	86.27
21.	AMOUNT ($)	423,442	414,405	393,706	381,030	312,743	390,597	4,481,237
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	43,068	43,068	43,068	43,068	43,068	43,068	43,068
24.	UNIT COST ($/BBL)	84.94	83.13	81.61	80.32	79.38	78.35	78.35
25.	AMOUNT ($)	3,658,241	3,580,166	3,514,720	3,459,210	3,418,704	3,374,485	3,374,485
26.	DAYS SUPPLY: NORMAL	278,900	278,900	278,900	278,900	288,787	290,936	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	70,000	70,000	55,000	40,000	40,000	40,000	507,857
30.	UNIT COST ($/TON)	71.94	71.94	71.94	71.94	71.94	71.94	71.94
31.	AMOUNT ($)	5,035,787	5,035,787	3,956,690	2,877,593	2,877,593	2,877,593	36,535,148
32.	BURNED:							
33.	UNITS (TONS)	69,620	72,400	68,500	39,200	0	22,900	610,410
34.	UNIT COST ($/TON)	79.85	79.69	79.73	79.69	0.00	79.72	77.74
35.	AMOUNT ($)	5,559,374	5,769,559	5,461,415	3,123,824	0	1,825,597	47,453,222
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	63,291	60,891	47,391	48,191	88,191	105,291	105,291
38.	UNIT COST ($/TON)	68.21	66.94	64.10	63.47	67.31	67.85	67.85
39.	AMOUNT ($)	4,317,107	4,076,260	3,037,907	3,058,564	5,936,157	7,144,064	7,144,064
40.	DAYS SUPPLY:	28	31	40	71	98	70	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	9,907,227	10,476,895	131,115,049
43.	UNIT COST ($/MCF)	3.90	3.90	3.89	3.87	3.99	4.13	3.99
44.	AMOUNT ($)	50,439,440	50,952,795	48,767,663	47,599,283	39,507,205	43,317,820	523,281,154
45.	BURNED:							
46.	UNITS (MCF)	12,946,375	13,064,755	12,552,694	12,301,864	10,004,504	10,476,895	131,115,049
47.	UNIT COST ($/MCF)	3.89	3.90	3.89	3.87	3.98	4.13	3.99
48.	AMOUNT ($)	50,425,840	50,950,395	48,771,663	47,591,283	39,771,005	43,279,420	523,283,554
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	291,829	291,829	291,829
51.	UNIT COST ($/MCF)	2.85	2.86	2.85	2.87	2.92	3.05	3.05
52.	AMOUNT ($)	1,108,800	1,111,200	1,107,200	1,115,200	851,400	889,800	889,800
53.	DAYS SUPPLY:	1	1	1	1	1	1	-
	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 ADJUSTMENT (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E6

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT	(9) TOTAL COST $	(10) GAINS ON SALES
Jan-21	SEMINOLE	JURISD. SCH. - D	2,980.0	0.0	2,980.0	2.580	2.776	76,890.00	82,717.00	5,827.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,980.0**	**0.0**	**2,980.0**	**2.580**	**2.776**	**76,890.00**	**82,717.00**	**5,827.00**
Feb-21	SEMINOLE	JURISD. SCH. - D	2,690.0	0.0	2,690.0	2.722	2.928	73,210.00	78,758.00	5,548.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,690.0**	**0.0**	**2,690.0**	**2.722**	**2.928**	**73,210.00**	**78,758.00**	**5,548.00**
Mar-21	SEMINOLE	JURISD. SCH. - D	2,870.0	0.0	2,870.0	2.900	3.120	83,230.00	89,538.00	6,308.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,870.0**	**0.0**	**2,870.0**	**2.900**	**3.120**	**83,230.00**	**89,538.00**	**6,308.00**
Apr-21	SEMINOLE	JURISD. SCH. - D	3,010.0	0.0	3,010.0	2.674	2.877	80,490.00	86,590.00	6,100.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,010.0**	**0.0**	**3,010.0**	**2.674**	**2.877**	**80,490.00**	**86,590.00**	**6,100.00**
May-21	SEMINOLE	JURISD. SCH. - D	2,920.0	0.0	2,920.0	3.042	3.273	88,840.00	95,573.00	6,733.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,920.0**	**0.0**	**2,920.0**	**3.042**	**3.273**	**88,840.00**	**95,573.00**	**6,733.00**
Jun-21	SEMINOLE	JURISD. SCH. - D	2,920.0	0.0	2,920.0	3.205	3.448	93,590.00	100,683.00	7,093.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,920.0**	**0.0**	**2,920.0**	**3.205**	**3.448**	**93,590.00**	**100,683.00**	**7,093.00**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

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-21	SEMINOLE	JURISD. SCH. - D	2,960.0	0.0	2,960.0	2.784	2.995	82,410.00	88,656.00	6,246.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,960.0**	**0.0**	**2,960.0**	**2.784**	**2.995**	**82,410.00**	**88,656.00**	**6,246.00**
Aug-21	SEMINOLE	JURISD. SCH. - D	3,000.0	0.0	3,000.0	2.765	2.975	82,960.00	89,247.00	6,287.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,000.0**	**0.0**	**3,000.0**	**2.765**	**2.975**	**82,960.00**	**89,247.00**	**6,287.00**
Sep-21	SEMINOLE	JURISD. SCH. - D	2,870.0	0.0	2,870.0	3.056	3.288	87,710.00	94,357.00	6,647.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,870.0**	**0.0**	**2,870.0**	**3.056**	**3.288**	**87,710.00**	**94,357.00**	**6,647.00**
Oct-21	SEMINOLE	JURISD. SCH. - D	2,960.0	0.0	2,960.0	2.531	2.723	74,910.00	80,587.00	5,677.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,960.0**	**0.0**	**2,960.0**	**2.531**	**2.723**	**74,910.00**	**80,587.00**	**5,677.00**
Nov-21	SEMINOLE	JURISD. SCH. - D	2,830.0	0.0	2,830.0	2.632	2.831	74,480.00	80,125.00	5,645.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**2,830.0**	**0.0**	**2,830.0**	**2.632**	**2.831**	**74,480.00**	**80,125.00**	**5,645.00**
Dec-21	SEMINOLE	JURISD. SCH. - D	3,030.0	0.0	3,030.0	2.481	2.669	75,160.00	80,856.00	5,696.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**3,030.0**	**0.0**	**3,030.0**	**2.481**	**2.669**	**75,160.00**	**80,856.00**	**5,696.00**
TOTAL										
Jan-21	SEMINOLE	JURISD. SCH. - D	35,040.0	0.0	35,040.0	2.779	2.990	973,880.00	1,047,687.00	73,807.00
THRU	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-21	**TOTAL**		**35,040.0**	**0.0**	**35,040.0**	**2.779**	**2.990**	**973,880.00**	**1,047,687.00**	**73,807.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-21	VARIOUS	FIRM	640.0	0.0	0.0	640.0	4.401	4.401	28,164.33
	TOTAL		640.0	0.0	0.0	640.0	4.401	4.401	28,164.33
Feb-21	VARIOUS	FIRM	1,754.0	0.0	0.0	1,754.0	4.338	4.338	76,088.66
	TOTAL		1,754.0	0.0	0.0	1,754.0	4.338	4.338	76,088.66
Mar-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	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-21	VARIOUS	FIRM	2,394.0	0.0	0.0	2,394.0	4.355	4.355	104,252.99
THRU Dec-21	TOTAL		2,394.0	0.0	0.0	2,394.0	4.355	4.355	104,252.99

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUST-MENT
Jan-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,000.0	0.0	0.0	9,000.0	2.412	2.412	217,090.00
	TOTAL		9,000.0	0.0	0.0	9,000.0	2.412	2.412	217,090.00
Feb-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,000.0	0.0	0.0	9,000.0	2.811	2.811	252,980.00
	TOTAL		9,000.0	0.0	0.0	9,000.0	2.811	2.811	252,980.00
Mar-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,750.0	0.0	0.0	8,750.0	2.253	2.253	197,130.00
	TOTAL		8,750.0	0.0	0.0	8,750.0	2.253	2.253	197,130.00
Apr-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,360.0	0.0	0.0	9,360.0	2.447	2.447	229,010.00
	TOTAL		9,360.0	0.0	0.0	9,360.0	2.447	2.447	229,010.00
May-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,790.0	0.0	0.0	8,790.0	2.644	2.644	232,390.00
	TOTAL		8,790.0	0.0	0.0	8,790.0	2.644	2.644	232,390.00
Jun-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,070.0	0.0	0.0	9,070.0	2.733	2.733	247,890.00
	TOTAL		9,070.0	0.0	0.0	9,070.0	2.733	2.733	247,890.00
Jul-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,030.0	0.0	0.0	9,030.0	2.785	2.785	251,500.00
	TOTAL		9,030.0	0.0	0.0	9,030.0	2.785	2.785	251,500.00
Aug-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,120.0	0.0	0.0	9,120.0	2.734	2.734	249,360.00
	TOTAL		9,120.0	0.0	0.0	9,120.0	2.734	2.734	249,360.00
Sep-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,930.0	0.0	0.0	8,930.0	2.781	2.781	248,330.00
	TOTAL		8,930.0	0.0	0.0	8,930.0	2.781	2.781	248,330.00
Oct-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,970.0	0.0	0.0	8,970.0	3.240	3.240	290,630.00
	TOTAL		8,970.0	0.0	0.0	8,970.0	3.240	3.240	290,630.00
Nov-21	VARIOUS	CO-GEN.							
		AS AVAIL.	8,800.0	0.0	0.0	8,800.0	3.135	3.135	275,890.00
	TOTAL		8,800.0	0.0	0.0	8,800.0	3.135	3.135	275,890.00
Dec-21	VARIOUS	CO-GEN.							
		AS AVAIL.	9,200.0	0.0	0.0	9,200.0	2.623	2.623	241,290.00
	TOTAL		9,200.0	0.0	0.0	9,200.0	2.623	2.623	241,290.00
TOTAL	VARIOUS	CO-GEN.							
Jan-21		AS AVAIL.	108,020.0	0.0	0.0	108,020.0	2.716	2.716	2,933,490.00
THRU	TOTAL		108,020.0	0.0	0.0	108,020.0	2.716	2.716	2,933,490.00
Dec-21									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) DOLLARS	FUEL SAVINGS (9B)-(8)
Jan-21	VARIOUS	SCH. - J	120,110.0	0.0	120,110.0	2.403	2,886,795.67	2.508	3,012,382.12	125,586.45
Feb-21	VARIOUS	SCH. - J	50,876.0	0.0	50,876.0	2.828	1,438,741.34	4.642	2,361,637.79	922,896.45
Mar-21	VARIOUS	SCH. - J	9,540.0	0.0	9,540.0	4.837	461,410.00	37.875	3,613,280.00	3,151,870.00
Apr-21	VARIOUS	SCH. - J	7,170.0	0.0	7,170.0	4.615	330,920.00	45.283	3,246,770.00	2,915,850.00
May-21	VARIOUS	SCH. - J	13,130.0	0.0	13,130.0	4.563	599,060.00	40.387	5,302,850.00	4,703,790.00
Jun-21	VARIOUS	SCH. - J	13,930.0	0.0	13,930.0	5.337	743,490.00	32.269	4,495,050.00	3,751,560.00
Jul-21	VARIOUS	SCH. - J	6,370.0	0.0	6,370.0	5.874	374,170.00	45.679	2,909,770.00	2,535,600.00
Aug-21	VARIOUS	SCH. - J	8,310.0	0.0	8,310.0	5.584	464,070.00	41.753	3,469,680.00	3,005,610.00
Sep-21	VARIOUS	SCH. - J	4,070.0	0.0	4,070.0	4.980	202,680.00	80.836	3,290,020.00	3,087,340.00
Oct-21	VARIOUS	SCH. - J	61,880.0	0.0	61,880.0	5.369	3,322,110.00	13.261	8,206,010.00	4,883,900.00
Nov-21	VARIOUS	SCH. - J	2,380.0	0.0	2,380.0	4.461	106,180.00	90.602	2,156,330.00	2,050,150.00
Dec-21	VARIOUS	SCH. - J	180.0	0.0	180.0	3.139	5,650.00	156.089	280,960.00	275,310.00
TOTAL	VARIOUS	SCH. - J	**297,946.0**	**0.0**	**297,946.0**	**3.670**	**10,935,277.01**	**14.212**	**42,344,739.91**	**31,409,462.90**

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

	Current Jun 2020 - Aug 2020	Current Sep 2020 - Dec 2020	Projected Jan 2021 - Dec 2021	Difference $	Difference %
Base Rate Revenue	67.76	67.76	67.30	(0.46)	-0.7%
Fuel Recovery Revenue	22.85	22.85	28.56	5.71	25.0%
Fuel Credit Recovery Revenue	(18.40)	0.00	0.00	0.00	0.0%
Conservation Revenue	2.32	2.32	2.22	(0.10)	-4.3%
Capacity Revenue	(0.12)	(0.12)	0.02	0.14	-116.7%
Environmental Revenue	2.44	2.44	2.69	0.25	10.2%
Storm Protection Plan Revenue	0.00	0.00	2.39	2.39	0.0%
Florida Gross Receipts Tax Revenue	1.97	2.44	2.65	0.21	8.6%
TOTAL REVENUE	**$78.82**	**$97.69**	**$105.83**	**$8.14**	**8.3%**

SCHEDULE H1

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

	ACTUAL 2018	ACTUAL 2019	ACT/EST 2020	EST 2021	DIFFERENCE (%) 2019-2018	2020-2019	2021-2020
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	51,583	183,150	3,367,451	4,481,237	255.1%	1738.6%	33.1%
3 COAL	125,828,296	45,241,314	31,036,456	47,453,222	-64.0%	-31.4%	52.9%
4 NATURAL GAS	505,830,903	480,359,200	390,212,873	523,283,554	-5.0%	-18.8%	34.1%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**631,710,782**	**525,783,664**	**424,616,780**	**575,218,013**	**-16.8%**	**-19.2%**	**35.5%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	173	582	15,631	27,693	236.4%	2585.7%	77.2%
10 COAL	3,533,451	1,194,254	739,232	1,119,680	-66.2%	-38.1%	51.5%
11 NATURAL GAS	16,096,514	17,513,363	16,729,044	17,444,726	8.8%	-4.5%	4.3%
12 NUCLEAR	118,322	756,215	1,239,637	1,585,270	539.1%	63.9%	27.9%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,748,460**	**19,464,414**	**18,723,544**	**20,177,369**	**-1.4%**	**-3.8%**	**7.8%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	405	1,436	29,665	51,946	254.6%	1965.8%	75.1%
17 COAL (TON)	1,626,026	570,012	396,204	610,410	-64.9%	-30.5%	54.1%
18 NATURAL GAS (MCF)	121,581,188	137,873,625	124,758,371	131,115,049	13.4%	-9.5%	5.1%
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]	1,349	8,362	173,875	304,543	519.9%	1979.3%	75.2%
23 COAL	38,881,879	13,177,799	8,959,418	13,733,780	-66.1%	-32.0%	53.3%
24 NATURAL GAS	124,229,756	140,983,651	127,781,699	134,413,197	13.5%	-9.4%	5.2%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**163,112,984**	**154,169,812**	**136,914,992**	**148,451,520**	**-5.5%**	**-11.2%**	**8.4%**
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	0.08	0.14	0.0%	0.0%	75.0%
30 COAL	17.89	6.13	3.95	5.54	-65.7%	-35.6%	40.3%
31 NATURAL GAS	81.51	89.98	89.35	86.46	10.4%	-0.7%	-3.2%
32 NUCLEAR	0.60	3.89	6.62	7.86	548.3%	70.2%	18.7%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	127.37	127.54	113.52	86.27	0.1%	-11.0%	-24.0%
37 COAL ($/TON)	77.38	79.37	78.33	77.74	2.6%	-1.3%	-0.8%
38 NATURAL GAS ($/MCF)	4.16	3.48	3.13	3.99	-16.3%	-10.1%	27.5%
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]	38.24	21.90	19.37	14.71	-42.7%	-11.6%	-24.1%
43 COAL	3.24	3.43	3.46	3.46	5.9%	0.9%	0.0%
44 NATURAL GAS	4.07	3.41	3.05	3.89	-16.2%	-10.6%	27.5%
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)	**3.87**	**3.41**	**3.10**	**3.87**	**-11.9%**	**-9.1%**	**24.8%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	7,798	14,368	11,124	10,997	84.3%	-22.6%	-1.1%
50 COAL	11,004	11,034	12,120	12,266	0.3%	9.8%	1.2%
51 NATURAL GAS	7,718	8,050	7,638	7,705	4.3%	-5.1%	0.9%
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)	**8,260**	**7,921**	**7,312**	**7,357**	**-4.1%**	**-7.7%**	**0.6%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL [1]	29.82	31.47	21.54	16.18	5.5%	-31.6%	-24.9%
57 COAL	3.56	3.79	4.20	4.24	6.5%	10.8%	1.0%
58 NATURAL GAS	3.14	2.74	2.33	3.00	-12.7%	-15.0%	28.8%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	**3.20**	**2.70**	**2.27**	**2.85**	**-15.6%**	**-15.9%**	**25.6%**

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

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2021 - DECEMBER 2021

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2021 through December 2021

	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	6,599,989	3.167	209,021,646	2.856	188,495,681
TIER II (Over 1,000) kWh	2,979,095	3.167	94,347,942	3.856	114,873,907
Total	9,579,084		303,369,588		303,369,588

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2021 THROUGH DECEMBER 2021

TESTIMONY AND EXHIBIT

OF

JEREMY B. CAIN

FILED: SEPTEMBER 3, 2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy B. Cain. 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, Asset Management.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have over 11 years of experience in the electric utility industry, specifically in the roles of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with the Asset Management processes throughout Energy Supply. Asset Management programs include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning in order to maintain and improve the performance of the generating units.

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 No. JC-1, 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 2021 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 and one coal unit are included. These are Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission's 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 2021 through December 2021 represent 87.4 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. Yes, Polk Unit 1, Polk Unit 2, and Bayside Unit 1 outages were identified as outliers and were removed.

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 2021 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 five units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2021 period, the projected EUOF for Bayside Unit 1 is 2.3 percent, the POF is 3.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 93.9 percent or:

$$100\% - (2.3\% + 3.8\%) = 93.9\%$$

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

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

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

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

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

$$EAF_{MAX} = 1 - [0.80\ (2.3\%) + 0.95\ (3.8\%)] = 94.5\%$$

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

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

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.3\%) + 1.10\ (3.8\%)] = 92.6\%$$

The equivalent availability maximum and minimum for the other four 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 2021 are shown on page 17 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2021; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from March 15, 2021 to March 28, 2021. There are 336 planned outage hours scheduled for the 2021 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 3.8 percent or:

$$\frac{336}{8{,}760} \times 100\% = 3.8\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 7.7 percent. Polk Unit 2 has a POF of 16.2 percent. Bayside Unit 2 has a POF of 3.8 percent, and Big Bend Unit 4 has a POF of 16.2 percent.

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

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 2.3 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 15, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(95 + 106)}{8{,}760} \times 100\% = 2.3\%$$

Relative to Bayside Unit 1, the EUOF of 2.3 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 14.6 percent. The unit will have two planned outages in 2021, and the POF is 7.7 percent. Therefore, the target equivalent availability for this unit is 77.7 percent.

Polk Unit 2

The projected EUOF for this unit is 3.2 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 80.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.3 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.9 percent.

Bayside Unit 2

The projected EUOF for this unit is 5.2 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Big Bend Unit 4

The projected EUOF for this unit is 29.9 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 54 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 88.4 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 15 of Document No. 1. Except for the month of March, 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 month of March, 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 afore mentioned agreed upon GPIF methodology.

Q. How were the targets determined?

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

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 25 through 29 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 2021 period.

A. The heat rate target for Polk Unit 1 is 9,684 Btu/Net kWh with a range of ±664 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,940 Btu/Net kWh with a range of ±185 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,352 Btu/Net kWh with a range of ±108 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,439 Btu/Net kWh with a range of ±121 Btu/Net kWh. The heat rate target for Big

Bend Unit 4 is 11,576 Btu/Net kWh with a range of ±615 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 11 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission's requirements?

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 determining the GPIF targets?

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 in Document No. 1, pages 7 through 11. 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 $459,381,860 is shown on Document No. 1, 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.

Column 4 totals $14,003,920 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 10.83 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 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, as shown on page 10 of Document No. 1, if Bayside Unit 1, operates at 7,244 average net operating heat rate, fuel savings would equal $1,516,300 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 11. 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 $14,003,920. 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 2021 is $3,589,402,384. This produces the maximum allowed jurisdictional incentive of $12,003,035 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 $7,001,961.

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).

$$
\begin{aligned}
GPIP = (&0.0482\ EAP_{PK1} + 0.0153\ EAP_{PK2} \\
&+ 0.1601\ EAP_{BAY1} + 0.0745\ EAP_{BAY2} \\
&+ 0.0129\ EAP_{BB4} + 0.2374\ HRP_{PK2} \\
&+ 0.1083\ HRP_{BAY1} + 0.1231\ HRP_{BAY2} \\
&+ 0.1368\ HRP_{BB4} + 0.0834\ HRP_{PK1})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2021 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

JEREMY B. CAIN

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2021 – DECEMBER 2021

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2021 - DECEMBER 2021
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2021 - DECEMBER 2021

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	14,003.9	7,002.0
+9	12,603.5	6,301.8
+8	11,203.1	5,601.6
+7	9,802.7	4,901.4
+6	8,402.4	4,201.2
+5	7,002.0	3,501.0
+4	5,601.6	2,800.8
+3	4,201.2	2,100.6
+2	2,800.8	1,400.4
+1	1,400.4	700.2
0	0.0	0.0
-1	(1,450.1)	(700.2)
-2	(2,900.2)	(1,400.4)
-3	(4,350.3)	(2,100.6)
-4	(5,800.4)	(2,800.8)
-5	(7,250.5)	(3,501.0)
-6	(8,700.6)	(4,201.2)
-7	(10,150.7)	(4,901.4)
-8	(11,600.7)	(5,601.6)
-9	(13,050.8)	(6,301.8)
-10	(14,500.9)	(7,002.0)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2021 - DECEMBER 2021

Line 1	Beginning of period balance of common equity: End of month common equity:		$	3,546,437,770	
Line 2	Month of January	2021	$	3,457,175,770	
Line 3	Month of February	2021	$	3,486,705,814	
Line 4	Month of March	2021	$	3,516,488,092	
Line 5	Month of April	2021	$	3,576,474,440	
Line 6	Month of May	2021	$	3,607,023,492	
Line 7	Month of June	2021	$	3,637,833,484	
Line 8	Month of July	2021	$	3,547,561,253	
Line 9	Month of August	2021	$	3,577,863,339	
Line 10	Month of September	2021	$	3,608,424,255	
Line 11	Month of October	2021	$	3,668,655,442	
Line 12	Month of November	2021	$	3,699,991,873	
Line 13	Month of December	2021	$	3,731,595,971	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,589,402,384	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.76%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	12,003,035	
Line 18	Jurisdictional Sales			19,545,089	MWH
Line 19	Total Sales			19,545,089	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)		$	12,003,035	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	7,001,961	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	7,001,961	

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 2021 - DECEMBER 2021

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	1.29%	54.0	60.7	40.4	181.0	(860.3)
POLK 1	4.82%	77.7	82.1	72.4	675.5	(1,134.0)
POLK 2	1.53%	80.6	82.1	77.7	213.7	(1,325.4)
BAYSIDE 1	16.01%	93.9	94.5	92.6	2,242.6	(74.8)
BAYSIDE 2	7.45%	90.9	92.2	88.5	1,043.8	(1,459.2)
GPIF SYSTEM	**31.11%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	13.68%	11,576	43.0	10,961	12,191	1,916.4	(1,916.4)
POLK 1	8.34%	9,684	82.1	9,020	10,348	1,167.3	(1,167.3)
POLK 2	23.74%	6,940	81.0	6,755	7,125	3,324.1	(3,324.1)
BAYSIDE 1	10.83%	7,352	79.6	7,244	7,460	1,516.3	(1,516.3)
BAYSIDE 2	12.31%	7,439	63.3	7,317	7,560	1,723.2	(1,723.2)
GPIF SYSTEM	**68.89%**						

DOCKET NO. 20200001-EI
GPIF 2021 PROJECTION
EXHIBIT NO. JC-1, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.20E
PAGE 5 OF 32

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 21 - DEC 21			ACTUAL PERFORMANCE JAN 19 - DEC 19			ACTUAL PERFORMANCE JAN 18 - DEC 18			ACTUAL PERFORMANCE JAN 17 - DEC 17		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 4	1.29%	4.2%	16.2	29.9	35.6	16.5	28.0	39.8	19.1	20.6	26.6	0.0	30.7	31.2
POLK 1	4.82%	15.5%	7.7	14.6	15.8	6.7	14.9	22.8	28.1	10.7	16.3	4.4	9.6	10.4
POLK 2	1.53%	4.9%	16.2	3.2	3.8	4.5	3.7	3.8	2.0	3.3	3.2	1.8	6.9	7.8
BAYSIDE 1	16.01%	51.5%	3.8	2.3	2.4	11.1	6.7	7.4	5.3	1.6	1.7	11.6	2.0	2.4
BAYSIDE 2	7.45%	24.0%	3.8	5.2	5.4	12.8	4.0	4.5	19.6	2.5	3.1	9.4	5.1	5.7
GPIF SYSTEM	**31.11%**	**100.0%**	**5.5**	**6.1**	**6.6**	**10.7**	**8.0**	**10.3**	**12.7**	**4.1**	**5.4**	**9.0**	**5.4**	**5.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**88.4**			**81.2**			**83.2**			**85.7**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
10.8	**5.8**	**7.2**	**83.4**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 21 - DEC 21	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 17 - DEC 17
BIG BEND 4	13.68%	19.9%	11,576	11,434	11,564	11,502
POLK 1	8.34%	12.1%	9,684	8,864	10,359	10,065
POLK 2	23.74%	34.5%	6,940	6,919	6,922	6,920
BAYSIDE 1	10.83%	15.7%	7,352	7,324	7,354	7,300
BAYSIDE 2	12.31%	17.9%	7,439	7,437	7,309	7,868
GPIF SYSTEM	**68.89%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**8,347**	**8,207**	**8,397**	**8,440**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2021 - DECEMBER 2021
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_3 BIG BEND 4	459,381.86	459,200.83	181.0	1.29%
EA_1 POLK 1	459,381.86	458,706.38	675.5	4.82%
EA_2 POLK 2	459,381.86	459,168.18	213.7	1.53%
EA_3 BAYSIDE 1	459,381.86	457,139.22	2,242.6	16.01%
EA_4 BAYSIDE 2	459,381.86	458,338.03	1,043.8	7.45%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	459,381.86	457,465.48	1,916.4	13.68%
AHR_1 POLK 1	459,381.86	458,214.59	1,167.3	8.34%
AHR_2 POLK 2	459,381.86	456,057.72	3,324.1	23.74%
AHR_3 BAYSIDE 1	459,381.86	457,865.60	1,516.3	10.83%
AHR_4 BAYSIDE 2	459,381.86	457,658.65	1,723.2	12.31%
TOTAL SAVINGS			**14,003.92**	**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.

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	181.0	60.7	+10	1,916.4	10,961
+9	162.9	64.7	+9	1,724.7	9,857
+8	144.8	68.6	+8	1,533.1	8,754
+7	126.7	72.5	+7	1,341.5	7,650
+6	108.6	76.4	+6	1,149.8	6,546
+5	90.5	80.4	+5	958.2	5,443
+4	72.4	84.3	+4	766.6	4,339
+3	54.3	88.2	+3	574.9	3,236
+2	36.2	92.1	+2	383.3	2,132
+1	18.1	96.1	+1	191.6	1,029
					(75)
0	0.0	100.0	0	0.0	0
					75
-1	(86.0)	94.0	-1	(191.6)	1,287
-2	(172.1)	88.1	-2	(383.3)	2,498
-3	(258.1)	82.1	-3	(574.9)	3,710
-4	(344.1)	76.2	-4	(766.6)	4,921
-5	(430.1)	70.2	-5	(958.2)	6,133
-6	(516.2)	64.2	-6	(1,149.8)	7,344
-7	(602.2)	58.3	-7	(1,341.5)	8,556
-8	(688.2)	52.3	-8	(1,533.1)	9,768
-9	(774.2)	46.4	-9	(1,724.7)	10,979
-10	(860.3)	40.4	-10	(1,916.4)	12,191
	Weighting Factor =	1.29%		Weighting Factor =	13.68%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

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	675.5	82.1	+10	1,167.3	9,020
+9	607.9	81.6	+9	1,050.5	9,079
+8	540.4	81.2	+8	933.8	9,138
+7	472.8	80.8	+7	817.1	9,197
+6	405.3	80.3	+6	700.4	9,256
+5	337.7	79.9	+5	583.6	9,315
+4	270.2	79.5	+4	466.9	9,374
+3	202.6	79.0	+3	350.2	9,433
+2	135.1	78.6	+2	233.5	9,491
+1	67.5	78.2	+1	116.7	9,550
					9,609
0	0.0	77.7	0	0.0	9,684
					9,759
-1	(113.4)	77.2	-1	(116.7)	9,818
-2	(226.8)	76.7	-2	(233.5)	9,877
-3	(340.2)	76.1	-3	(350.2)	9,936
-4	(453.6)	75.6	-4	(466.9)	9,995
-5	(567.0)	75.0	-5	(583.6)	10,054
-6	(680.4)	74.5	-6	(700.4)	10,112
-7	(793.8)	74.0	-7	(817.1)	10,171
-8	(907.2)	73.4	-8	(933.8)	10,230
-9	(1,020.6)	72.9	-9	(1,050.5)	10,289
-10	(1,134.0)	72.4	-10	(1,167.3)	10,348
	Weighting Factor =	4.82%		Weighting Factor =	8.34%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

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	213.7	82.1	+10	3,324.1	6,755
+9	192.3	81.9	+9	2,991.7	6,766
+8	170.9	81.8	+8	2,659.3	6,777
+7	149.6	81.6	+7	2,326.9	6,788
+6	128.2	81.5	+6	1,994.5	6,799
+5	106.8	81.3	+5	1,662.1	6,810
+4	85.5	81.2	+4	1,329.7	6,821
+3	64.1	81.1	+3	997.2	6,832
+2	42.7	80.9	+2	664.8	6,843
+1	21.4	80.8	+1	332.4	6,854
					6,865
0	0.0	80.6	0	0.0	6,940
					7,015
-1	(132.5)	80.3	-1	(332.4)	7,026
-2	(265.1)	80.0	-2	(664.8)	7,037
-3	(397.6)	79.7	-3	(997.2)	7,048
-4	(530.2)	79.5	-4	(1,329.7)	7,059
-5	(662.7)	79.2	-5	(1,662.1)	7,070
-6	(795.2)	78.9	-6	(1,994.5)	7,081
-7	(927.8)	78.6	-7	(2,326.9)	7,092
-8	(1,060.3)	78.3	-8	(2,659.3)	7,103
-9	(1,192.9)	78.0	-9	(2,991.7)	7,114
-10	(1,325.4)	77.7	-10	(3,324.1)	7,125
	Weighting Factor =	1.53%		Weighting Factor =	23.74%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

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	2,242.6	94.5	+10	1,516.3	7,244
+9	2,018.4	94.5	+9	1,364.6	7,247
+8	1,794.1	94.4	+8	1,213.0	7,251
+7	1,569.8	94.3	+7	1,061.4	7,254
+6	1,345.6	94.3	+6	909.8	7,257
+5	1,121.3	94.2	+5	758.1	7,261
+4	897.1	94.1	+4	606.5	7,264
+3	672.8	94.1	+3	454.9	7,267
+2	448.5	94.0	+2	303.3	7,271
+1	224.3	93.9	+1	151.6	7,274
					7,277
0	0.0	93.9	0	0.0	7,352
					7,427
-1	(7.5)	93.7	-1	(151.6)	7,431
-2	(15.0)	93.6	-2	(303.3)	7,434
-3	(22.4)	93.5	-3	(454.9)	7,437
-4	(29.9)	93.4	-4	(606.5)	7,441
-5	(37.4)	93.2	-5	(758.1)	7,444
-6	(44.9)	93.1	-6	(909.8)	7,447
-7	(52.4)	93.0	-7	(1,061.4)	7,451
-8	(59.8)	92.8	-8	(1,213.0)	7,454
-9	(67.3)	92.7	-9	(1,364.6)	7,457
-10	(74.8)	92.6	-10	(1,516.3)	7,460
	Weighting Factor =	16.01%		Weighting Factor =	10.83%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2021 - DECEMBER 2021

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,043.8	92.2	+10	1,723.2	7,317
+9	939.4	92.1	+9	1,550.9	7,322
+8	835.1	91.9	+8	1,378.6	7,326
+7	730.7	91.8	+7	1,206.2	7,331
+6	626.3	91.7	+6	1,033.9	7,336
+5	521.9	91.6	+5	861.6	7,340
+4	417.5	91.4	+4	689.3	7,345
+3	313.1	91.3	+3	517.0	7,350
+2	208.8	91.2	+2	344.6	7,354
+1	104.4	91.1	+1	172.3	7,359
					7,364
0	0.0	90.9	0	0.0	7,439
					7,514
-1	(145.9)	90.7	-1	(172.3)	7,518
-2	(291.8)	90.5	-2	(344.6)	7,523
-3	(437.8)	90.2	-3	(517.0)	7,528
-4	(583.7)	90.0	-4	(689.3)	7,532
-5	(729.6)	89.7	-5	(861.6)	7,537
-6	(875.5)	89.5	-6	(1,033.9)	7,541
-7	(1,021.4)	89.2	-7	(1,206.2)	7,546
-8	(1,167.4)	89.0	-8	(1,378.6)	7,551
-9	(1,313.3)	88.7	-9	(1,550.9)	7,555
-10	(1,459.2)	88.5	-10	(1,723.2)	7,560
	Weighting Factor =	7.45%		Weighting Factor =	12.31%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	64.4	57.5	41.5	64.4	64.4	64.4	64.4	64.4	64.4	64.4	8.6	24.9	54.0
2. POF	0.0	10.7	35.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	61.3	16.2
3. EUOF	35.6	31.8	23.0	35.6	35.6	35.6	35.6	35.6	35.6	35.6	4.8	13.8	29.9
4. EUOR	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	615	556	147	377	615	595	615	615	595	260	0	238	5,228
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	129	116	597	343	129	125	129	129	125	484	720	506	3,532
9. POH	0	72	264	0	0	0	0	0	0	0	624	456	1,416
10. EFOH	158	127	102	153	158	153	158	158	153	158	20	61	1,557
11. EMOH	107	87	69	104	107	104	107	107	104	107	14	42	1,060
12. OPER BTU (GBTU)	1,184	1,075	354	742	1,365	1,319	1,343	1,379	1,291	566	0	436	11,061
13. NET GEN (MWH)	101,280	92,020	30,950	63,690	118,600	114,520	116,420	119,950	111,870	49,110	0	37,160	955,570
14. ANOHR (Btu/kwh)	11,689	11,684	11,442	11,644	11,512	11,514	11,532	11,500	11,539	11,534	12,575	11,735	11,576
15. NOF (%)	38.1	38.3	48.7	40.0	45.7	45.6	44.9	46.2	44.6	44.8	0.0	36.1	43.0
16. NPC (MW)	432	432	432	422	422	422	422	422	422	422	422	432	425
17. ANOHR EQUATION	ANOHR = NOF(		-23.261	) +	12,575								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

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-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	84.2	84.2	84.2	84.2	46.2	84.2	84.2	84.2	84.2	84.2	78.6	51.6	77.7
2. POF	0.0	0.0	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	6.7	38.7	7.7
3. EUOF	15.8	15.8	15.8	15.8	8.7	15.8	15.8	15.8	15.8	15.8	14.7	9.7	14.6
4. EUOR	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	112	306	360	214	192	320	345	289	309	484	214	16	3,161
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	632	366	384	506	552	400	399	455	411	260	506	728	5,599
9. POH	0	0	0	0	336	0	0	0	0	0	48	288	672
10. EFOH	39	35	39	38	21	38	39	39	38	39	35	24	422
11. EMOH	79	71	79	76	43	76	79	79	76	79	71	48	856
12. OPER BTU (GBTU)	181	495	612	359	339	557	600	510	540	870	352	26	5,443
13. NET GEN (MWH)	18,560	50,920	63,050	37,040	35,110	57,590	62,100	52,750	55,880	90,050	36,350	2,640	562,040
14. ANOHR (Btu/kwh)	9,726	9,725	9,709	9,683	9,663	9,669	9,669	9,664	9,667	9,657	9,689	9,727	9,684
15. NOF (%)	72.0	72.4	76.1	82.4	87.1	85.7	85.7	86.9	86.1	88.6	80.9	71.7	82.1
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217

17. ANOHR EQUATION ANOHR = NOF(-4.177) + 10,027

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

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-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	96.2	0.0	43.4	96.2	96.2	96.2	96.2	96.2	96.2	52.7	96.2	96.2	80.6
2. POF	0.0	100.0	54.8	0.0	0.0	0.0	0.0	0.0	0.0	45.2	0.0	0.0	16.2
3. EUOF	3.8	0.0	1.7	3.8	3.8	3.8	3.8	3.8	3.8	2.1	3.8	3.8	3.2
4. EUOR	3.8	0.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	723	0	678	709	733	709	733	733	706	402	709	728	7,563
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	21	672	66	11	11	11	11	11	14	342	11	16	1,197
9. POH	0	672	408	0	0	0	0	0	0	336	0	0	1,416
10. EFOH	10	0	5	10	10	10	10	10	10	6	10	10	101
11. EMOH	18	0	8	18	18	18	18	18	18	10	18	18	181
12. OPER BTU (GBTU)	4,459	0	4,674	4,404	4,437	4,419	4,434	4,435	4,410	2,449	4,418	4,462	47,042
13. NET GEN (MWH)	637,090	0	675,000	637,350	640,390	639,680	639,870	640,040	638,510	353,640	639,490	637,090	6,778,150
14. ANOHR (Btu/kwh)	7,000	0	6,924	6,910	6,929	6,908	6,930	6,930	6,906	6,925	6,908	7,004	6,940
15. NOF (%)	73.4	0.0	83.0	84.7	82.3	85.0	82.3	82.3	85.2	82.9	85.0	72.9	81.0
16. NPC (MW)	1,200	1,200	1,200	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,200	1,107
17. ANOHR EQUATION	ANOHR = NOF(		-7.900	) +	7,580								

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ORIGINAL SHEET NO. 8.401.20E
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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

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-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	97.6	97.6	53.5	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	93.9
2. POF	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	2.4	2.4	1.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.3
4. EUOR	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	726	656	395	701	726	702	725	725	702	725	702	672	8,157
7. RSH	0	0	3	2	0	1	1	1	1	1	1	54	67
8. UH	18	16	346	17	18	17	18	18	17	18	17	18	536
9. POH	0	0	336	0	0	0	0	0	0	0	0	0	336
10. EFOH	8	8	5	8	8	8	8	8	8	8	8	8	95
11. EMOH	9	8	5	9	9	9	9	9	9	9	9	9	106
12. OPER BTU (GBTU)	2,368	3,423	1,960	2,832	3,030	3,118	3,241	3,283	3,244	3,064	2,840	2,478	34,916
13. NET GEN (MWH)	317,840	468,270	267,460	384,950	412,470	425,620	442,670	448,630	443,730	417,380	386,040	334,020	4,749,080
14. ANOHR (Btu/kwh)	7,450	7,310	7,329	7,357	7,347	7,325	7,322	7,318	7,310	7,342	7,357	7,420	7,352
15. NOF (%)	55.3	90.1	85.5	78.3	81.0	86.5	87.1	88.3	90.2	82.1	78.4	62.8	79.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-4.013	) +	7,672								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2021 - DECEMBER 2021

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-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021
1. EAF (%)	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	94.6	50.4	94.6	90.9
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.8
3. EUOF	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	2.9	5.4	5.2
4. EUOR	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	502	635	703	680	703	680	703	703	680	703	360	691	7,743
7. RSH	202	1	1	1	1	1	1	1	1	1	3	13	224
8. UH	40	36	40	39	40	39	40	40	39	40	357	40	793
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. EFOH	11	10	11	11	11	11	11	11	11	11	6	11	129
11. EMOH	29	26	29	28	29	28	29	29	28	29	15	29	329
12. OPER BTU (GBTU)	1,397	3,607	3,886	2,642	2,607	3,187	3,404	3,511	3,544	3,705	1,435	2,031	35,271
13. NET GEN (MWH)	175,410	498,850	534,170	348,580	341,680	434,050	466,630	484,510	493,800	517,730	190,040	256,200	4,741,650
14. ANOHR (Btu/kwh)	7,964	7,231	7,275	7,581	7,631	7,343	7,294	7,246	7,176	7,157	7,552	7,928	7,439
15. NOF (%)	33.4	75.0	72.6	55.2	52.3	68.7	71.4	74.2	78.2	79.3	56.8	35.4	63.3
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF(		-17.589	) +	8,551								

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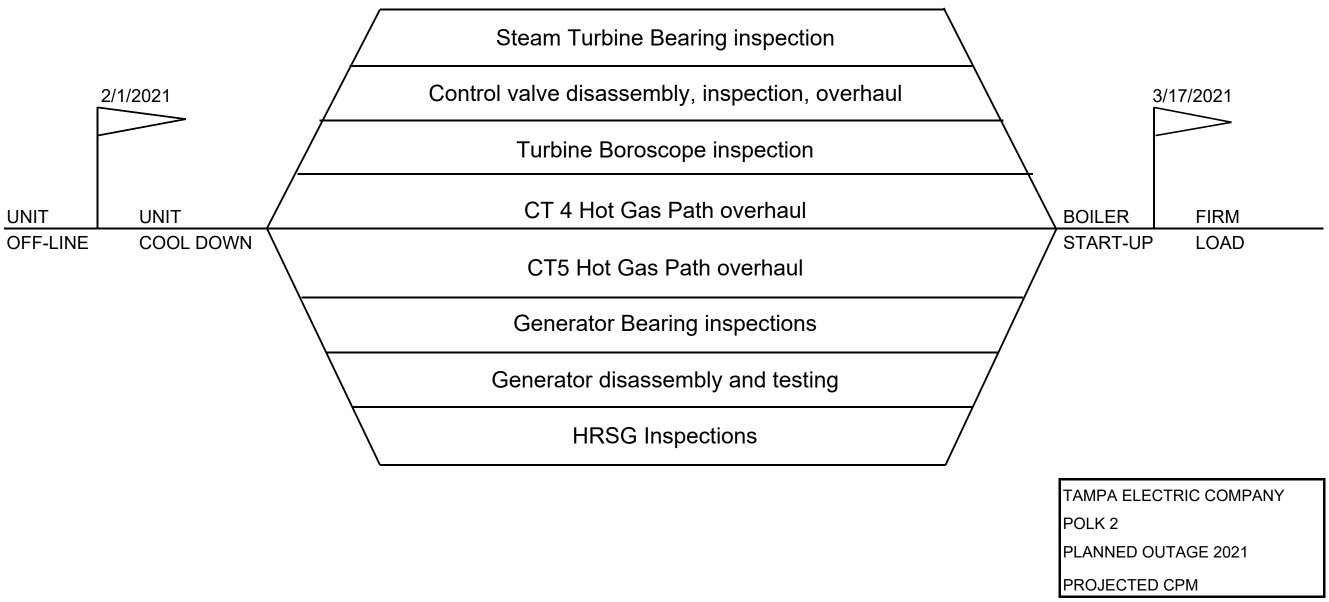
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2021 - DECEMBER 2021

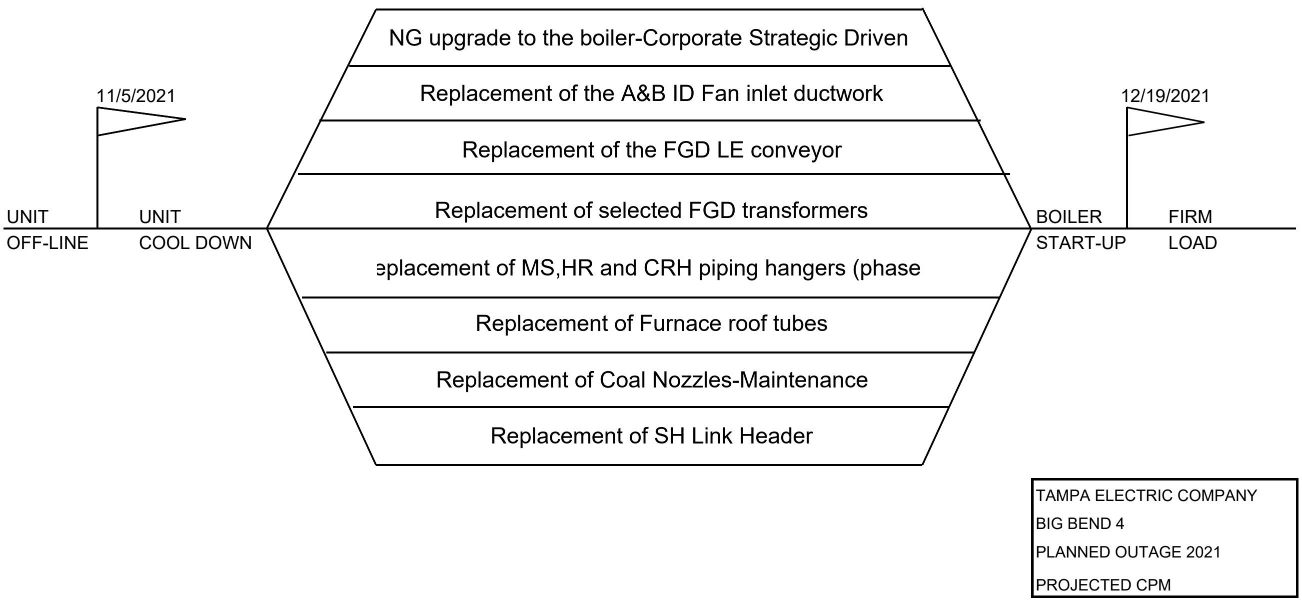
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 4	Mar 29	-	Apr 11	Fuel System Clean-up Planned Outage
+		Nov 05	-	Dec 19	NG upgrade to the boiler-Corporate Strategic Driven, Replacement of the A&B ID Fan inlet ductwork Replacement of the FGD LE conveyor Replacement of selected FGD transformers Replacement of MS,HR and CRH piping hangers Replacement of Furnace roof tubes Replacement of Coal Nozzles-Maintenance Replacement of SH Link Header
	POLK 1	May 15	-	May 28	Combined Cycle Planned Outage
		Nov 29	-	Dec 12	Combined Cycle Planned Outage
+	POLK 2	Feb 01	-	Mar 17	Control valve disassembly, inspection, overhaul Steam Turbine Bearing inspection Turbine Boroscope inspection CT 4 Hot Gas Path overhaul CT5 Hot Gas Path overhaul Generator Bearing inspections Generator disassembly and testing HRSG Inspections
		Oct 08	-	Oct 21	Combined Cycle Planned Outage
	BAYSIDE 1	Mar 15	-	Mar 28	Combined Cycle Planned Outage
	BAYSIDE 2	Nov 11	-	Nov 24	Combined Cycle Planned Outage

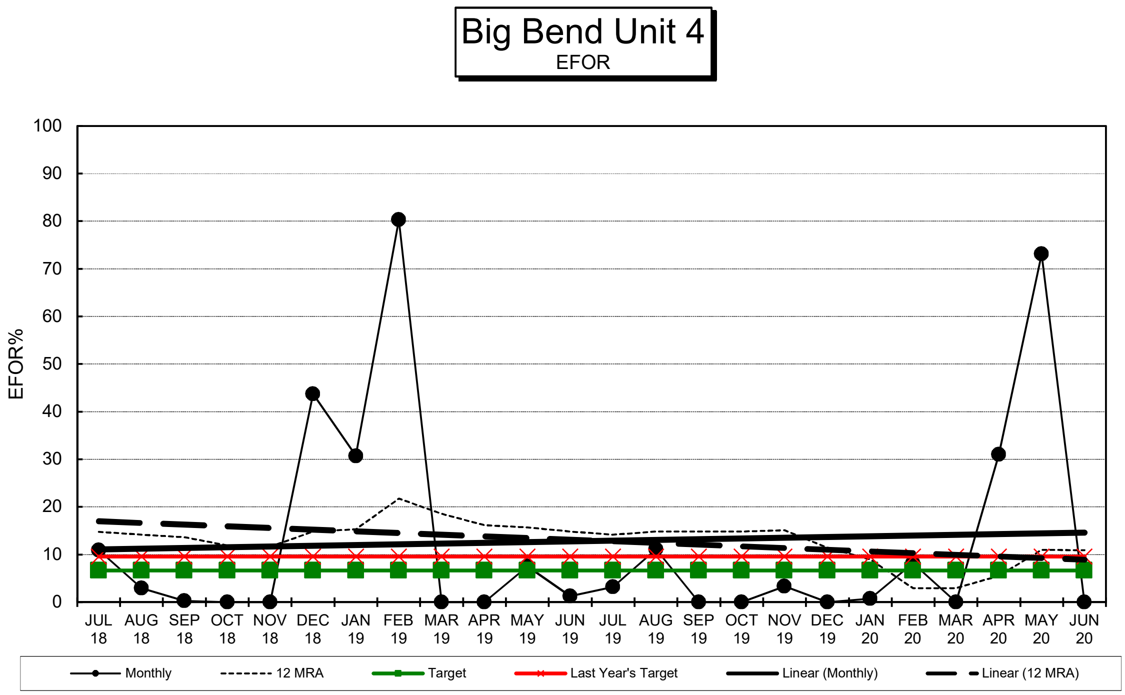
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2021 - DECEMBER 2021



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2021 - DECEMBER 2021




Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
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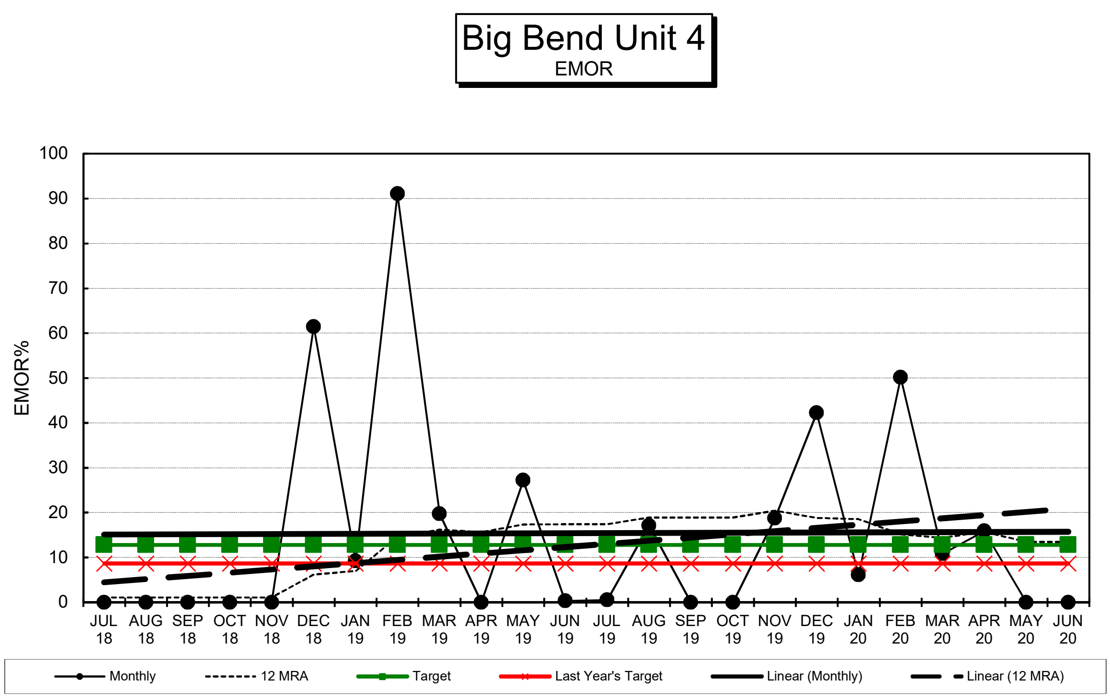
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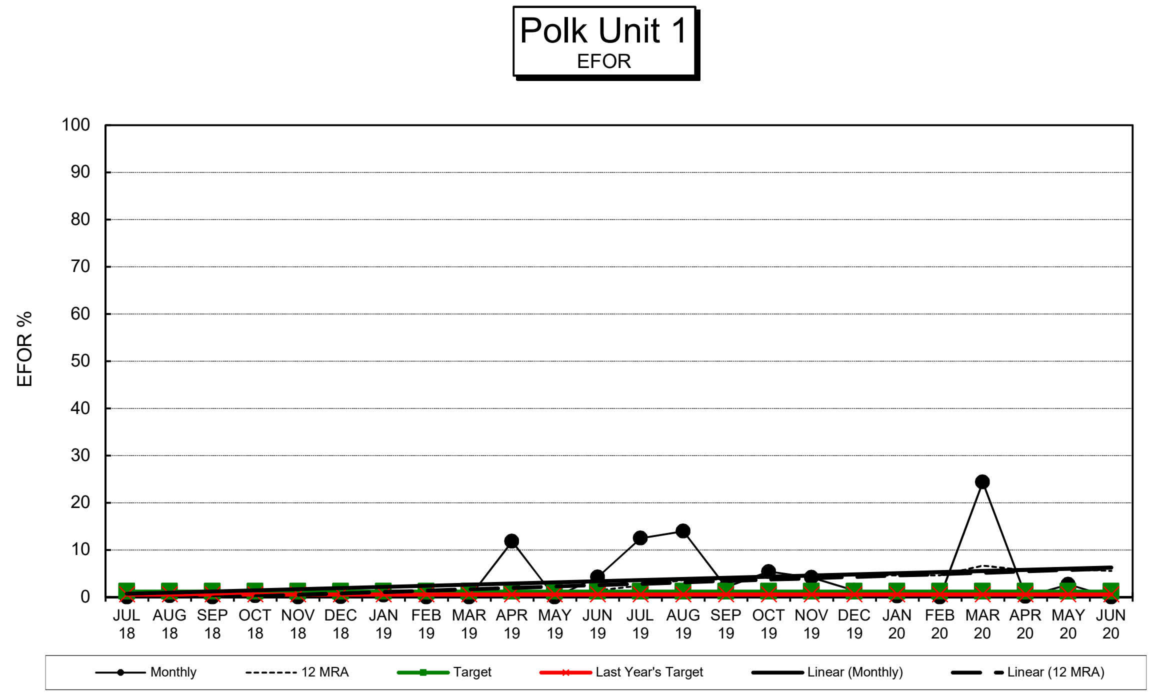
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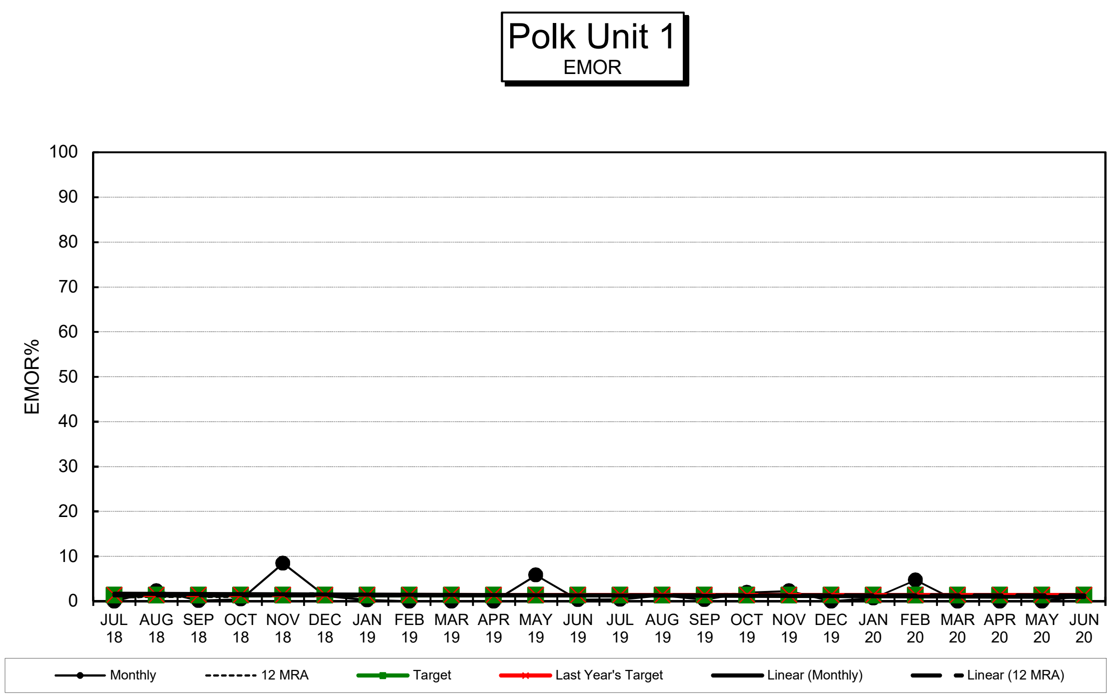
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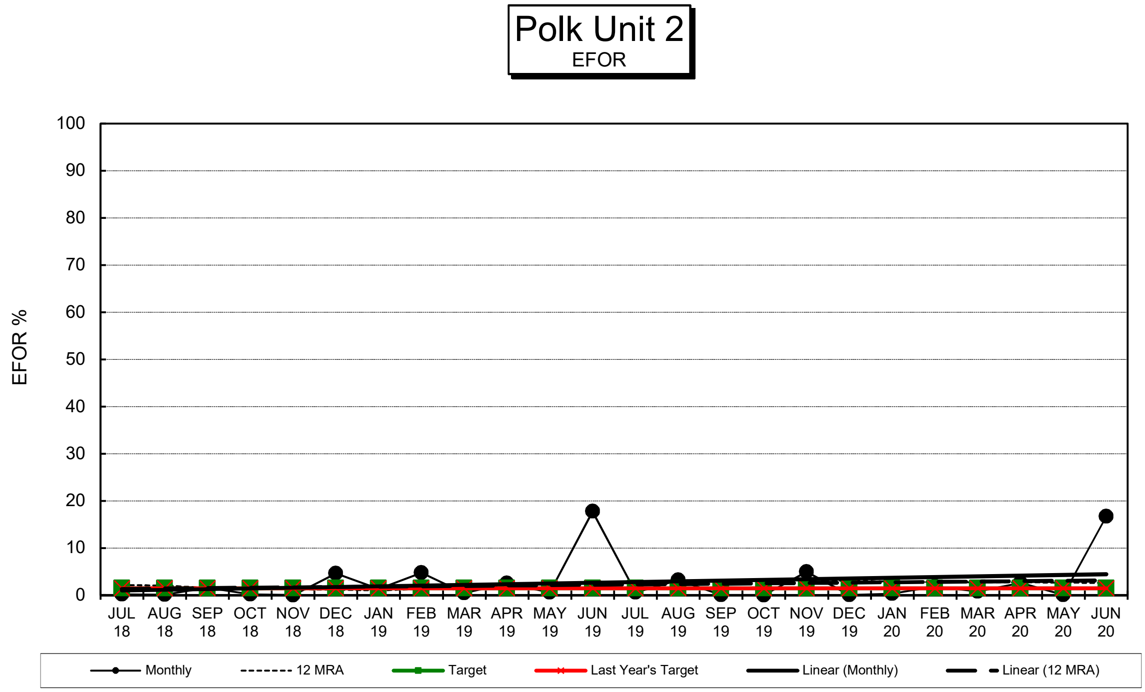
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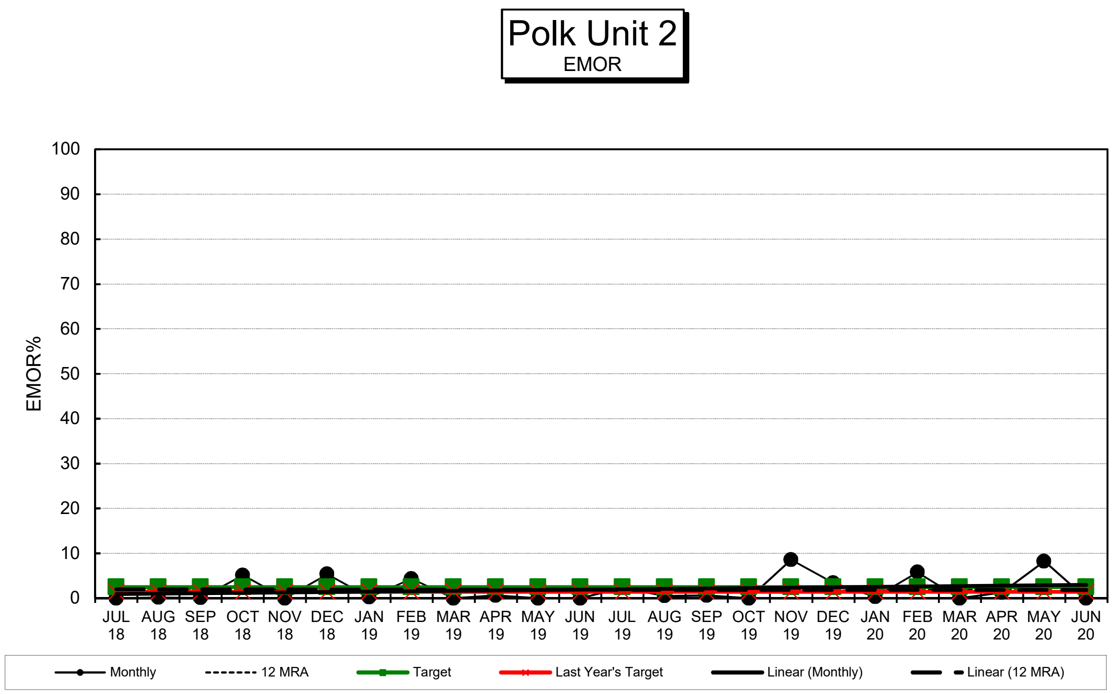
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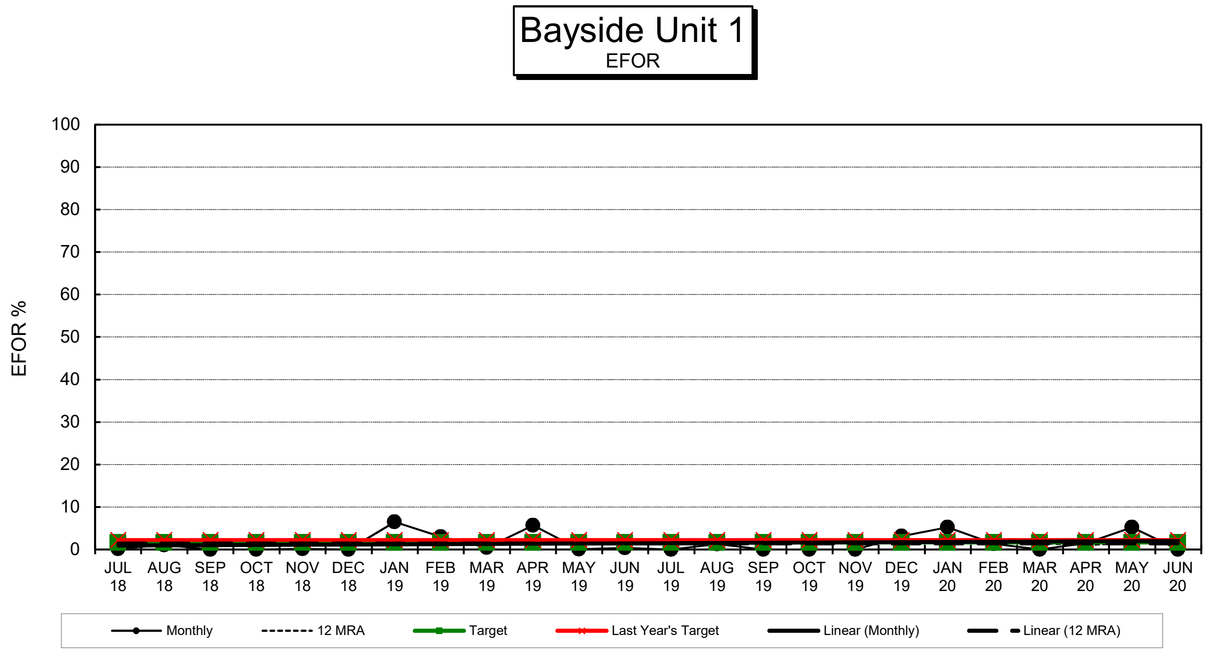
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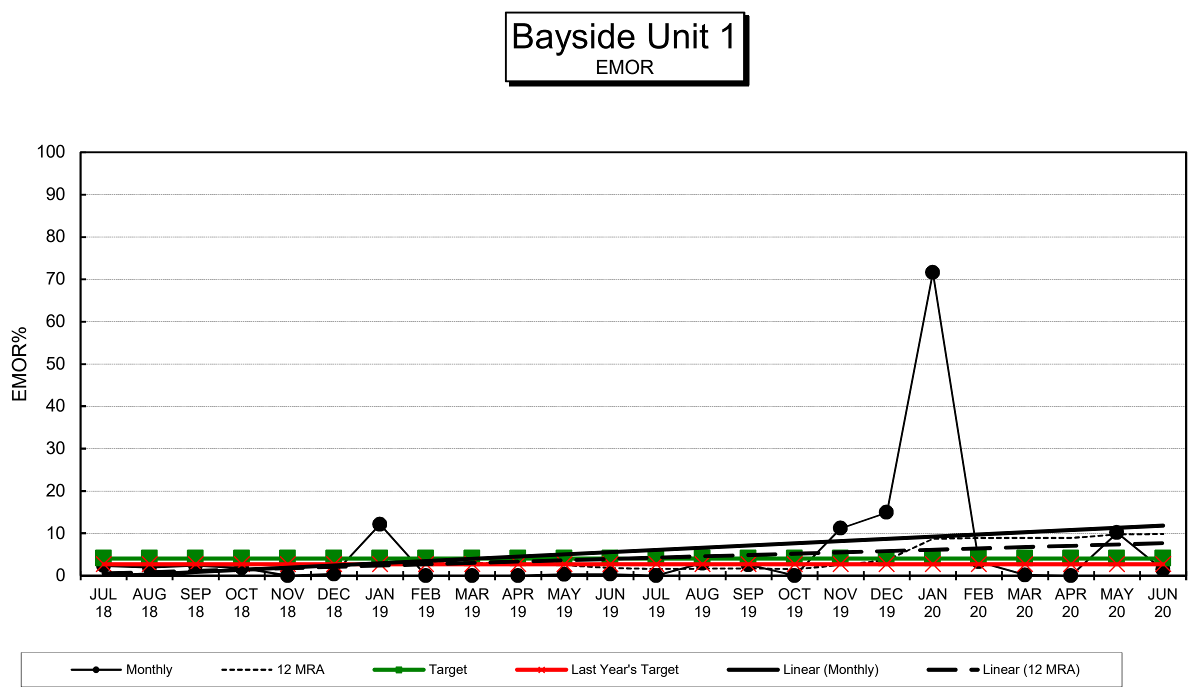
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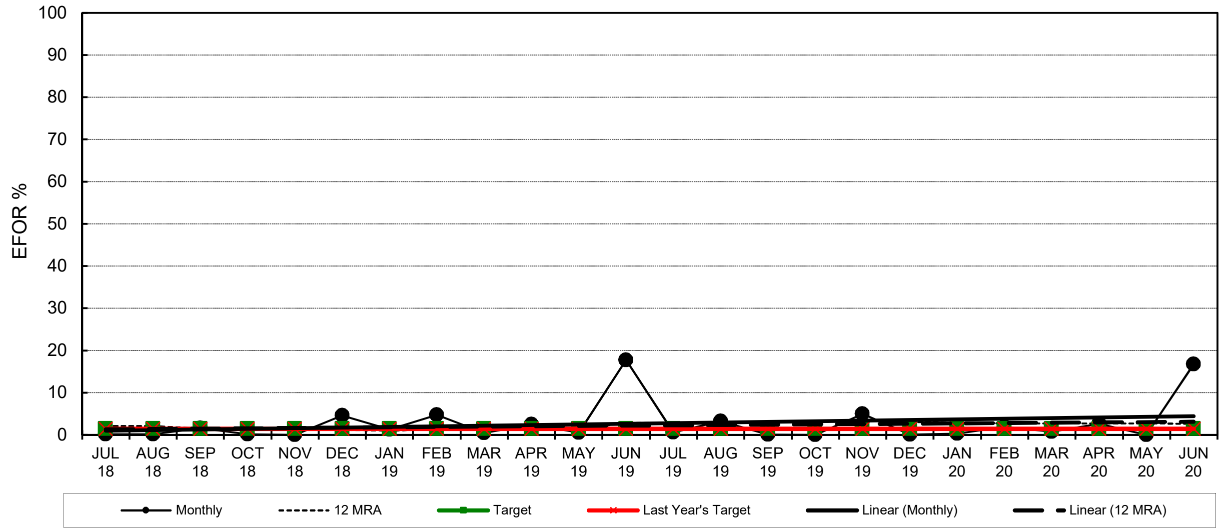

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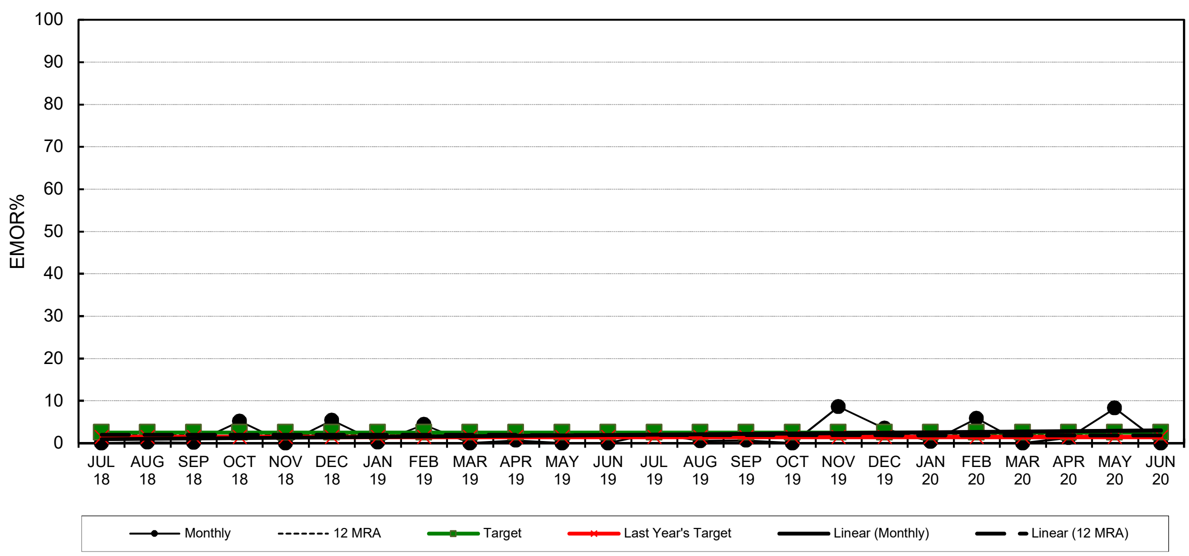
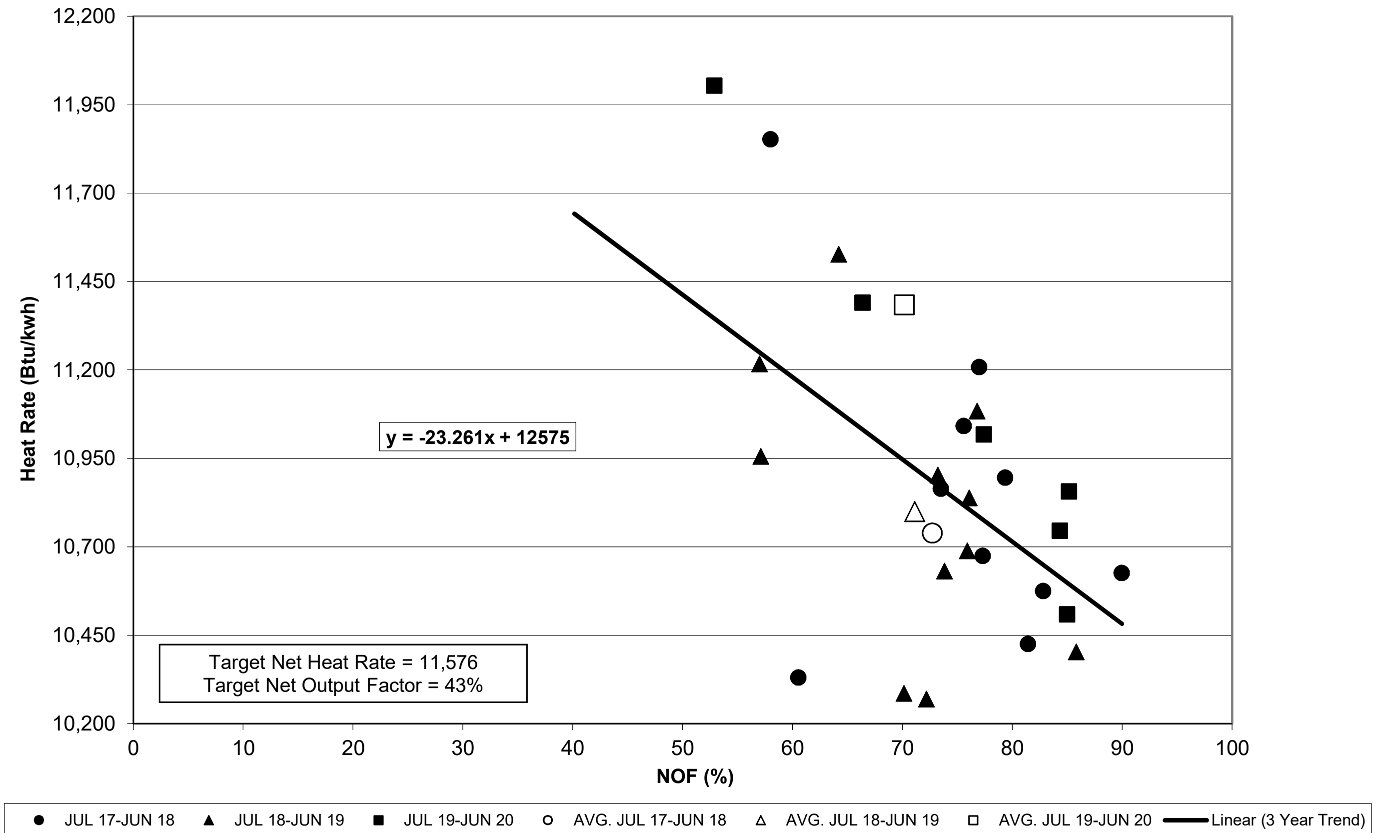
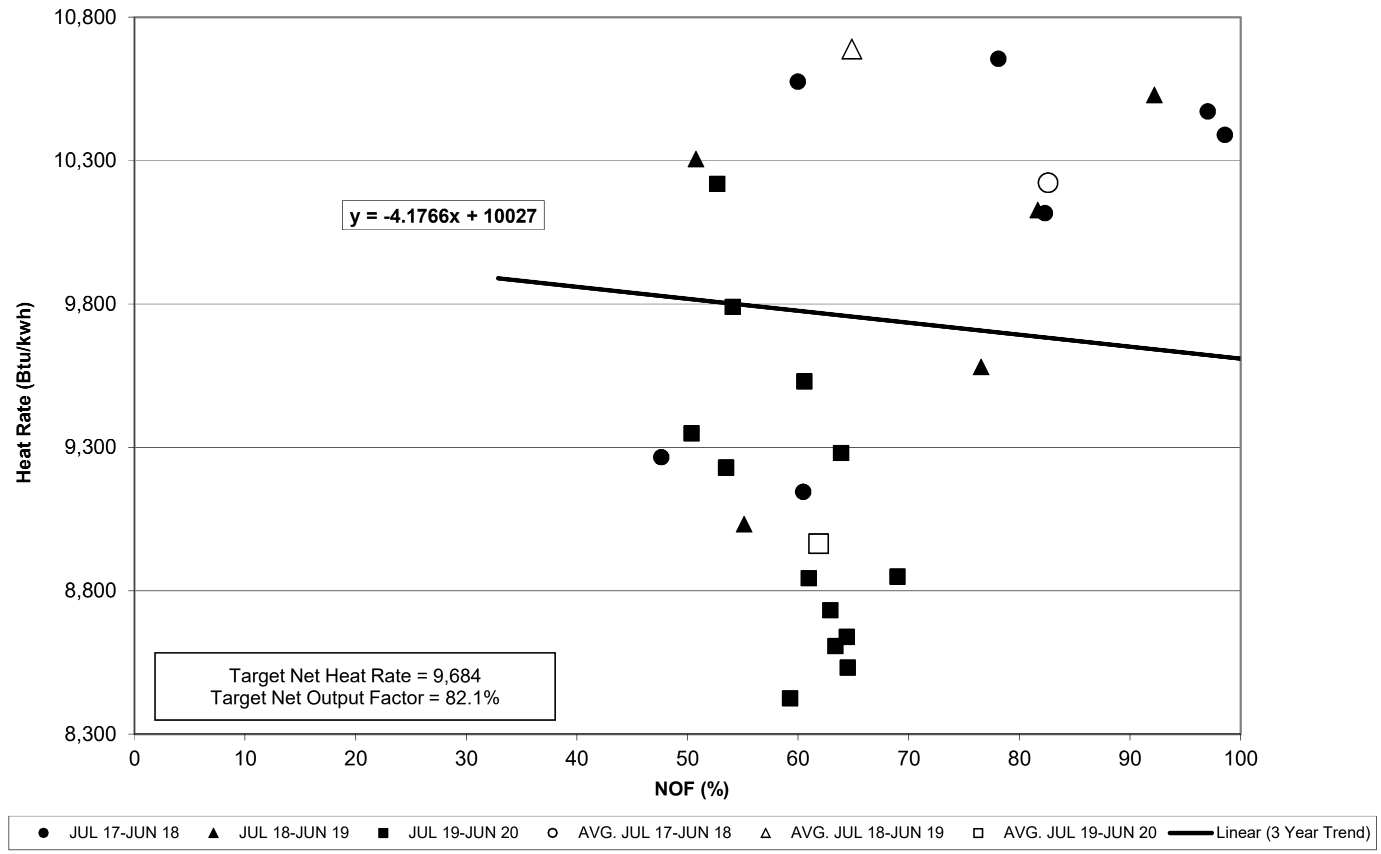


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4

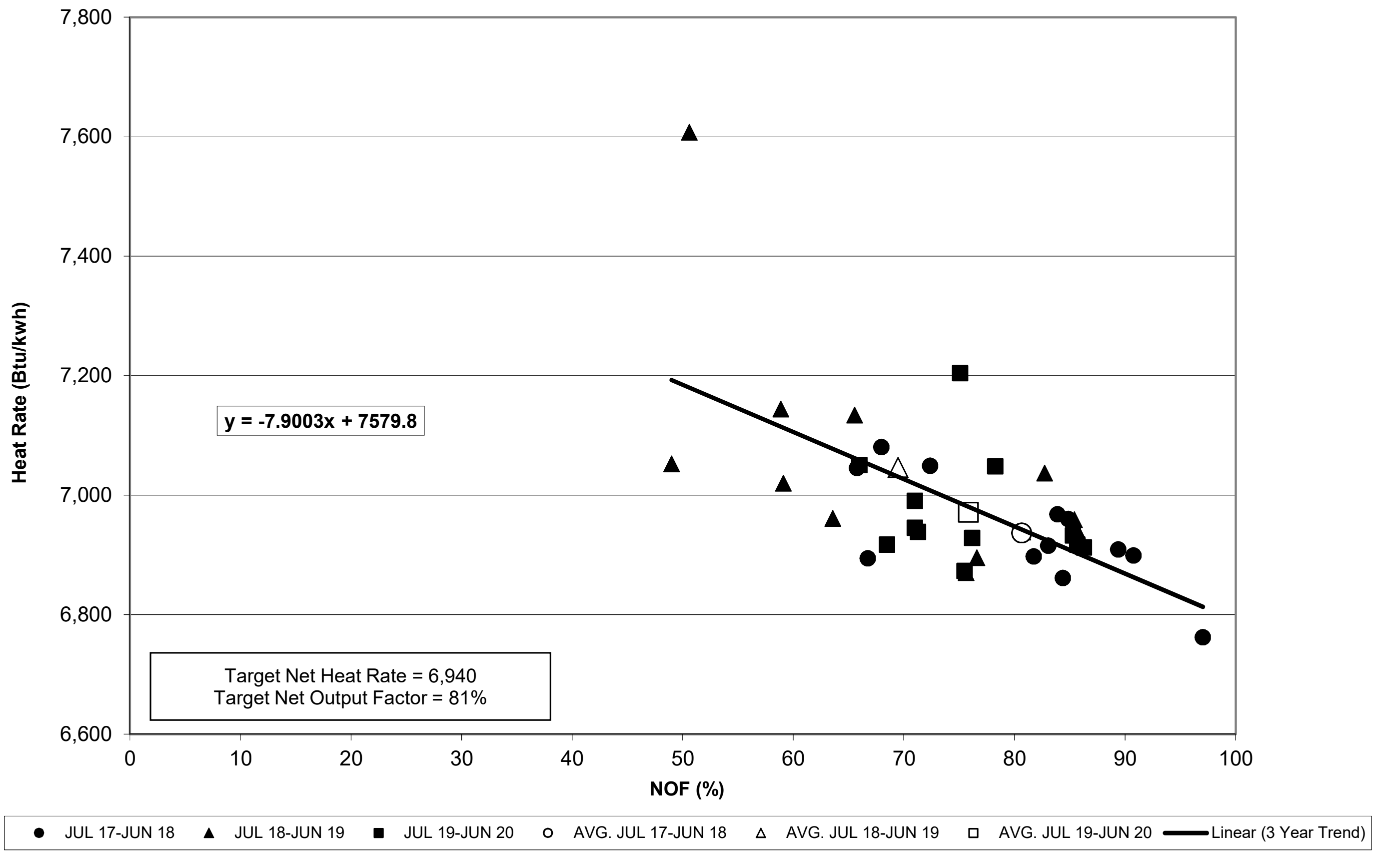


DOCKET NO. 20200001-EI
GPIF 2021 PROJECTION
EXHIBIT NO. JC-1, DOCUMENT NO. 1
ORIGINAL SHEET NO. 8.401.20E

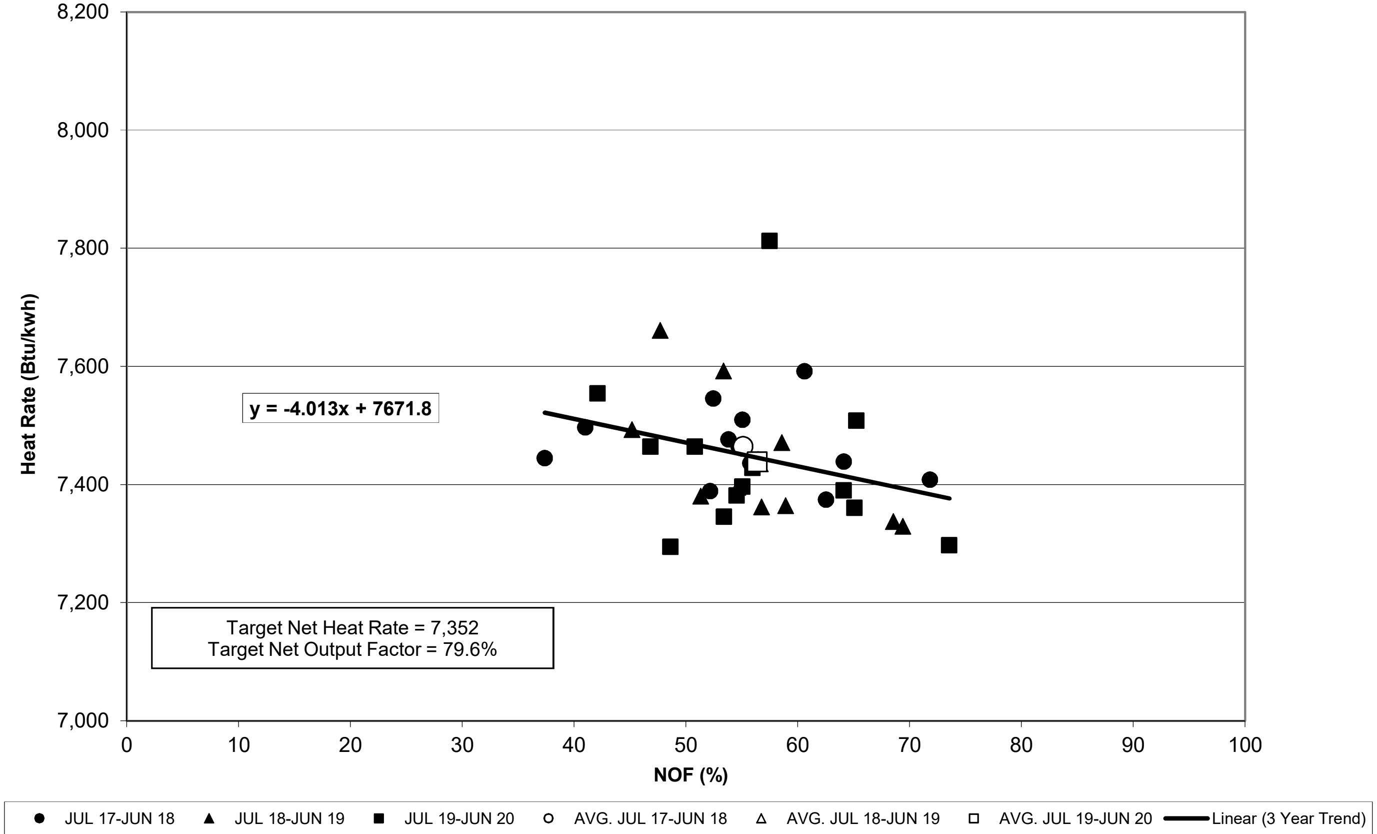
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1



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



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



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GPIF 2021 PROJECTION
EXHIBIT NO. JC-1, DOCUMENT NO. 1
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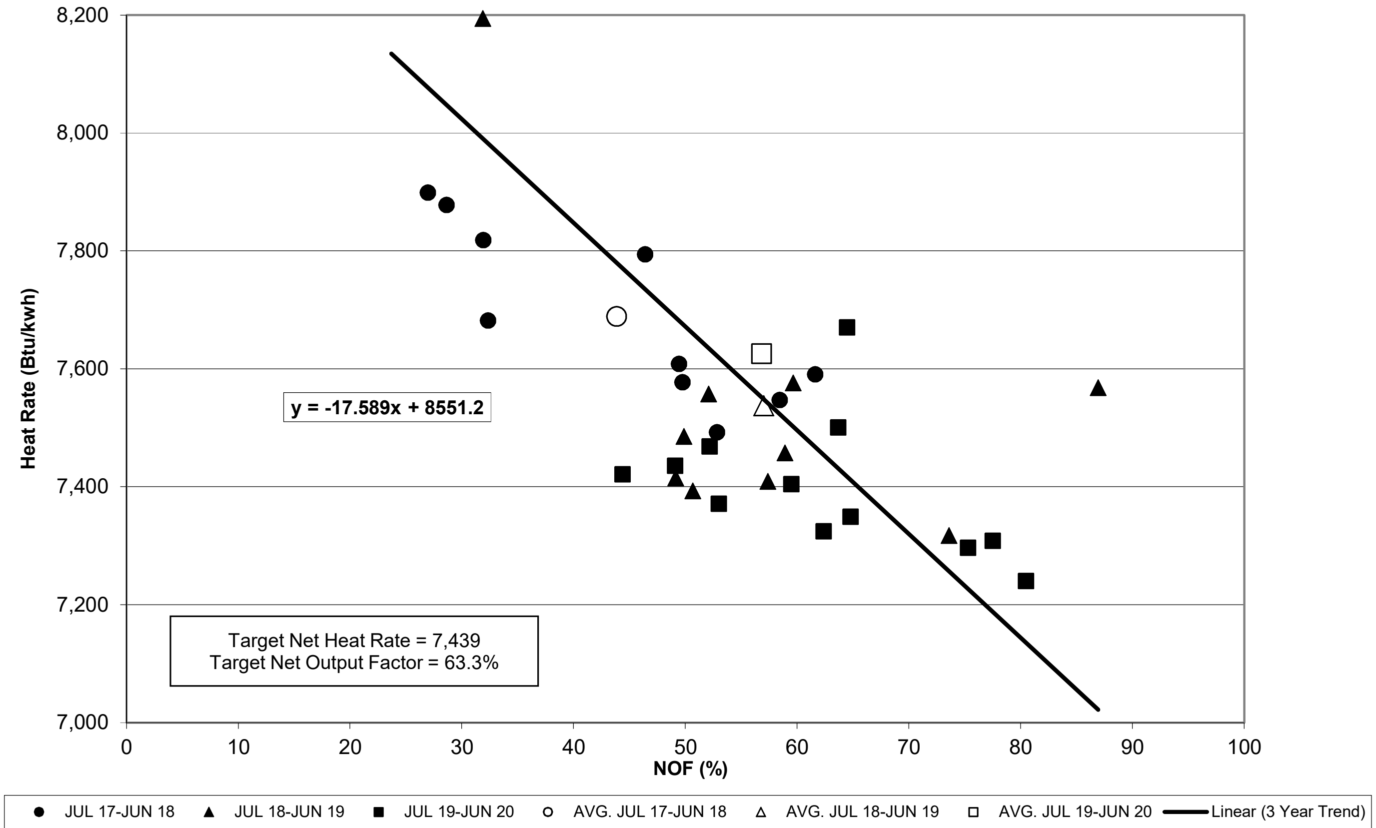
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2021 - DECEMBER 2021

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 4		458	425
POLK 1		225	217
POLK 2		1,130	1,107
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,533	3,449
	SYSTEM TOTAL	**5,153**	**5,025**
	% OF SYSTEM TOTAL	**68.6%**	**68.6%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2021 - DECEMBER 2021

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		0	0
BIG BEND 2		363	343
BIG BEND 3		368	348
BIG BEND 4		458	425
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,249	1,175
POLK 1		225	217
POLK 2		1,130	1,107
	POLK TOTAL	1,355	1,324
SOLAR		596	596
	SOLAR TOTAL	596	596
	SYSTEM TOTAL	**5,153**	**5,025**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2021 - DECEMBER 2021

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,778,150	33.31%	33.31%
BAYSIDE	1	4,749,080	23.34%	56.66%
BAYSIDE	2	4,741,650	23.31%	79.96%
SOLAR		1,567,130	7.70%	87.66%
BIG BEND	4	955,570	4.70%	92.36%
BIG BEND	3	579,130	2.85%	95.21%
POLK	1	562,040	2.76%	97.97%
BIG BEND	2	224,830	1.11%	99.08%
BAYSIDE	5	48,530	0.24%	99.31%
BAYSIDE	6	43,040	0.21%	99.53%
BAYSIDE	3	37,370	0.18%	99.71%
BAYSIDE	4	33,390	0.16%	99.87%
BIG BEND CT	4	25,860	0.13%	100.00%
BIG BEND	1	-	0.00%	100.00%
TOTAL GENERATION		20,345,770	100.00%	

GENERATION BY COAL UNITS: 955,570 MWH
% GENERATION BY COAL UNITS: 4.70%

GENERATION BY NATURAL GAS UNITS: 17,823,070 MWH
% GENERATION BY NATURAL GAS UNITS: 87.60%

GENERATION BY SOLAR UNITS: 1,567,130 MWH
% GENERATION BY SOLAR UNITS 7.70%

GENERATION BY GPIF UNITS: 17,786,490 MWH
% GENERATION BY GPIF UNITS: 87.42%

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2021 – DECEMBER 2021

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2021 - DECEMBER 2021

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 4[1]	54.0	16.2	29.9	11,576
Polk 1[2]	77.7	7.7	14.6	9,684
Polk 2[3]	80.6	16.2	3.2	6,940
Bayside 1[4]	93.9	3.8	2.3	7,352
Bayside 2[5]	90.9	3.8	5.2	7,439

1 Original Sheet 8.401.20E, Page 12

2 Original Sheet 8.401.20E, Page 13

3 Original Sheet 8.401.20E, Page 14

4 Original Sheet 8.401.20E, Page 15

5 Original Sheet 8.401.20E, Page 16

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2021 THROUGH DECEMBER 2021

TESTIMONY
OF
JOHN C. HEISEY

FILED: SEPTEMBER 3, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

Q. Have you previously filed testimony in Docket No. 20200001-EI?

A. Yes, I submitted direct testimony on March 2, 2020.

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

A. No, it has not.

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, solar, coal, and, as a backup fuel, oil. Big Bend Unit 2 can operate on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas. Polk Unit 1 can operate on natural gas or a blend of petroleum coke and coal. Currently, the company is operating Big Bend Unit 2, Big Bend Unit 3 and Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle 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 is primarily for testing, and oil is a negligible percentage of system generation. During 2020, continued low natural gas prices equate to lower fuel prices for customers. Based upon the 2020 actual-estimate projections, the company expects 2020 total system generation, excluding purchased power, to be

89 percent natural gas, 7 percent solar, and 4 percent coal.

Likewise, in 2021, natural gas-fired and solar generation are expected to be 87 percent and 8 percent of total generation, respectively, with coal-fired generation making up 5 percent of total generation.

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

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain many 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.

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. 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 creditworthy 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 services 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 directly 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 (via Gulfstream backhaul). The ability to deliver natural gas 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 to support the station's steam generating units and aero-derivative combustion turbine. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Unit 1 and Polk Unit 2. The addition of Sabal Trail to the company's delivery options enhances reliability, supply, price, and location diversity.

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

A. Tampa Electric’s natural gas usage is expected to remain stable in 2021. The strategy of burning economical natural gas in dual-fueled units continues to provide lower overall costs to customers.

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, and Southern Pines Energy Center in Eastern Mississippi to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in these two locations.

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”), Gulf South pipeline (“Gulf

South”) and Transco’s Mobile Bay Lateral (“Transco”). SESH, Gulf South and Transco connect the receipt points of FGT, Gulfstream and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH, Gulf South and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2020 and 2021 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 longer-term pipeline capacity to support the company’s portfolio of gas-fired generation assets. In 2020, Tampa Electric acquired additional pipeline capacity on Gulf South, which is similar to existing upstream capacity on SESH and Transco. This capacity provides additional diversification of pipelines and gas supply receipt points, access to lower cost onshore supply basins, and minimizes the risk of declining Mobile Bay offshore production. In 2021, Tampa Electric acquired additional Sabal Trail capacity which will enhance reliability, supply, price, and location diversity.

Coal Supply Strategy

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

A. Like its natural gas strategy, Tampa Electric uses a portfolio approach to coal procurement. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and are 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 blend of petroleum coke and 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 quality characteristics, price, availability, deliverability, and credit worthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically 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 2021.

A. Since the company is projected to use less coal and more natural gas in 2021 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts and, as necessary, spot purchases in support of the most economic commitment and dispatch for the generation fleet. The short-term and spot 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, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1. As a result of declining solid fuel burns over the last few years, Tampa Electric has transitioned to purchasing delivered coal, where waterborne coal supply and transportation are arranged by the supplier. The complex logistics of procuring quality-specific coal for multiple units is no longer necessary at Tampa Electric as fewer units are burning solid fuel and the projected consumption is declining. Procuring delivered coal continues to provide customers with competitive coal prices through a simplified process. Commodity and transportation of coal by rail is still being arranged separately, as necessary.

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 various benefits. Those benefits include 1) access to more potential coal suppliers, which results in 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 among transporters for future solid fuel transportation contracts.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2020 and 2021?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2020 and is evaluating how much coal to receive by rail in 2021.

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 supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric’s solid fuel transportation portfolio?

A. The continued trend of an abundant volume of natural gas available at historically low prices results in Tampa Electric’s continued use of natural gas in the dual-fueled Big Bend and Polk units. In addition, the company’s strategy of utilizing short-term and spot delivered solid fuel purchases allows Tampa Electric to reduce its solid fuel deliveries going forward, which aligns well with the economical use of natural gas. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and transportation in the remainder of 2020 and 2021 than in previous years.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2021 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. These factors include the relative price of delivered solid fuel compared to the delivered natural gas and wholesale power markets. Thus, the actual quantity of solid fuel burned may vary significantly each year. In developing its solid fuel portfolio, 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.

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, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2021 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 August2020, 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, such as IHS Markit and *Coal Daily*. 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 2021 projected fuel prices compare to the fuel prices projected for 2020 in the company’s mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices low. However, though demand impacts from the COVID-19 pandemic further reduced 2020 natural gas prices to historically low levels, a rebound is expected in 2021 as demand is expected to outpace supply. Additionally, there is a significant amount of uncertainty associated with the natural gas prices for 2021 as a result of the pandemic. The commodity price for natural gas during 2021 is projected to be higher ($2.88 per MMBtu) than the 2020 price ($2.05 per MMBtu) projected in the company’s mid-course correction fuel filing. The 2021 coal commodity price projection is slightly higher ($41.03 per ton) than the price projected for 2020 ($39.52 per ton) during preparation of the 2020 mid-course correction fuel clause factors. International demand for coal is elevating coal prices despite minimal domestic demand.

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. 20200001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2021 THROUGH DECEMBER 2021

TESTIMONY

OF

BENJAMIN F. SMITH II

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TAMPA ELECTRIC COMPANY
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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") as Manager, Gas and Power Origination within the Fuel and Planning Services 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 within the Fuel and Planning Services 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, other wholesale developers and independent power producers, as well as with natural gas pipeline owners and transporters.

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

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

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and 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, meet operating reserve requirements, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company diligently 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. 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 2020 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 2020 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke Energy Florida (DEF), the Florida Municipal Power Agency (FMPA), Florida Power & Light (FPL), and the Orlando Utilities Commission (OUC).

Tampa Electric secured two non-firm and five firm purchases in 2020. The company secured the non-firm purchases during the first quarter of 2020, with DEF and FPL. The DEF non-firm purchase is an extension of Tampa Electric's previous contract to purchase non-firm energy from DEF for the period February 2019 through February 2020. The extension covers the period March 2020 through February 2021, and the energy volume available under the contract remains at a maximum of 515 MW per hour. The DEF extension does not have a must-take obligation. The extension provides Tampa Electric the flexibility to schedule the energy when beneficial to customers. The FPL non-firm purchase is a must-take for 150-300 MW, depending on the month and hour, and is for the term April through November 2020. The must-take hours are hours ending 7 through 24 (i.e., HE 7-24), May through October, and HE 7-23, April and November. Combined, the two non-firm transactions are estimated to result in $5.25 million in savings to customers. As authorized by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017, these savings flow through the company's optimization mechanism which are described in the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery docket annual true-up filing along with mechanism saving sharing reporting and accompanying testimony of Tampa Electric witness John C. Heisey.

The five firm purchase agreements by dates of occurrence are:

- December 2019 through February 2020: 112 MW from FMPA
- July 2020 through September 2020: 74 MW from FMPA
- December 2020 through February 2021: 150 MW from FMPA, 160 MW from FPL, and 100 MW from OUC

The company secured these purchase agreements during the fourth quarter of 2019. All of the agreements are peaking call options, and a portion of the agreements have been entered into for reliability purposes. The 112 MW from FMPA and 95 MW of the 150 MW from FMPA are to meet the company's 20 percent firm reserve margin criteria during the winter 2020 and winter 2021 periods, respectively. The balance of the purchase agreements represent economic purchases and support the Big Bend Modernization Project by allowing an early re-powering outage on Big Bend Unit 1, which is the unit being modernized. The early re-powering outage provides the Modernization team with more flexibility to schedule work on the unit, given the Modernization's two new combustion turbines are expected to be in-service by the fall of 2021. The economic portion of these purchases (i.e., 74 MW FMPA, 160 MW FPL, 100 MW OUC, and 55 MW of the FMPA 150 MW) is estimated to provide a combined $445.9 thousand in savings to customers, $325.6 thousand of which are expected to be generated in 2020. As mentioned earlier, these savings flow through the company's optimization mechanism and benefit customers in accordance with the methodology approved by the Commission.

Tampa Electric has not secured other forward purchases for 2020 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2021 and beyond?

A. Other than the previously mentioned DEF extension and firm purchases for December 2020 through February 2021, Tampa Electric has made no other forward purchases to date. However, the company will continue to identify and evaluate purchase opportunities for 2021 and beyond that bring value to customers. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2021 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 existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if appropriate, 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. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2020 and 2021.

A. Tampa Electric entered into various non-separated (e.g., next-hour and next-day sales) wholesale sales in 2020, and the company anticipates making additional non-separated sales during the balance of 2020 and 2021. The gains from these sales are shared between Tampa Electric and its customers in accordance with the company's optimization mechanism.

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.