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September 3, 2021

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. 20210001-EI

Dear Mr. Teitzman:

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 Patrick A. Bokor (PAB-2);

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)

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 2021, to the following:

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Malcolm N. Means

ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 20210001-EI FILED: September 3, 2021

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, 2021 through December 31, 2021 will be an under-recovery of $ 325,418 (See Exhibit No. MAS-3, Document No. 2, Schedule E1-C).

2. The company's projected expenditures for the period January 1, 2022 through December 31, 2022, 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, 2022 through December 31, 2022, produce a fuel and purchased power factor for the new period of 3.057 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, 2021 through December 31, 2021 will be an under-recovery of $25,180, 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, 2022 through December 31, 2022, 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 0.0026 cents per kWh. For demand-measured customers, the factor Tampa Electric proposes to recover is $0.09 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 $3,673,726 for performance during the period January 1, 2020 through December 31, 2020, 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, 2022 through December 31, 2022 with such proposed targets and ranges being detailed in the testimony and exhibits of Tampa Electric witness Patrick A. Bokor filed herewith.

Optimization Mechanism

8. Tampa Electric has calculated that it is subject to an Optimization Mechanism sharing amount of $1,285,228, 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 2021.

Respectfully submitted,

Malcolm N. Means

JAMES D. BEASLEY
J. JEFFRY WAHLEN
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Ausley McMullen
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 3rd day of September 2021.

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Malcolm N. Means
ATTORNEY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY AND EXHIBIT

OF

M. ASHLEY SIZEMORE

FILED: SEPTEMBER 3, 2021

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. 20210001-EI?

A. Yes, I submitted direct testimony on April 2, 2021 and July 27,2021. I submitted revisions to my April 2, 2021 testimony on July 23, 2021.

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

A. No, they have 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 2022 through December 2022. 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 2022.

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 2022 through December 2022 as well as Schedule H1 for 2019 through 2022. 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.

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

A. Yes, with one caveat. On August 6, 2021, Tampa Electric filed a 2021 Stipulation and Settlement Agreement ("2021 Agreement") in Docket No. 20210034-EI, Petition for rate increase by Tampa Electric Company, which is currently scheduled for hearing on October 21, 2021. Among other things, the 2021 Agreement includes proposed changes to the company's existing rate design across rate classes. The company plans to file revised fuel and capacity clause schedules that reflect the 2021 Agreement in the coming weeks and request approval of those factors for the period January through December 2022. However, if the settlement agreement is not approved by the Commission, then the company requests approval of the factors provided in Exhibit No. MAS-3, Document Nos. 1 and 2, for the period January 2022 until the issues in Docket No. 20210034-EI are resolved. These factors were prepared under my direction and supervision.

Q. How were the fuel and capacity cost recovery clause factors calculated?

A. The fuel and capacity cost recovery factors were calculated as shown on Document Nos. 1 and 2. These factors were calculated based on the current approved rate design and schedules as set out in the 2017 Amended and Restated Settlement Agreement approved by the Commission in Docket No. 20170271-EI, which amended and extended the 2013 Stipulation that resolved the company's last base rate case (Docket No. 20130040-EI).

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. As previously stated, if the company's 2021 Agreement is not approved, then Tampa Electric seeks approval of the proposed capacity cost recovery factors, prepared under my direction and supervision, that 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 $25,180 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2022.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2022, if the company's 2021 Agreement is not approved, for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.031	
GS and CS Secondary	0.027	
GSD, SBF Standard		
Secondary		0.09
Primary		0.09
Transmission		0.09
IS, IST, SBI		
Primary		0.07

Transmission		0.07
GSD Optional		
Secondary	0.021	
Primary	0.021	
Transmission	0.021	
LS1 Secondary	0.004	

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 0.026 cents per kWh compare to the factor for September 2021 through December 2021?

A. The proposed capacity cost recovery factor of 0.026 cents per kWh beginning in January 2022 is 0.118 cents per kWh (or $1.18 per 1,000 kWh) less than the average capacity cost recovery factor credit of 0.144 cents per kWh for the September 2021 through December 2021 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 period beginning in January 2022?

A. As I previously stated, approval of the company's pending 2021 Agreement would require modifications to the rate schedules for these factors. If the Commission does not approve the company's settlement agreement, then the appropriate amount for the period beginning in January 2022 is 3.057 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 2022 through December 2022.

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 $3,673,726, 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 2022 through December 2022 period. The net true-up amount is an under-recovery of $325,418. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,285,228.

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 2022 through December 2022. 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 the period beginning in January 2022.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.057
Tier I (Up to 1,000 kWh)	2.745
Tier II (Over 1,000 kWh)	3.745
Distribution Primary	3.026
Transmission	2.996
Lighting Service	3.008
Distribution Secondary	3.318(on-peak)
	2.944(off-peak)
Distribution Primary	3.285(on-peak)
	2.915(off-peak)
Transmission	3.252(on-peak)
	2.885(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.057 cents per kWh compare to the levelized fuel adjustment factor for the September 2021 through December 2021 period?

A. The proposed fuel charge factor of 3.057 cents per kWh is

1.198 cents per kWh (or $11.98 per 1,000 kWh) lower than the average fuel charge factor of 4.255 cents per kWh for the September 2021 through December 2021 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2022 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 short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2022 projection. However, if the settlement agreement is not approved by the Commission, then Tampa Electric's projected 2022 benchmark for non-separated wholesale sales would be $767,628. The $767,628 is the three-year average of $1,498,686, $422,867 and $381,332 in gains for 2019, 2020 and 2021 (actual/estimated).

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 if the company's 2021 Agreement is not approved?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $12.47 in the period beginning January 2022, when compared to the September 2021 through December 2021 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 2022.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2022 - DECEMBER 2022

AND

SCHEDULE E12

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
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	52.98%	9,728,165	2,096	1.07447	1.05324	10,246,140	2,252	49.26%	59.49%	58.70%
GS, CS	62.08%	953,392	175	1.07447	1.05323	1,004,139	188	4.83%	4.97%	4.96%
GSD Optional	4.10%	417,435	60	1.06971	1.04880	437,805	64	2.11%	1.69%	1.72%
GSD, SBF	75.51%	7,681,911	1,101	1.06971	1.04880	8,056,777	1,178	38.74%	31.11%	31.70%
IS,SBI	105.90%	920,157	99	1.03064	1.01680	935,613	102	4.50%	2.69%	2.83%
LS1	802.58%	110,703	2	1.07447	1.05324	116,598	2	0.56%	0.05%	0.09%
TOTAL		19,811,763	3,533			20,797,072	3,786	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2021 projected calendar data.
(2) Projected MWH sales for the period January 2022 thru December 2022.
(3) Based on 12 months average CP at meter.
(4) Based on 2021 projected demand losses.
(5) Based on 2021 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 2022 THROUGH DECEMBER 2022
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	0	0	0	706,062	706,062	706,062	776,668	776,668	776,668	776,668	706,062	0	5,930,921
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,178)	(746,114)
4	TOTAL CAPACITY DOLLARS	($62,176)	($62,176)	($62,176)	$643,886	$643,886	$643,886	$714,492	$714,492	$714,492	$714,492	$643,886	($62,178)	$5,184,807
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	($62,176)	($62,176)	($62,176)	$643,886	$643,886	$643,886	$714,492	$714,492	$714,492	$714,492	$643,886	($62,178)	$5,184,806
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2021 - DEC. 2021													25,180
8	SOBRA 3 TRUE-UP													(85,648)
9	TOTAL													$5,124,338
10	REVENUE TAX FACTOR													1.00072
11	TOTAL RECOVERABLE CAPACITY DOLLARS													$5,128,028

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
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	49.26%	59.49%	194,254	2,816,068	3,010,322	9,728,165	9,728,165				0.00031
GS, CS	4.83%	4.97%	19,047	235,264	254,311	953,392	953,392				0.00027
GSD, SBF											
Secondary						6,307,319	6,307,319			0.09	
Primary						1,369,359	1,355,666			0.09	
Transmission						5,233	5,128			0.09	
GSD, SBF - Standard	38.74%	31.11%	152,769	1,472,649	1,625,418	7,681,911	7,668,113	58.83%	17,854,692		
GSD - Optional	2.11%	1.69%	8,321	79,999	88,320						
Secondary						406,871	406,871				0.00021
Primary						10,564	10,459				0.00021
Transmission						0	0				0.00021
IS, SBI											
Primary						189,417	187,523			0.07	
Transmission						730,740	716,125			0.07	
Total IS, SBI	4.50%	2.69%	17,746	127,336	145,082	920,157	903,648	63.63%	1,945,276		
LS1	0.56%	0.05%	2,208	2,367	4,575	110,703	110,703				0.00004
TOTAL	100.00%	100.00%	394,345	4,733,683	5,128,028	19,811,763	19,781,351				0.00026

(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 2022 through December 2022.
(7) Projected kWh sales at secondary for the period January 2022 through December 2022.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2022 through December 2022.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

REDACTED

TAMPA ELECTRIC COMPANY

SCHEDULE E12

CAPACITY COSTS

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

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

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

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
SEMINOLE ELECTRIC	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
VARIOUS	[redacted]												
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	(62,176)	(62,176)	(62,176)	643,886	643,886	643,886	714,492	714,492	714,492	714,492	643,886	(62,178)	5,184,807
TOTAL CAPACITY	**($62,176)**	**($62,176)**	**($62,176)**	**$643,886**	**$643,886**	**$643,886**	**$714,492**	**$714,492**	**$714,492**	**$714,492**	**$643,886**	**($62,178)**	**$5,184,807**

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2022 - DECEMBER 2022

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

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TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	591,244,371	20,728,070	2.85239
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustment	0	20,728,070 [1]	0.00000
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**591,244,371**	**20,728,070**	**2.85239**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	0	0	0.00000
7.	Energy Cost of Economy Purchases (E9)	6,737,130	104,970	6.41815
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	1,866,220	68,840	2.71095
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**8,603,350**	**173,810**	**4.94986**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**20,901,880**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	980,190	35,040	2.79735
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	69,080	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**1,049,270**	**35,040**	**2.99449**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		1,198	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**598,798,451**	**20,865,642**	**2.86978**
20.	Net Unbilled	NA [1][a]	NA [a]	NA
21.	Company Use	1,033,121 [1]	36,000	0.00522
22.	T & D Losses	29,337,798 [1]	1,022,301	0.14812
23.	System MWH Sales	598,798,451	19,807,340	3.02311
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	598,798,451	19,807,340	3.02311
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	598,798,451	19,807,340	3.02311
28.	Optimization Mechanism{2}	1,285,228	19,807,340	0.00649
29.	True-up (2)	325,418	19,807,340	0.00164
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	600,409,097	19,807,340	3.03125
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	600,841,392	19,807,340	3.03343
33.	GPIF Adjusted for Taxes (2)	3,673,726	19,807,340	0.01855
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	604,515,118	19,807,340	3.05198
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.052**

[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 2022 THROUGH DECEMBER 2022

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2021 - December 2021 (6 months actual, 6 months estimated)	($44,617,507)
2.	PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN SEPTEMBER - DECEMBER 2021 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	($49,015,848)
3.	DIFFERENCE IN 2020 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2021 RATES AND AMOUNT COLLECTED IN 2021 ($25,479,055 under-recovery less ($2,123,255) refunded each month January through August 2021)	($8,493,015)
4.	ACTUAL-ESTIMATED 2021 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	($4,094,674)
5.	FINAL TRUE-UP (January 2020 - December 2020) (Per True-Up filed April 2, 2021)	3,769,256
6.	TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2022 (Line 4 + Line 5) To be included in the 12-month projected period January 2022 through December 2022 (2022 Schedule E1, line 29)	($325,418)
7.	JURISDICTIONAL MWH SALES (Projected January 2022 through December 2022)	19,807,340
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,776,928)	**0.0016**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2022 through December 2022)	$3,673,726	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2022 through December 2022)	($325,418)	
	C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2022 through December 2022)	$1,285,228	
2.	TOTAL SALES (January 2022 through December 2022)	19,807,340	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,776,928)	**0.0186**	Cents/kWh
	B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,776,928)	**0.0016**	Cents/kWh
	C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,776,928)	**0.0065**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E1-D

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.09	$22.07
OFF PEAK	69.91	$19.58
	100.00	1.1272

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$598,798,451		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,807,340		
2a	Effective MWH Sales (Jurisd)		19,776,928		
3	Cost Per KWH Sold	(line 1 / line 2)	3.0231		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 29)	$325,418		
7	Optimization Mechanism	(Sch E1 line 28)	$1,285,228		
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$600,409,097		
9	Revenue Tax Factor		1.00072		
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	3.0381		
11	GPIF Factor	(Sch E1-C line 3A)	0.0186		
12	Recovery Factor Including GPIF	(line 10 + line 11)	3.0567	3.3184	2.944
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.057	3.318	2.944

14	Hours: ON PEAK	25.60%
15	OFF PEAK	74.40%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,502,027		17,502,027
Distribution Primary	1,569,341	0.99	1,553,647
Transmission	735,973	0.98	721,254
Total	19,807,340		19,776,928

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.057	3.318	2.944
Distribution Primary	3.026	3.285	2.915
Transmission	2.996	3.252	2.885
RS 1st Tier	2.745		
RS 2nd Tier	3.745		
Lighting	3.008		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

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)		2.745	3.745
Distribution Secondary	3.057		
Distribution Primary	3.026		
Transmission	2.996		
Lighting Service [(1)]	3.008		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.318		
Distribution Secondary - Off-Peak	2.944		
Distribution Primary - On-Peak	3.285		
Distribution Primary - Off-Peak	2.915		
Transmission - On-Peak	3.252		
Transmission - Off-Peak	2.885		

(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 2022 THROUGH DECEMBER 2022

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
							ESTIMATED							TOTAL
		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	PERIOD
1.	Fuel Cost of System Net Generation	50,628,655	43,712,330	45,704,776	43,168,114	49,710,665	56,554,931	58,231,044	59,752,774	53,251,426	47,781,768	39,999,180	42,748,708	591,244,371
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	96,568	87,586	92,414	81,142	86,998	94,887	87,362	91,825	86,173	87,051	73,242	84,022	1,049,270
4.	Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	149,230	139,130	164,470	141,730	130,060	169,370	150,520	173,790	184,140	165,380	154,990	143,410	1,866,220
7.	Energy Cost of Economy Purchases	14,270	10,250	5,180	1,700	26,170	480,100	609,210	364,870	4,111,460	1,108,180	1,320	4,420	6,737,130
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**	**50,695,587**	**43,774,124**	**45,782,012**	**43,230,402**	**49,779,897**	**57,109,514**	**58,903,412**	**60,199,609**	**57,460,853**	**48,968,277**	**40,082,248**	**42,812,516**	**598,798,451**
11.	Jurisdictional MWH Sold	1,484,835	1,360,586	1,350,140	1,437,866	1,599,548	1,857,040	1,948,278	1,942,542	2,005,956	1,835,903	1,536,267	1,448,380	19,807,340
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)	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
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)	**50,695,587**	**43,774,124**	**45,782,012**	**43,230,402**	**49,779,897**	**57,109,514**	**58,903,412**	**60,199,609**	**57,460,853**	**48,968,277**	**40,082,248**	**42,812,516**	**598,798,451**
16.	Cost Per kWh Sold (Cents/kWh)	3.4142	3.2173	3.3909	3.0066	3.1121	3.0753	3.0234	3.0990	2.8645	2.6673	2.6091	2.9559	3.0231
17.	Optimization Mechanism (Cents/kWh)[2]	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065
18.	True-up (Cents/kWh) [2]	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
19.	Total (Cents/kWh) (Line 16+17+18)	3.4223	3.2254	3.3990	3.0147	3.1202	3.0834	3.0315	3.1071	2.8726	2.6754	2.6172	2.9640	3.0312
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)	3.4248	3.2277	3.4014	3.0169	3.1224	3.0856	3.0337	3.1093	2.8747	2.6773	2.6191	2.9661	3.0334
22.	GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186
23.	**TOTAL RECOVERY FACTOR (LINE 21+22)**	**3.4434**	**3.2463**	**3.4200**	**3.0355**	**3.1410**	**3.1042**	**3.0523**	**3.1279**	**2.8933**	**2.6959**	**2.6377**	**2.9847**	**3.0520**
24.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.443**	**3.246**	**3.420**	**3.036**	**3.141**	**3.104**	**3.052**	**3.128**	**2.893**	**2.696**	**2.638**	**2.985**	**3.052**

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

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TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022

SCHEDULE E3

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	91,149	90,787	90,425	90,061	89,697	89,332
3. COAL	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
4. NATURAL GAS	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**50,628,655**	**43,712,330**	**45,704,776**	**43,168,114**	**49,710,665**	**56,554,931**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300
10. COAL	136,740	118,250	106,710	92,550	136,640	144,780
11. NATURAL GAS	1,242,630	1,086,820	1,214,550	1,278,940	1,470,280	1,643,510
12. SOLAR	127,340	142,060	175,360	218,220	240,250	206,030
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,507,010**	**1,347,430**	**1,496,920**	**1,590,010**	**1,847,470**	**1,994,620**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665
17. COAL (TON)	72,550	63,500	57,140	50,210	73,110	75,560
18. NATURAL GAS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
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	3,900	3,900	3,900	3,900	3,900	3,900
23. COAL	1,632,410	1,428,790	1,285,690	1,129,690	1,644,990	1,700,000
24. NATURAL GAS	9,112,610	7,990,500	8,973,090	9,437,680	10,826,040	12,738,500
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,748,920**	**9,423,190**	**10,262,680**	**10,571,270**	**12,474,930**	**14,442,400**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.02	0.02
30. COAL	9.07	8.78	7.13	5.82	7.40	7.25
31. NATURAL GAS	82.46	80.66	81.14	80.44	79.58	82.40
32. SOLAR	8.45	10.54	11.71	13.72	13.00	10.33
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)	137.07	136.52	135.98	135.43	134.88	134.33
37. COAL ($/TON)	62.11	62.83	62.33	63.25	62.52	62.61
38. NATURAL GAS ($/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.37	23.28	23.19	23.09	23.00	22.91
43. COAL	2.76	2.79	2.77	2.81	2.78	2.78
44. NATURAL GAS	5.05	4.96	4.69	4.23	4.16	4.06
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.71**	**4.64**	**4.45**	**4.08**	**3.98**	**3.92**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	11,938	12,083	12,048	12,206	12,039	11,742
51. NATURAL GAS	7,333	7,352	7,388	7,379	7,363	7,751
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,133**	**6,993**	**6,856**	**6,649**	**6,752**	**7,241**
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	30.38	30.26	30.14	30.02	29.90	29.78
57. COAL	3.30	3.37	3.34	3.43	3.35	3.27
58. NATURAL GAS	3.70	3.65	3.46	3.12	3.06	3.15
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)	**3.36**	**3.24**	**3.05**	**2.71**	**2.69**	**2.84**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

SCHEDULE E3

		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
3.	COAL	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
4.	NATURAL GAS	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**58,231,044**	**59,752,774**	**53,251,426**	**47,781,768**	**39,999,180**	**42,748,708**	**591,244,371**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	300	300	300	300	300	300	3,600
10.	COAL	154,270	158,760	154,310	15,880	114,030	130,860	1,463,780
11.	NATURAL GAS	1,719,190	1,762,600	1,604,070	1,634,990	1,232,580	1,265,350	17,155,510
12.	SOLAR	200,630	193,910	167,470	166,660	129,810	137,440	2,105,180
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,074,390**	**2,115,570**	**1,926,150**	**1,817,830**	**1,476,720**	**1,533,950**	**20,728,070**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	665	665	665	665	665	665	7,980
17.	COAL (TON)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
18.	NATURAL GAS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
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	3,900	3,900	3,900	3,900	3,900	3,900	46,800
23.	COAL	1,797,510	1,836,030	1,782,840	182,090	1,405,660	1,581,590	17,407,290
24.	NATURAL GAS	13,015,500	13,496,970	11,842,940	11,543,620	8,350,810	8,638,150	125,966,410
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**14,816,910**	**15,336,900**	**13,629,680**	**11,729,610**	**9,760,370**	**10,223,640**	**143,420,500**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.02	0.02	0.02	0.02	0.02
30.	COAL	7.44	7.50	8.01	0.87	7.72	8.53	7.06
31.	NATURAL GAS	82.88	83.32	83.28	89.94	83.47	82.49	82.76
32.	SOLAR	9.67	9.17	8.69	9.17	8.79	8.96	10.16
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)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
37.	COAL ($/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
38.	NATURAL GAS ($/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
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 ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	22.81	22.72	22.63	22.54	22.46	22.37	22.86
43.	COAL	2.79	2.79	2.79	2.80	2.80	2.80	2.79
44.	NATURAL GAS	4.08	4.04	4.07	4.09	4.31	4.43	4.30
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.93**	**3.90**	**3.91**	**4.07**	**4.10**	**4.18**	**4.12**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,000
50.	COAL	11,652	11,565	11,554	11,467	12,327	12,086	11,892
51.	NATURAL GAS	7,571	7,657	7,383	7,060	6,775	6,827	7,343
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,143**	**7,250**	**7,076**	**6,453**	**6,609**	**6,665**	**6,919**
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	29.66	29.54	29.42	29.31	29.19	29.08	29.72
57.	COAL	3.25	3.23	3.23	3.21	3.45	3.38	3.31
58.	NATURAL GAS	3.09	3.09	3.00	2.89	2.92	3.02	3.16
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)**	**2.81**	**2.82**	**2.76**	**2.63**	**2.71**	**2.79**	**2.85**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(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	2,860	256.3	-	256.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,780	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,120	18.3	-	18.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,290	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,380	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,670	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,430	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,470	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,490	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,240	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,590	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,480.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,320.0	13.2	-	13.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,380.0	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,380.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	(3) **878.0**	**127,340**	**19.5**	**-**	**19.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	355	13,490	5.1	-	-	-	GAS	155,170	1,027,969	159,510.0	805,129	5.97	5.19
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**355**	**13,490**	**5.1**	**82.1**	**52.8**	**11,824**		**-**	**-**	**159,510.0**	**805,129**	**5.97**	**-**
24. B.B.#4 (GAS)	160	7,200	6.0	-	-	-	GAS	83,580	1,027,997	85,920.0	433,670	6.02	5.19
25. B.B.#4 (COAL)	432	136,740	42.5	-	-	-	COAL	72,550	22,500,482	1,632,410.0	4,505,889	3.30	62.11
26. BIG BEND #4 TOTAL	**432**	**143,940**	**44.8**	**89.3**	**48.9**	**11,938**		**-**	**-**	**1,718,330.0**	**4,939,559**	**3.43**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,840	-	5.19
28. B.B.C.T.#4 TOTAL	**61**	**70**	**0.2**	**98.3**	**57.4**	**13,000**	**GAS**	**890**	**1,022,472**	**910.0**	**4,618**	**6.60**	**5.19**
29. B.B.C.T.#5 TOTAL	**350**	**7,140**	**2.7**	**96.0**	**63.8**	**9,821**	**GAS**	**68,210**	**1,028,002**	**70,120.0**	**353,920**	**4.96**	**5.19**
30. B.B.C.T.#6 TOTAL	**350**	**3,250**	**1.2**	**96.1**	**58.0**	**9,966**	**GAS**	**31,520**	**1,027,602**	**32,390.0**	**163,547**	**5.03**	**5.19**
31. BIG BEND STATION TOTAL	**1,898**	**167,890**	**11.9**	**74.3**	**49.8**	**11,801**	**-**	**-**	**-**	**1,981,260.0**	**6,303,613**	**3.75**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	5,380	3.1	-	73.1	8,959	GAS	46,880	1,028,157	48,200.0	243,246	4.52	5.19
34. POLK #1 TOTAL	**230**	**5,380**	**3.1**	**93.8**	**73.1**	**8,959**	**-**	**-**	**-**	**48,200.0**	**243,246**	**4.52**	**-**
35. POLK #2 ST DUCT FIRING	120	2,040	2.3	-	85.0	8,157	GAS	16,190	1,027,795	16,640.0	84,005	4.12	5.19
36. POLK #2 ST W/O DUCT FIRING	360	623,040	-	-	-	-		4,198,315	1,028,003	4,315,880.0	21,783,742	3.50	5.19
37. POLK #2 ST TOTAL	**480**	**625,080**	**175.0**	**-**	**173.6**	**6,931**	**GAS**	**-**	**-**	**4,332,520.0**	**21,867,747**	**3.50**	**-**
38. POLK #2 CT (GAS)	180	930	0.7	-	64.6	11,591	GAS	10,490	1,027,645	10,780.0	54,429	5.85	5.19
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,643	30.43	137.07
40. POLK #2 TOTAL	(4) **180**	**1,080**	**0.8**	**-**	**66.4**	**11,787**	**-**	**-**	**-**	**12,730.0**	**100,072**	**9.27**	**-**
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,506	30.34	137.07
43. POLK #3 TOTAL	(4) **180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**45,506**	**30.34**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
45. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,200**	**626,310**	**70.2**	**97.4**	**172.2**	**6,941**	**-**	**-**	**-**	**4,347,200.0**	**22,013,325**	**3.51**	**-**
47. POLK STATION TOTAL	**1,430**	**631,690**	**59.4**	**96.8**	**168.2**	**6,958**	**-**	**-**	**-**	**4,395,400.0**	**22,256,571**	**3.52**	**-**
48. BAYSIDE #1	792	343,790	58.3	96.6	61.1	7,309	GAS	2,444,440	1,027,994	2,512,870.0	12,683,434	3.69	5.19
49. BAYSIDE #2	1,047	235,990	30.3	97.3	32.7	7,863	GAS	1,805,030	1,027,994	1,855,560.0	9,365,737	3.97	5.19
50. BAYSIDE #3	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
51. BAYSIDE #4	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
52. BAYSIDE #5	61	70	0.2	98.6	57.4	13,714	GAS	930	1,032,258	960.0	4,825	6.89	5.19
53. BAYSIDE #6	61	80	0.2	98.6	65.6	11,875	GAS	930	1,021,505	950.0	4,825	6.03	5.19
54. BAYSIDE STATION TOTAL	**2,083**	**580,090**	**37.4**	**97.2**	**45.1**	**7,537**	**GAS**	**4,253,190**	**1,027,995**	**4,372,260.0**	**22,068,471**	**3.80**	**5.19**
55. SYSTEM TOTAL	**6,289**	**1,507,010**	**32.2**	**76.6**	**79.5**	**7,133**	**-**	**-**	**-**	**10,748,920.0**	**50,628,655**	**3.36**	**-**

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

DOCKET NO. 20210001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 11 OF 42

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(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	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,030	300.6	-	300.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,280	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,710	23.5	-	23.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,060	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	9,310	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	8,520	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,790	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	7,460	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	12,120	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,960	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,920	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,020.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,450.0	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	11,990.0	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,990.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**142,060**	**24.1**	**-**	**24.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	355	13,500	5.7	-	-	-	GAS	155,270	1,028,016	159,620.0	790,955	5.86	5.09
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**355**	**13,500**	**5.7**	**48.5**	**52.8**	**11,824**		**-**	**-**	**159,620.0**	**790,955**	**5.86**	**-**
24. B.B.#4 (GAS)	160	6,230	5.8	-	-	-	GAS	73,150	1,027,888	75,190.0	372,630	5.98	5.09
25. B.B.#4 (COAL)	432	118,250	40.7	-	-	-	COAL	63,500	22,500,630	1,428,790.0	3,989,914	3.37	62.83
26. BIG BEND #4 TOTAL	**432**	**124,480**	**42.9**	**89.3**	**46.8**	**12,082**		**-**	**-**	**1,503,980.0**	**4,362,544**	**3.50**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,168	-	5.09
28. B.B.C.T.#4 TOTAL	**61**	**10**	**0.0**	**98.3**	**16.4**	**24,000**	**GAS**	**230**	**1,043,478**	**240.0**	**1,172**	**11.72**	**5.10**
29. B.B.C.T.#5 TOTAL	**350**	**5,190**	**2.2**	**94.9**	**51.1**	**10,023**	**GAS**	**50,610**	**1,027,860**	**52,020.0**	**257,811**	**4.97**	**5.09**
30. B.B.C.T.#6 TOTAL	**350**	**1,540**	**0.7**	**96.1**	**55.0**	**9,766**	**GAS**	**14,630**	**1,028,025**	**15,040.0**	**74,526**	**4.84**	**5.09**
31. BIG BEND STATION TOTAL	**1,898**	**144,720**	**11.3**	**67.8**	**47.5**	**11,960**	**-**	**-**	**-**	**1,730,900.0**	**5,523,176**	**3.82**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	8,230	5.3	-	74.5	8,898	GAS	71,230	1,028,078	73,230.0	362,850	4.41	5.09
34. POLK #1 TOTAL	**230**	**8,230**	**5.3**	**93.8**	**74.5**	**8,898**	**-**	**-**	**-**	**73,230.0**	**362,850**	**4.41**	**-**
35. POLK #2 ST DUCT FIRING	120	2,260	2.8	-	75.3	8,190	GAS	18,000	1,028,333	18,510.0	91,693	4.06	5.09
36. POLK #2 ST W/O DUCT FIRING	360	555,510	-	-	-	-		3,742,155	1,028,001	3,846,940.0	19,062,772	3.43	5.09
37. POLK #2 ST TOTAL	**480**	**557,770**	**172.9**	**-**	**172.4**	**6,930**	**GAS**	**-**	**-**	**3,865,450.0**	**19,154,465**	**3.43**	**-**
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,462	30.31	136.52
40. POLK #2 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**45,462**	**30.31**	**-**
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,325	30.22	136.52
43. POLK #3 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**45,325**	**30.22**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(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)
44. POLK #4 CT (GAS) TOTAL [(4)]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
45. POLK #5 CT (GAS) TOTAL [(4)]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,200**	**558,070**	**69.2**	**97.4**	**172.1**	**6,933**	**-**	**-**	**-**	**3,869,350.0**	**19,245,252**	**3.45**	**-**
47. POLK STATION TOTAL	**1,430**	**566,300**	**58.9**	**96.8**	**165.7**	**6,962**	**-**	**-**	**-**	**3,942,580.0**	**19,608,102**	**3.46**	**-**
48. BAYSIDE #1	792	276,720	52.0	96.6	56.4	7,348	GAS	1,978,040	1,028,002	2,033,430.0	10,076,260	3.64	5.09
49. BAYSIDE #2	1,047	217,230	30.9	97.3	32.2	7,879	GAS	1,664,970	1,027,994	1,711,580.0	8,481,462	3.90	5.09
50. BAYSIDE #3	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
51. BAYSIDE #4	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
52. BAYSIDE #5	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
53. BAYSIDE #6	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
54. BAYSIDE STATION TOTAL	**2,083**	**494,350**	**35.3**	**97.2**	**42.4**	**7,585**	**GAS**	**3,647,590**	**1,027,997**	**3,749,710.0**	**18,581,052**	**3.76**	**5.09**
55. SYSTEM TOTAL	**6,289**	**1,347,430**	**31.9**	**74.7**	**78.4**	**6,993**	**-**	**-**	**-**	**9,423,190.0**	**43,712,330**	**3.24**	**-**

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: MARCH 2022

(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	4,060	364.3	-	364.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,260	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,750	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,290	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,050	24.5	-	24.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,120	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,280	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,770	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,460	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,640	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,720.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	9,900.0	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,060.0	36.2	-	36.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,060.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**175,360**	**26.9**	**-**	**26.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	355	13,510	5.1	-	-	-	GAS	155,390	1,027,994	159,740.0	748,099	5.54	4.81
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**400**	**13,510**	**4.5**	**82.1**	**46.9**	**11,824**		**-**	**-**	**159,740.0**	**748,099**	**5.54**	**-**
24. B.B.#4 (GAS)	160	5,620	4.7	-	-	-	GAS	65,820	1,028,107	67,670.0	316,879	5.64	4.81
25. B.B.#4 (COAL)	432	106,710	33.2	-	-	-	COAL	57,140	22,500,700	1,285,690.0	3,561,514	3.34	62.33
26. BIG BEND #4 TOTAL	**432**	**112,330**	**35.0**	**72.0**	**47.3**	**12,048**		**-**	**-**	**1,353,360.0**	**3,878,393**	**3.45**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	30,138	-	4.81
28. B.B.C.T.#4 TOTAL	**61**	**10**	**0.0**	**98.3**	**16.4**	**29,000**	**GAS**	**280**	**1,035,714**	**290.0**	**1,348**	**13.48**	**4.81**
29. B.B.C.T.#5 TOTAL	**350**	**9,720**	**3.7**	**96.9**	**56.7**	**9,894**	**GAS**	**93,550**	**1,028,006**	**96,170.0**	**450,380**	**4.63**	**4.81**
30. B.B.C.T.#6 TOTAL	**350**	**4,030**	**1.5**	**96.1**	**52.3**	**10,050**	**GAS**	**39,390**	**1,028,180**	**40,500.0**	**189,636**	**4.71**	**4.81**
31. BIG BEND STATION TOTAL	**1,943**	**139,600**	**9.7**	**70.7**	**47.9**	**11,820**	**-**	**-**	**-**	**1,650,060.0**	**5,297,994**	**3.80**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	25,040	14.7	-	73.6	8,919	GAS	217,260	1,027,985	223,340.0	1,045,961	4.18	4.81
34. POLK #1 TOTAL	**230**	**25,040**	**14.7**	**93.8**	**73.6**	**8,919**	**-**	**-**	**-**	**223,340.0**	**1,045,961**	**4.18**	**-**
35. POLK #2 ST DUCT FIRING	120	3,610	4.0	-	79.2	8,163	GAS	28,670	1,027,904	29,470.0	138,027	3.82	4.81
36. POLK #2 ST W/O DUCT FIRING	360	510,580	-	-	-	-		3,440,515	1,028,003	3,536,860.0	16,563,765	3.24	4.81
37. POLK #2 ST TOTAL	**480**	**514,190**	**144.2**	**-**	**166.3**	**6,936**	**GAS**	**-**	**-**	**3,566,330.0**	**16,701,792**	**3.25**	**-**
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,281	30.19	135.98
40. POLK #2 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**45,281**	**30.19**	**-**
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,144	30.10	135.98
43. POLK #3 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**45,144**	**30.10**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
45. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,200**	**514,490**	**57.7**	**81.7**	**166.1**	**6,939**	**-**	**-**	**-**	**3,570,230.0**	**16,792,217**	**3.26**	**-**
47. POLK STATION TOTAL	**1,430**	**539,530**	**50.8**	**83.7**	**148.8**	**7,031**	**-**	**-**	**-**	**3,793,570.0**	**17,838,178**	**3.31**	**-**
48. BAYSIDE #1	792	345,880	58.8	96.6	60.8	7,316	GAS	2,461,540	1,027,999	2,530,460.0	11,850,659	3.43	4.81
49. BAYSIDE #2	1,047	296,530	38.1	97.3	39.2	7,716	GAS	2,225,700	1,027,996	2,288,010.0	10,715,249	3.61	4.81
50. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
51. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
52. BAYSIDE #5	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
53. BAYSIDE #6	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
54. BAYSIDE STATION TOTAL	**2,083**	**642,430**	**41.5**	**91.4**	**48.5**	**7,501**	**GAS**	**4,687,800**	**1,027,998**	**4,819,050.0**	**22,568,604**	**3.51**	**4.81**
55. SYSTEM TOTAL	**6,334**	**1,496,920**	**31.8**	**70.6**	**79.9**	**6,856**	**-**	**-**	**-**	**10,262,680.0**	**45,704,776**	**3.05**	**-**

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: APRIL 2022

(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	4,620	427.8	-	427.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,310	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	18,040	33.8	-	33.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,530	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,530	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	13,270	33.6	-	33.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,200	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,550	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	18,700	34.8	-	34.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,600	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,160	35.2	-	35.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,190.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	13,000.0	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	18,450.0	49.0	-	49.0	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	18,450.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**218,220**	**34.5**	**-**	**34.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
24. B.B.#4 (GAS)	155	4,870	4.4	-	-	-	GAS	57,840	1,028,008	59,460.0	251,201	5.16	4.34
25. B.B.#4 (COAL)	422	92,550	30.5	-	-	-	COAL	50,210	22,499,303	1,129,690.0	3,175,693	3.43	63.25
26. BIG BEND #4 TOTAL	**422**	**97,420**	**32.1**	**65.5**	**47.7**	**12,206**		**-**	**-**	**1,189,150.0**	**3,426,894**	**3.52**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,026,761	7,290.0	30,835	-	4.34
28. B.B.C.T.#4 TOTAL	**56**	**0**	**0.0**	**78.6**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
29. B.B.C.T.#5 TOTAL	**330**	**32,340**	**13.6**	**95.9**	**100.0**	**9,428**	**GAS**	**296,590**	**1,027,985**	**304,890.0**	**1,288,095**	**3.98**	**4.34**
30. B.B.C.T.#6 TOTAL	**330**	**7,960**	**3.4**	**96.1**	**56.1**	**9,922**	**GAS**	**76,830**	**1,027,984**	**78,980.0**	**333,674**	**4.19**	**4.34**
31. BIG BEND STATION TOTAL	**1,823**	**137,720**	**10.5**	**67.8**	**54.9**	**11,422**	**-**	**-**	**-**	**1,573,020.0**	**5,079,498**	**3.69**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	15,840	10.5	-	80.2	8,912	GAS	137,310	1,028,039	141,160.0	596,340	3.76	4.34
34. POLK #1 TOTAL	**220**	**15,840**	**10.0**	**93.8**	**80.2**	**8,912**	**-**	**-**	**-**	**141,160.0**	**596,340**	**3.76**	**-**
35. POLK #2 ST DUCT FIRING	120	6,900	8.0	-	62.5	8,280	GAS	55,570	1,028,073	57,130.0	241,341	3.50	4.34
36. POLK #2 ST W/O DUCT FIRING	341	528,880	-	-	-	-		3,557,535	1,028,001	3,657,150.0	15,450,435	2.92	4.34
37. POLK #2 ST TOTAL	**461**	**535,780**	**161.4**	**-**	**144.9**	**6,932**	**GAS**	**-**	**-**	**3,714,280.0**	**15,691,776**	**2.93**	**-**
38. POLK #2 CT (GAS)	150	1,010	0.9	-	96.2	10,822	GAS	10,640	1,027,256	10,930.0	46,210	4.58	4.34
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	45,098	30.07	135.43
40. POLK #2 TOTAL (4)	**150**	**1,160**	**1.1**	**-**	**95.9**	**11,103**	**-**	**-**	**-**	**12,880.0**	**91,308**	**7.87**	**-**
41. POLK #3 CT (GAS)	150	860	0.8	-	95.6	10,756	GAS	8,990	1,028,921	9,250.0	39,044	4.54	4.34
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,963	29.98	135.43
43. POLK #3 TOTAL (4)	**150**	**1,010**	**0.9**	**-**	**95.4**	**11,089**	**-**	**-**	**-**	**11,200.0**	**84,007**	**8.32**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**860**	**0.8**	**-**	**95.6**	**10,849**	**GAS**	**9,070**	**1,028,666**	**9,330.0**	**39,391**	**4.58**	**4.34**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,061**	**538,810**	**70.5**	**97.4**	**143.7**	**6,955**	**-**	**-**	**-**	**3,747,690.0**	**15,906,482**	**2.95**	**-**
47. POLK STATION TOTAL	**1,281**	**554,650**	**60.1**	**96.8**	**137.2**	**7,011**	**-**	**-**	**-**	**3,888,850.0**	**16,502,822**	**2.98**	**-**
48. BAYSIDE #1	720	353,440	68.2	96.6	70.6	7,372	GAS	2,534,590	1,027,997	2,605,550.0	11,007,768	3.11	4.34
49. BAYSIDE #2	954	324,850	47.3	51.9	48.6	7,666	GAS	2,422,490	1,028,000	2,490,320.0	10,520,915	3.24	4.34
50. BAYSIDE #3	56	290	0.7	98.6	86.3	12,103	GAS	3,400	1,032,353	3,510.0	14,766	5.09	4.34
51. BAYSIDE #4	56	170	0.4	78.9	101.2	11,765	GAS	1,950	1,025,641	2,000.0	8,469	4.98	4.34
52. BAYSIDE #5	56	290	0.7	78.9	86.3	11,862	GAS	3,340	1,029,940	3,440.0	14,506	5.00	4.34
53. BAYSIDE #6	56	380	0.9	78.9	84.8	12,053	GAS	4,460	1,026,906	4,580.0	19,370	5.10	4.34
54. BAYSIDE STATION TOTAL	**1,898**	**679,420**	**49.7**	**72.6**	**58.1**	**7,520**	**GAS**	**4,970,230**	**1,028,001**	**5,109,400.0**	**21,585,794**	**3.18**	**4.34**
55. SYSTEM TOTAL	**5,880**	**1,590,010**	**37.6**	**65.6**	**93.7**	**6,649**	**-**	**-**	**-**	**10,571,270.0**	**43,168,114**	**2.71**	**-**

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

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(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	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,990	447.1	-	447.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,440	37.3	-	37.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,230	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,350	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	16,270	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	14,840	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	10,020	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	12,910	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	20,170	36.3	-	36.3	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,410	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	17,040	38.3	-	38.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,940.0	37.5	-	37.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	14,580.0	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	20,700.0	53.2	-	53.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	20,700.0	37.4	-	37.4	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**240,250**	**36.8**	**-**	**36.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**395**	**0**	**0.0**	**82.1**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
24. B.B.#4 (GAS)	155	7,190	6.2	-	-	-	GAS	84,220	1,028,022	86,580.0	360,201	5.01	4.28
25. B.B.#4 (COAL)	422	136,640	43.5	-	-	-	COAL	73,110	22,500,205	1,644,990.0	4,571,140	3.35	62.52
26. BIG BEND #4 TOTAL	**422**	**143,830**	**45.8**	**89.3**	**50.0**	**12,039**		**-**	**-**	**1,731,570.0**	**4,931,341**	**3.43**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	2,090	1,028,708	2,150.0	8,939	-	4.28
28. B.B.C.T.#4 TOTAL	**56**	**10**	**0.0**	**98.3**	**17.9**	**31,000**	**GAS**	**300**	**1,033,333**	**310.0**	**1,283**	**12.83**	**4.28**
29. B.B.C.T.#5 TOTAL	**330**	**41,580**	**16.9**	**96.9**	**100.0**	**9,424**	**GAS**	**381,160**	**1,027,993**	**391,830.0**	**1,630,189**	**3.92**	**4.28**
30. B.B.C.T.#6 TOTAL	**330**	**11,420**	**4.7**	**96.1**	**58.7**	**9,789**	**GAS**	**108,740**	**1,028,049**	**111,790.0**	**465,072**	**4.07**	**4.28**
31. BIG BEND STATION TOTAL	**1,873**	**196,840**	**14.1**	**74.4**	**56.4**	**11,357**	**-**	**-**	**-**	**2,235,500.0**	**7,036,824**	**3.57**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	6,550	4.2	-	86.6	8,777	GAS	55,920	1,028,076	57,490.0	239,165	3.65	4.28
34. POLK #1 TOTAL	**220**	**6,550**	**4.0**	**72.6**	**86.6**	**8,777**	**-**	**-**	**-**	**57,490.0**	**239,165**	**3.65**	**-**
35. POLK #2 ST DUCT FIRING	120	18,460	20.7	-	77.3	8,274	GAS	148,580	1,027,998	152,740.0	635,464	3.44	4.28
36. POLK #2 ST W/O DUCT FIRING	341	600,860	-	-	-	-		4,040,365	1,028,001	4,153,500.0	17,280,294	2.88	4.28
37. POLK #2 ST TOTAL	**461**	**619,320**	**180.6**	**-**	**144.0**	**6,953**	**GAS**	**-**	**-**	**4,306,240.0**	**17,915,758**	**2.89**	**-**
38. POLK #2 CT (GAS)	150	1,350	1.2	-	100.0	10,674	GAS	14,020	1,027,817	14,410.0	59,963	4.44	4.28
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,916	29.94	134.88
40. POLK #2 TOTAL (4)	**150**	**1,500**	**1.3**	**-**	**99.4**	**10,907**	**-**	**-**	**-**	**16,360.0**	**104,879**	**6.99**	**-**
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,742	GAS	12,550	1,027,092	12,890.0	53,675	4.47	4.28
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,781	29.85	134.88
43. POLK #3 TOTAL (4)	**150**	**1,350**	**1.2**	**-**	**99.3**	**10,993**	**-**	**-**	**-**	**14,840.0**	**98,456**	**7.29**	**-**

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DOCKET NO. 20210001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 18 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**600**	**0.5**	**-**	**100.0**	**10,767**	**GAS**	**6,280**	**1,028,662**	**6,460.0**	**26,859**	**4.48**	**4.28**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,061**	**622,770**	**78.9**	**97.4**	**142.9**	**6,975**	**-**	**-**	**-**	**4,343,900.0**	**18,145,952**	**2.91**	**-**
47. POLK STATION TOTAL	**1,281**	**629,320**	**66.0**	**93.2**	**140.9**	**6,994**	**-**	**-**	**-**	**4,401,390.0**	**18,385,117**	**2.92**	**-**
48. BAYSIDE #1	720	391,490	73.1	96.6	75.5	7,345	GAS	2,797,030	1,028,001	2,875,350.0	11,962,657	3.06	4.28
49. BAYSIDE #2	954	384,720	54.2	97.3	57.7	7,552	GAS	2,826,390	1,028,000	2,905,530.0	12,088,227	3.14	4.28
50. BAYSIDE #3	56	1,310	3.1	98.6	86.6	11,771	GAS	15,000	1,028,000	15,420.0	64,154	4.90	4.28
51. BAYSIDE #4	56	630	1.5	98.6	93.8	11,841	GAS	7,250	1,028,966	7,460.0	31,008	4.92	4.28
52. BAYSIDE #5	56	1,590	3.8	98.6	86.0	11,748	GAS	18,180	1,027,503	18,680.0	77,754	4.89	4.28
53. BAYSIDE #6	56	1,320	3.2	79.5	87.3	11,818	GAS	15,180	1,027,668	15,600.0	64,924	4.92	4.28
54. BAYSIDE STATION TOTAL	**1,898**	**781,060**	**55.3**	**96.6**	**65.6**	**7,475**	**GAS**	**5,679,030**	**1,027,999**	**5,838,040.0**	**24,288,724**	**3.11**	**4.28**
55. SYSTEM TOTAL	**5,930**	**1,847,470**	**41.9**	**74.5**	**101.2**	**6,752**	**-**	**-**	**-**	**12,474,930.0**	**49,710,665**	**2.69**	**-**

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

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

DOCKET NO. 20210001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 19 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(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	4,420	409.3	-	409.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,790	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,430	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,440	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,020	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,800	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,680	32.2	-	32.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,120	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,570	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,510	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,740	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,950.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,500.0	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,740.0	47.1	-	47.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,740.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**206,030**	**32.6**	**-**	**32.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	51,360	20.7	-	-	-	GAS	582,810	1,027,985	599,120.0	2,429,064	4.73	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**51,360**	**20.7**	**82.1**	**60.0**	**11,665**		**-**	**-**	**599,120.0**	**2,429,064**	**4.73**	**-**
24. B.B.#4 (GAS)	155	7,620	6.8	-	-	-	GAS	87,040	1,027,918	89,470.0	362,770	4.76	4.17
25. B.B.#4 (COAL)	422	144,780	47.7	-	-	-	COAL	75,560	22,498,677	1,700,000.0	4,730,807	3.27	62.61
26. BIG BEND #4 TOTAL	**422**	**152,400**	**50.2**	**89.3**	**54.7**	**11,742**		**-**	**-**	**1,789,470.0**	**5,093,577**	**3.34**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,290	1,028,182	21,890.0	88,734	-	4.17
28. B.B.C.T.#4 TOTAL	**56**	**2,150**	**5.3**	**98.3**	**85.3**	**11,795**	**GAS**	**24,660**	**1,028,386**	**25,360.0**	**102,779**	**4.78**	**4.17**
29. B.B.C.T.#5 TOTAL	**330**	**52,070**	**21.9**	**96.9**	**22.3**	**11,751**	**GAS**	**595,240**	**1,027,989**	**611,900.0**	**2,480,871**	**4.76**	**4.17**
30. B.B.C.T.#6 TOTAL	**330**	**12,960**	**5.5**	**96.1**	**5.6**	**19,951**	**GAS**	**251,520**	**1,027,990**	**258,560.0**	**1,048,298**	**8.09**	**4.17**
31. BIG BEND STATION TOTAL	**1,823**	**270,940**	**20.6**	**74.1**	**32.5**	**12,122**	**-**	**-**	**-**	**3,284,410.0**	**11,243,323**	**4.15**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	59,650	39.5	-	87.1	8,781	GAS	509,530	1,028,006	523,800.0	2,123,645	3.56	4.17
34. POLK #1 TOTAL	**220**	**59,650**	**37.7**	**93.8**	**87.1**	**8,781**	**-**	**-**	**-**	**523,800.0**	**2,123,645**	**3.56**	**-**
35. POLK #2 ST DUCT FIRING	120	27,910	32.3	-	92.3	8,275	GAS	224,670	1,027,997	230,960.0	936,391	3.36	4.17
36. POLK #2 ST W/O DUCT FIRING	341	594,750	-	-	-	-		3,998,515	1,028,004	4,110,490.0	16,665,211	2.80	4.17
37. POLK #2 ST TOTAL	**461**	**622,660**	**187.6**	**-**	**141.0**	**6,972**	**GAS**	**-**	**-**	**4,341,450.0**	**17,601,602**	**2.83**	**-**
38. POLK #2 CT (GAS)	150	300	0.3	-	100.0	10,733	GAS	3,130	1,028,754	3,220.0	13,044	4.35	4.17
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,733	29.82	134.33
40. POLK #2 TOTAL (4)	**150**	**450**	**0.4**	**-**	**98.0**	**11,489**	**-**	**-**	**-**	**5,170.0**	**57,777**	**12.84**	**-**
41. POLK #3 CT (GAS)	150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	13,379	4.46	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,599	29.73	134.33
43. POLK #3 TOTAL (4)	**150**	**450**	**0.4**	**-**	**98.0**	**11,667**	**-**	**-**	**-**	**5,250.0**	**57,978**	**12.88**	**-**

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**300**	**0.3**	**-**	**100.0**	**11,000**	**GAS**	**3,210**	**1,028,037**	**3,300.0**	**13,379**	**4.46**	**4.17**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,061**	**623,860**	**81.7**	**97.4**	**140.6**	**6,981**	**-**	**-**	**-**	**4,355,170.0**	**17,730,736**	**2.84**	**-**
47. POLK STATION TOTAL	**1,281**	**683,510**	**74.1**	**96.8**	**127.1**	**7,138**	**-**	**-**	**-**	**4,878,970.0**	**19,854,381**	**2.90**	**-**
48. BAYSIDE #1	720	396,130	76.4	96.6	79.0	7,325	GAS	2,822,700	1,027,998	2,901,730.0	11,764,590	2.97	4.17
49. BAYSIDE #2	954	416,000	60.6	97.3	63.0	7,501	GAS	3,035,300	1,027,997	3,120,280.0	12,650,675	3.04	4.17
50. BAYSIDE #3	56	5,410	13.4	98.6	89.5	11,603	GAS	61,050	1,028,174	62,770.0	254,447	4.70	4.17
51. BAYSIDE #4	56	4,370	10.8	98.6	89.7	11,643	GAS	49,500	1,027,879	50,880.0	206,309	4.72	4.17
52. BAYSIDE #5	56	6,820	16.9	98.6	85.8	11,729	GAS	77,810	1,028,017	79,990.0	324,300	4.76	4.17
53. BAYSIDE #6	56	5,410	13.4	98.6	86.3	11,713	GAS	61,640	1,028,066	63,370.0	256,906	4.75	4.17
54. BAYSIDE STATION TOTAL	**1,898**	**834,140**	**61.0**	**97.2**	**70.3**	**7,528**	**GAS**	**6,108,000**	**1,027,999**	**6,279,020.0**	**25,457,227**	**3.05**	**4.17**
55. SYSTEM TOTAL	**5,880**	**1,994,620**	**47.1**	**75.4**	**84.4**	**7,241**	**-**	**-**	**-**	**14,442,400.0**	**56,554,931**	**2.84**	**-**

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

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

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(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	4,270	382.6	-	382.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,270	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,880	30.6	-	30.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,240	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,590	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,410	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,460	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,760	29.3	-	29.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,330	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,300	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,280	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,770.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,110.0	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,190.0	44.2	-	44.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,190.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**200,630**	**30.7**	**-**	**30.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	50,200	19.6	-	-	-	GAS	580,440	1,027,996	596,690.0	2,432,654	4.85	4.19
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**50,200**	**19.6**	**82.1**	**55.1**	**11,886**		**-**	**-**	**596,690.0**	**2,432,654**	**4.85**	**-**
24. B.B.#4 (GAS)	155	8,120	7.0	-	-	-	GAS	92,030	1,028,034	94,610.0	385,702	4.75	4.19
25. B.B.#4 (COAL)	422	154,270	49.1	-	-	-	COAL	79,890	22,499,812	1,797,510.0	5,010,894	3.25	62.72
26. BIG BEND #4 TOTAL	**422**	**162,390**	**51.7**	**89.3**	**56.4**	**11,652**		**-**	**-**	**1,892,120.0**	**5,396,596**	**3.32**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	16,280	1,028,256	16,740.0	68,230	-	4.19
28. B.B.C.T.#4 TOTAL	**56**	**2,830**	**6.8**	**98.3**	**76.6**	**12,155**	**GAS**	**33,460**	**1,028,093**	**34,400.0**	**140,233**	**4.96**	**4.19**
29. B.B.C.T.#5 TOTAL	**330**	**57,960**	**23.6**	**96.9**	**24.1**	**9,101**	**GAS**	**513,150**	**1,028,004**	**527,520.0**	**2,150,637**	**3.71**	**4.19**
30. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**80**	**1,000,000**	**80.0**	**335**	**0.00**	**4.19**
31. BIG BEND STATION TOTAL	**1,823**	**273,380**	**20.2**	**74.1**	**31.6**	**11,160**	**-**	**-**	**-**	**3,050,810.0**	**10,188,685**	**3.73**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	55,670	35.6	-	87.2	8,779	GAS	475,380	1,028,020	488,700.0	1,992,341	3.58	4.19
34. POLK #1 TOTAL	**220**	**55,670**	**34.0**	**93.8**	**87.2**	**8,779**	**-**	**-**	**-**	**488,700.0**	**1,992,341**	**3.58**	**-**
35. POLK #2 ST DUCT FIRING	120	28,680	32.1	-	90.5	8,275	GAS	230,850	1,028,027	237,320.0	967,504	3.37	4.19
36. POLK #2 ST W/O DUCT FIRING	341	617,480	-	-	-	-		4,151,525	1,028,001	4,267,770.0	17,399,249	2.82	4.19
37. POLK #2 ST TOTAL	**461**	**646,160**	**188.4**	**-**	**140.4**	**6,972**	**GAS**	**-**	**-**	**4,505,090.0**	**18,366,753**	**2.84**	**-**
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,700	GAS	15,620	1,027,529	16,050.0	65,464	4.36	4.19
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,553	29.70	133.79
40. POLK #2 TOTAL (4)	**150**	**1,650**	**1.5**	**-**	**99.5**	**10,909**	**-**	**-**	**-**	**18,000.0**	**110,017**	**6.67**	**-**
41. POLK #3 CT (GAS)	150	1,050	0.9	-	100.0	10,686	GAS	10,910	1,028,414	11,220.0	45,724	4.35	4.19
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,420	29.61	133.80
43. POLK #3 TOTAL (4)	**150**	**1,200**	**1.1**	**-**	**99.3**	**10,975**	**-**	**-**	**-**	**13,170.0**	**90,144**	**7.51**	**-**

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DOCKET NO. 20210001-EI
EXHIBIT NO. MAS-3
DOCUMENT NO. 2, PAGE 22 OF 42

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,350**	**1.2**	**-**	**100.0**	**10,733**	**GAS**	**14,100**	**1,027,660**	**14,490.0**	**59,094**	**4.38**	**4.19**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,200**	**1.1**	**-**	**100.0**	**10,742**	**GAS**	**12,550**	**1,027,092**	**12,890.0**	**52,598**	**4.38**	**4.19**
46. POLK #2 CC TOTAL	**1,061**	**651,560**	**82.5**	**97.4**	**139.0**	**7,004**	**-**	**-**	**-**	**4,563,640.0**	**18,678,606**	**2.87**	**-**
47. POLK STATION TOTAL	**1,281**	**707,230**	**74.2**	**96.8**	**127.3**	**7,144**	**-**	**-**	**-**	**5,052,340.0**	**20,670,947**	**2.92**	**-**
48. BAYSIDE #1	720	416,240	77.7	96.6	80.3	7,318	GAS	2,963,250	1,028,000	3,046,220.0	12,419,129	2.98	4.19
49. BAYSIDE #2	954	452,840	63.8	97.3	65.7	7,476	GAS	3,293,140	1,028,001	3,385,350.0	13,801,715	3.05	4.19
50. BAYSIDE #3	56	5,710	13.7	98.6	84.3	11,764	GAS	65,330	1,028,165	67,170.0	273,801	4.80	4.19
51. BAYSIDE #4	56	4,890	11.7	98.6	85.6	11,722	GAS	55,780	1,027,608	57,320.0	233,777	4.78	4.19
52. BAYSIDE #5	56	7,050	16.9	98.6	86.2	11,672	GAS	80,060	1,027,854	82,290.0	335,535	4.76	4.19
53. BAYSIDE #6	56	6,420	15.4	98.6	84.3	11,746	GAS	73,360	1,027,944	75,410.0	307,455	4.79	4.19
54. BAYSIDE STATION TOTAL	**1,898**	**893,150**	**63.2**	**97.2**	**72.2**	**7,517**	**GAS**	**6,530,920**	**1,027,996**	**6,713,760.0**	**27,371,412**	**3.06**	**4.19**
55. SYSTEM TOTAL	**5,880**	**2,074,390**	**47.4**	**75.4**	**84.5**	**7,143**	**-**	**-**	**-**	**14,816,910.0**	**58,231,044**	**2.81**	**-**

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: AUGUST 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) (2)	AS BURNED FUEL COST ($) (1)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,180	374.6	-	374.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,700	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,280	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,650	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,120	29.0	-	29.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	11,990	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,320	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,390	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	15,830	28.5	-	28.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,780	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,560.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	11,680.0	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	16,570.0	42.6	-	42.6	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	16,570.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**193,910**	**29.7**	**-**	**29.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**1,055**	**3,320**	**0.4**	**0.0**	**13.1**	**7,461**	**GAS**	**24,090**	**1,028,227**	**24,770.0**	**99,941**	**3.01**	**4.15**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	43,110	16.8	-	-	-	GAS	490,850	1,028,013	504,600.0	2,036,365	4.72	4.15
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**43,110**	**16.8**	**82.1**	**58.9**	**11,705**		**-**	**-**	**504,600.0**	**2,036,365**	**4.72**	**-**
24. B.B.#4 (GAS)	155	8,360	7.2	-	-	-	GAS	94,000	1,027,979	96,630.0	389,973	4.66	4.15
25. B.B.#4 (COAL)	422	158,760	50.6	-	-	-	COAL	81,600	22,500,368	1,836,030.0	5,123,910	3.23	62.79
26. BIG BEND #4 TOTAL	**422**	**167,120**	**53.2**	**89.3**	**58.1**	**11,565**		**-**	**-**	**1,932,660.0**	**5,513,883**	**3.30**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	17,120	1,028,037	17,600.0	71,025	-	4.15
28. B.B.C.T.#4 TOTAL	**56**	**2,870**	**6.9**	**98.3**	**81.3**	**11,969**	**GAS**	**33,420**	**1,027,828**	**34,350.0**	**138,648**	**4.83**	**4.15**
29. B.B.C.T.#5 TOTAL	**330**	**63,010**	**25.7**	**96.9**	**29.0**	**9,100**	**GAS**	**557,770**	**1,027,986**	**573,380.0**	**2,313,992**	**3.67**	**4.15**
30. B.B.C.T.#6 TOTAL	**330**	**120,960**	**49.3**	**96.1**	**55.6**	**9,101**	**GAS**	**1,070,830**	**1,028,006**	**1,100,820.0**	**4,442,499**	**3.67**	**4.15**
31. BIG BEND STATION TOTAL	**2,878**	**400,390**	**18.7**	**47.0**	**48.5**	**10,416**	**-**	**-**	**-**	**4,170,580.0**	**14,616,353**	**3.65**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	53,040	33.9	-	84.2	8,838	GAS	456,010	1,027,982	468,770.0	1,891,826	3.57	4.15
34. POLK #1 TOTAL	**220**	**53,040**	**32.4**	**93.8**	**84.2**	**8,838**	**-**	**-**	**-**	**468,770.0**	**1,891,826**	**3.57**	**-**
35. POLK #2 ST DUCT FIRING	120	21,660	24.3	-	91.6	8,277	GAS	174,410	1,027,980	179,290.0	723,566	3.34	4.15
36. POLK #2 ST W/O DUCT FIRING	341	618,070	-	-	-	-		4,155,105	1,028,000	4,271,450.0	17,238,076	2.79	4.15
37. POLK #2 ST TOTAL	**461**	**639,730**	**186.5**	**-**	**149.1**	**6,957**	**GAS**	**-**	**-**	**4,450,740.0**	**17,961,642**	**2.81**	**-**
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,727	GAS	15,660	1,027,458	16,090.0	64,967	4.33	4.15
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,375	29.58	133.26
40. POLK #2 TOTAL (4)	**150**	**1,650**	**1.5**	**-**	**99.5**	**10,933**	**-**	**-**	**-**	**18,040.0**	**109,342**	**6.63**	**-**
41. POLK #3 CT (GAS)	150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	58,496	4.33	4.15
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,243	29.50	133.26
43. POLK #3 TOTAL (4)	**150**	**1,500**	**1.3**	**-**	**99.4**	**10,960**	**-**	**-**	**-**	**16,440.0**	**102,739**	**6.85**	**-**

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2022

(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)
44. POLK #4 CT (GAS) TOTAL	(4)	**150**	**1,350**	**1.2**	**-**	**100.0**	**10,733**	**GAS**	**14,100**	**1,027,660**	**14,490.0**	**58,496**	**4.33**	**4.15**
45. POLK #5 CT (GAS) TOTAL	(4)	**150**	**1,200**	**1.1**	**-**	**100.0**	**10,675**	**GAS**	**12,470**	**1,027,265**	**12,810.0**	**51,734**	**4.31**	**4.15**
46. POLK #2 CC TOTAL		**1,061**	**645,430**	**81.8**	**97.4**	**147.1**	**6,991**	**-**	**-**	**-**	**4,512,520.0**	**18,283,953**	**2.83**	**-**
47. POLK STATION TOTAL		**1,281**	**698,470**	**73.3**	**96.8**	**132.2**	**7,132**	**-**	**-**	**-**	**4,981,290.0**	**20,175,779**	**2.89**	**-**
48. BAYSIDE #1		720	387,880	72.4	96.6	78.6	7,327	GAS	2,764,590	1,027,997	2,841,990.0	11,469,316	2.96	4.15
49. BAYSIDE #2		954	418,950	59.0	97.3	61.1	7,521	GAS	3,064,920	1,027,997	3,150,730.0	12,715,280	3.04	4.15
50. BAYSIDE #3		56	3,810	9.1	98.6	81.0	11,953	GAS	44,290	1,028,223	45,540.0	183,744	4.82	4.15
51. BAYSIDE #4		56	3,250	7.8	98.6	80.6	12,049	GAS	38,090	1,028,091	39,160.0	158,022	4.86	4.15
52. BAYSIDE #5		56	4,590	11.0	98.6	76.6	12,142	GAS	54,210	1,028,039	55,730.0	224,898	4.90	4.15
53. BAYSIDE #6		56	4,320	10.4	98.6	79.5	12,009	GAS	50,470	1,027,937	51,880.0	209,382	4.85	4.15
54. BAYSIDE STATION TOTAL		**1,898**	**822,800**	**58.3**	**97.2**	**68.6**	**7,517**	**GAS**	**6,016,570**	**1,027,999**	**6,185,030.0**	**24,960,642**	**3.03**	**4.15**
55. SYSTEM TOTAL		**6,935**	**2,115,570**	**41.0**	**64.0**	**89.3**	**7,250**	**-**	**-**	**-**	**15,336,900.0**	**59,752,774**	**2.82**	**-**

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 2022

(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	3,470	321.3	-	321.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,650	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,140	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,340	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,390	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,420	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,720	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,030	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,680	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,370	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,990	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,830.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,150.0	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,400.0	38.2	-	38.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,400.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**167,470**	**26.5**	**-**	**26.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**1,055**	**296,610**	**39.0**	**0.0**	**40.0**	**6,291**	**GAS**	**1,815,250**	**1,028,007**	**1,866,090.0**	**7,578,296**	**2.55**	**4.17**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	48,640	19.6	-	-	-	GAS	549,750	1,027,995	565,140.0	2,295,094	4.72	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**48,640**	**19.6**	**82.1**	**61.0**	**11,619**		**-**	**-**	**565,140.0**	**2,295,094**	**4.72**	**-**
24. B.B.#4 (GAS)	155	8,130	7.3	-	-	-	GAS	91,280	1,027,936	93,830.0	381,075	4.69	4.17
25. B.B.#4 (COAL)	422	154,310	50.8	-	-	-	COAL	79,240	22,499,243	1,782,840.0	4,979,203	3.23	62.84
26. BIG BEND #4 TOTAL	**422**	**162,440**	**53.5**	**89.3**	**58.3**	**11,553**		**-**	**-**	**1,876,670.0**	**5,360,278**	**3.30**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,300	1,027,700	21,890.0	88,923	-	4.17
28. B.B.C.T.#4 TOTAL	**56**	**8,700**	**21.6**	**98.3**	**86.3**	**11,622**	**GAS**	**98,350**	**1,028,063**	**101,110.0**	**410,591**	**4.72**	**4.17**
29. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. BIG BEND STATION TOTAL	**2,878**	**516,390**	**24.9**	**47.0**	**46.5**	**8,538**	**-**	**-**	**-**	**4,409,010.0**	**15,733,182**	**3.05**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	54,730	36.2	-	90.8	8,696	GAS	462,980	1,027,993	475,940.0	1,932,846	3.53	4.17
34. POLK #1 TOTAL	**220**	**54,730**	**34.6**	**93.8**	**90.8**	**8,696**	**-**	**-**	**-**	**475,940.0**	**1,932,846**	**3.53**	**-**
35. POLK #2 ST DUCT FIRING	120	31,280	36.2	-	89.3	8,276	GAS	251,810	1,027,997	258,860.0	1,051,255	3.36	4.17
36. POLK #2 ST W/O DUCT FIRING	341	573,230	-	-	-	-		3,857,255	1,028,003	3,965,270.0	16,103,247	2.81	4.17
37. POLK #2 ST TOTAL	**461**	**604,510**	**182.1**	**-**	**130.9**	**6,988**	**GAS**	**-**	**-**	**4,224,130.0**	**17,154,502**	**2.84**	**-**
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,200	29.47	132.73
40. POLK #2 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**44,201**	**29.47**	**-**
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,708	GAS	12,500	1,028,000	12,850.0	52,185	4.35	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,067	29.38	132.73
43. POLK #3 TOTAL (4)	**150**	**1,350**	**1.3**	**-**	**99.3**	**10,963**	**-**	**-**	**-**	**14,800.0**	**96,252**	**7.13**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,040**	**1.0**	**-**	**99.0**	**10,817**	**GAS**	**10,950**	**1,027,397**	**11,250.0**	**45,714**	**4.40**	**4.17**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**900**	**0.8**	**-**	**100.0**	**10,722**	**GAS**	**9,390**	**1,027,689**	**9,650.0**	**39,201**	**4.36**	**4.17**
46. POLK #2 CC TOTAL	**1,061**	**607,950**	**79.6**	**97.4**	**130.2**	**7,010**	**-**	**-**	**-**	**4,261,780.0**	**17,379,870**	**2.86**	**-**
47. POLK STATION TOTAL	**1,281**	**662,680**	**71.8**	**96.8**	**121.6**	**7,149**	**-**	**-**	**-**	**4,737,720.0**	**19,312,716**	**2.91**	**-**
48. BAYSIDE #1	720	101,560	19.6	29.0	67.5	7,400	GAS	731,050	1,028,014	751,530.0	3,051,984	3.01	4.17
49. BAYSIDE #2	954	440,590	64.1	97.3	66.0	7,482	GAS	3,206,840	1,027,996	3,296,620.0	13,387,898	3.04	4.17
50. BAYSIDE #3	56	8,860	22.0	98.6	87.4	11,620	GAS	100,130	1,028,163	102,950.0	418,022	4.72	4.17
51. BAYSIDE #4	56	8,920	22.1	98.6	88.5	11,557	GAS	100,280	1,028,022	103,090.0	418,648	4.69	4.17
52. BAYSIDE #5	56	9,650	23.9	98.6	85.3	11,662	GAS	109,470	1,028,044	112,540.0	457,015	4.74	4.17
53. BAYSIDE #6	56	10,030	24.9	98.6	87.4	11,587	GAS	113,050	1,028,041	116,220.0	471,961	4.71	4.17
54. BAYSIDE STATION TOTAL	**1,898**	**579,610**	**42.4**	**71.5**	**67.3**	**7,734**	**GAS**	**4,360,820**	**1,028,006**	**4,482,950.0**	**18,205,528**	**3.14**	**4.17**
55. SYSTEM TOTAL	**6,935**	**1,926,150**	**38.6**	**56.9**	**83.2**	**7,076**	**-**	**-**	**-**	**13,629,680.0**	**53,251,426**	**2.76**	**-**

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: OCTOBER 2022

(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	3,590	321.7	-	321.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,490	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,990	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,980	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,250	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,300	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,100	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,930	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,210	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,850	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,790.0	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,070.0	18.2	-	18.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,280.0	36.7	-	36.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,280.0	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**166,660**	**25.5**	**-**	**25.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**1,055**	**664,980**	**84.7**	**0.0**	**86.8**	**6,234**	**GAS**	**4,032,710**	**1,028,004**	**4,145,640.0**	**16,927,062**	**2.55**	**4.20**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	44,880	17.5	-	-	-	GAS	510,250	1,028,025	524,550.0	2,141,744	4.77	4.20
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**44,880**	**17.5**	**82.1**	**59.4**	**11,688**		**-**	**-**	**524,550.0**	**2,141,744**	**4.77**	**-**
24. B.B.#4 (GAS)	155	830	0.7	-	-	-	GAS	9,320	1,027,897	9,580.0	39,120	4.71	4.20
25. B.B.#4 (COAL)	422	15,880	5.1	-	-	-	COAL	8,090	22,508,035	182,090.0	509,008	3.21	62.92
26. BIG BEND #4 TOTAL	**422**	**16,710**	**5.3**	**8.6**	**60.0**	**11,470**		**-**	**-**	**191,670.0**	**548,128**	**3.28**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,028,076	12,450.0	50,831	-	4.20
28. B.B.C.T.#4 TOTAL	**56**	**2,180**	**5.2**	**98.3**	**76.3**	**12,197**	**GAS**	**25,880**	**1,027,434**	**26,590.0**	**108,630**	**4.98**	**4.20**
29. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. BIG BEND STATION TOTAL	**2,878**	**728,750**	**34.0**	**35.1**	**83.6**	**6,708**	**-**	**-**	**-**	**4,888,450.0**	**19,776,395**	**2.71**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	47,070	30.1	-	83.0	8,883	GAS	406,740	1,028,003	418,130.0	1,707,267	3.63	4.20
34. POLK #1 TOTAL	**220**	**47,070**	**28.8**	**93.8**	**83.0**	**8,883**	**-**	**-**	**-**	**418,130.0**	**1,707,267**	**3.63**	**-**
35. POLK #2 ST DUCT FIRING	120	17,210	19.3	-	81.5	8,276	GAS	138,550	1,028,004	142,430.0	581,555	3.38	4.20
36. POLK #2 ST W/O DUCT FIRING	341	523,710	-	-	-	-		3,534,145	1,028,003	3,633,110.0	14,834,364	2.83	4.20
37. POLK #2 ST TOTAL	**461**	**540,920**	**157.7**	**-**	**129.1**	**6,980**	**GAS**	**-**	**-**	**3,775,540.0**	**15,415,919**	**2.85**	**-**
38. POLK #2 CT (GAS)	150	410	0.4	-	68.3	12,293	GAS	4,910	1,026,477	5,040.0	20,610	5.03	4.20
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,027	29.35	132.21
40. POLK #2 TOTAL (4)	**150**	**560**	**0.5**	**-**	**73.8**	**12,482**	**-**	**-**	**-**	**6,990.0**	**64,637**	**11.54**	**-**
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,895	29.26	132.21
43. POLK #3 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**43,895**	**29.26**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2022

(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)
44. POLK #4 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
45. POLK #5 CT (GAS) TOTAL	[4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL		**1,061**	**541,630**	**68.6**	**97.4**	**128.7**	**6,987**	**-**	**-**	**-**	**3,784,480.0**	**15,524,451**	**2.87**	**-**
47. POLK STATION TOTAL		**1,281**	**588,700**	**61.8**	**96.8**	**118.3**	**7,139**	**-**	**-**	**-**	**4,202,610.0**	**17,231,718**	**2.93**	**-**
48. BAYSIDE #1		720	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
49. BAYSIDE #2		954	318,550	44.9	97.3	46.4	7,709	GAS	2,388,740	1,027,994	2,455,610.0	10,026,594	3.15	4.20
50. BAYSIDE #3		56	3,580	8.6	98.6	79.9	12,006	GAS	41,830	1,027,492	42,980.0	175,579	4.90	4.20
51. BAYSIDE #4		56	3,100	7.4	98.6	81.4	11,965	GAS	36,080	1,027,993	37,090.0	151,444	4.89	4.20
52. BAYSIDE #5		56	4,890	11.7	98.6	76.6	12,125	GAS	57,680	1,027,913	59,290.0	242,108	4.95	4.20
53. BAYSIDE #6		56	3,600	8.6	98.6	78.4	12,106	GAS	42,390	1,028,073	43,580.0	177,930	4.94	4.20
54. BAYSIDE STATION TOTAL		**1,898**	**333,720**	**23.6**	**60.5**	**47.3**	**7,906**	**GAS**	**2,566,720**	**1,027,985**	**2,638,550.0**	**10,773,655**	**3.23**	**4.20**
55. SYSTEM TOTAL		**6,935**	**1,817,830**	**35.2**	**49.0**	**95.2**	**6,453**	**-**	**-**	**-**	**11,729,610.0**	**47,781,768**	**2.63**	**-**

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: NOVEMBER 2022

(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	2,960	273.7	-	273.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,090	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,450	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	11,980	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,390	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,680	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,010	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,670	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,740	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,860	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,590.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,530.0	14.1	-	14.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,690.0	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,690.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL (3)	**878.0**	**129,810**	**20.5**	**-**	**20.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
19. BIG BEND #1 CC TOTAL	**1,055**	**758,410**	**99.7**	**0.0**	**102.3**	**6,229**	**GAS**	**4,595,280**	**1,028,000**	**4,723,950.0**	**20,323,688**	**2.68**	**4.42**
20. BIG BEND #2 TOTAL	**340**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. B.B.#3 (GAS)	345	9,030	3.6	-	-	-	GAS	104,650	1,027,998	107,580.0	462,839	5.13	4.42
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	**345**	**9,030**	**3.6**	**43.8**	**54.5**	**11,914**		**-**	**-**	**107,580.0**	**462,839**	**5.13**	**-**
24. B.B.#4 (GAS)	155	6,000	5.4	-	-	-	GAS	71,970	1,027,928	73,980.0	318,304	5.31	4.42
25. B.B.#4 (COAL)	422	114,030	37.5	-	-	-	COAL	62,470	22,501,361	1,405,660.0	3,930,668	3.45	62.92
26. BIG BEND #4 TOTAL	**422**	**120,030**	**39.4**	**83.3**	**46.2**	**12,327**		**-**	**-**	**1,479,640.0**	**4,248,972**	**3.54**	**-**
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,027,250	12,440.0	53,559	-	4.42
28. B.B.C.T.#4 TOTAL	**56**	**110**	**0.3**	**98.3**	**65.5**	**13,091**	**GAS**	**1,400**	**1,028,571**	**1,440.0**	**6,192**	**5.63**	**4.42**
29. B.B.C.T.#5 TOTAL	**330**	**0**	**0.0**	**96.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
30. B.B.C.T.#6 TOTAL	**330**	**0**	**0.0**	**96.1**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
31. BIG BEND STATION TOTAL	**2,878**	**887,580**	**42.8**	**41.5**	**87.2**	**7,112**	**-**	**-**	**-**	**6,312,610.0**	**25,095,250**	**2.83**	**-**
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	7,830	5.2	-	79.3	8,921	GAS	67,950	1,027,962	69,850.0	300,525	3.84	4.42
34. POLK #1 TOTAL	**220**	**7,830**	**4.9**	**93.8**	**79.3**	**8,921**	**-**	**-**	**-**	**69,850.0**	**300,525**	**3.84**	**-**
35. POLK #2 ST DUCT FIRING	120	1,580	1.8	-	59.8	8,247	GAS	12,680	1,027,603	13,030.0	56,080	3.55	4.42
36. POLK #2 ST W/O DUCT FIRING	341	302,000	-	-	-	-		2,079,175	1,028,004	2,137,400.0	9,195,632	3.04	4.42
37. POLK #2 ST TOTAL	**461**	**303,580**	**91.3**	**-**	**90.1**	**7,084**	**GAS**	**-**	**-**	**2,150,430.0**	**9,251,712**	**3.05**	**-**
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	43,857	29.24	131.70
40. POLK #2 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**43,857**	**29.24**	**-**
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,725	29.15	131.70
43. POLK #3 TOTAL (4)	**150**	**150**	**0.1**	**-**	**94.3**	**13,000**	**-**	**-**	**-**	**1,950.0**	**43,725**	**29.15**	**-**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2022

(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)
44. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
45. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
46. POLK #2 CC TOTAL	**1,061**	**303,880**	**39.7**	**97.4**	**90.1**	**7,089**	**-**	**-**	**-**	**2,154,330.0**	**9,339,294**	**3.07**	**-**
47. POLK STATION TOTAL	**1,281**	**311,710**	**33.7**	**96.8**	**89.4**	**7,135**	**-**	**-**	**-**	**2,224,180.0**	**9,639,819**	**3.09**	**-**
48. BAYSIDE #1	720	15,230	2.9	25.8	32.0	7,957	GAS	117,880	1,027,995	121,180.0	521,351	3.42	4.42
49. BAYSIDE #2	954	131,950	19.2	97.3	26.8	8,308	GAS	1,066,370	1,028,020	1,096,250.0	4,716,268	3.57	4.42
50. BAYSIDE #3	56	120	0.3	98.6	71.4	12,917	GAS	1,510	1,026,490	1,550.0	6,678	5.57	4.42
51. BAYSIDE #4	56	60	0.1	98.6	53.6	14,833	GAS	870	1,022,989	890.0	3,848	6.41	4.42
52. BAYSIDE #5	56	140	0.3	98.6	62.5	14,071	GAS	1,920	1,026,042	1,970.0	8,492	6.07	4.42
53. BAYSIDE #6	56	120	0.3	98.6	53.6	14,500	GAS	1,690	1,029,586	1,740.0	7,474	6.23	4.42
54. BAYSIDE STATION TOTAL	**1,898**	**147,620**	**10.8**	**70.3**	**27.3**	**8,289**	**GAS**	**1,190,240**	**1,028,011**	**1,223,580.0**	**5,264,111**	**3.57**	**4.42**
55. SYSTEM TOTAL	**6,935**	**1,476,720**	**29.5**	**54.3**	**81.4**	**6,609**	**-**	**-**	**-**	**9,760,370.0**	**39,999,180**	**2.71**	**-**

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

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

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(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	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,680	240.1	-	240.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,470	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,770	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,360	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,030	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,450	15.8	-	15.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,030	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,600	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,430	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,410	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,440	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,010	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,320	11.4	-	11.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	8,970	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,970	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	22.2	7,860	47.6	-	47.6	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	65.0	8,080	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,680	5.1	-	5.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	66.8	8,460	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
22. SOLAR TOTAL (3)	**1102.0**	**137,440**	**16.8**	**-**	**16.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
23. BIG BEND #1 CC TOTAL	**1,120**	**787,780**	**94.5**	**98.0**	**96.9**	**6,277**	**GAS**	**4,810,060**	**1,028,002**	**4,944,750.0**	**21,872,120**	**2.78**	**4.55**
24. BIG BEND #2 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
25. B.B.#3 (GAS)	355	13,470	5.1	-	-	-	GAS	155,030	1,028,059	159,380.0	704,947	5.23	4.55
26. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
27. BIG BEND #3 TOTAL	**355**	**13,470**	**5.1**	**82.1**	**52.7**	**11,832**		**-**	**-**	**159,380.0**	**704,947**	**5.23**	**-**
28. B.B.#4 (GAS)	160	6,890	5.8	-	-	-	GAS	80,970	1,028,035	83,240.0	368,184	5.34	4.55
29. B.B.#4 (COAL)	432	130,860	40.7	-	-	-	COAL	70,290	22,500,925	1,581,590.0	4,423,948	3.38	62.94
30. BIG BEND #4 TOTAL	**432**	**137,750**	**42.9**	**89.3**	**46.8**	**12,086**		**-**	**-**	**1,664,830.0**	**4,792,132**	**3.48**	**-**
31. B.B. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	28,465	-	4.55
32. B.B.C.T.#4 TOTAL	**61**	**430**	**0.9**	**98.3**	**88.1**	**11,628**	**GAS**	**4,880**	**1,024,590**	**5,000.0**	**22,190**	**5.16**	**4.55**
33. B.B.C.T.#5 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. B.B.C.T.#6 TOTAL	**350**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
35. BIG BEND STATION TOTAL	**3,018**	**939,430**	**41.8**	**60.8**	**82.9**	**7,211**	**-**	**-**	**-**	**6,773,960.0**	**27,419,854**	**2.92**	**-**
36. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
37. POLK #1 CT (GAS)	230	21,630	12.6	-	73.5	8,961	GAS	188,540	1,028,058	193,830.0	857,322	3.96	4.55
38. POLK #1 TOTAL	**230**	**21,630**	**12.6**	**93.8**	**73.5**	**8,961**	**-**	**-**	**-**	**193,830.0**	**857,322**	**3.96**	**-**
39. POLK #2 ST DUCT FIRING	120	2,310	2.6	-	83.7	8,182	GAS	18,380	1,028,292	18,900.0	83,577	3.62	4.55
40. POLK #2 ST W/O DUCT FIRING	360	239,370	-	-	-	-		1,659,095	1,028,006	1,705,560.0	7,544,173	3.15	4.55
41. POLK #2 ST TOTAL	**480**	**241,680**	**67.7**	**-**	**80.6**	**7,135**	**GAS**	**-**	**-**	**1,724,460.0**	**7,627,750**	**3.16**	**-**
42. POLK #2 CT (GAS)	180	1,580	1.2	-	67.5	11,652	GAS	17,900	1,028,492	18,410.0	81,393	5.15	4.55
43. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	43,688	29.13	131.20
44. POLK #2 TOTAL (4)	**180**	**1,730**	**1.3**	**-**	**68.5**	**11,769**	**-**	**-**	**-**	**20,360.0**	**125,081**	**7.23**	**-**
45. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	43,558	29.04	131.20
47. POLK #3 TOTAL (4)	**180**	**150**	**0.1**	**-**	**80.2**	**13,000**	**-**	**-**	**-**	**1,950.0**	**43,558**	**29.04**	**-**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(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)
48. POLK #4 CT (GAS) TOTAL [4]	**180**	**940**	**0.7**	**-**	**65.3**	**11,681**	**GAS**	**10,680**	**1,028,090**	**10,980.0**	**48,564**	**5.17**	**4.55**
49. POLK #5 CT (GAS) TOTAL [4]	**180**	**930**	**0.7**	**-**	**64.6**	**11,806**	**GAS**	**10,680**	**1,028,090**	**10,980.0**	**48,564**	**5.22**	**4.55**
50. POLK #2 CC TOTAL	**1,200**	**245,430**	**27.5**	**81.7**	**79.9**	**7,207**	**-**	**-**	**-**	**1,768,730.0**	**7,893,517**	**3.22**	**-**
51. POLK STATION TOTAL	**1,430**	**267,060**	**25.1**	**83.7**	**78.9**	**7,349**	**-**	**-**	**-**	**1,962,560.0**	**8,750,839**	**3.28**	**-**
52. BAYSIDE #1	792	137,370	23.3	96.6	32.7	7,702	GAS	1,029,200	1,028,002	1,058,020.0	4,679,939	3.41	4.55
53. BAYSIDE #2	1,047	51,050	6.6	97.3	28.3	8,042	GAS	399,370	1,027,994	410,550.0	1,815,999	3.56	4.55
54. BAYSIDE #3	61	380	0.8	98.6	89.0	11,342	GAS	4,190	1,028,640	4,310.0	19,053	5.01	4.55
55. BAYSIDE #4	61	330	0.7	98.6	90.2	11,485	GAS	3,690	1,027,100	3,790.0	16,779	5.08	4.55
56. BAYSIDE #5	61	470	1.0	98.6	85.6	11,723	GAS	5,360	1,027,985	5,510.0	24,373	5.19	4.55
57. BAYSIDE #6	61	420	0.9	98.6	86.1	11,762	GAS	4,810	1,027,027	4,940.0	21,872	5.21	4.55
58. BAYSIDE STATION TOTAL	**2,083**	**190,020**	**12.3**	**97.2**	**31.5**	**7,826**	**GAS**	**1,446,620**	**1,027,996**	**1,487,120.0**	**6,578,015**	**3.46**	**4.55**
59. SYSTEM TOTAL	**7,633**	**1,533,950**	**27.0**	**66.2**	**77.1**	**6,665**	**-**	**-**	**-**	**10,223,640.0**	**42,748,708**	**2.79**	**-**

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 2022 THROUGH JUNE 2022

		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
	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)	665	665	665	665	665	665
16.	UNIT COST ($/BBL)	102.65	102.38	101.85	101.07	100.43	99.96
17.	AMOUNT ($)	68,265	68,083	67,728	67,209	66,788	66,475
18.	BURNED:						
19.	UNITS (BBL)	665	665	665	665	665	665
20.	UNIT COST ($/BBL)	137.07	136.52	135.98	135.43	134.88	134.33
21.	AMOUNT ($)	91,149	90,787	90,425	90,061	89,697	89,332
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760
24.	UNIT COST ($/BBL)	137.03	136.49	135.94	135.40	134.85	134.30
25.	AMOUNT ($)	5,722,460	5,699,756	5,677,059	5,654,207	5,631,298	5,608,440
26.	DAYS SUPPLY: NORMAL	1,909,609	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	65,000	55,000	70,000	70,000	55,000	45,000
30.	UNIT COST ($/TON)	64.46	63.99	63.38	63.47	64.03	61.43
31.	AMOUNT ($)	4,190,125	3,519,461	4,436,677	4,442,855	3,521,454	2,764,201
32.	BURNED:						
33.	UNITS (TONS)	72,550	63,500	57,140	50,210	73,110	75,560
34.	UNIT COST ($/TON)	62.11	62.83	62.33	63.25	62.52	62.61
35.	AMOUNT ($)	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	232,888	224,388	237,248	257,038	238,928	208,368
38.	UNIT COST ($/TON)	60.96	61.42	61.84	62.22	62.62	62.46
39.	AMOUNT ($)	14,196,096	13,782,069	14,672,013	15,992,163	14,961,389	13,014,329
40.	DAYS SUPPLY:	108	117	121	118	96	81
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	8,871,536	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
43.	UNIT COST ($/MCF)	5.19	5.09	4.80	4.32	4.27	4.17
44.	AMOUNT ($)	46,057,217	39,598,109	41,955,637	39,702,520	45,016,467	51,745,193
45.	BURNED:						
46.	UNITS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
47.	UNIT COST ($/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
48.	AMOUNT ($)	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105
51.	UNIT COST ($/MCF)	3.92	3.83	3.58	3.07	2.98	3.01
52.	AMOUNT ($)	1,524,320	1,490,800	1,393,600	1,193,760	1,160,400	1,170,800
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 2022 THROUGH DECEMBER 2022

		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	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)	665	665	665	665	665	665	7,980
16.	UNIT COST ($/BBL)	99.82	99.73	99.66	99.62	99.57	99.46	100.52
17.	AMOUNT ($)	66,383	66,323	66,277	66,250	66,212	66,144	802,137
18.	BURNED:							
19.	UNITS (BBL)	665	665	665	665	665	665	7,980
20.	UNIT COST ($/BBL)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
21.	AMOUNT ($)	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760	41,760
24.	UNIT COST ($/BBL)	133.76	133.23	132.70	132.18	131.67	131.16	131.16
25.	AMOUNT ($)	5,585,850	5,563,555	5,541,565	5,519,893	5,498,523	5,477,422	5,477,422
26.	DAYS SUPPLY: NORMAL	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	85,000	75,000	50,000	65,000	50,000	60,000	745,000
30.	UNIT COST ($/TON)	63.16	63.39	61.43	62.84	61.43	61.43	62.97
31.	AMOUNT ($)	5,368,545	4,754,278	3,071,334	4,084,755	3,071,334	3,685,601	46,910,620
32.	BURNED:							
33.	UNITS (TONS)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
34.	UNIT COST ($/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
35.	AMOUNT ($)	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	213,478	206,878	177,638	234,548	222,078	211,788	211,788
38.	UNIT COST ($/TON)	62.74	63.05	62.81	62.82	62.55	62.19	62.19
39.	AMOUNT ($)	13,392,646	13,044,122	11,156,751	14,734,591	13,891,417	13,171,253	13,171,253
40.	DAYS SUPPLY:	82	113	108	153	100	92	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,541
43.	UNIT COST ($/MCF)	4.19	4.15	4.17	4.20	4.43	4.55	4.41
44.	AMOUNT ($)	53,145,337	54,542,646	48,178,436	47,195,478	36,003,650	38,286,074	541,426,764
45.	BURNED:							
46.	UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
47.	UNIT COST ($/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
48.	AMOUNT ($)	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51.	UNIT COST ($/MCF)	3.05	3.05	3.04	3.06	3.12	3.25	3.25
52.	AMOUNT ($)	1,184,960	1,187,361	1,181,839	1,192,479	1,215,200	1,263,760	1,263,760
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 2022 THROUGH JUNE 2022

(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-22	SEMINOLE	JURISD.	SCH. - D	2,900.0	0.0	2,900.0	3.111	3.330	90,210.00	96,568.00	6,358.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,900.0**	**0.0**	**2,900.0**	**3.111**	**3.330**	**90,210.00**	**96,568.00**	**6,358.00**
Feb-22	SEMINOLE	JURISD.	SCH. - D	2,770.0	0.0	2,770.0	2.954	3.162	81,820.00	87,586.00	5,766.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,770.0**	**0.0**	**2,770.0**	**2.954**	**3.162**	**81,820.00**	**87,586.00**	**5,766.00**
Mar-22	SEMINOLE	JURISD.	SCH. - D	2,990.0	0.0	2,990.0	2.887	3.091	86,330.00	92,414.00	6,084.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,990.0**	**0.0**	**2,990.0**	**2.887**	**3.091**	**86,330.00**	**92,414.00**	**6,084.00**
Apr-22	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.632	2.817	75,800.00	81,142.00	5,342.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,880.0**	**0.0**	**2,880.0**	**2.632**	**2.817**	**75,800.00**	**81,142.00**	**5,342.00**
May-22	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.822	3.021	81,270.00	86,998.00	5,728.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,880.0**	**0.0**	**2,880.0**	**2.822**	**3.021**	**81,270.00**	**86,998.00**	**5,728.00**
Jun-22	SEMINOLE	JURISD.	SCH. - D	3,000.0	0.0	3,000.0	2.955	3.163	88,640.00	94,887.00	6,247.00
	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**	**2.955**	**3.163**	**88,640.00**	**94,887.00**	**6,247.00**

TAMPA ELECTRIC COMPANY

POWER SOLD

ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

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-22	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	2.776	2.971	81,610.00	87,362.00	5,752.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,940.0**	**0.0**	**2,940.0**	**2.776**	**2.971**	**81,610.00**	**87,362.00**	**5,752.00**
Aug-22	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	2.918	3.123	85,780.00	91,825.00	6,045.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,940.0**	**0.0**	**2,940.0**	**2.918**	**3.123**	**85,780.00**	**91,825.00**	**6,045.00**
Sep-22	SEMINOLE	JURISD.	SCH. - D	2,960.0	0.0	2,960.0	2.720	2.911	80,500.00	86,173.00	5,673.00
	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**	**2.720**	**2.911**	**80,500.00**	**86,173.00**	**5,673.00**
Oct-22	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.757	2.951	81,320.00	87,051.00	5,731.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,950.0**	**0.0**	**2,950.0**	**2.757**	**2.951**	**81,320.00**	**87,051.00**	**5,731.00**
Nov-22	SEMINOLE	JURISD.	SCH. - D	2,800.0	0.0	2,800.0	2.444	2.616	68,420.00	73,242.00	4,822.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**2,800.0**	**0.0**	**2,800.0**	**2.444**	**2.616**	**68,420.00**	**73,242.00**	**4,822.00**
Dec-22	SEMINOLE	JURISD.	SCH. - D	3,030.0	0.0	3,030.0	2.590	2.773	78,490.00	84,022.00	5,532.00
	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**	**2.590**	**2.773**	**78,490.00**	**84,022.00**	**5,532.00**
TOTAL											
Jan-22	SEMINOLE	JURISD.	SCH. - D	35,040.0	0.0	35,040.0	2.797	2.994	980,190.00	1,049,270.00	69,080.00
THRU	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-22	**TOTAL**			**35,040.0**	**0.0**	**35,040.0**	**2.797**	**2.994**	**980,190.00**	**1,049,270.00**	**69,080.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
Jan-22	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
Feb-22	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
Mar-22	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-22	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-22	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-22	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-22	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-22	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-22	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-22	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-22	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-22	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-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
THRU Dec-22	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUST-MENT
Jan-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
	TOTAL		5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
Feb-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
Mar-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
	TOTAL		5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
Apr-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
May-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
Jun-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
	TOTAL		5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
Jul-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
	TOTAL		5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
Aug-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
Sep-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
	TOTAL		5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
Oct-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
Nov-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
Dec-22	VARIOUS	CO-GEN.							
		AS AVAIL.	5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
	TOTAL		5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
TOTAL	VARIOUS	CO-GEN.							
Jan-22		AS AVAIL.	68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00
THRU	TOTAL		68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00
Dec-22									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

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-22	VARIOUS	SCH. - J	260.0	0.0	260.0	5.488	14,270.00	55.792	145,060.00	130,790.00
Feb-22	VARIOUS	SCH. - J	190.0	0.0	190.0	5.395	10,250.00	64.447	122,450.00	112,200.00
Mar-22	VARIOUS	SCH. - J	90.0	0.0	90.0	5.756	5,180.00	303.622	273,260.00	268,080.00
Apr-22	VARIOUS	SCH. - J	30.0	0.0	30.0	5.667	1,700.00	3,713.700	1,114,110.00	1,112,410.00
May-22	VARIOUS	SCH. - J	600.0	0.0	600.0	4.362	26,170.00	220.233	1,321,400.00	1,295,230.00
Jun-22	VARIOUS	SCH. - J	8,210.0	0.0	8,210.0	5.848	480,100.00	40.894	3,357,370.00	2,877,270.00
Jul-22	VARIOUS	SCH. - J	8,730.0	0.0	8,730.0	6.978	609,210.00	41.340	3,608,990.00	2,999,780.00
Aug-22	VARIOUS	SCH. - J	5,490.0	0.0	5,490.0	6.646	364,870.00	60.824	3,339,230.00	2,974,360.00
Sep-22	VARIOUS	SCH. - J	61,730.0	0.0	61,730.0	6.660	4,111,460.00	11.514	7,107,430.00	2,995,970.00
Oct-22	VARIOUS	SCH. - J	19,540.0	0.0	19,540.0	5.671	1,108,180.00	21.879	4,275,230.00	3,167,050.00
Nov-22	VARIOUS	SCH. - J	20.0	0.0	20.0	6.600	1,320.00	5,610.950	1,122,190.00	1,120,870.00
Dec-22	VARIOUS	SCH. - J	80.0	0.0	80.0	5.525	4,420.00	678.713	542,970.00	538,550.00
TOTAL	VARIOUS	SCH. - J	**104,970.0**	**0.0**	**104,970.0**	**6.418**	**6,737,130.00**	**25.083**	**26,329,690.00**	**19,592,560.00**

SCHEDULE E10

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

	Current	Current	Projected	Difference	
	Jan 2021 - Aug 2021	Sep 2021 - Dec 2021	Jan 2022 - Dec 2022	$	%
Base Rate Revenue	67.30	67.30	67.30	0.00	0.0%
Fuel Recovery Revenue	28.56	39.38	27.45	(11.93)	-30.3%
Conservation Revenue	1.66	1.66	2.36	0.70	42.2%
Capacity Revenue	0.02	1.70	0.31	(1.39)	-81.8%
Environmental Revenue	2.69	2.69	2.63	(0.06)	-2.2%
Storm Protection Plan Revenue	2.39	2.39	2.91	0.52	21.8%
Florida Gross Receipts Tax Revenue	2.63	2.95	2.64	(0.31)	-10.5%
TOTAL REVENUE	**$105.25**	**$118.07**	**$105.60**	**($12.47)**	**-10.6%**

SCHEDULE H1

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

	ACTUAL 2019	ACTUAL 2020	ACT/EST 2021	EST 2022	DIFFERENCE (%) 2020-2019	2021-2020	2022-2021
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL {1}	183,150	636,201	764,784	1,070,059	247.4%	20.2%	39.9%
3 COAL	45,241,314	33,991,967	50,861,452	48,512,588	-24.9%	49.6%	-4.6%
4 NATURAL GAS	480,359,200	379,848,073	539,523,560	541,661,724	-20.9%	42.0%	0.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**525,783,664**	**414,476,241**	**591,149,796**	**591,244,371**	**-21.2%**	**42.6%**	**0.0%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL {1}	582	1,901	2,276	3,600	226.6%	19.7%	58.2%
10 COAL	1,194,254	903,680	1,402,956	1,463,780	-24.3%	55.2%	4.3%
11 NATURAL GAS	17,513,363	16,519,857	15,869,733	17,155,510	-5.7%	-3.9%	8.1%
12 NUCLEAR	756,215	1,119,822	1,430,357	2,105,180	48.1%	27.7%	47.2%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,464,414**	**18,545,260**	**18,705,322**	**20,728,070**	**-4.7%**	**0.9%**	**10.8%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) {1}	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) {1}	1,436	4,345	5,444	7,980	202.6%	25.3%	46.6%
17 COAL (TON)	570,012	431,512	692,719	773,650	-24.3%	60.5%	11.7%
18 NATURAL GAS (MCF)	137,873,625	127,992,191	121,415,204	122,671,540	-7.2%	-5.1%	1.0%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL {1}	8,362	25,328	31,824	46,800	202.9%	25.6%	47.1%
23 COAL	13,177,799	9,830,729	15,775,515	17,407,290	-25.4%	60.5%	10.3%
24 NATURAL GAS	140,983,651	131,021,110	124,368,185	125,966,410	-7.1%	-5.1%	1.3%
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)	**154,169,812**	**140,877,167**	**140,175,524**	**143,420,500**	**-8.6%**	**-0.5%**	**2.3%**
GENERATION MIX (% MWH)							
28 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL {1}	0.00	0.01	0.01	0.02	0.0%	0.0%	100.0%
30 COAL	6.13	4.87	7.50	7.06	-20.6%	54.0%	-5.9%
31 NATURAL GAS	89.98	89.08	84.84	82.76	-1.0%	-4.8%	-2.5%
32 NUCLEAR	3.89	6.04	7.65	10.16	55.3%	26.7%	32.8%
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}	127.54	146.42	140.48	134.09	14.8%	-4.1%	-4.5%
37 COAL ($/TON)	79.37	78.77	73.42	62.71	-0.8%	-6.8%	-14.6%
38 NATURAL GAS ($/MCF)	3.48	2.97	4.44	4.42	-14.7%	49.5%	-0.5%
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}	21.90	25.12	24.03	22.86	14.7%	-4.3%	-4.9%
43 COAL	3.43	3.46	3.22	2.79	0.9%	-6.9%	-13.4%
44 NATURAL GAS	3.41	2.90	4.34	4.30	-15.0%	49.7%	-0.9%
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)	**3.41**	**2.94**	**4.22**	**4.12**	**-13.8%**	**43.5%**	**-2.4%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL {1}	14,368	13,324	13,982	13,000	-7.3%	4.9%	-7.0%
50 COAL	11,034	10,879	11,244	11,892	-1.4%	3.4%	5.8%
51 NATURAL GAS	8,050	7,931	7,837	7,343	-1.5%	-1.2%	-6.3%
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)	**7,921**	**7,596**	**7,494**	**6,919**	**-4.1%**	**-1.3%**	**-7.7%**
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL {1}	31.47	33.47	33.60	29.72	6.4%	0.4%	-11.5%
57 COAL	3.79	3.76	3.63	3.31	-0.8%	-3.5%	-8.8%
58 NATURAL GAS	2.74	2.30	3.40	3.16	-16.1%	47.8%	-7.1%
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)	**2.70**	**2.23**	**3.16**	**2.85**	**-17.4%**	**41.7%**	**-9.8%**

{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 2022 - DECEMBER 2022

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2022 through December 2022

	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	6,622,149	3.057	202,439,095	2.745	181,777,990
TIER II (Over 1,000) kWh	3,003,068	3.057	91,803,776	3.745	112,464,881
Total	9,625,217		294,242,871		294,242,871

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS
JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY AND EXHIBIT
OF
PATRICK A. BOKOR

FILED: SEPTEMBER 3, 2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

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

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

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

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have over 15 years of experience in the electric industry, in the areas of unit commitment and economic dispatch, power and gas trading, accounting, and risk management. In my current role, I am responsible for developing and implementing business plans and strategic initiatives to optimize business performance of Tampa

Electric's generation. Specifically, I am responsible for directing short-term resource availability, preparation of the hourly, daily and weekend Unit Commitment Plan for review and approval by grid operations, fleet optimization, and overall operating and business performance.

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. PAB-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2022 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 2022 through December 2022 represent 82.6 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, Big Bend Unit 4 and Polk 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 2022 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 2022 period, the projected EUOF for Big Bend Unit 4 is 16.2 percent, the POF is 12.1 percent. Therefore, the target EAF for Big Bend Unit 4 equals 71.7 percent or:

$$100\% - (16.2\% + 12.1\%) = 71.7\%$$

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 Big Bend Unit 4 example:

$$EAF_{MAX} = 1 - [0.80\ (16.2\%) + 0.95\ (12.1\%)] = 75.6\%$$

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 Big Bend Unit 4 example,

$$EAF_{MIN} = 1 - [1.40\ (16.2\%) + 1.10\ (12.1\%)] = 64.0\%$$

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 2022 through December 2022 are shown on page 17 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2022; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for planned outages from April 1, 2022 to April 14, 2022 and from October 4, 2022 to November 2, 2022. There are 1,056 planned outage hours scheduled for the 2022 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 4 is 12.1 percent or:

$$\frac{1,056}{8,760} \times 100\% = 12.1\%$$

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 1.9 percent. Polk Unit 2 has a POF of 7.9 percent. Bayside Unit 1 has a POF of 20.3 percent, and Bayside Unit 2 has a POF of 3.8 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 16.2 percent for Big Bend Unit 4. The EUOF of Big Bend Unit 4 is verified by the data shown on page 12, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(673 + 747)}{8{,}760} \times 100\% = 16.2\%$$

Relative to Big Bend Unit 4, the EUOF of 16.2 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 10.3 percent. The unit will have one planned outage in 2022, and the POF is 1.9 percent. Therefore, the target equivalent availability for this unit is 87.7 percent.

Polk Unit 2

The projected EUOF for this unit is 2.7 percent. The unit will have two planned outages in 2022, and the POF is 7.9 percent. Therefore, the target equivalent availability for this unit is 89.3 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.4 percent. The unit will have one planned outage in 2022, and the POF is 20.3 percent. Therefore, the target equivalent availability for this unit is 77.4 percent.

Bayside Unit 2

The projected EUOF for this unit is 3.4 percent. The unit will have one planned outage in 2022, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 92.7 percent.

Big Bend Unit 4

The projected EUOF for this unit is 16.2 percent. The unit will have two planned outages in 2022, and the POF is 12.1 percent. Therefore, the target equivalent availability for this unit is 71.7 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 82.1 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 Big Bend Unit 4 on page 12 of Document No. 1. Except for the months of April, October, and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of April, October, and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the 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 2022 period.

A. The heat rate target for Polk Unit 1 is 8,855 Btu/Net kWh with a range of ±1,584 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,841 Btu/Net kWh with a range of ±923 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,339 Btu/Net kWh with a range of ±171 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,695 Btu/Net kWh with a range of ±276 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,726 Btu/Net kWh with a range of ±1,102 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 $487,019,890 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 $31,877,118 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 Big Bend Unit 4, the weighting factor for average net operating heat rate is 11.18 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 7 of Document No. 1, if Big Bend Unit 4, operates at 9,624 average net operating heat rate, fuel savings would equal $3,563,326 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 $31,877,118. 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 2022 through December 2022 is $4,108,620,276. This produces the maximum allowed jurisdictional incentive of $13,796,217 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 $15,938,559.

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).

$$GPIP = (0.0050\ EAP_{PK1} + 0.0501\ EAP_{PK2} + 0.0186\ EAP_{BAY1} + 0.0144\ EAP_{BAY2} + 0.0438\ EAP_{BB4} + 0.5247\ HRP_{PK2} + 0.0445\ HRP_{BAY1} + 0.1209\ HRP_{BAY2} + 0.1118\ HRP_{BB4} + 0.0662\ HRP_{PK1})$$

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 2022 through December 2022 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.

EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKOR

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2022 - DECEMBER 2022

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2022 - DECEMBER 2022
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2022 - DECEMBER 2022

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	31,877.1	13,796.2
+9	28,689.4	12,416.6
+8	25,501.7	11,037.0
+7	22,314.0	9,657.4
+6	19,126.3	8,277.7
+5	15,938.6	6,898.1
+4	12,750.8	5,518.5
+3	9,563.1	4,138.9
+2	6,375.4	2,759.2
+1	3,187.7	1,379.6
0	0.0	0.0
-1	(3,159.1)	(1,379.6)
-2	(6,318.1)	(2,759.2)
-3	(9,477.2)	(4,138.9)
-4	(12,636.2)	(5,518.5)
-5	(15,795.3)	(6,898.1)
-6	(18,954.4)	(8,277.7)
-7	(22,113.4)	(9,657.4)
-8	(25,272.5)	(11,037.0)
-9	(28,431.5)	(12,416.6)
-10	(31,590.6)	(13,796.2)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2022 - DECEMBER 2022

Line 1	Beginning of period balance of common equity: End of month common equity:		$	4,003,519,446	
Line 2	Month of January	2022	$	4,021,748,185	
Line 3	Month of February	2022	$	4,056,100,618	
Line 4	Month of March	2022	$	4,090,746,477	
Line 5	Month of April	2022	$	4,038,461,239	
Line 6	Month of May	2022	$	4,072,956,429	
Line 7	Month of June	2022	$	4,107,746,265	
Line 8	Month of July	2022	$	4,125,833,476	
Line 9	Month of August	2022	$	4,161,074,971	
Line 10	Month of September	2022	$	4,196,617,486	
Line 11	Month of October	2022	$	4,143,592,373	
Line 12	Month of November	2022	$	4,178,985,558	
Line 13	Month of December	2022	$	4,214,681,059	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	4,108,620,276	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.45%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	13,796,217	
Line 18	Jurisdictional Sales			19,807,340	MWH
Line 19	Total Sales			19,807,340	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)		$	13,796,217	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	15,938,559	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	13,796,217	

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 2022 - DECEMBER 2022

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	4.38%	71.7	75.6	64.0	1,396.6	(1,511.6)
POLK 1	0.50%	87.7	89.9	83.4	160.0	(226.0)
POLK 2	5.01%	89.3	90.3	87.5	1,595.5	(1,422.5)
BAYSIDE 1	1.86%	77.4	78.9	74.4	592.7	(66.4)
BAYSIDE 2	1.44%	92.7	93.6	91.0	458.8	(690.7)
GPIF SYSTEM	**13.19%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	11.18%	10,726	47.8	9,624	11,828	3,563.3	(3,563.3)
POLK 1	6.62%	8,855	79.1	7,271	10,440	2,111.3	(2,111.3)
POLK 2	52.47%	6,841	76.0	5,918	7,764	16,725.7	(16,725.7)
BAYSIDE 1	4.45%	7,339	65.3	7,168	7,510	1,417.9	(1,417.9)
BAYSIDE 2	12.09%	7,695	47.4	7,419	7,971	3,855.2	(3,855.2)
GPIF SYSTEM	**86.81%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 22 - DEC 22 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 20 - DEC 20 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 19 - DEC 19 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 18 - DEC 18 POF	EUOF	EUOR
BIG BEND 4	4.38%	33.2%	12.1	16.2	18.4	39.1	24.8	40.6	16.5	28.0	39.8	19.1	20.6	26.6
POLK 1	0.50%	3.8%	1.9	10.3	10.5	5.3	22.4	33.3	6.7	14.9	22.8	28.1	10.7	16.3
POLK 2	5.01%	38.0%	7.9	2.7	2.9	3.2	10.4	10.1	4.5	3.7	3.8	2.0	3.3	3.2
BAYSIDE 1	1.86%	14.1%	20.3	2.4	3.0	7.8	3.4	3.9	11.1	6.7	7.4	5.3	1.6	1.7
BAYSIDE 2	1.44%	10.9%	3.8	3.4	3.6	4.3	5.9	6.3	12.8	4.0	4.5	19.6	2.5	3.1
GPIF SYSTEM	**13.19%**	**100.0%**	**10.4**	**7.5**	**8.5**	**16.0**	**14.1**	**19.8**	**10.4**	**12.6**	**17.1**	**11.1**	**9.0**	**11.3**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**82.1**			**69.9**			**77.0**			**79.9**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
12.5	**11.9**	**16.0**	**75.6**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 22 - DEC 22	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 20 - DEC 20	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18
BIG BEND 4	11.18%	12.9%	10,726	11,017	10,986	10,959
POLK 1	6.62%	7.6%	8,855	8,774	8,757	10,367
POLK 2	52.47%	60.4%	6,841	6,640	7,458	6,983
BAYSIDE 1	4.45%	5.1%	7,339	7,363	7,361	7,378
BAYSIDE 2	12.09%	13.9%	7,695	7,619	7,726	7,594
GPIF SYSTEM	**86.81%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**7,639**	**7,540**	**8,044**	**7,859**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2022 - DECEMBER 2022
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	487,019.89	485,623.26	1,396.63	4.38%
EA_1 POLK 1	487,019.89	486,859.87	160.02	0.50%
EA_2 POLK 2	487,019.89	485,424.37	1,595.52	5.01%
EA_3 BAYSIDE 1	487,019.89	486,427.17	592.72	1.86%
EA_4 BAYSIDE 2	487,019.89	486,561.10	458.79	1.44%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	487,019.89	483,456.56	3,563.33	11.18%
AHR_1 POLK 1	487,019.89	484,908.57	2,111.32	6.62%
AHR_2 POLK 2	487,019.89	470,294.19	16,725.70	52.47%
AHR_3 BAYSIDE 1	487,019.89	485,601.97	1,417.92	4.45%
AHR_4 BAYSIDE 2	487,019.89	483,164.72	3,855.17	12.09%
TOTAL SAVINGS			**31,877.12**	**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 2022 - DECEMBER 2022

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,396.6	75.6	+10	3,563.3	9,624
+9	1,257.0	78.0	+9	3,207.0	9,727
+8	1,117.3	80.5	+8	2,850.7	9,829
+7	977.6	82.9	+7	2,494.3	9,932
+6	838.0	85.3	+6	2,138.0	10,035
+5	698.3	87.8	+5	1,781.7	10,137
+4	558.7	90.2	+4	1,425.3	10,240
+3	419.0	92.7	+3	1,069.0	10,343
+2	279.3	95.1	+2	712.7	10,446
+1	139.7	97.6	+1	356.3	10,548
					10,651
0	0.0	100.0	0	0.0	10,726
					10,801
-1	(151.2)	96.4	-1	(356.3)	10,904
-2	(302.3)	92.8	-2	(712.7)	11,007
-3	(453.5)	89.2	-3	(1,069.0)	11,109
-4	(604.6)	85.6	-4	(1,425.3)	11,212
-5	(755.8)	82.0	-5	(1,781.7)	11,315
-6	(906.9)	78.4	-6	(2,138.0)	11,418
-7	(1,058.1)	74.8	-7	(2,494.3)	11,520
-8	(1,209.3)	71.2	-8	(2,850.7)	11,623
-9	(1,360.4)	67.6	-9	(3,207.0)	11,726
-10	(1,511.6)	64.0	-10	(3,563.3)	11,828
	Weighting Factor =	4.38%		Weighting Factor =	11.18%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

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	160.0	89.9	+10	2,111.3	7,271
+9	144.0	89.7	+9	1,900.2	7,422
+8	128.0	89.5	+8	1,689.1	7,573
+7	112.0	89.3	+7	1,477.9	7,724
+6	96.0	89.0	+6	1,266.8	7,875
+5	80.0	88.8	+5	1,055.7	8,026
+4	64.0	88.6	+4	844.5	8,177
+3	48.0	88.4	+3	633.4	8,327
+2	32.0	88.2	+2	422.3	8,478
+1	16.0	88.0	+1	211.1	8,629
					8,780
0	0.0	87.7	0	0.0	8,855
					8,930
-1	(22.6)	87.3	-1	(211.1)	9,081
-2	(45.2)	86.9	-2	(422.3)	9,232
-3	(67.8)	86.4	-3	(633.4)	9,383
-4	(90.4)	86.0	-4	(844.5)	9,534
-5	(113.0)	85.6	-5	(1,055.7)	9,685
-6	(135.6)	85.1	-6	(1,266.8)	9,836
-7	(158.2)	84.7	-7	(1,477.9)	9,987
-8	(180.8)	84.3	-8	(1,689.1)	10,138
-9	(203.4)	83.8	-9	(1,900.2)	10,289
-10	(226.0)	83.4	-10	(2,111.3)	10,440
	Weighting Factor =	0.50%		Weighting Factor =	6.62%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

POLK 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,595.5	90.3	+10	16,725.7	5,918
+9	1,436.0	90.2	+9	15,053.1	6,003
+8	1,276.4	90.1	+8	13,380.6	6,088
+7	1,116.9	90.0	+7	11,708.0	6,173
+6	957.3	89.9	+6	10,035.4	6,257
+5	797.8	89.8	+5	8,362.9	6,342
+4	638.2	89.7	+4	6,690.3	6,427
+3	478.7	89.6	+3	5,017.7	6,512
+2	319.1	89.5	+2	3,345.1	6,596
+1	159.6	89.4	+1	1,672.6	6,681
					6,766
0	0.0	89.3	0	0.0	6,841
					6,916
-1	(142.3)	89.2	-1	(1,672.6)	7,001
-2	(284.5)	89.0	-2	(3,345.1)	7,086
-3	(426.8)	88.8	-3	(5,017.7)	7,170
-4	(569.0)	88.6	-4	(6,690.3)	7,255
-5	(711.3)	88.4	-5	(8,362.9)	7,340
-6	(853.5)	88.2	-6	(10,035.4)	7,425
-7	(995.8)	88.0	-7	(11,708.0)	7,510
-8	(1,138.0)	87.8	-8	(13,380.6)	7,594
-9	(1,280.3)	87.6	-9	(15,053.1)	7,679
-10	(1,422.5)	87.5	-10	(16,725.7)	7,764
	Weighting Factor =	5.01%		Weighting Factor =	52.47%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

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	592.7	78.9	+10	1,417.9	7,168
+9	533.4	78.7	+9	1,276.1	7,178
+8	474.2	78.6	+8	1,134.3	7,188
+7	414.9	78.4	+7	992.5	7,197
+6	355.6	78.3	+6	850.8	7,207
+5	296.4	78.1	+5	709.0	7,216
+4	237.1	78.0	+4	567.2	7,226
+3	177.8	77.8	+3	425.4	7,236
+2	118.5	77.7	+2	283.6	7,245
+1	59.3	77.5	+1	141.8	7,255
					7,264
0	0.0	77.4	0	0.0	7,339
					7,414
-1	(6.6)	77.1	-1	(141.8)	7,424
-2	(13.3)	76.8	-2	(283.6)	7,434
-3	(19.9)	76.5	-3	(425.4)	7,443
-4	(26.5)	76.2	-4	(567.2)	7,453
-5	(33.2)	75.9	-5	(709.0)	7,462
-6	(39.8)	75.6	-6	(850.8)	7,472
-7	(46.5)	75.3	-7	(992.5)	7,482
-8	(53.1)	75.0	-8	(1,134.3)	7,491
-9	(59.7)	74.7	-9	(1,276.1)	7,501
-10	(66.4)	74.4	-10	(1,417.9)	7,510
	Weighting Factor =	1.86%		Weighting Factor =	4.45%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

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	458.8	93.6	+10	3,855.2	7,419
+9	412.9	93.5	+9	3,469.7	7,439
+8	367.0	93.4	+8	3,084.1	7,459
+7	321.2	93.4	+7	2,698.6	7,479
+6	275.3	93.3	+6	2,313.1	7,499
+5	229.4	93.2	+5	1,927.6	7,519
+4	183.5	93.1	+4	1,542.1	7,540
+3	137.6	93.0	+3	1,156.6	7,560
+2	91.8	92.9	+2	771.0	7,580
+1	45.9	92.8	+1	385.5	7,600
					7,620
0	0.0	92.7	0	0.0	7,695
					7,770
-1	(69.1)	92.6	-1	(385.5)	7,790
-2	(138.1)	92.4	-2	(771.0)	7,810
-3	(207.2)	92.2	-3	(1,156.6)	7,830
-4	(276.3)	92.0	-4	(1,542.1)	7,850
-5	(345.3)	91.9	-5	(1,927.6)	7,870
-6	(414.4)	91.7	-6	(2,313.1)	7,891
-7	(483.5)	91.5	-7	(2,698.6)	7,911
-8	(552.5)	91.3	-8	(3,084.1)	7,931
-9	(621.6)	91.2	-9	(3,469.7)	7,951
-10	(690.7)	91.0	-10	(3,855.2)	7,971
	Weighting Factor =	1.44%		Weighting Factor =	12.09%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

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-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022
1. EAF (%)	81.6	81.6	81.6	43.5	81.6	81.6	81.6	81.6	81.6	7.9	76.1	81.6	71.7
2. POF	0.0	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	90.3	6.7	0.0	12.1
3. EUOF	18.4	18.4	18.4	9.8	18.4	18.4	18.4	18.4	18.4	1.8	17.2	18.4	16.2
4. EUOR	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	673	608	542	477	673	651	673	673	651	66	608	673	6,968
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	71	64	202	243	71	69	71	71	69	678	112	71	1,792
9. POH	0	0	0	336	0	0	0	0	0	672	48	0	1,056
10. EFOH	65	59	65	34	65	63	65	65	63	6	59	65	673
11. EMOH	72	65	72	37	72	70	72	72	70	7	65	72	747
12. OPER BTU (GBTU)	1,470	1,266	1,123	983	1,416	1,430	1,509	1,577	1,613	167	1,251	1,398	15,204
13. NET GEN (MWH)	137,010	117,830	104,500	91,550	131,920	133,370	140,840	147,300	150,960	15,670	116,460	130,100	1,417,510
14. ANOHR (Btu/kwh)	10,730	10,743	10,745	10,740	10,734	10,722	10,716	10,703	10,685	10,678	10,740	10,744	10,726
15. NOF (%)	47.1	44.9	44.6	45.5	46.4	48.5	49.6	51.9	55.0	56.3	45.4	44.7	47.8
16. NPC (MW)	432	432	432	422	422	422	422	422	422	422	422	432	425
17. ANOHR EQUATION	ANOHR = NOF(		-5.752	) +	11,001								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

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-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022
1. EAF (%)	89.5	89.5	89.5	89.5	69.3	89.5	89.5	89.5	89.5	89.5	89.5	89.5	87.7
2. POF	0.0	0.0	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3. EUOF	10.5	10.5	10.5	10.5	8.2	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.3
4. EUOR	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	64	32	114	185	154	276	406	334	444	501	272	144	2,926
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	680	640	630	535	590	444	338	410	276	243	448	600	5,834
9. POH	0	0	0	0	168	0	0	0	0	0	0	0	168
10. EFOH	0	0	0	0	0	0	0	0	0	0	0	0	1
11. EMOH	78	71	78	76	61	76	78	78	76	78	76	78	905
12. OPER BTU (GBTU)	97	48	168	271	230	421	615	496	691	781	395	213	4,438
13. NET GEN (MWH)	10,860	5,340	18,740	30,630	26,020	47,770	69,780	56,150	78,730	88,920	44,490	23,720	501,150
14. ANOHR (Btu/kwh)	8,930	8,947	8,962	8,858	8,836	8,808	8,816	8,841	8,780	8,778	8,872	8,960	8,855
15. NOF (%)	73.8	72.6	71.5	78.8	80.5	82.4	81.8	80.1	84.4	84.5	77.9	71.6	79.1
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217
17. ANOHR EQUATION	ANOHR = NOF(		-14.091	) +	9,969								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

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-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022
1. EAF (%)	97.1	97.1	21.9	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	81.4	89.3
2. POF	0.0	0.0	77.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	7.9
3. EUOF	2.9	2.9	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.5	2.7
4. EUOR	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	719	650	593	703	726	703	726	726	703	726	703	596	8,274
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	25	22	151	17	18	17	18	18	17	18	17	148	486
9. POH	0	0	576	0	0	0	0	0	0	0	0	120	696
10. EFOH	12	11	3	12	12	12	12	12	12	12	12	10	133
11. EMOH	10	9	2	9	10	9	10	10	9	10	9	8	105
12. OPER BTU (GBTU)	4,695	4,226	3,737	3,758	4,269	4,304	4,429	4,402	4,192	4,220	2,349	1,971	47,610
13. NET GEN (MWH)	706,640	634,120	549,650	539,980	651,230	679,030	696,250	688,390	646,460	638,210	290,900	238,550	6,959,410
14. ANOHR (Btu/kwh)	6,644	6,664	6,799	6,960	6,555	6,339	6,361	6,395	6,485	6,612	8,074	8,262	6,841
15. NOF (%)	81.9	81.3	77.2	72.4	84.5	91.0	90.4	89.4	86.7	82.9	39.0	33.4	76.0
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(		-33.331	) +	9,373								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

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-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022
1. EAF (%)	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	29.1	0.0	25.9	97.0	77.4
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	100.0	73.3	0.0	20.3
3. EUOF	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.9	0.0	0.8	3.0	2.4
4. EUOR	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	3.0	3.0	3.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	687	645	718	694	714	694	717	718	209	0	76	676	6,548
7. RSH	35	7	4	5	8	5	5	4	1	0	110	46	230
8. UH	22	20	22	21	22	21	22	22	510	744	534	22	1,982
9. POH	0	0	0	0	0	0	0	0	504	744	528	0	1,776
10. EFOH	15	14	15	15	15	15	15	15	4	0	4	15	145
11. EMOH	7	6	7	6	7	6	7	7	2	0	2	7	61
12. OPER BTU (GBTU)	2,242	1,961	2,540	2,554	2,741	2,913	3,031	2,796	756	0	114	1,226	22,953
13. NET GEN (MWH)	302,630	263,750	344,540	350,150	377,110	403,700	420,270	385,060	103,560	0	14,950	161,680	3,127,400
14. ANOHR (Btu/kwh)	7,407	7,435	7,372	7,293	7,269	7,216	7,212	7,261	7,302	0	7,599	7,584	7,339
15. NOF (%)	55.6	51.6	60.6	72.0	75.3	83.0	83.6	76.5	70.7	0.0	28.1	30.2	65.3
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-6.975	) +	7,795								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

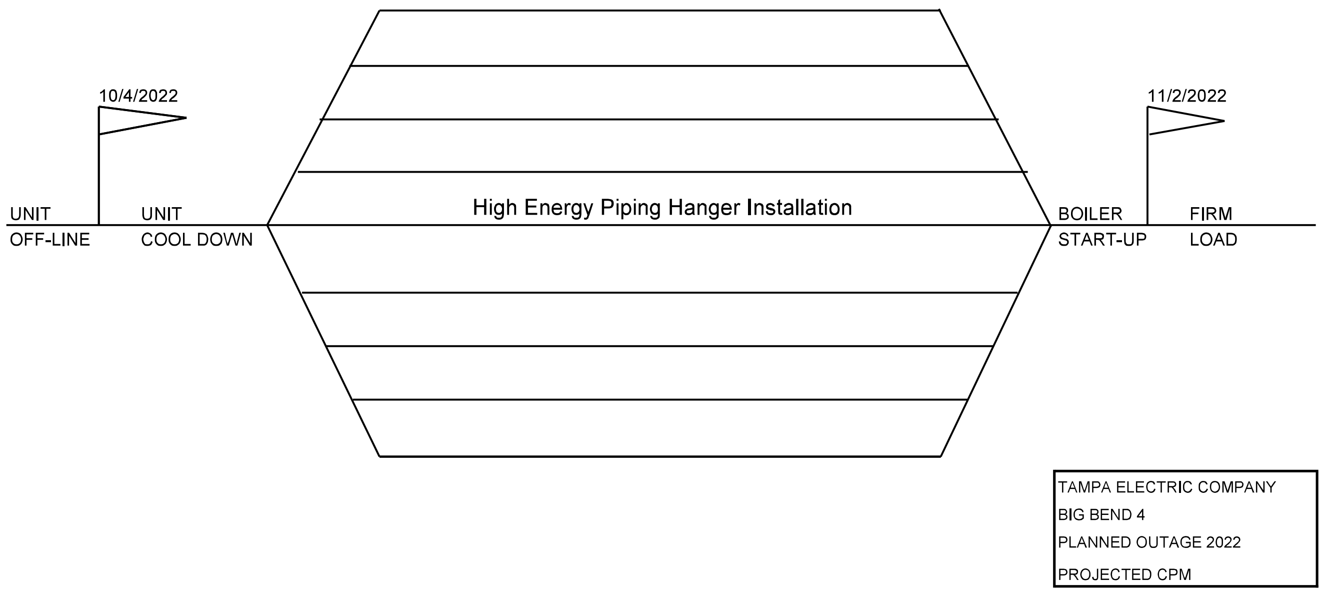
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022
1. EAF (%)	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	90.0	59.1	92.7
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7	38.7	3.8
3. EUOF	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.3	2.2	3.4
4. EUOR	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	669	623	700	691	716	694	717	716	694	717	514	172	7,623
7. RSH	49	25	18	3	2	0	1	2	0	1	134	268	502
8. UH	26	24	26	26	26	26	26	26	26	26	72	304	635
9. POH	0	0	0	0	0	0	0	0	0	0	48	288	336
10. EFOH	6	6	6	6	6	6	6	6	6	6	6	4	70
11. EMOH	20	18	20	20	20	20	20	20	20	20	18	12	229
12. OPER BTU (GBTU)	1,542	1,328	2,176	2,371	2,735	3,086	3,165	2,862	2,946	3,024	889	424	26,920
13. NET GEN (MWH)	190,460	163,160	275,920	308,720	361,910	420,290	430,350	381,650	397,300	407,300	108,630	52,670	3,498,360
14. ANOHR (Btu/kwh)	8,094	8,137	7,888	7,681	7,557	7,344	7,355	7,498	7,414	7,423	8,182	8,054	7,695
15. NOF (%)	27.2	25.0	37.6	48.1	54.4	65.2	64.6	57.4	61.6	61.1	22.7	29.2	47.4
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(	-19.753	) +		8,631								

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2022 - DECEMBER 2022

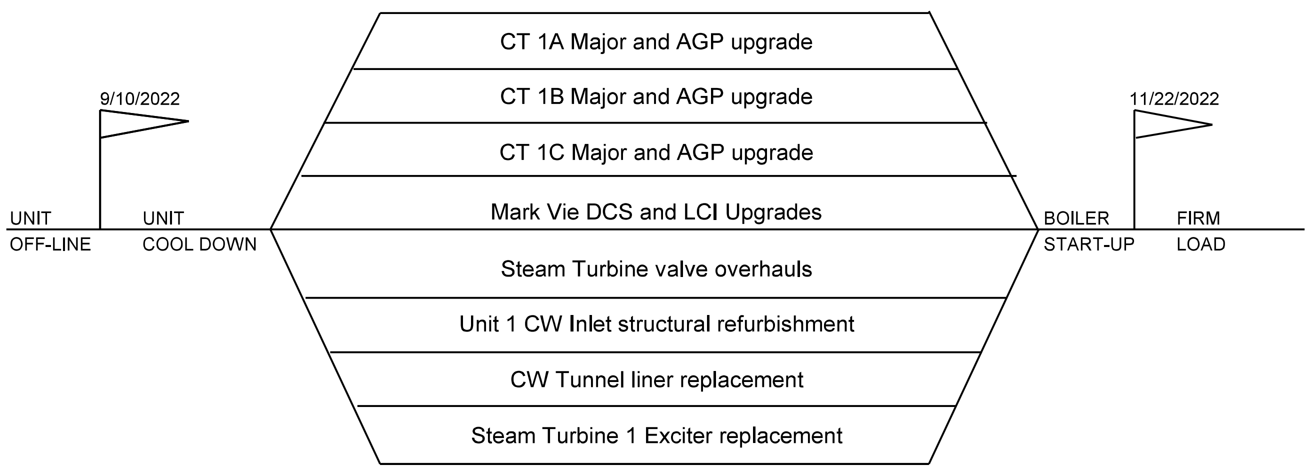
	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
	BIG BEND 4	Apr 01 - Apr 14	Fuel System Clean
+		Oct 04 - Nov 02	High Energy Piping Hanger Installation
	POLK 1	May 18 - May 24	Combined Cycle Planned Outage
	POLK 2	Mar 03 - Mar 26	Combined Cycle Planned Outage
		Dec 13 - Dec 17	Combined Cycle Planned Outage
+	BAYSIDE 1	Sep 10 - Nov 22	CT 1A Major and AGP upgrade CT 1B Major and AGP upgrade CT 1C Major and AGP upgrade Mark Vie DCS and LCI Upgrades Steam Turbine valve overhauls Unit 1 CW Inlet structural refurbishment CW Tunnel liner replacement Steam Turbine 1 Exciter replacement
	BAYSIDE 2	Nov 29 - Dec 12	Combined Cycle Planned Outage

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

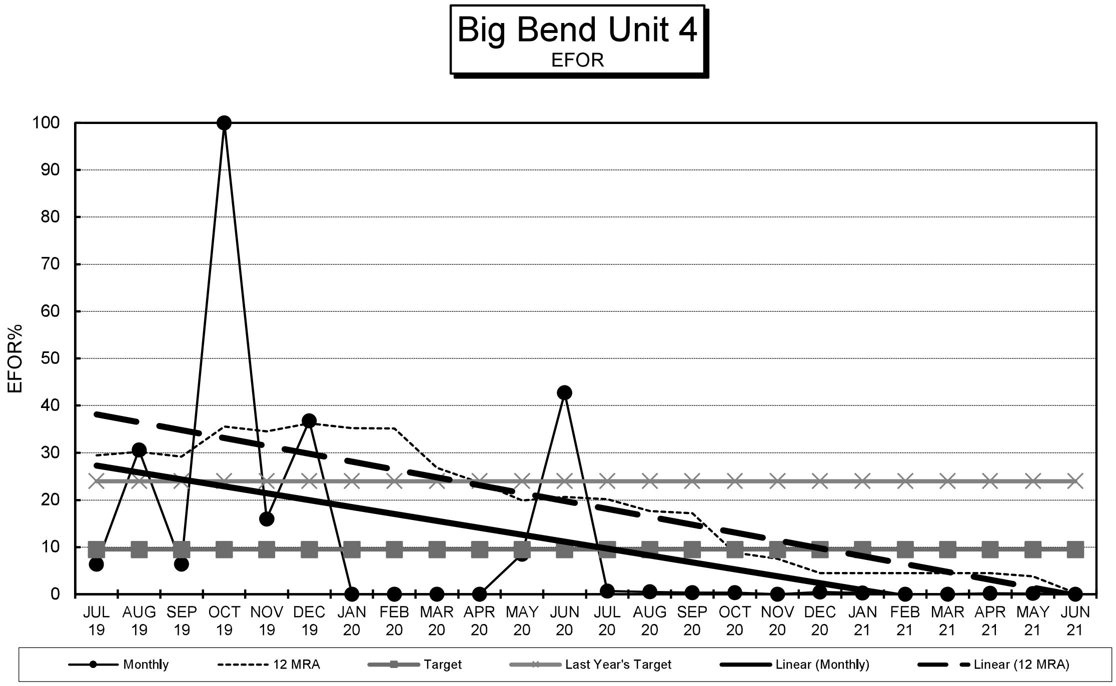
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2022 - DECEMBER 2022



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2022 - DECEMBER 2022



TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2022
PROJECTED CPM


Big Bend Unit 4
EFOR
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Monthly
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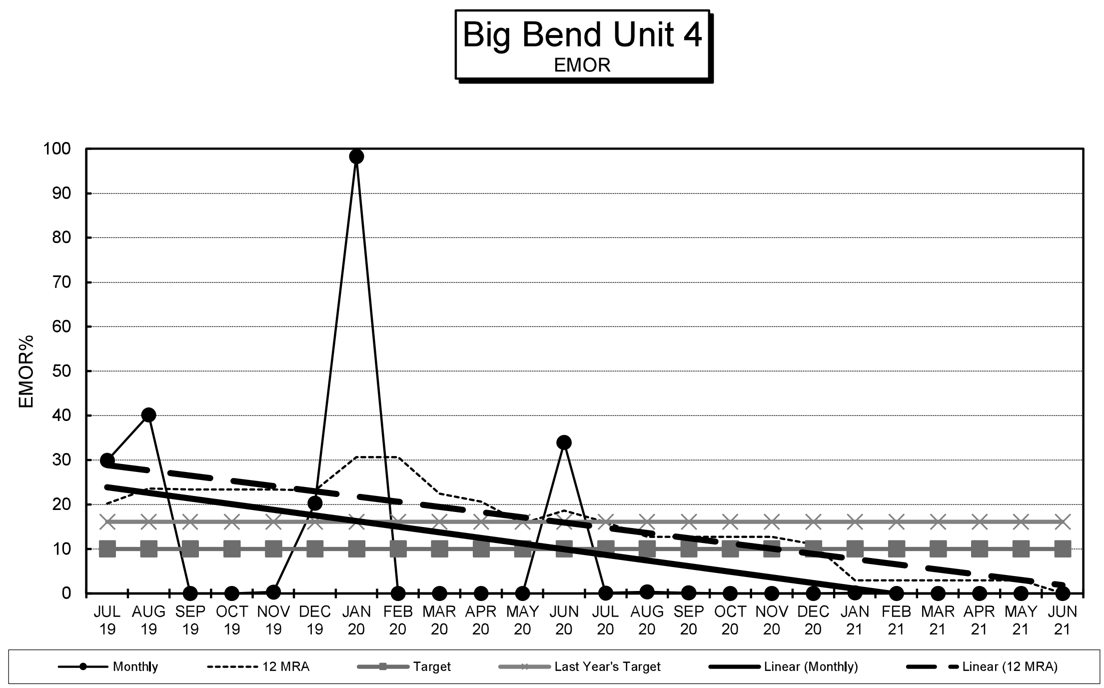
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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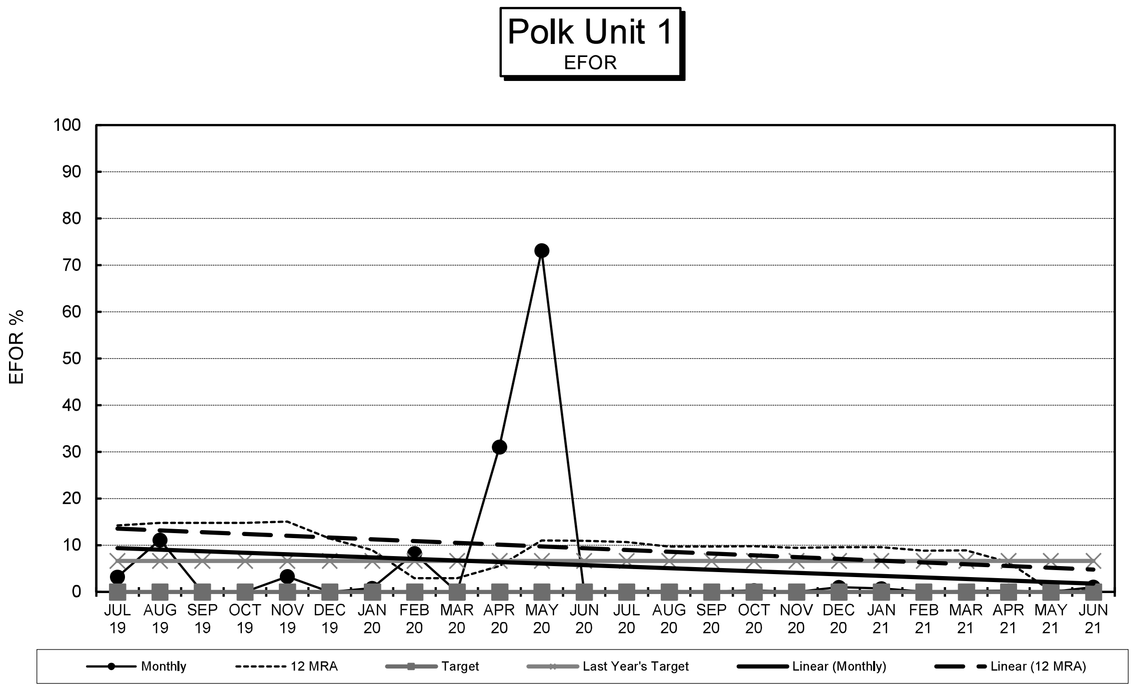
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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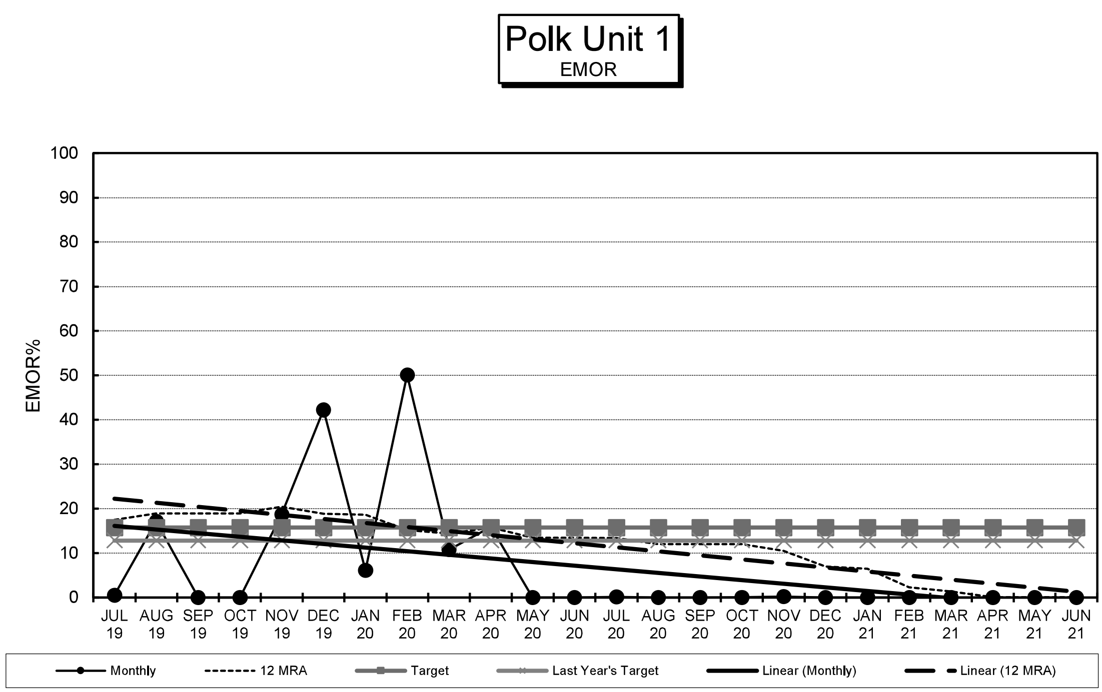
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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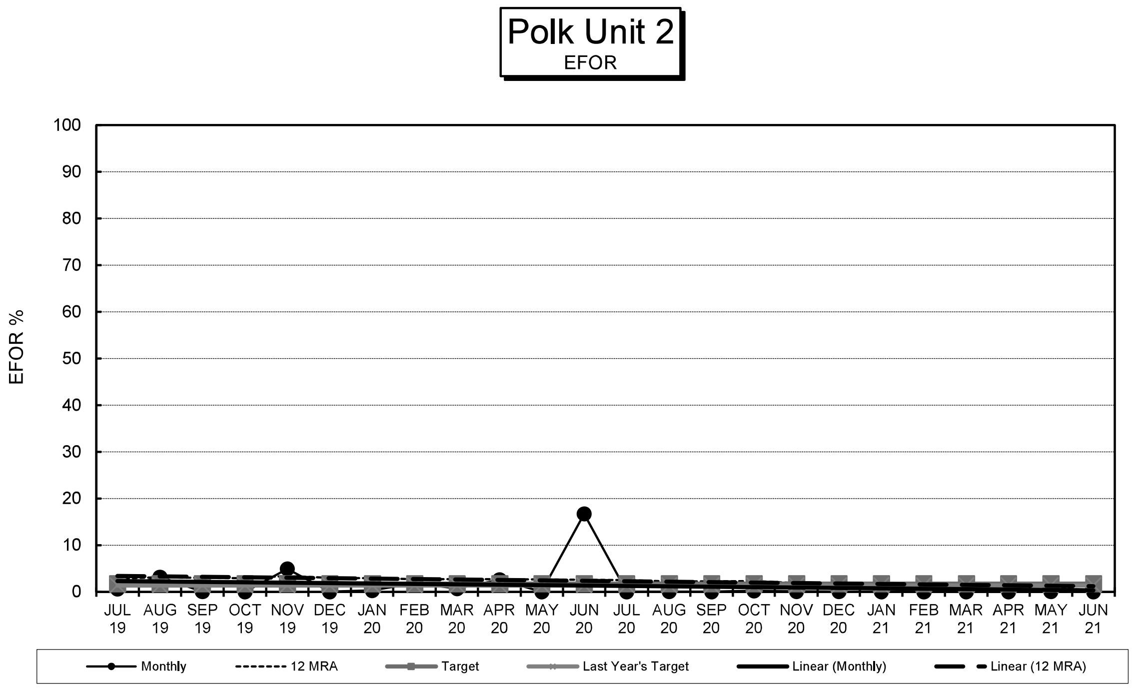
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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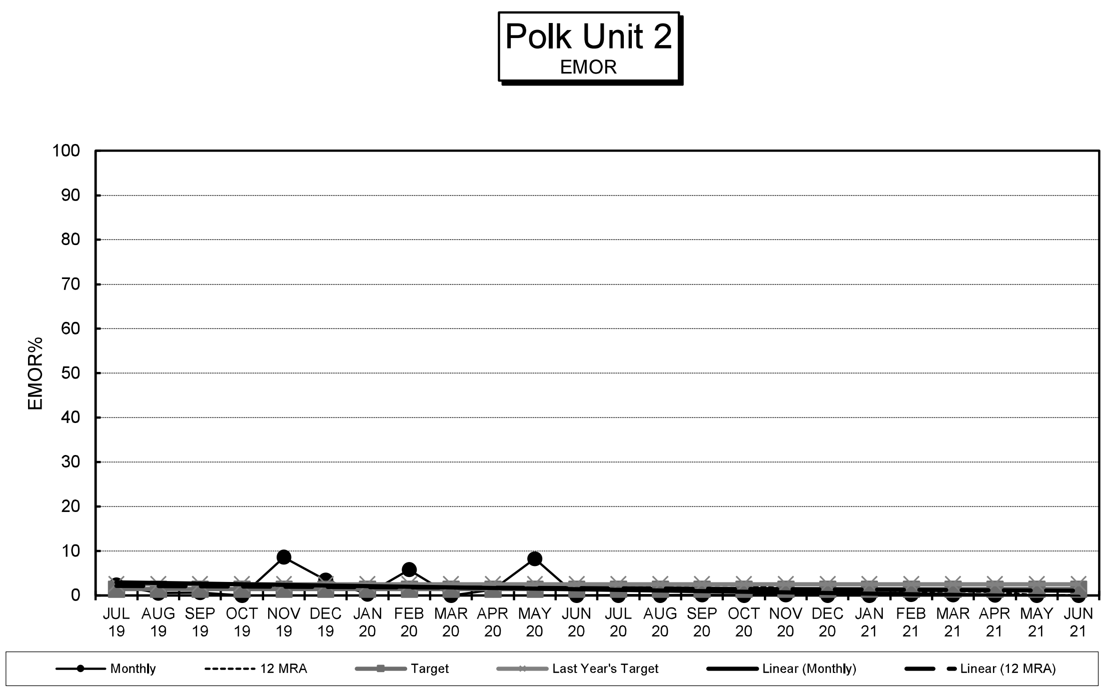
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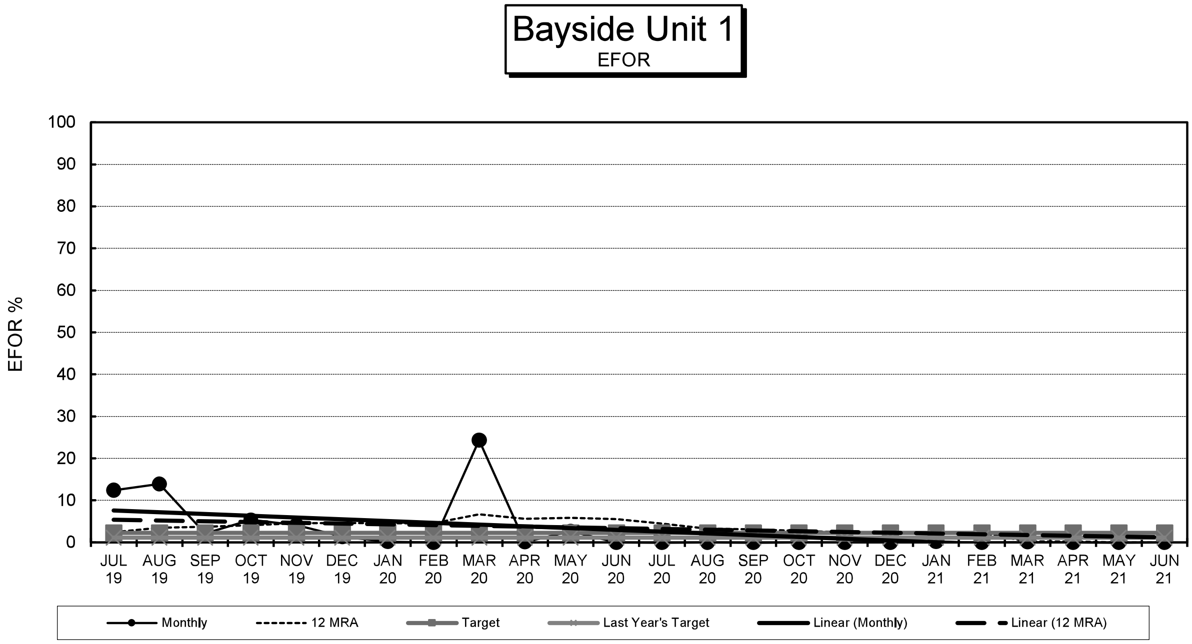
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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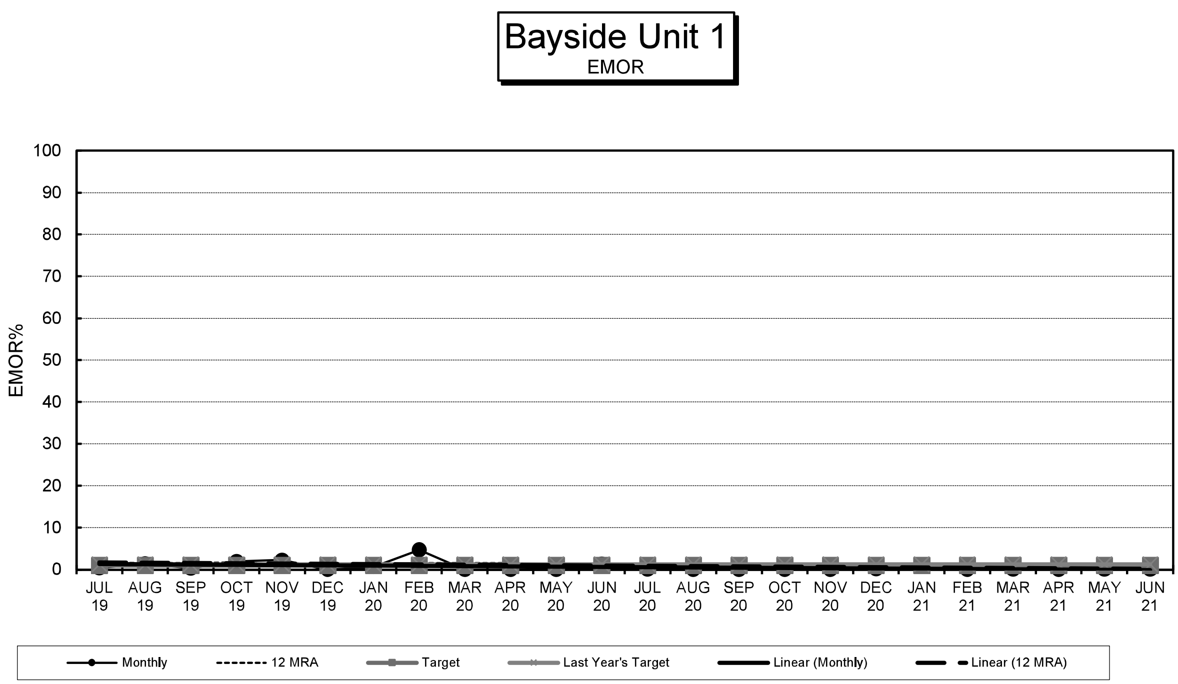
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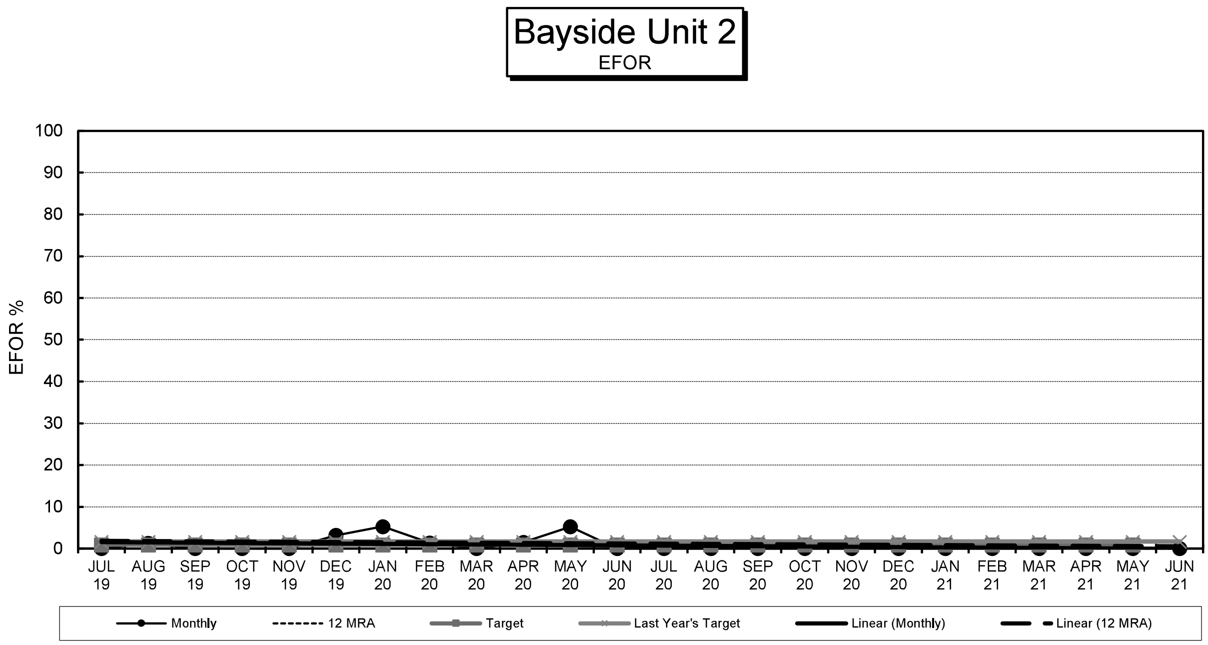
Bayside Unit 2
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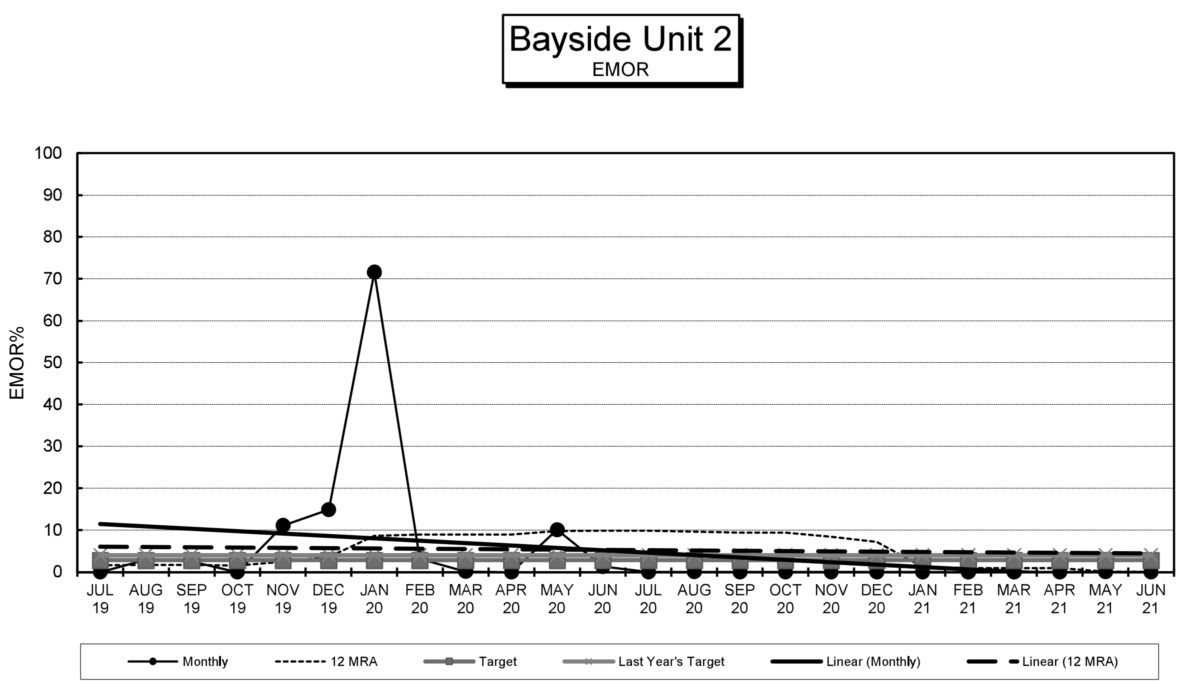
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Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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

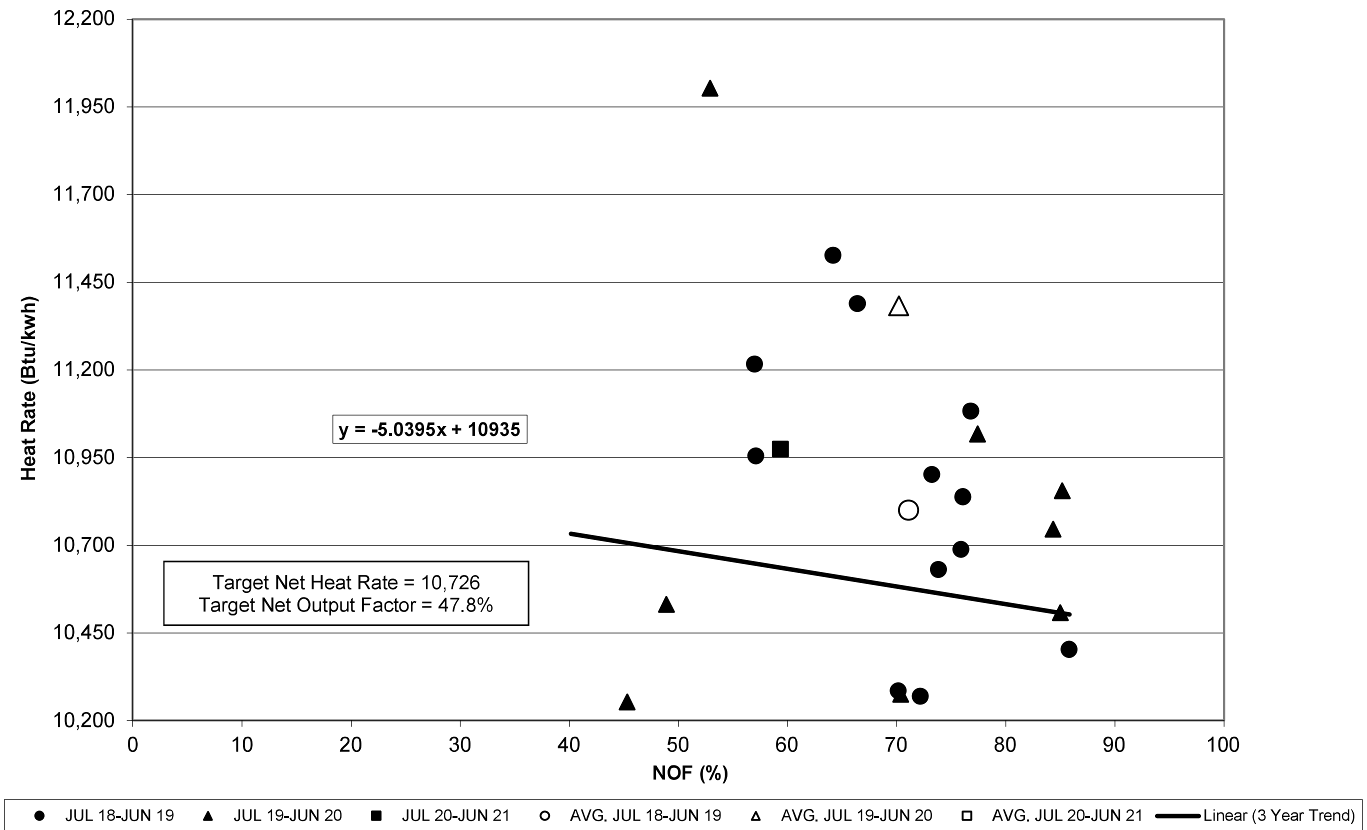

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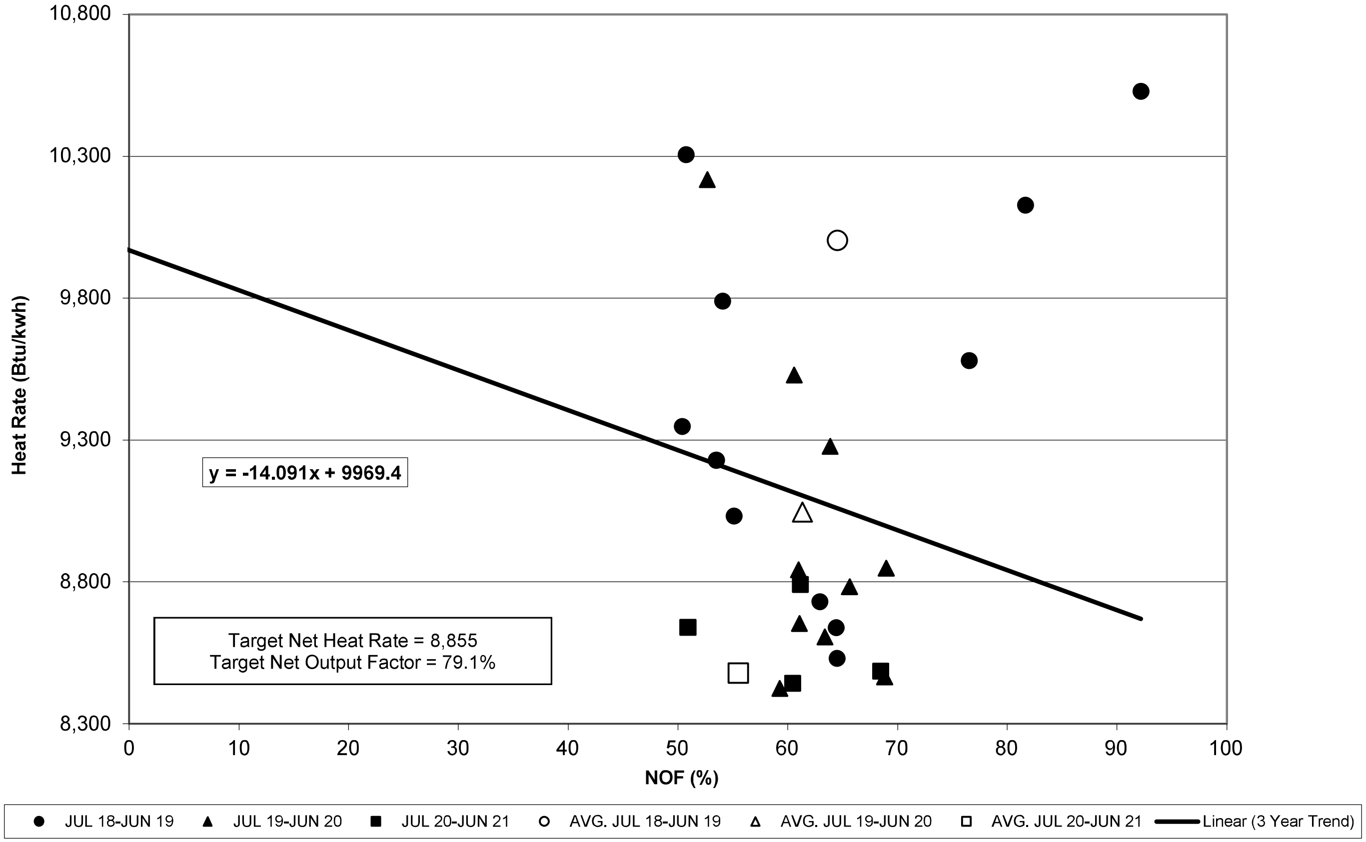
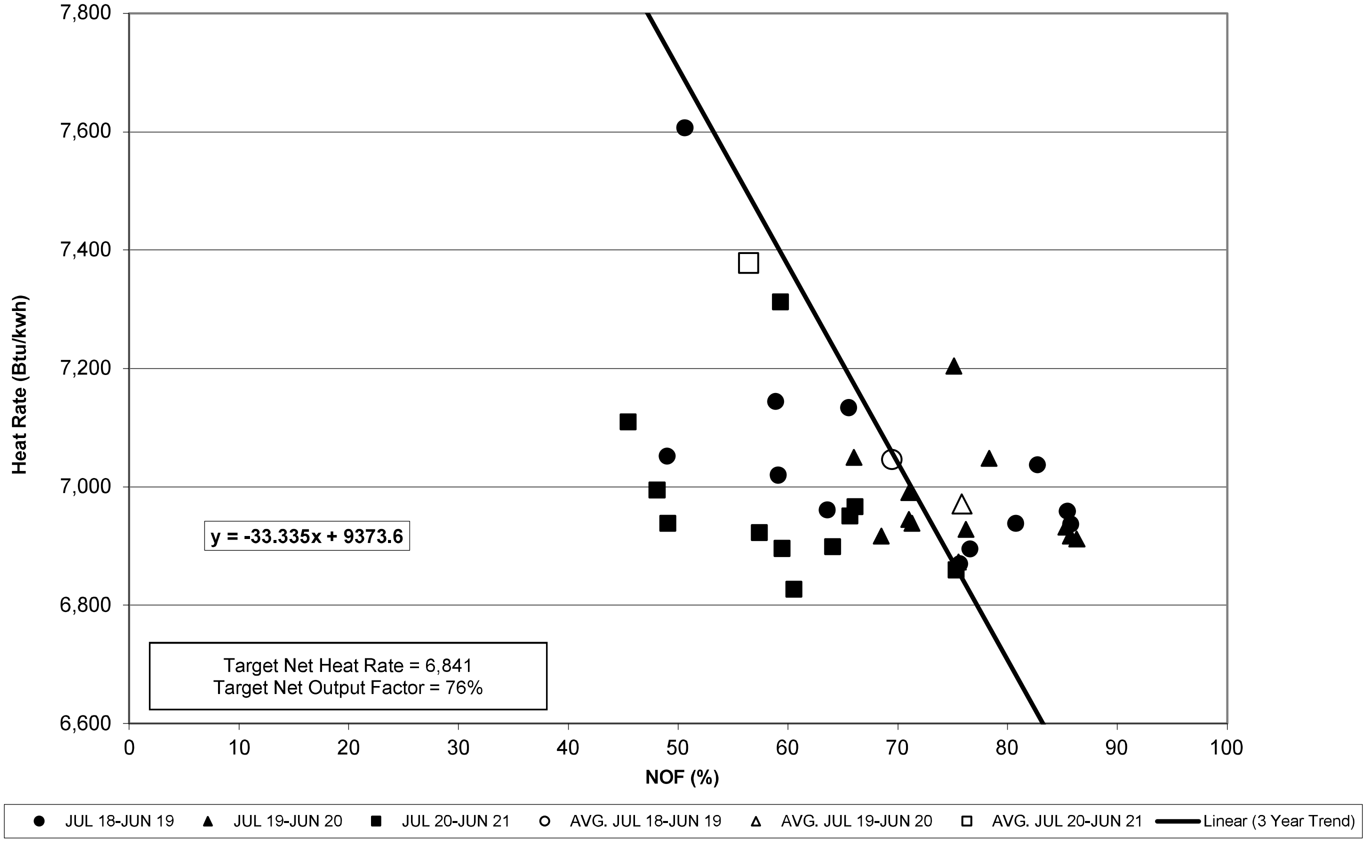
EXHIBIT NO. ______ (PAB-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
DOCUMENT NO. 1
PAGE 25 OF 32

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

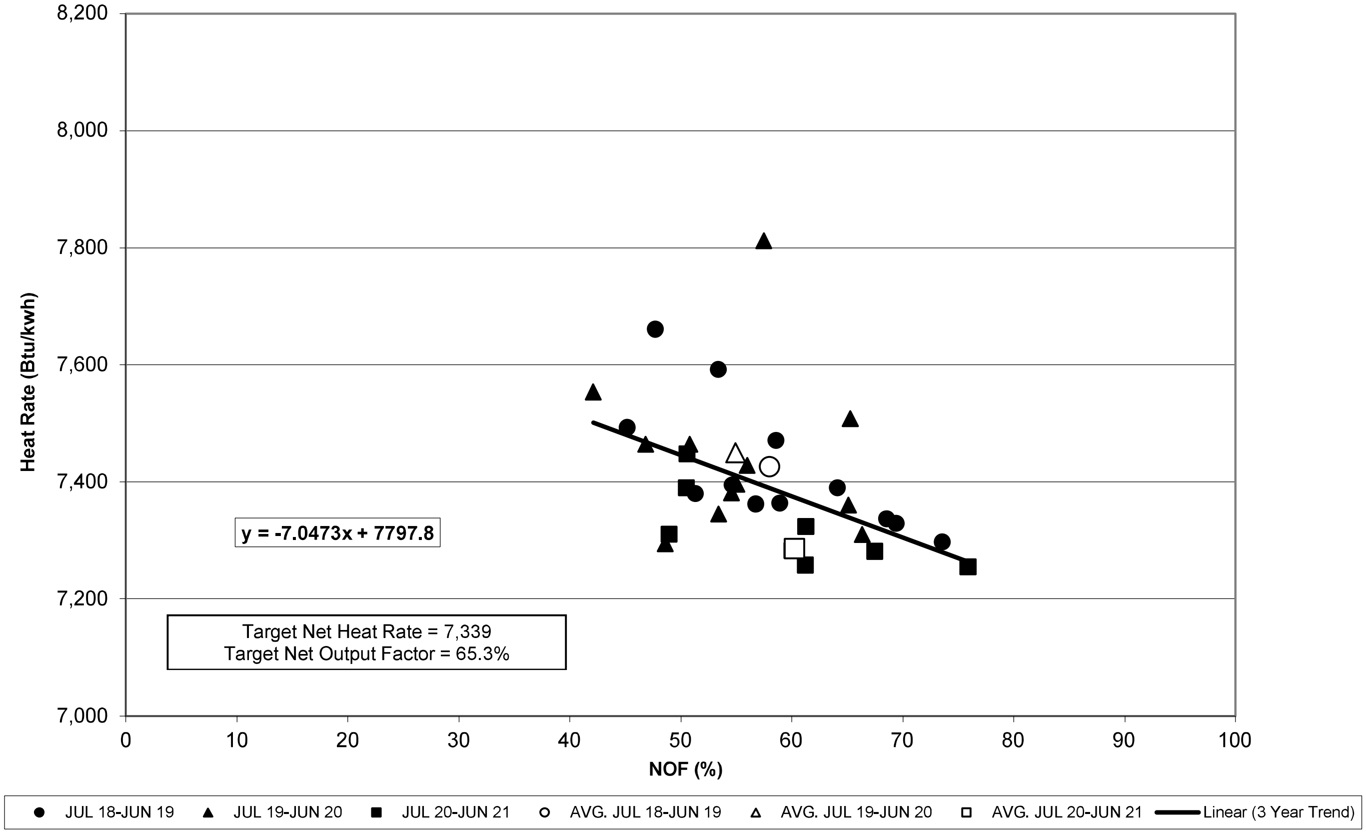


ORIGINAL SHEET NO. 8.401.20E
PAGE 26 OF 32

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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ORIGINAL SHEET NO. 8.401.20E
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EXHIBIT NO.______ (PAB-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
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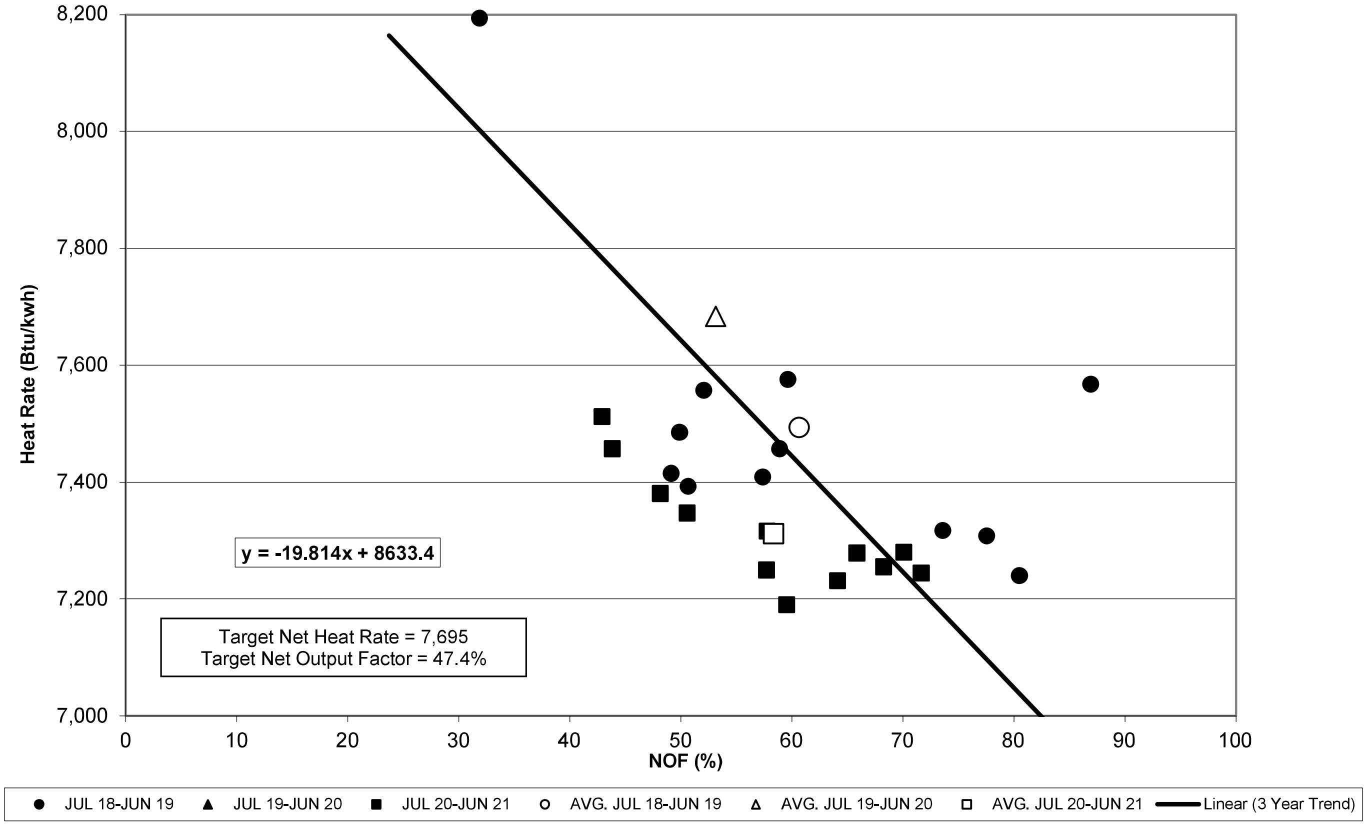
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2022 - DECEMBER 2022

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 2022 - DECEMBER 2022

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 2022 - DECEMBER 2022

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,959,410	37.07%	37.07%
BAYSIDE	2	3,498,360	18.64%	55.71%
BAYSIDE	1	3,127,400	16.66%	72.37%
SOLAR		1,544,800	8.23%	80.60%
BIG BEND	4	1,417,510	7.55%	88.15%
BIG BEND	1	756,930	4.03%	92.19%
POLK	1	501,150	2.67%	94.86%
BIG BEND	3	375,250	2.00%	96.85%
BIG BEND	5	256,820	1.37%	98.22%
BIG BEND	6	192,610	1.03%	99.25%
BAYSIDE	5	31,110	0.17%	99.41%
BAYSIDE	6	30,020	0.16%	99.57%
BAYSIDE	3	27,280	0.15%	99.72%
BIG BEND CT	4	26,660	0.14%	99.86%
BAYSIDE	4	25,860	0.14%	100.00%
BIG BEND	2	-	0.00%	100.00%
TOTAL GENERATION		18,771,170	100.00%	

GENERATION BY COAL UNITS:	1,417,510 MWH		GENERATION BY NATURAL GAS UNITS:	15,808,860 MWH
% GENERATION BY COAL UNITS	7.55%		% GENERATION BY NATURAL GAS UNITS:	84.22%
GENERATION BY SOLAR UNITS:	1,544,800 MWH		GENERATION BY GPIF UNITS:	15,503,830 MWH
% GENERATION BY SOLAR UNIT	8.23%		% GENERATION BY GPIF UNITS:	82.59%

EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKAR

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2022 - DECEMBER 2022

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2022 - DECEMBER 2022

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 4[1]	71.7	12.1	16.2	10,726
Polk 1[2]	87.7	1.9	10.3	8,855
Polk 2[3]	89.3	7.9	2.7	6,841
Bayside 1[4]	77.4	20.3	2.4	7,339
Bayside 2[5]	92.7	3.8	3.4	7,695

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

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY

OF

JOHN C. HEISEY

FILED: SEPTEMBER 3, 2021

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 Director, Origination and Trading.

Q. Have you previously filed testimony in Docket No. 20210001-EI?

A. Yes, I submitted direct testimony on April 2, 2021 and July 27, 2021.

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

A. Yes. My position is Director, Origination and Trading, as of August 2021.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for directing all activities associated with the procurement and delivery of energy commodities for Tampa Electric's generation fleet. Such activities include the trading, optimization, strategy, planning, origination, compliance and regulatory oversight of natural gas, power, coal, oil, byproducts, and associated delivery. I am also responsible for all aspects of the Optimization Mechanism.

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 generation portfolio includes natural gas, solar, coal, and, as a backup fuel, oil powered units. Big Bend Unit 2 operates on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas.

Big Bend Modernization project's first phase, Big Bend combustion turbine Units 5 and 6, is expected to be in service in December 2021 and will operate on natural gas. The second phase of the Big Bend Modernization project includes the addition of the Heat Recovery Steam Generator ("HRSG") in December 2022 and will result in the unit's operation in combined cycle mode. 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. Based upon the 2021 actual-estimate projections, the company expects 2021 total system generation, excluding purchased power, to be 85 percent natural gas, 7.5 percent solar, and 7.5 percent coal.

Likewise, in 2022, natural gas-fired and solar generation are expected to be 83 percent and 10 percent of total generation, respectively, with coal-fired generation making up 7 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 creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and 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 while maintaining the flexibility to adapt to any changing fuel needs. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. Tampa Electric targets natural gas supply that is reliable and resistant to the impacts of extreme weather. 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, extreme weather 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 to mitigate costs for 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 also receives 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, aero-derivative combustion turbine, and upcoming Big Bend Modernization project. Later this year, the first phase of a new gas pipeline lateral will be completed that allows natural gas to be delivered to the Big Bend Station from FGT under certain conditions, such as a Gulfstream outage. This lateral increases the fuel delivery reliability for Big Bend Station. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Units 1 and 2.

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 steady in 2022. Though the additional solar generation and the retirement of Big Bend Unit 2 will result in a reduction in natural gas usage in the period, they will be offset by increased natural gas usage at the efficient Big Bend Modernization project. 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. This storage was used during Storm Uri in February 2021 to replace interrupted supply and to mitigate costs for our customers.

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. All receipt points in the portfolio are reviewed annually to ensure access to reliable supply basins.

Q. Has Tampa Electric acquired additional natural gas transportation for 2021 and 2022 due to greater use of natural gas?

A. Yes, with 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 2021, Tampa Electric acquired short-term capacity on FGT in January and February to increase the reliability of the portfolio for its projected winter peak. In addition, a power purchase was executed for January as a lower cost solution compared to acquiring additional short-term pipeline capacity, as mentioned in the testimony of Tampa Electric witness Benjamin F. Smith, II. In the summer of 2021, Tampa Electric acquired additional pipeline capacity on Sabal Trail. This capacity provides additional transportation for the portfolio as Tampa Electric continues to transition from coal-fired generation to cleaner burning natural gas-fired generation. For 2022, Tampa Electric modified and extended existing Gulf South transportation. As a contractual requirement at the end of 2022, Tampa Electric will replace its Sabal Trail capacity with Gulfstream capacity to supply the Big Bend Modernization project and other portfolio gas requirements.

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 that 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 2022.

A. Since the company is projected to use less coal and more natural gas in 2022 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. 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 now purchases delivered coal, where waterborne coal supply and transportation are arranged by the supplier. Procuring delivered waterborne 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 2021 and 2022?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2021 and is evaluating how much coal to receive by rail in 2022.

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 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. Yes. Tampa Electric continues to burn natural gas as the economic fuel in Big Bend Unit 3 and Polk Unit 1. Big Bend Unit 4 is projected to burn coal in 2022. In addition, the company's strategy of utilizing short-term and spot delivered solid fuel purchases allows Tampa Electric to maintain flexibility in its solid fuel portfolio while reducing 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 2021 and 2022 than in previous years.

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. Are there any other pertinent aspects of how Tampa Electric manages its 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 2022 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"), S&P Scenario Planning Service Annual Guidebook (originally produced by PIRA Energy Group), 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 ending in July 2021, 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 commodity and transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as IHS Markit and Argus *Coal Daily*. Also, the price projections are specific to the 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 2022 projected fuel prices compare to the fuel prices projected for 2021 in the company's mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices relatively low. However, in 2021, demand outpaced supply as the post COVID-19 economic recovery drove domestic gas demand through increased LNG exports, increased natural gas exports to Mexico, and increased industrial demand. Strong gas demand from power generation early in the summer decreased storage inventory levels below the five-year average while gas production remained static. Natural gas prices started rising in the second half of 2021 and are expected to remain elevated through the first quarter of 2022 until increased production helps to balance the market. Additionally, there is uncertainty associated with natural gas prices for 2022 due to the ongoing pandemic.

The commodity price for natural gas during 2022 is projected to be slightly lower ($3.16 per MMBtu) than the 2021 price ($3.21 per MMBtu) projected in the company's mid-course correction fuel filing. The 2022 delivered coal price projection is slightly lower ($62.28 per ton) than the price projected for 2021 ($63.42 per ton) during preparation of the 2021 mid-course correction fuel clause factors.

Q. Does this conclude your direct testimony?

A. Yes.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY

OF

BENJAMIN F. SMITH II

FILED: SEPTEMBER 3, 2021

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 byproduct 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 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 2021 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 10 percent of the company's expected needs for 2021 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").

Presently, Tampa Electric has seven forward purchases applicable to the year 2021. Four of them have terms that carried over from 2020 as described in my 2020 testimony and summarized in the following bullet points.

- Three (3) firm peaking call options for the period December 2020 through February 2021: 160 MW from FPL, 100 MW from OUC, and 150 MW from FMPA. Ninety-five megawatts (95 MW) of the FMPA 150 MW were to meet the company's 20 percent firm reserve margin criteria during the 2021 winter season. The balance of the purchases was for economic reasons. The company secured these purchase agreements during the fourth quarter of 2019 at an estimated savings to customers (excluding the reliability portion of the FMPA purchase) of $325.6 thousand for 2021. These savings flowed through the company's optimization mechanism and benefited customers in accordance with the methodology approved by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017.

- A non-firm purchase from DEF, which was an extension of Tampa Electric's previous contract to purchase non-firm energy from DEF. The extension covered the period March 2020 through February 2021. The energy volume available under the contract remained at a maximum of 515 MW per hour. The DEF extension did not have a must-take obligation. The extension provided Tampa Electric the flexibility to schedule the energy when beneficial to customers. In February 2021, Tampa Electric and DEF extended the contract again for the period March through November 2021 and thus far, for the period January through July 2021, and thus far, the purchase has provided $1.4 million in projected savings to customers, which flow through the optimization mechanism.

The company's remaining three forward purchases are from OUC and FPL, executed in December 2020 and February 2021, respectively. A description of the purchases follows.

- A 200 MW, firm, peaking call option from OUC for the month of January 2021. The purchase was a reliability purchase to ensure energy service to customers in the event Tampa Electric experienced cold weather.

The purchase helped reduce the company’s exposure to natural gas supply risk during its winter peak. Natural gas risks and mitigation are discussed in the testimony of Tampa Electric witness John C. Heisey, filed concurrently in this docket.

Two economy, non-firm, must-take energy purchases from FPL. Each purchase is for 150 MW. One covers the period March through November 2021. The other covers the period April through October 2021. The purchases provide a projected $3.4 million of savings to customers, which flow through the optimization mechanism.

Tampa Electric has not secured other forward purchases for 2021 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 2022 and beyond?

A. Tampa Electric currently has no forward purchases for

2022. However, the company expects to incur capacity costs and has included them in its 2022 Capacity Cost Recovery Clause projection. The projected capacity clause costs total $5.9 million and support firm purchases for the Big Bend Modernization Project testing, if needed, as well as economic forward purchases. A further explanation of these transmission costs is below.

The final phase of the Big Bend Modernization Project construction occurs in 2022. Testing of the project's combined cycle operation will occur during the period July through October 2022, and the project team will periodically need operational control of the new Big Bend combustion turbines, Units 5 and 6, that will drive the combined cycle. Depending on key factors—such as projected load, unit availabilities, and planned maintenance—the company may purchase energy due to limited availability of the new Big Bend combustion turbines or the potential intermittency of their generation during times of combined cycle testing.

Tampa Electric included $3.1 million in its 2022 capacity clause costs for the cost of firm transmission purchases during the Big Bend Modernization Project test period, to secure the path for firm power products during the project’s testing. The amount is based on 330 MW per month which equates to the size of one Big Bend combustion turbine, for the four months of July through October, at an assumed firm transmission rate of $ 2.35354/KW per month. Tampa Electric’s transmission cost rate applied in this estimate is the current Florida Power & Light firm monthly point-to-point transmission rate.

Additionally, over the past several years, as noted previously with the economic purchases from FPL in 2021, Tampa Electric has identified forward, season-long economy energy purchases that produced savings for customers, and it expects to make such purchases again in 2022. While these agreements will be negotiated closer to the time they are needed, the company’s projected transmission costs are based on recent history and market expectations. While Tampa Electric has yet to identify and secure economic purchase opportunities for 2022, the company included in its projection the dollars associated with these transmission costs.

The terms of the company’s recent forward economy purchases were generally in the April through November timeframe and for about 300 MW. In 2022, the company will continue to identify and evaluate monthly and seasonal forward purchase opportunities that bring value to customers. Because 330 MW of transmission costs for Big Bend Modernization Project testing are already included for July through October, these additional transmission costs for economy purchases are for the months of April, May, June, and November only. The transmission costs for these months are estimated to be $2.8 million. This amount is based on the 300 MW per month for the four months at an assumed firm transmission rate of $ 2.35354/KW per month. The transmission cost rate applied in this estimate is the current Florida Power & Light firm monthly point-to-point transmission rate.

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 2021 and 2022.

A. Tampa Electric entered into various non-separated (*e.g.*, next-hour and next-day sales) wholesale sales in 2021, and the company anticipates making additional non-separated sales during the balance of 2021 and 2022. The gains from these sales are shared between Tampa Electric and its customers through 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 wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes.