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September 5, 2024

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 20240001-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Projection Testimony for the period January 2025 through December 2025, as follows:

- Prepared Direct Testimony of Elena B. Vance and Exhibit EBV-2;

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bml
Attachment

cc: All Parties of Record (w/encl.)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Projection Testimony, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 5th day of September 2024 to the following:

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Malcolm N. Means

ATTORNEY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

PROJECTIONS

JANUARY 2025 THROUGH DECEMBER 2025

TESTIMONY AND EXHIBIT

OF

ELENA B. VANCE

FILED: SEPTEMBER 5, 2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELENA B. VANCE

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

A. My name is Elena B. Vance. 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 Chemical Engineering from the University of South Florida in 1999 and a Master of Business Administration with a concentration in Finance in 2003 from the University of Tampa. I have accumulated 27 years of experience in the electric industry, with experience in the areas of plant operations, unit commitment and economic dispatch, and resource planning. In my current role, I am responsible for short term study analysis, unit commitment and dispatch and economic analysis.

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. EBV-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 2025 period.

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

A. Four natural gas combined cycle ("CC") units are included. These are Big Bend Unit 1 CC, Polk Unit 2, and Bayside Units 1 and 2.

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 2025 through December 2025 represent the top 82 percent of the total forecasted system net generation for this period. It includes generation from the Big Bend Unit 1 CC, commissioned in December 2022. Tampa Electric included Big Bend Unit 1 CC as it is the most efficient unit and makes up 38 percent of our generation.

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 1 CC and Polk Unit 2 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 2025 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2025 period, the projected EUOF for Bayside Unit 1 is 2.0 percent, the POF is 27.4 percent. Therefore, the target EAF for Bayside Unit 1 equals 70.6 percent or:

$$100\% - (2.0\% + 27.4\%) = 70.6\%$$

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

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

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

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

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

$$EAF_{MAX} = 1 - [0.80\ (2.0\%) + 0.95\ (27.4\%)] = 72.3\%$$

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

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

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

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

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.0\%) + 1.10\ (27.4\%)] = 67.0\%$$

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 2025 through December 2025 are shown on page 15 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2025; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from February 16, 2025, to May 26, 2025. There are 2,400 planned outage hours scheduled for the 2025 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 27.4 percent or:

$$\frac{2,400}{8,760} \times 100\% = 27.4\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Big Bend Unit 1 CC has a POF of 3.8 percent, Bayside Unit 1 has a POF of 27.4 percent, Bayside Unit 2 has a POF of 3.8 percent, and Polk Unit 2 has a POF of 21.9 percent.

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

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 2.0 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 13, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(32 + 147)}{8,760} \times 100\% = 2.0\%$$

Relative to Bayside Unit 1, the EUOF of 2.0 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1 CC

The projected EUOF for this unit is 2.7 percent. The unit will have two planned outages in 2025, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.4 percent.

Polk Unit 2

The projected EUOF for this unit is 6.1 percent. The unit will have two planned outages in 2025, and the POF is 21.9 percent. Therefore, the target equivalent availability for this unit is 71.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.0 percent. The unit will have one planned outage in 2025, and the POF is 27.4 percent. Therefore, the target equivalent availability for this unit is 70.6 percent.

Bayside Unit 2

The projected EUOF for this unit is 2.8 percent. The unit will have two planned outages in 2025, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.3 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 77.6 percent is shown on page 5 of Document No. 1.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 13 of Document No. 1. Except for the months of March and April, 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 March and April, 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 22 through 25 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 2025 period.

A. The heat rate target for Big Bend Unit 1 CC is 6,262 Btu/Net kWh with a range of ±26 Btu/Net kWh. The heat rate target for Polk Unit 2 is 7,456 Btu/Net kWh with a range of ±415 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,349 Btu/Net kWh with a range of ±268 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,723 Btu/Net kWh with a range of ±915 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on pages 7 through 10 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 10. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $714,669,940 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 $31,371,180 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 30.75 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 10 of Document

No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 9 of Document No. 1, if Bayside Unit 1, operates at 7,081 average net operating heat rate, fuel savings would equal $9,645,600 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 10. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $31,371,180. 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 2025 through December 2025 is $5,583,632,449. This produces the maximum allowed jurisdictional incentive of $18,756,155 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 $15,685,589.

Q. Please summarize your direct testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP).

$$\begin{aligned} GPIP = (&0.1536\ EAP_{PK2} + 0.0719\ EAP_{BAY1} \\ &+ 0.0079\ EAP_{BAY2} + 0.0796\ EAP_{BBCC1} \\ &+ 0.1513\ HRP_{PK2} + 0.3075\ HRP_{BAY1} \\ &+ 0.2014\ HRP_{BAY2} + 0.0269\ HRP_{BBCC1}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January 2025 through December 2025 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT TO THE TESTIMONY

OF

ELENA B. VANCE

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2025 - DECEMBER 2025

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2025 - DECEMBER 2025
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2025 - DECEMBER 2025

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	31,371.2	15,685.6
+9	28,234.1	14,117.0
+8	25,096.9	12,548.5
+7	21,959.8	10,979.9
+6	18,822.7	9,411.4
+5	15,685.6	7,842.8
+4	12,548.5	6,274.2
+3	9,411.4	4,705.7
+2	6,274.2	3,137.1
+1	3,137.1	1,568.6
0	0.0	0.0
-1	(4,150.7)	(1,568.6)
-2	(8,301.3)	(3,137.1)
-3	(12,452.0)	(4,705.7)
-4	(16,602.7)	(6,274.2)
-5	(20,753.3)	(7,842.8)
-6	(24,904.0)	(9,411.4)
-7	(29,054.7)	(10,979.9)
-8	(33,205.3)	(12,548.5)
-9	(37,356.0)	(14,117.0)
-10	(41,506.7)	(15,685.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2025 - DECEMBER 2025

Line 1	Beginning of period balance of common equity:		$	5,325,088,263	
	End of month common equity:				
Line 2	Month of January	2025	$	5,253,155,772	
Line 3	Month of February	2025	$	5,457,807,596	
Line 4	Month of March	2025	$	5,504,198,961	
Line 5	Month of April	2025	$	5,371,873,954	
Line 6	Month of May	2025	$	5,572,534,882	
Line 7	Month of June	2025	$	5,619,901,429	
Line 8	Month of July	2025	$	5,551,968,123	
Line 9	Month of August	2025	$	5,749,159,852	
Line 10	Month of September	2025	$	5,798,027,710	
Line 11	Month of October	2025	$	5,669,184,664	
Line 12	Month of November	2025	$	5,832,372,734	
Line 13	Month of December	2025	$	5,881,947,902	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	5,583,632,449	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			74.42%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	18,756,155	
Line 18	Jurisdictional Sales			20,517,664	MWH
Line 19	Total Sales			20,517,664	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)		$	18,756,155	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$	15,685,589	
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$	15,685,589	

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 2025 - DECEMBER 2025

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND CC 1	7.96%	93.4	94.2	92.0	2,497.4	(9,653.7)
POLK 2	15.36%	71.9	74.3	67.3	4,818.3	(2,057.9)
BAYSIDE 1	7.19%	70.6	72.3	67.0	2,255.5	(4,153.4)
BAYSIDE 2	0.79%	93.3	94.1	91.8	247.4	(4,089.2)
GPIF SYSTEM	**31.30%**					

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 CC 1	2.69%	6,262	92.3	6,236	6,288	843.0	(843.0)
POLK 2	15.13%	7,456	48.0	7,042	7,871	4,746.9	(4,746.9)
BAYSIDE 1	30.75%	7,349	73.0	7,081	7,617	9,645.6	(9,645.6)
BAYSIDE 2	20.14%	7,723	52.5	6,808	8,638	6,317.1	(6,317.1)
GPIF SYSTEM	**68.70%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 25 - DEC 25			ACTUAL PERFORMANCE JAN 23 - DEC 23			ACTUAL PERFORMANCE JAN 22 - DEC 22			ACTUAL PERFORMANCE JAN 21 - DEC 21		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND CC 1	7.96%	25.4%	3.8	2.7	7.9	10.0	17.3	19.2	NA	NA	NA	NA	NA	NA
POLK 2	15.36%	49.1%	21.9	6.1	7.9	5.3	3.9	4.1	4.6	4.6	4.9	11.0	3.7	4.1
BAYSIDE 1	7.19%	23.0%	27.4	2.0	2.8	7.8	1.3	1.4	21.7	3.5	4.5	5.4	5.8	6.1
BAYSIDE 2	0.79%	2.5%	3.8	2.8	2.9	15.1	1.6	2.4	6.1	3.2	3.4	5.5	1.9	2.0
GPIF SYSTEM	**31.30%**	**100.0%**	**18.1**	**4.2**	**6.6**	**7.3**	**6.6**	**7.3**	**7.4**	**3.2**	**3.5**	**6.8**	**3.2**	**3.5**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**77.6**			**86.1**			**89.5**			**90.0**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
7.2	**4.3**	**4.8**	**88.5**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 25 - DEC 25	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 23 - DEC 23	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 22 - DEC 22	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 21 - DEC 21
BIG BEND CC 1	2.69%	3.9%	6,262	6,479	6,028	NA
POLK 2	15.13%	22.0%	7,456	7,344	7,420	7,368
BAYSIDE 1	30.75%	44.8%	7,349	7,267	7,330	7,331
BAYSIDE 2	20.14%	29.3%	7,723	7,524	7,621	7,653
GPIF SYSTEM	**68.70%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**7,440**	**7,329**	**7,384**	**7,147**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2025 - DECEMBER 2025
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 CC 1	714,669.94	712,172.58	2,497.36	7.96%
EA_2 POLK 2	714,669.94	709,851.66	4,818.29	15.36%
EA_3 BAYSIDE 1	714,669.94	712,414.44	2,255.50	7.19%
EA_4 BAYSIDE 2	714,669.94	714,422.49	247.45	0.79%
AVERAGE HEAT RATE				
AHR_3 BIG BEND CC 1	714,669.94	713,826.97	842.97	2.69%
AHR_2 POLK 2	714,669.94	709,923.04	4,746.91	15.13%
AHR_3 BAYSIDE 1	714,669.94	705,024.38	9,645.56	30.75%
AHR_4 BAYSIDE 2	714,669.94	708,352.80	6,317.14	20.14%
TOTAL SAVINGS			**31,371.18**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2025 - DECEMBER 2025

BIG BEND CC 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,497.4	94.2	+10	843.0	6,236
+9	2,247.6	94.1	+9	758.7	6,231
+8	1,997.9	94.0	+8	674.4	6,227
+7	1,748.2	93.9	+7	590.1	6,222
+6	1,498.4	93.9	+6	505.8	6,217
+5	1,248.7	93.8	+5	421.5	6,212
+4	998.9	93.7	+4	337.2	6,207
+3	749.2	93.6	+3	252.9	6,202
+2	499.5	93.6	+2	168.6	6,197
+1	249.7	93.5	+1	84.3	6,192
					6,187
0	0.0	93.4	0	0.0	6,262
					6,337
-1	(965.4)	93.3	-1	(84.3)	6,332
-2	(1,930.7)	93.1	-2	(168.6)	6,327
-3	(2,896.1)	93.0	-3	(252.9)	6,322
-4	(3,861.5)	92.8	-4	(337.2)	6,318
-5	(4,826.8)	92.7	-5	(421.5)	6,313
-6	(5,792.2)	92.5	-6	(505.8)	6,308
-7	(6,757.6)	92.4	-7	(590.1)	6,303
-8	(7,723.0)	92.2	-8	(674.4)	6,298
-9	(8,688.3)	92.1	-9	(758.7)	6,293
-10	(9,653.7)	92.0	-10	(843.0)	6,288
	Weighting Factor =	7.96%		Weighting Factor =	2.69%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2025 - DECEMBER 2025

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	4,818.3	74.3	+10	4,746.9	7,042
+9	4,336.5	74.0	+9	4,272.2	7,076
+8	3,854.6	73.8	+8	3,797.5	7,110
+7	3,372.8	73.6	+7	3,322.8	7,144
+6	2,891.0	73.3	+6	2,848.1	7,178
+5	2,409.1	73.1	+5	2,373.5	7,212
+4	1,927.3	72.9	+4	1,898.8	7,245
+3	1,445.5	72.6	+3	1,424.1	7,279
+2	963.7	72.4	+2	949.4	7,313
+1	481.8	72.2	+1	474.7	7,347
					7,381
0	0.0	71.9	0	0.0	7,456
					7,531
-1	(205.8)	71.5	-1	(474.7)	7,565
-2	(411.6)	71.0	-2	(949.4)	7,599
-3	(617.4)	70.6	-3	(1,424.1)	7,633
-4	(823.2)	70.1	-4	(1,898.8)	7,667
-5	(1,028.9)	69.6	-5	(2,373.5)	7,701
-6	(1,234.7)	69.2	-6	(2,848.1)	7,735
-7	(1,440.5)	68.7	-7	(3,322.8)	7,769
-8	(1,646.3)	68.2	-8	(3,797.5)	7,803
-9	(1,852.1)	67.8	-9	(4,272.2)	7,837
-10	(2,057.9)	67.3	-10	(4,746.9)	7,871
	Weighting Factor =	15.36%		Weighting Factor =	15.13%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2025 - DECEMBER 2025

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,255.5	72.3	+10	9,645.6	7,081
+9	2,030.0	72.2	+9	8,681.0	7,100
+8	1,804.4	72.0	+8	7,716.4	7,119
+7	1,578.9	71.8	+7	6,751.9	7,139
+6	1,353.3	71.6	+6	5,787.3	7,158
+5	1,127.8	71.4	+5	4,822.8	7,177
+4	902.2	71.3	+4	3,858.2	7,197
+3	676.7	71.1	+3	2,893.7	7,216
+2	451.1	70.9	+2	1,929.1	7,235
+1	225.6	70.7	+1	964.6	7,255
					7,274
0	0.0	70.6	0	0.0	7,349
					7,424
-1	(415.3)	70.2	-1	(964.6)	7,443
-2	(830.7)	69.8	-2	(1,929.1)	7,462
-3	(1,246.0)	69.5	-3	(2,893.7)	7,482
-4	(1,661.3)	69.1	-4	(3,858.2)	7,501
-5	(2,076.7)	68.8	-5	(4,822.8)	7,520
-6	(2,492.0)	68.4	-6	(5,787.3)	7,540
-7	(2,907.3)	68.1	-7	(6,751.9)	7,559
-8	(3,322.7)	67.7	-8	(7,716.4)	7,578
-9	(3,738.0)	67.4	-9	(8,681.0)	7,598
-10	(4,153.4)	67.0	-10	(9,645.6)	7,617
	Weighting Factor =	7.19%		Weighting Factor =	30.75%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2025 - DECEMBER 2025

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	247.4	94.1	+10	6,317.1	6,808
+9	222.7	94.0	+9	5,685.4	6,892
+8	198.0	93.9	+8	5,053.7	6,976
+7	173.2	93.9	+7	4,422.0	7,060
+6	148.5	93.8	+6	3,790.3	7,144
+5	123.7	93.7	+5	3,158.6	7,228
+4	99.0	93.6	+4	2,526.9	7,312
+3	74.2	93.6	+3	1,895.1	7,396
+2	49.5	93.5	+2	1,263.4	7,480
+1	24.7	93.4	+1	631.7	7,564
					7,648
0	0.0	93.3	0	0.0	7,723
					7,798
-1	(408.9)	93.2	-1	(631.7)	7,882
-2	(817.8)	93.0	-2	(1,263.4)	7,966
-3	(1,226.7)	92.9	-3	(1,895.1)	8,050
-4	(1,635.7)	92.7	-4	(2,526.9)	8,134
-5	(2,044.6)	92.6	-5	(3,158.6)	8,218
-6	(2,453.5)	92.4	-6	(3,790.3)	8,302
-7	(2,862.4)	92.3	-7	(4,422.0)	8,386
-8	(3,271.3)	92.1	-8	(5,053.7)	8,470
-9	(3,680.2)	92.0	-9	(5,685.4)	8,554
-10	(4,089.2)	91.8	-10	(6,317.1)	8,638
	Weighting Factor =	0.79%		Weighting Factor =	20.14%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2025 - DECEMBER 2025

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 CC 1	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
1. EAF (%)	97.2	97.2	97.2	68.0	97.2	97.2	97.2	97.2	97.2	97.2	81.0	97.2	93.4
2. POF	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7	0.0	3.8
3. EUOF	2.8	2.8	2.8	2.0	2.8	2.8	2.8	2.8	2.8	2.8	2.4	2.8	2.7
4. EUOR	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	744	672	578	504	744	720	744	744	720	744	600	744	8,258
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	0	0	166	216	0	0	0	0	0	0	120	0	502
9. POH	0	0	0	216	0	0	0	0	0	0	120	0	336
10. EFOH	1	1	1	1	1	1	1	1	1	1	1	1	10
11. EMOH	20	18	20	14	20	20	20	20	20	20	16	20	230
12. OPER BTU (GBTU)	4,330	4,444	3,807	2,422	4,771	4,666	4,843	4,829	4,674	4,386	3,168	4,960	51,359
13. NET GEN (MWH)	681,270	712,106	609,543	375,160	767,880	752,300	781,499	778,911	753,903	696,933	496,189	795,662	8,201,356
14. ANOHR (Btu/kwh)	6,356	6,241	6,245	6,455	6,213	6,202	6,197	6,200	6,200	6,293	6,386	6,233	6,262
15. NOF (%)	81.8	94.6	94.2	70.6	97.8	99.0	99.6	99.2	99.2	88.8	78.4	95.5	92.3
16. NPC (MW)	1,120	1,120	1,120	1,055	1,055	1,055	1,055	1,055	1,055	1,055	1,055	1,120	1,077

17. ANOHR EQUATION ANOHR = NOF(-8.897) + 7,083

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2025 - DECEMBER 2025

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-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
1. EAF (%)	92.1	92.1	92.1	92.1	92.1	61.4	92.1	92.1	49.1	0.0	15.4	92.1	71.9
2. POF	0.0	0.0	0.0	0.0	0.0	33.3	0.0	0.0	46.7	100.0	83.3	0.0	21.9
3. EUOF	7.9	7.9	7.9	7.9	7.9	5.2	7.9	7.9	4.2	0.0	1.3	7.9	6.1
4. EUOR	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	0.0	7.9	7.9	7.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	744	436	351	618	718	427	157	722	61	0	91	736	5,061
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	0	236	393	102	26	293	587	22	659	744	629	8	3,699
9. POH	0	0	0	0	0	240	0	0	336	744	600	0	1,920
10. EFOH	16	14	16	15	16	10	16	16	8	0	3	16	146
11. EMOH	43	38	43	41	43	27	43	43	22	0	7	43	392
12. OPER BTU (GBTU)	3,556	2,058	940	2,252	2,636	2,180	674	3,132	329	0	265	2,791	20,919
13. NET GEN (MWH)	490,839	283,612	122,275	297,210	348,252	298,476	90,354	420,518	45,385	0	34,389	374,285	2,805,595
14. ANOHR (Btu/kwh)	7,244	7,257	7,684	7,576	7,571	7,303	7,458	7,449	7,247	0	7,705	7,458	7,456
15. NOF (%)	62.2	61.3	32.8	40.1	40.4	58.3	48.0	48.5	62.0	0.0	31.5	47.9	48.0
16. NPC (MW)	1,061	1,061	1,061	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,061	1,154
17. ANOHR EQUATION	ANOHR = NOF(		-14.998	) +	8,177								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2025 - DECEMBER 2025

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-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
1. EAF (%)	97.2	52.1	0.0	0.0	15.7	97.2	97.2	97.2	97.2	97.2	97.2	97.2	70.6
2. POF	0.0	46.4	100.0	100.0	83.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4
3. EUOF	2.8	1.5	0.0	0.0	0.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.0
4. EUOR	2.8	2.8	0.0	0.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	216	55	0	0	12	720	686	744	720	744	468	188	4,553
7. RSH	507	295	0	0	105	0	37	0	0	0	232	535	1,710
8. UH	21	322	744	720	627	0	21	0	0	0	20	21	2,497
9. POH	0	312	744	720	624	0	0	0	0	0	0	0	2,400
10. EFOH	4	2	0	0	1	4	4	4	4	4	4	4	32
11. EMOH	17	8	0	0	3	17	17	17	17	17	17	17	147
12. OPER BTU (GBTU)	517	149	0	0	50	2,889	3,048	3,137	3,315	3,447	1,950	509	19,097
13. NET GEN (MWH)	67,975	19,650	0	0	6,773	393,112	418,203	428,465	456,280	474,833	266,136	67,204	2,598,631
14. ANOHR (Btu/kwh)	7,611	7,574	0	0	7,332	7,350	7,288	7,321	7,264	7,260	7,328	7,574	7,349
15. NOF (%)	37.2	42.2	0.0	0.0	75.4	72.9	81.4	76.9	84.6	85.2	75.9	42.2	73.0
16. NPC (MW)	847	847	847	749	749	749	749	749	749	749	749	847	781
17. ANOHR EQUATION	ANOHR = NOF(		-7.294	) +	7,882								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2025 - DECEMBER 2025

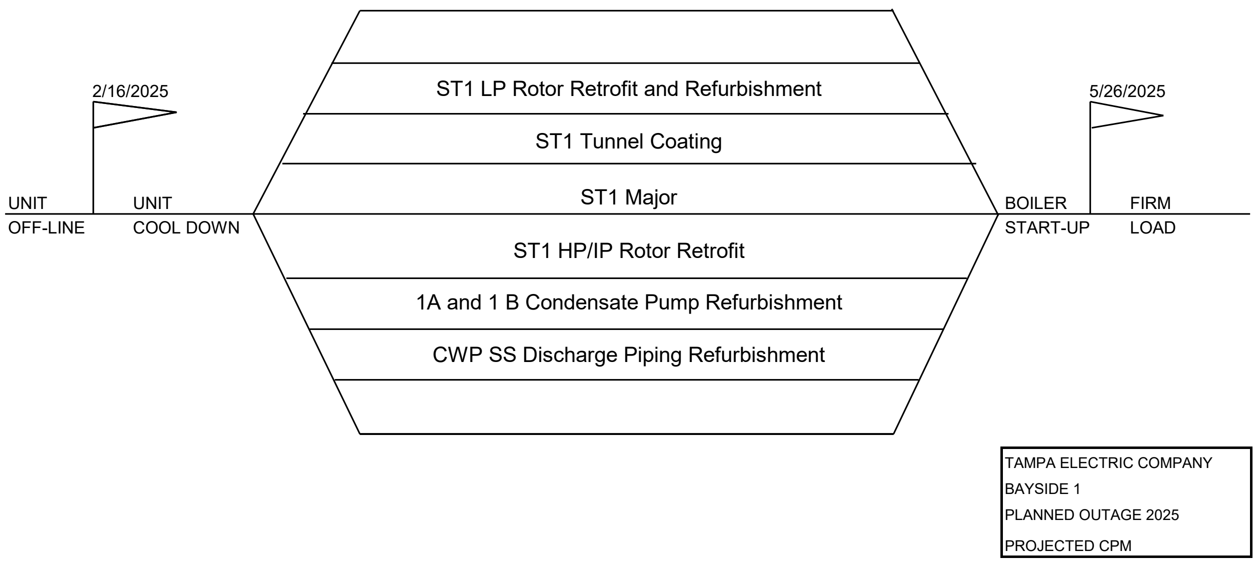
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
1. EAF (%)	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	53.2	97.1	97.1	93.3
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.2	0.0	0.0	3.8
3. EUOF	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	1.6	2.9	2.9	2.8
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	297	362	744	720	744	669	707	584	693	395	701	416	7,032
7. RSH	425	290	0	0	0	30	15	138	6	1	19	306	1,230
8. UH	22	20	0	0	22	21	22	22	21	348	0	22	519
9. POH	0	0	0	0	0	0	0	0	0	336	0	0	336
10. EFOH	8	7	8	8	8	8	8	8	8	4	8	8	90
11. EMOH	14	12	14	13	14	13	14	14	13	8	13	14	157
12. OPER BTU (GBTU)	1,101	1,418	3,378	3,514	2,983	2,389	3,419	2,105	2,993	1,738	2,960	1,354	29,652
13. NET GEN (MWH)	135,185	176,208	437,122	490,327	384,956	298,580	474,893	263,702	396,100	231,651	388,584	162,018	3,839,326
14. ANOHR (Btu/kwh)	8,148	8,047	7,727	7,166	7,749	8,003	7,199	7,984	7,556	7,503	7,618	8,357	7,723
15. NOF (%)	40.6	43.4	52.4	68.2	51.8	44.7	67.2	45.2	57.2	58.7	55.5	34.7	52.5
16. NPC (MW)	1,121	1,121	1,121	999	999	999	999	999	999	999	999	1,121	1,039
17. ANOHR EQUATION	ANOHR = NOF(	-35.618	) +		9,594								

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2025 - DECEMBER 2025

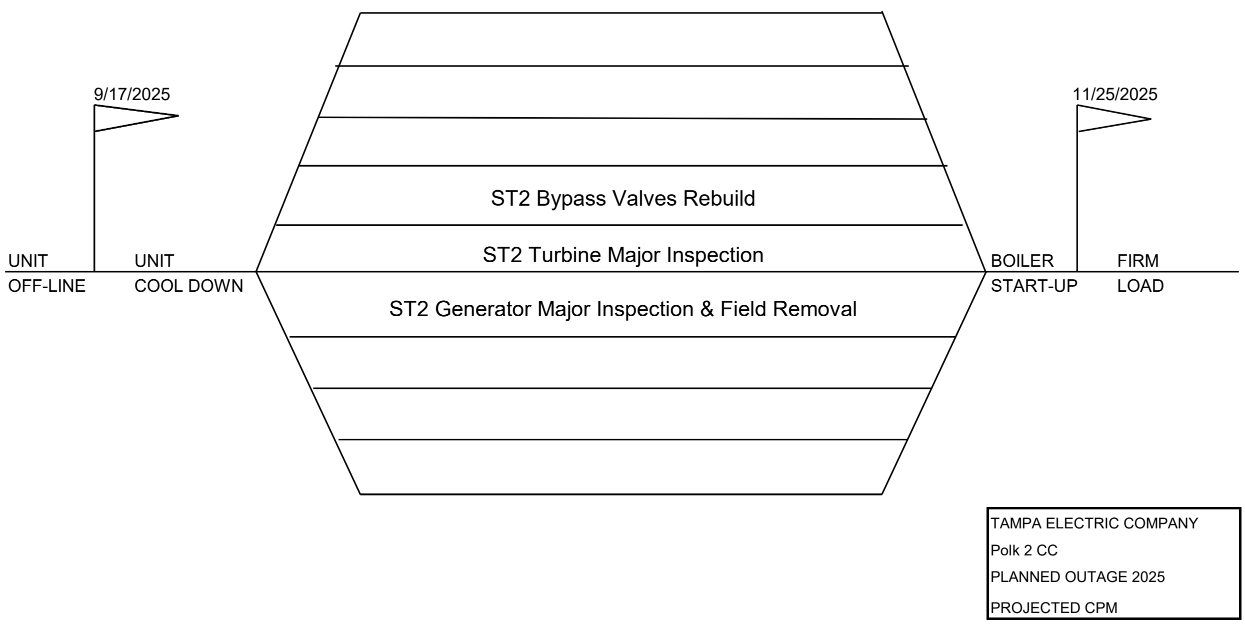
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	Polk 2 CC	Jun 02	-	Jun 11	Combined Cycle Planned Outage
+		Sep 17	-	Nov 25	Steam Turbine Major Outage
+	BAYSIDE 1	Feb 16	-	May 26	ST1 Major Outage and Refurbishment
	BAYSIDE 2	Oct 12	-	Oct 25	Combined Cycle Planned Outage
		Dec 02	-	Dec 09	Combined Cycle Planned Outage
	BB CC1	Apr 06	-	Apr 14	Combined Cycle Planned Outage
		Nov 05		Nov 09	Combined Cycle Planned Outage

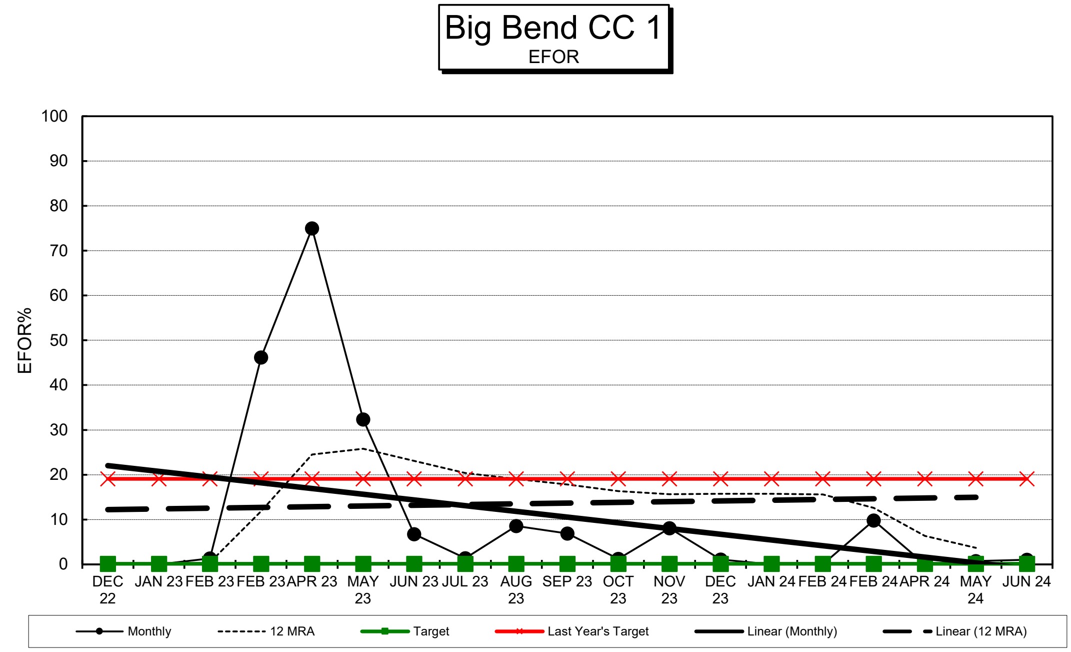
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

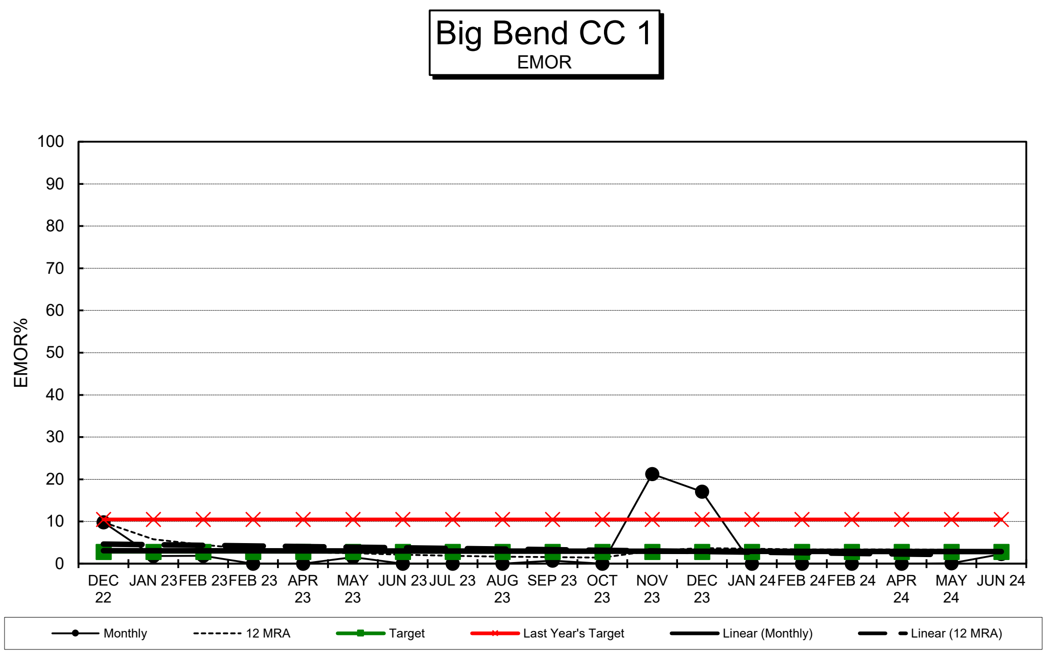
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2025 - DECEMBER 2025

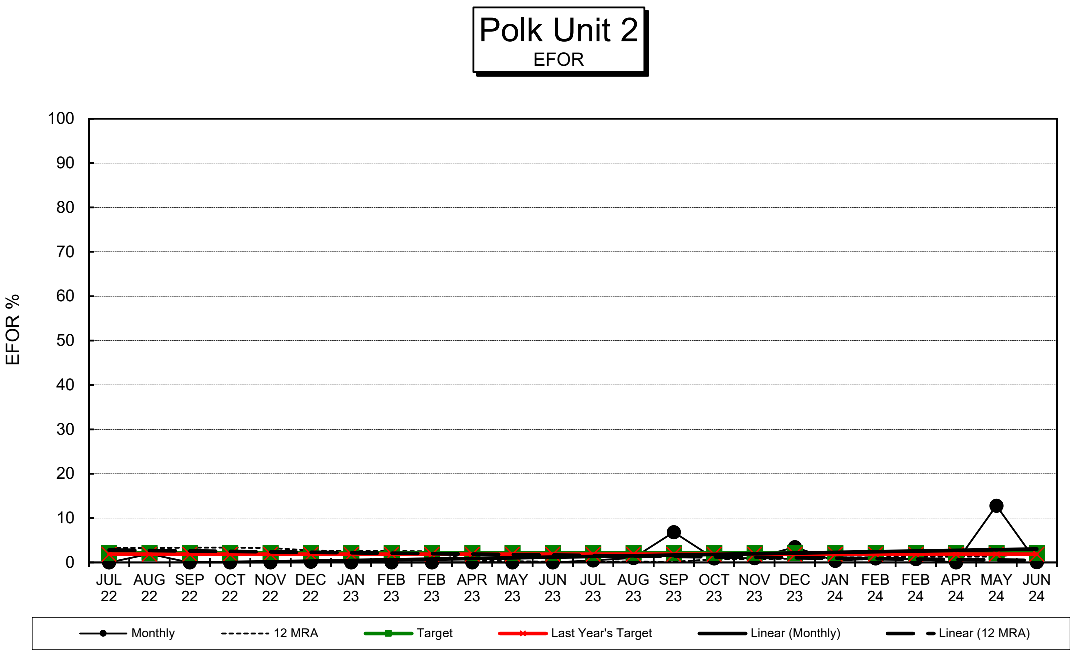


TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2025 - DECEMBER 2025




Big Bend CC 1
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
DEC 22
JAN 23
FEB 23
FEB 23
APR 23
MAY 23
JUN 23
JUL 23
AUG 23
SEP 23
OCT 23
NOV 23
DEC 23
JAN 24
FEB 24
FEB 24
APR 24
MAY 24
JUN 24
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend CC 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
DEC 22
JAN 23
FEB 23
FEB 23
APR 23
MAY 23
JUN 23
JUL 23
AUG 23
SEP 23
OCT 23
NOV 23
DEC 23
JAN 24
FEB 24
FEB 24
APR 24
MAY 24
JUN 24
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 22
AUG 22
SEP 22
OCT 22
NOV 22
DEC 22
JAN 23
FEB 23
FEB 23
APR 23
MAY 23
JUN 23
JUL 23
AUG 23
SEP 23
OCT 23
NOV 23
DEC 23
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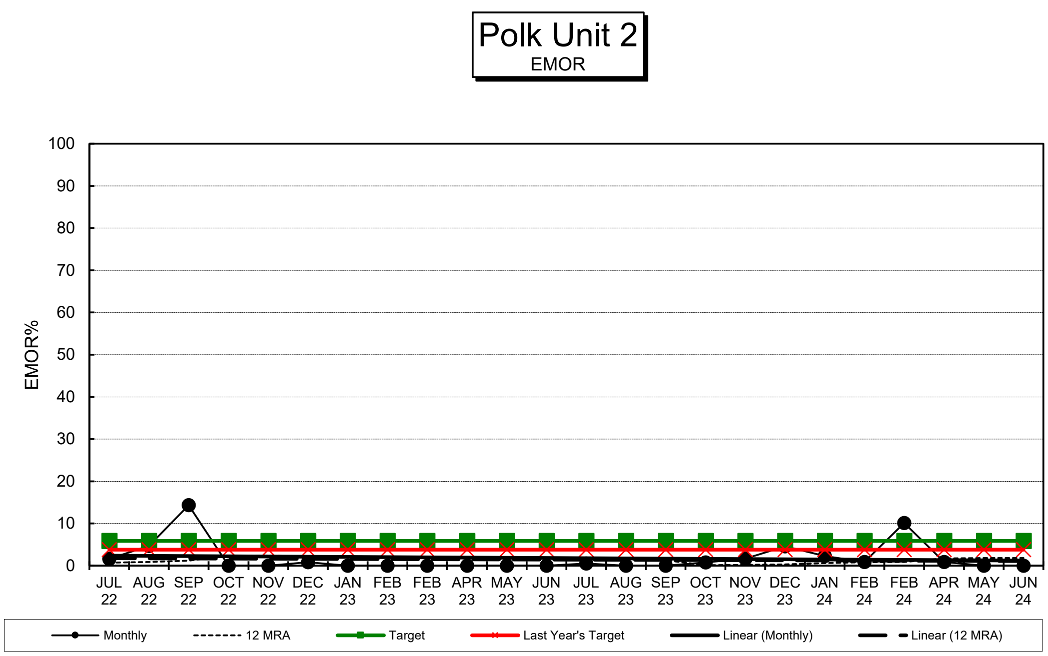
MAY 24
JUN 24
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR%
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FEB 24
APR 24
MAY 24
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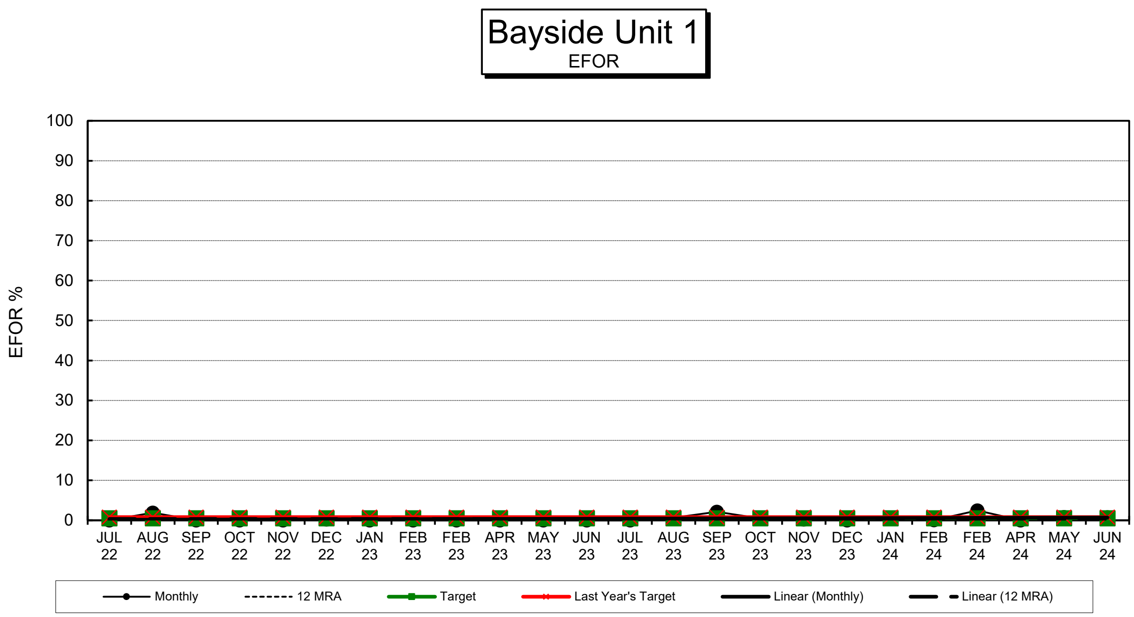
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR %
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80
70
60
50
40
30
20
10
0
JUL 22
AUG 22
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OCT 22
NOV 22
DEC 22
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APR 23
MAY 23
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JAN 24
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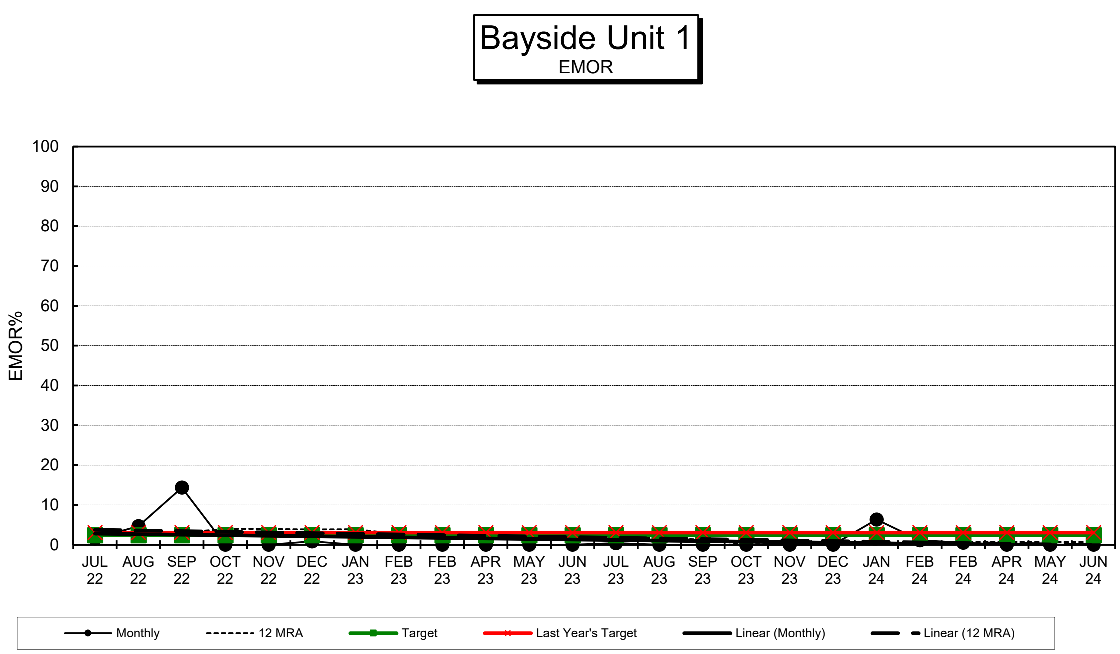
APR 24
MAY 24
JUN 24
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
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EMOR%
100
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80
70
60
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AUG 22
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OCT 22
NOV 22
DEC 22
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JAN 24
FEB 24
FEB 24
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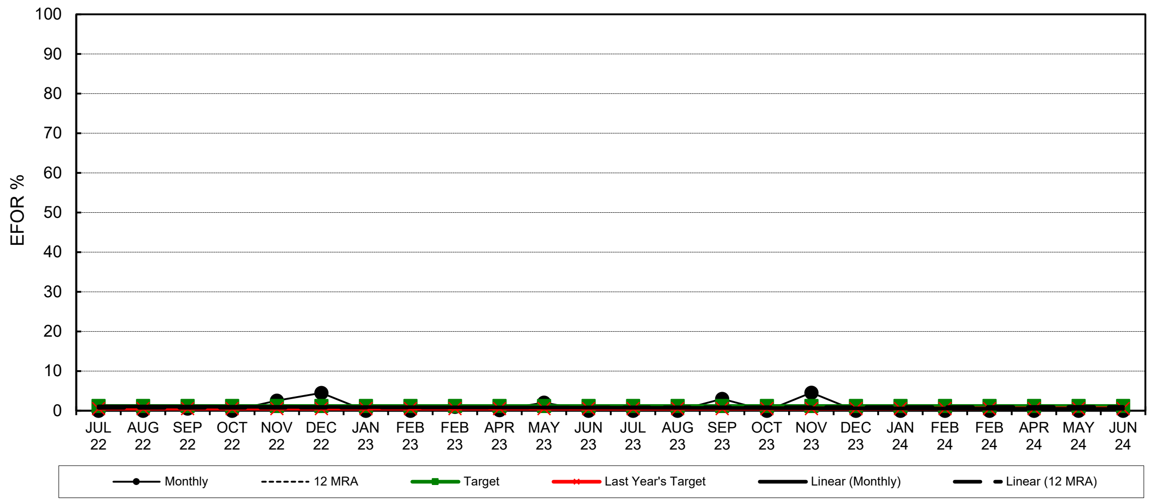
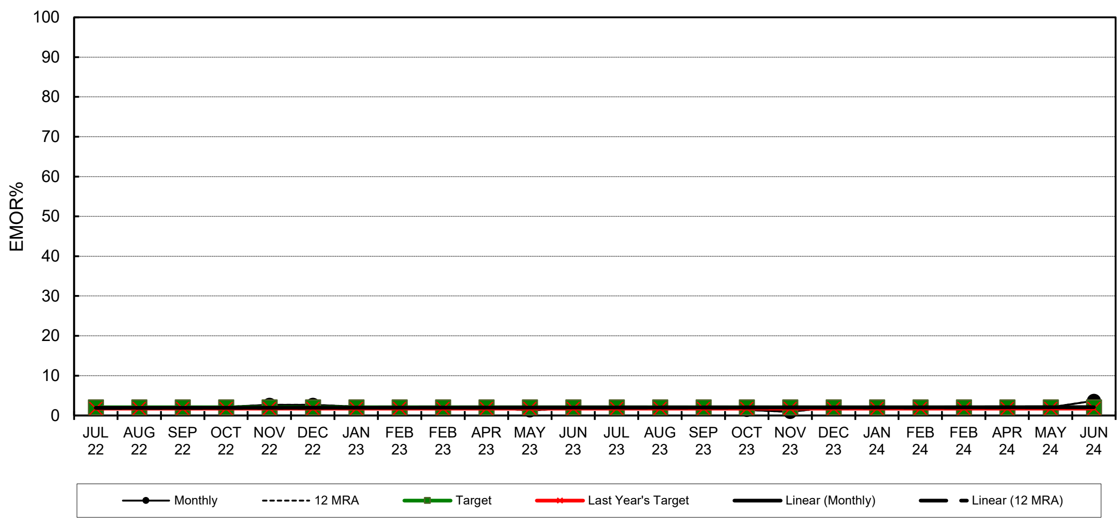
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

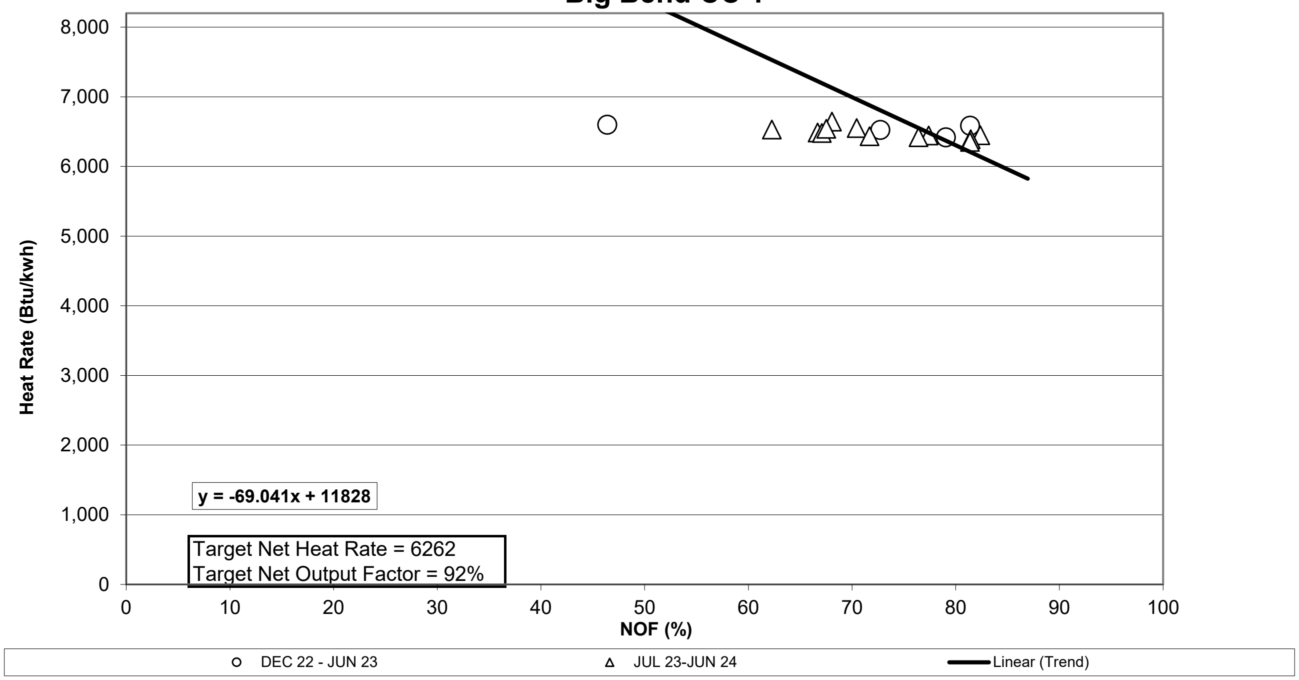
Bayside Unit 2
EFOR



Bayside Unit 2
EMOR



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



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DOCUMENT NO. 1

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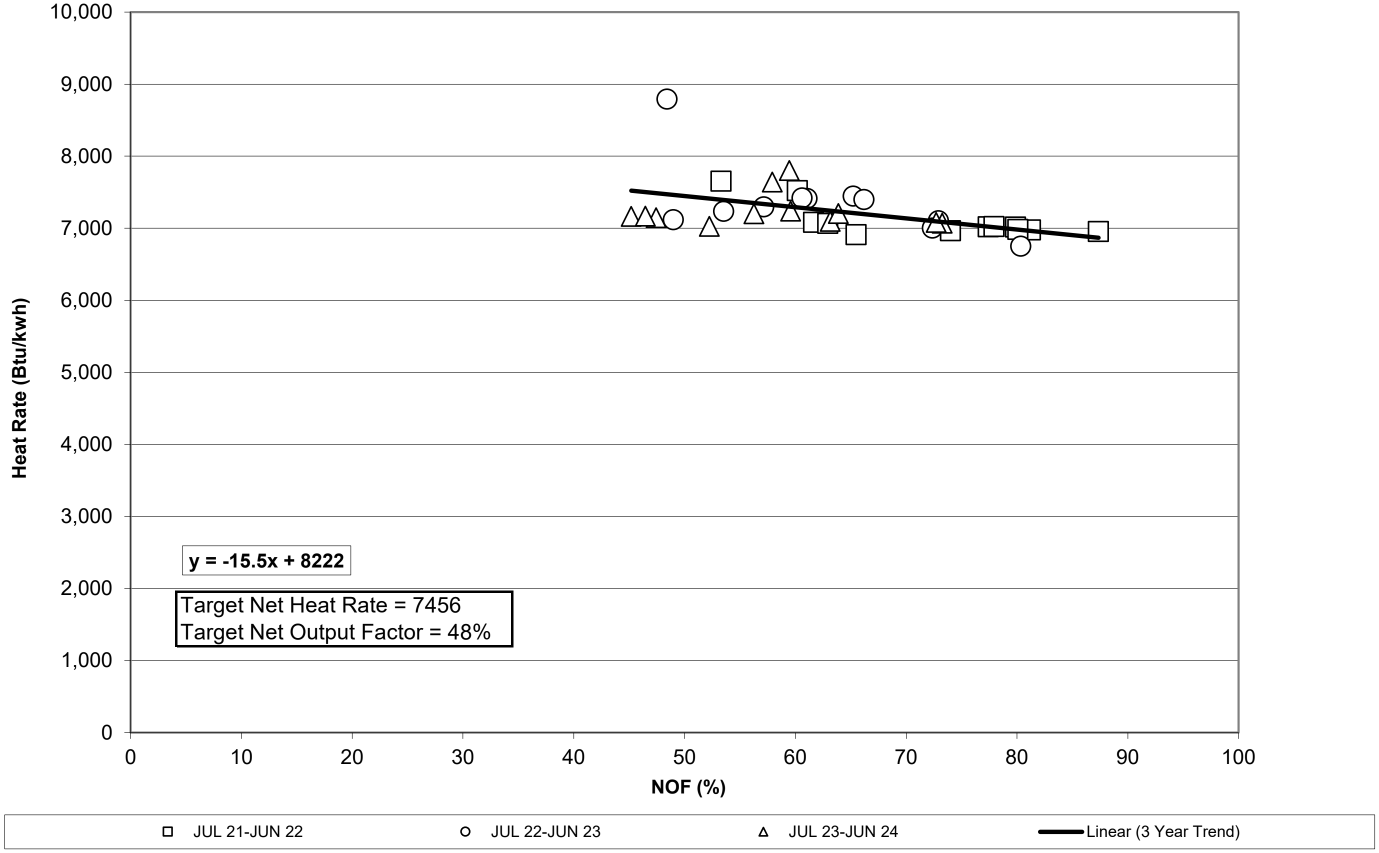
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 2



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TAMPA ELECTRIC COMPANY
DOCKET NO. 20240001-EI
DOCUMENT NO. 1
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Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1

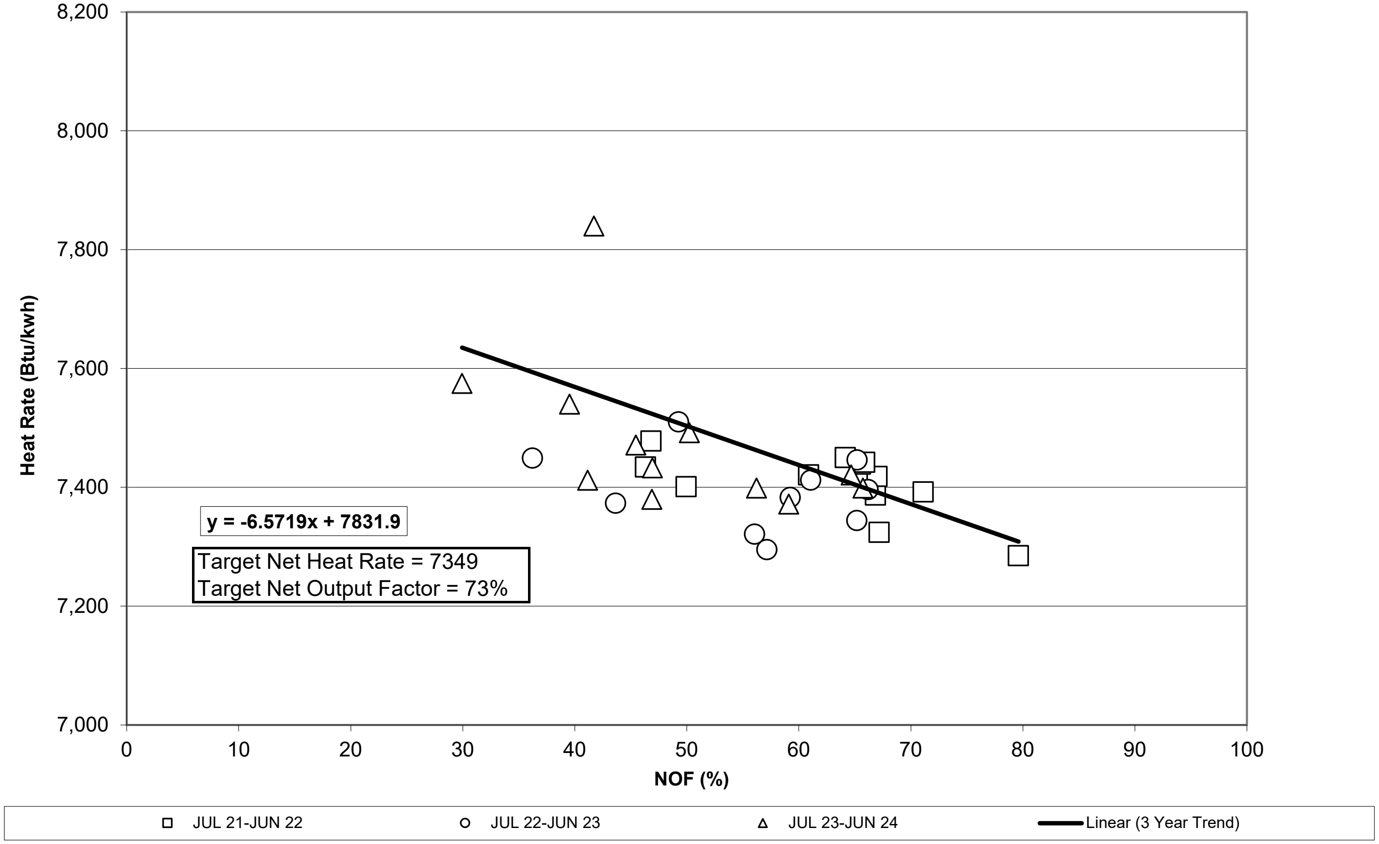

EXHIBIT NO. ____ (EBV-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20240001-EI
DOCUMENT NO. 1
PAGE 24 OF 28

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

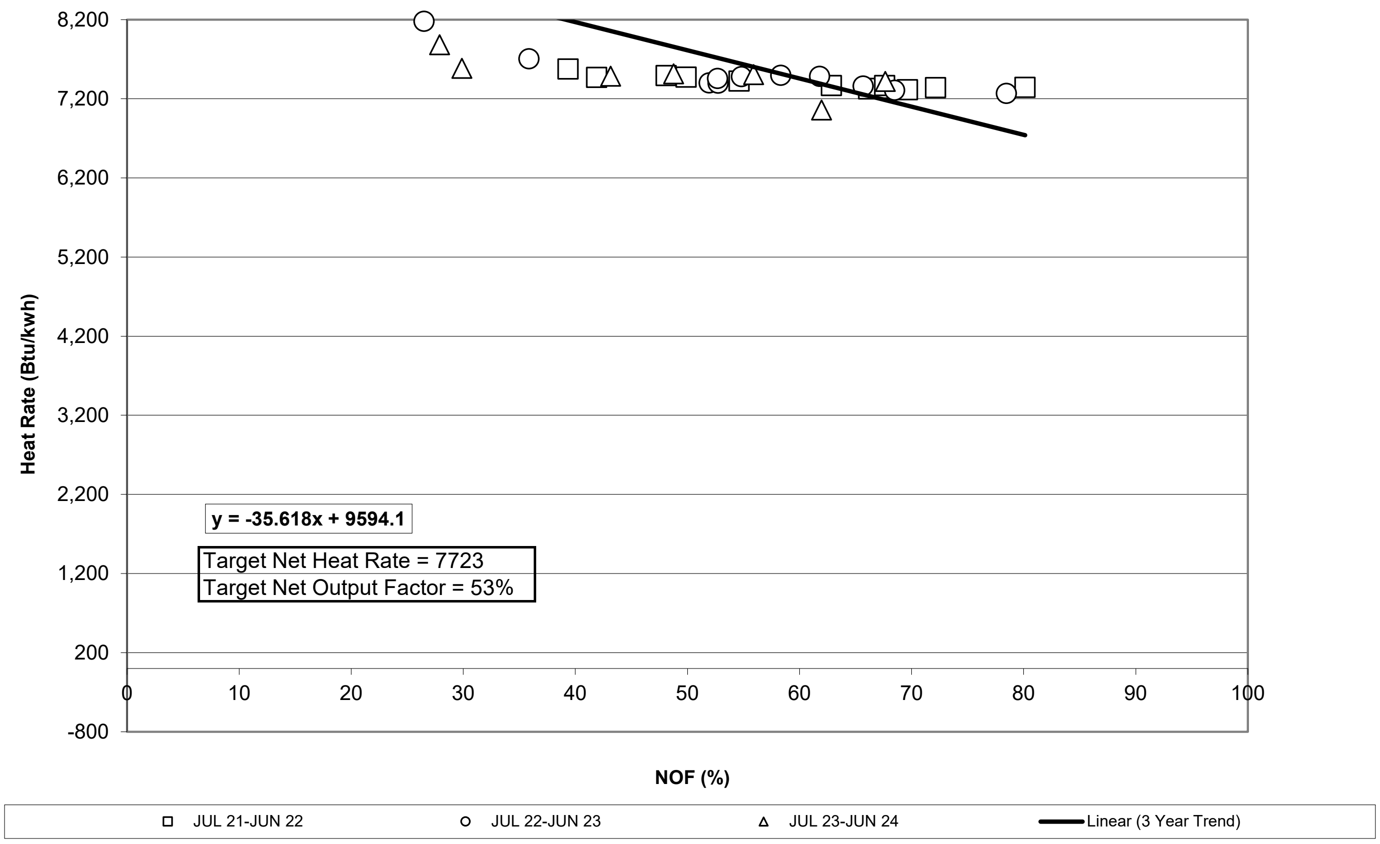

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EXHIBIT NO. _____ (EBV-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20240001-EI
DOCUMENT NO. 1
PAGE 25 OF 28

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2025 - DECEMBER 2025

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND CC 1		1,108	1,077
POLK 2		1,130	1,154
BAYSIDE 1		791	782
BAYSIDE 2		1,091	1,040
	GPIF TOTAL	4,120	4,052
	SYSTEM TOTAL	**6,524**	**6,345**
	% OF SYSTEM TOTAL	**63.2%**	**63.9%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2025 - DECEMBER 2025

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		791	782
BAYSIDE 2		1,091	1,040
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	2,116	2,052
BIG BEND 1		1,108	1,077
BIG BEND 3		0	0
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,639	1,573
POLK 1		290	220
POLK 2		1,130	1,154
	POLK TOTAL	1,420	1,374
SOLAR		1,349	1,346
	SOLAR TOTAL	1,349	1,346
	SYSTEM TOTAL	**6,524**	**6,345**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2025 - DECEMBER 2025

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BIG BEND	1	8,201,356	38.32%	38.32%
BAYSIDE	2	3,839,326	17.94%	56.26%
SOLAR		2,808,549	13.12%	69.38%
POLK	2	2,805,595	13.11%	82.49%
BAYSIDE	1	2,598,631	12.14%	94.64%
BIG BEND	4	731,012	3.42%	98.05%
POLK	1	123,688	0.58%	98.63%
MACDILL	1&2	83,795	0.39%	99.02%
BAYSIDE	3	43,152	0.20%	99.22%
BAYSIDE	5	43,138	0.20%	99.43%
BAYSIDE	6	42,269	0.20%	99.62%
BAYSIDE	4	41,235	0.19%	99.82%
BIG BEND CT	4	39,475	0.18%	100.00%
TOTAL GENERATION		21,401,223	100.00%	

GENERATION BY COAL UNITS:	186,427 MWH	GENERATION BY NATURAL GAS UNITS:	18,322,453 MWH
% GENERATION BY COAL UNITS	0.87%	% GENERATION BY NATURAL GAS UNITS:	85.61%
GENERATION BY SOLAR UNITS:	2,808,549 MWH	GENERATION BY GPIF UNITS:	17,444,909 MWH
% GENERATION BY SOLAR UNIT	13.12%	% GENERATION BY GPIF UNITS:	81.51%

EXHIBIT TO THE TESTIMONY

OF

ELENA B. VANCE

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2025 - DECEMBER 2025

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2025 - DECEMBER 2025

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend CC 1[1]	93.4	3.8	2.7	6,262
Polk 2[2]	71.9	21.9	6.1	7,456
Bayside 1[3]	70.6	27.4	2.0	7,349
Bayside 2[4]	93.3	3.8	2.8	7,723

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