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March 16, 2019

VIA: ELECTRONIC FILING

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

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 20200001-EI

Dear Mr. Teitzman:

Attached for filing in the above docket on behalf of Tampa Electric Company are the following:

1. Petition for Approval of Generating Performance Incentive Factor Results for the Twelve Month Period Ending December 2019.

2. Prepared Direct Testimony and Exhibit (JBC-1) of Jeremy B. Cain regarding Generating Performance Incentive Factor True-Up for the period January 2019 through December 2019.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/bmp
Attachments

cc: All parties of record (w/attachments)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	))))	DOCKET NO. 20200001-EI FILED: March 16, 2020

TAMPA ELECTRIC COMPANY'S PETITION FOR APPROVAL OF GENERATING PERFORMANCE INCENTIVE FACTOR RESULTS FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 2019

Tampa Electric Company ("Tampa Electric" or "the company") hereby petitions this Commission for approval of the company's results for the twelve-month period ending December 2019. In support of this Petition, Tampa Electric states as follows:

1. By Order No. PSC-2018-0610-FOF-EI, dated December 26, 2018, the Commission approved Tampa Electric's GPIF targets for the period January 2019 through December 2019. The application of the GPIF formula to the performance of the company's GPIF units during that period produces a reward of $2,858,056. The calculation of the company's GPIF reward is discussed and supported in the prepared direct testimony and exhibit of Tampa Electric witness Jeremy B. Cain, which are being filed together with this petition and incorporated herein by reference.

2. Tampa Electric is not aware of any disputed issues of material fact relative to the relief requested herein.

WHEREFORE, Tampa Electric respectfully requests the Commission to approve $2,858,056 as its GPIF reward for the period ending December 2019 and authorize the inclusion of this amount in the calculation of Tampa Electric's fuel factors for the period beginning January 2021.

DATED this 16th day of March 2020.

Respectfully submitted,

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Ausley McMullen
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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition and Testimony, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 16th day of March 2020 to the following:

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ATTORNEY

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TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR

TRUE-UP

JANUARY 2019 THROUGH DECEMBER 2019

TESTIMONY AND EXHIBIT

OF

JEREMY B. CAIN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy Cain. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager of Asset Management, Bayside Station.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have accumulated 10 years of experience in the electric utility industry, with experience in the areas of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for physical asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with Asset Management programs throughout Energy Supply. Asset Management processes include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning to maintain and improve the performance of the generating units.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor (“GPIF”) for the period January 2019 through December 2019. I will also compare these results to the targets established for the period.

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

A. Yes, I prepared Exhibit No. JBC-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Commission. Document No. 2 provides the company’s Actual Unit Performance Data for the 2019 period.

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

A. Polk Units 1 and 2 and Bayside Units 1 and 2 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2019 through December 2019 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 22. Based upon 5.274 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $2,858,056 for the period.

Q. Please proceed with your review of the actual results for the January 2019 through December 2019 period.

A. On Document No. 1, page 3 of 22, the actual average common equity for the period is shown on line 14 as $3,015,639,377. This produces the maximum penalty or reward amount of $5,419,348 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the four units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 22, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in Section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 22, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Polk Unit No. 1

On this unit, 720 planned outage hours were originally scheduled for 2019. Actual outage activities required 419 planned outage hours. Consequently, the actual equivalent availability of 78.9 percent is adjusted to 77.0 percent, as shown on Document No. 1, page 7 of 22.

Polk Unit No. 2

On this unit, 576 planned outage hours were originally scheduled for 2019. Actual outage activities required 391.4 planned outage hours. Consequently, the actual equivalent availability of 92.6 percent is adjusted to 90.6 percent, as shown on Document No. 1, page 8 of 22.

Bayside Unit No. 1

On this unit, 624 planned outage hours were originally scheduled for 2019. Actual outage activities required 973.6 planned outage hours. Consequently, the actual equivalent availability of 85.1 percent is adjusted to 89.1 percent, as shown on Document No. 1, page 9 of 22.

Bayside Unit No. 2

On this unit, 671 planned outage hours were originally scheduled for 2019. Actual outage activities required 998 planned outage hours. Consequently, the actual equivalent availability of 85.5 percent is adjusted to 89.0 percent, as shown on Document No. 1, page 10 of 22.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availability for each unit is shown on Document No. 1, page 6 of 22, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's four GPIF units are shown on Document No. 1, page 6 of 22. The adjustment was developed based on the guidelines of Section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 22, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January

2019 through December 2019 period?

A. This is shown on Document No. 1, page 2 of 22. The weighting factors shown on page 4 of 22, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 22, column 4, are substituted within the equation found on page 22 of 22. The resulting value of 5.274 is in the GPIF table on page 2 of 22, and the reward amount of $2,858,056 is calculated using linear interpolation.

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

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $5,419,348 as shown in Document No. 1, pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

GENERATING PERFORMANCE INCENTIVE FACTOR

INDEX

EXHIBIT TO THE TESTIMONY OF

JEREMY B. CAIN

DOCKET NO. 20200001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2019 – DECEMBER 2019

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2019 - DECEMBER 2019
TRUE-UP

TABLE OF CONTENTS

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

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

GPI POINTS 5.274

REWARD DOLLARS $2,858,056

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

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,867,405,914	
Line 2	Month of January	2019	$	2,882,004,481	
Line 3	Month of February	2019	$	2,909,743,602	
Line 4	Month of March	2019	$	2,924,640,926	
Line 5	Month of April	2019	$	2,946,588,417	
Line 6	Month of May	2019	$	3,011,756,553	
Line 7	Month of June	2019	$	3,047,198,358	
Line 8	Month of July	2019	$	3,085,572,885	
Line 9	Month of August	2019	$	3,033,558,076	
Line 10	Month of September	2019	$	3,069,893,560	
Line 11	Month of October	2019	$	3,104,286,978	
Line 12	Month of November	2019	$	3,155,976,279	
Line 13	Month of December	2019	$	3,164,685,873	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,015,639,377	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			75.30%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,012,482	
Line 18	Jurisdictional Sales			19,783,566	MWH
Line 19	Total Sales			19,783,566	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$	10,012,482	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-Point level from Sheet No. 3.515)		$	5,419,348	
Line 23	**Maximum Allowed GPIF Reward (At 10 GPIF-Point Level; the lesser of line 21 and line 22)**		**$**	**5,419,348**	

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
POLK 1	77.0%	EAF	5.07%	-10.000	-0.507
POLK 2	90.6%	EAF	1.90%	-1.742	-0.033
BAYSIDE 1	89.1%	EAF	1.11%	-10.000	-0.111
BAYSIDE 2	89.0%	EAF	3.12%	10.000	0.312
POLK 1	8,880	ANOHR	10.57%	10.000	1.057
POLK 2	6,469	ANOHR	36.89%	10.000	3.689
BAYSIDE 1	7,344	ANOHR	14.00%	0.000	0.000
BAYSIDE 2	7,438	ANOHR	27.35%	3.170	0.867
			100.00%		5.274

GPIF REWARD	**$ 2,858,056**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	EST. FUEL SAVINGS/ LOSS ($000)
POLK 1	5.07%	83.3	85.4	79.1	549.8	(342.2)	77.0%	(342.2)
POLK 2	1.90%	90.9	91.7	89.2	205.7	(1,759.2)	90.6%	(306.4)
BAYSIDE 1	1.11%	91.0	91.7	89.5	120.0	(60.0)	89.1%	(60.0)
BAYSIDE 2	3.12%	87.4	88.8	84.7	337.7	(773.7)	89.0%	337.7
GPIF SYSTEM	**11.19%**				**1,213.2**	**(2,935.1)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	EST. FUEL SAVINGS/ LOSS ($000)
POLK 1	10.57%	10,124	86.4	9,187	11,061	1,145.8	(1,145.8)	8,880	1,145.8
POLK 2	36.89%	6,904	81.0	6,731	7,077	3,998.7	(3,998.7)	6,469	3,998.7
BAYSIDE 1	14.00%	7,400	80.6	7,284	7,516	1,517.1	(1,517.1)	7,344	0.0
BAYSIDE 2	27.35%	7,561	60.5	7,334	7,789	2,964.0	(2,964.0)	7,438	939.6
GPIF SYSTEM	**88.81%**					**9,625.5**	**(9,625.5)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2019 - DECEMBER 2019

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
POLK 1	78.9	-1.9	77.0
POLK 2	92.6	-2.0	90.6
BAYSIDE 1	85.1	4.0	89.1
BAYSIDE 2	85.5	3.5	89.0

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
POLK 1	8,960	-80	8,880
POLK 2	6,997	-528	6,469
BAYSIDE 1	7,402	-58	7,344
BAYSIDE 2	7,408	30	7,438

(1) Documentation of adjustments to Actual EAF on pages 7 - 10

(2) Documentation of adjustments to Actual ANOHR on pages 11 - 14

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 5.07%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	83.3	78.9	77.0
POH	720.0	419.0	720.0
FOH + EFOH	599.1	620.3	597.9
MOH + EMOH	143.3	729.0	702.7
POF	8.2	4.8	8.2
EFOF	6.8	7.1	6.8
EMOF	1.6	8.3	8.0
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 720}{8760 - 419} \times (620.3 + 729) = 1,300.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 8.2 - \frac{1300.6}{8,760.0} \times 100 = 77.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 1.90%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	90.9	92.6	90.6
POH	576.0	391.4	576.0
FOH + EFOH	108.5	179.1	175.1
MOH + EMOH	113.5	76.0	74.3
POF	6.6	4.5	6.6
EFOF	1.2	2.0	2.0
EMOF	1.3	0.9	0.8
	-1.742	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 391.4} \times (179.1 + 76) = 249.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{249.5}{8,760.0} \times 100 = 90.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 1.11%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	91.0	85.1	89.1
POH	624.0	973.6	624.0
FOH + EFOH	83.9	259.4	271.0
MOH + EMOH	82.8	62.5	65.3
POF	7.1	11.1	7.1
EFOF	1.0	3.0	3.1
EMOF	0.9	0.7	0.7
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 624}{8760 - 973.6} \times (259.4 + 62.5) = 336.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 7.1 - \frac{336.4}{8{,}760.0} \times 100 = 89.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 3.12%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	87.4	85.5	89.0
POH	671.0	998.0	671.0
FOH + EFOH	204.3	132.1	137.7
MOH + EMOH	224.5	144.8	150.9
POF	7.7	11.4	7.7
EFOF	2.3	1.5	1.6
EMOF	2.6	1.7	1.7
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times \left(FOH + EFOH + MOH + EMOH\right) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 671}{8760 - 998} \times (132.1 + 144.8) = 288.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 7.7 - \frac{288.6}{8{,}760.0} \times 100 = 89.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 10.57%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,124	8,960
NET GENERATION (GWH)	458.2	622.5
OPERATING BTU (10^9)	3,747.9	5,577.4
NET OUTPUT FACTOR	86.4	59.0

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-2.93) + 10377.49 = ANOHR

59 * (-2.93) + 10377.49 = 10,204

8,960 - 10,204 = -1244

10,124 + -1244 = 8,880 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 36.89%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	6,904	6,997
NET GENERATION (GWH)	7,509.5	6,399.5
OPERATING BTU (10^9)	51,036.1	44,776.0
NET OUTPUT FACTOR	81.0	71.2

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-53.86) + 11266.21 = ANOHR

71.2 * (-53.86) + 11266.21 = 7,431

6,997 - 7,431 = -434

6,904 + -434 = 6,469 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 14.00%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,400	7,402
NET GENERATION (GWH)	4,520.1	3,192.8
OPERATING BTU (10^9)	32,958.7	23,632.0
NET OUTPUT FACTOR	80.6	60.2

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-2.85) + 7629.82 = ANOHR

60.2 * (-2.85) + 7629.82 = 7,458

7,402 - 7,458 = -56

7,400 + -56 = 7,344 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2019 - DECEMBER 2019

WEIGHTING FACTOR = 27.35%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,561	7,408
NET GENERATION (GWH)	4,441.0	4,648.5
OPERATING BTU (10^9)	33,370.3	34,437.1
NET OUTPUT FACTOR	60.5	64.9

3.170 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-6.67) + 7964.98 = ANOHR

64.9 * (-6.67) + 7964.98 = 7,532

7,408 - 7,532 = -124

7,561 + -124 = 7,438 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

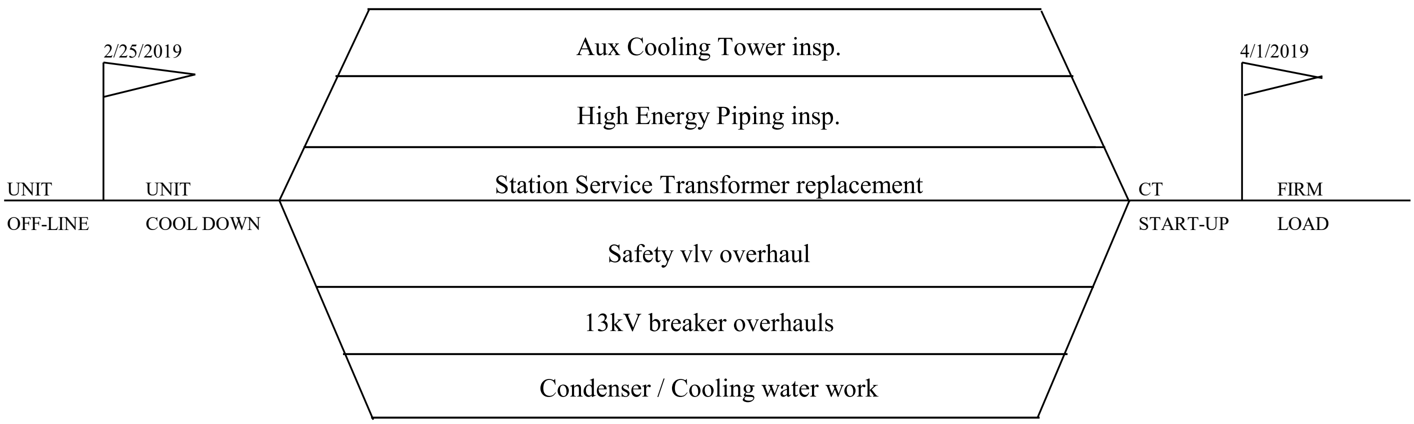
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2019 - DECEMBER 2019

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	POLK 1	Oct 09	-	Oct 26	Fuel System Cleanup
	POLK 2	Apr 09	-	Apr 22	LP Steam Vlv repairs, Hotwell inspection
		Nov 19	-	Nov 25	Fuel System Cleanup
+	BAYSIDE 1	Feb 25	-	Apr 01	Station Service Transformer replacement, Aux Cooling Tower insp., High Energy Piping insp., Safety vlv overhaul, 13kV breaker overhauls, Condenser / Cooling water work
		Oct 27	-	Nov 09	Fuel System Cleanup
	BAYSIDE 2	Jan 12	-	Feb 01	Fuel System Cleanup
		Dec 02		Dec 16	Fuel System Cleanup

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

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2019 - DECEMBER 2019



TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2019
ACTUAL CPM

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	549.8	85.4	+10	1,145.8	9,187
+9	494.8	85.2	+9	1,031.2	9,274
+8	439.8	85.0	+8	916.6	9,360
+7	384.9	84.8	+7	802.1	9,446
+6	329.9	84.6	+6	687.5	9,532
+5	274.9	84.4	+5	572.9	9,618
+4	219.9	84.1	+4	458.3	9,704
+3	164.9	83.9	+3	343.7	9,791
+2	110.0	83.7	+2	229.2	9,877
+1	55.0	83.5	+1	114.6	9,963
					10,049
0	0.0	83.3	0	0.0	10,124
					10,199
-1	(34.2)	82.9	-1	(114.6)	10,285
-2	(68.4)	82.5	-2	(229.2)	10,372
-3	(102.7)	82.0	-3	(343.7)	10,458
-4	(136.9)	81.6	-4	(458.3)	10,544
-5	(171.1)	81.2	-5	(572.9)	10,630
-6	(205.3)	80.8	-6	(687.5)	10,716
-7	(239.6)	80.4	-7	(802.1)	10,802
-8	(273.8)	79.9	-8	(916.6)	10,889
-9	(308.0)	79.5	-9	(1,031.2)	10,975
-10	(342.2)	79.1	-10	(1,145.8)	11,061

AHR POINTS 10.000

Adjusted ANOHR 8,880

EAF POINTS -10.000

Adjusted EAF 77.0

Weighting Factor = 5.07%

Weighting Factor = 10.57%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

POLK 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	205.7	91.7	+10	3,998.7	6,731
+9	185.2	91.6	+9	3,598.8	6,741
+8	164.6	91.6	+8	3,198.9	6,750
+7	144.0	91.5	+7	2,799.1	6,760
+6	123.4	91.4	+6	2,399.2	6,770
+5	102.9	91.3	+5	1,999.3	6,780
+4	82.3	91.2	+4	1,599.5	6,790
+3	61.7	91.1	+3	1,199.6	6,799
+2	41.1	91.1	+2	799.7	6,809
+1	20.6	91.0	+1	399.9	6,819
					6,829
0	0.0	90.9	0	0.0	6,904
					6,979
-1	(175.9)	90.7	-1	(399.9)	6,988
-2	(351.8)	90.6	-2	(799.7)	6,998
-3	(527.8)	90.4	-3	(1,199.6)	7,008
-4	(703.7)	90.2	-4	(1,599.5)	7,018
-5	(879.6)	90.1	-5	(1,999.3)	7,028
-6	(1,055.5)	89.9	-6	(2,399.2)	7,037
-7	(1,231.5)	89.7	-7	(2,799.1)	7,047
-8	(1,407.4)	89.6	-8	(3,198.9)	7,057
-9	(1,583.3)	89.4	-9	(3,598.8)	7,067
-10	(1,759.2)	89.2	-10	(3,998.7)	7,077

AHR POINTS 10.000

Adjusted ANOHR 6,469

EAF POINTS -1.742

Adjusted EAF 90.6

Weighting Factor = 1.90%

Weighting Factor = 36.89%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	120.0	91.7	+10	1,517.1	7,284
+9	108.0	91.6	+9	1,365.4	7,288
+8	96.0	91.6	+8	1,213.7	7,292
+7	84.0	91.5	+7	1,061.9	7,296
+6	72.0	91.4	+6	910.2	7,300
+5	60.0	91.3	+5	758.5	7,305
+4	48.0	91.3	+4	606.8	7,309
+3	36.0	91.2	+3	455.1	7,313
+2	24.0	91.1	+2	303.4	7,317
+1	12.0	91.0	+1	151.7	7,321
					7,325
0	0.0	91.0	0	0.0	7,400
					7,475
-1	(6.0)	90.8	-1	(151.7)	7,479
-2	(12.0)	90.7	-2	(303.4)	7,483
-3	(18.0)	90.5	-3	(455.1)	7,487
-4	(24.0)	90.4	-4	(606.8)	7,491
-5	(30.0)	90.2	-5	(758.5)	7,495
-6	(36.0)	90.1	-6	(910.2)	7,500
-7	(42.0)	89.9	-7	(1,061.9)	7,504
-8	(48.0)	89.8	-8	(1,213.7)	7,508
-9	(54.0)	89.6	-9	(1,365.4)	7,512
-10	(60.0)	89.5	-10	(1,517.1)	7,516

AHR POINTS 0.000

Adjusted ANOHR 7,344

EAF POINTS -10.000

Adjusted EAF 89.1

Weighting Factor = 1.11%

Weighting Factor = 14.00%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2019 - DECEMBER 2019

BAYSIDE 2

EAF POINTS 10.000

Adjusted EAF 89.0

AHR POINTS 3.170

Adjusted ANOHR 7,438

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	337.7	88.8	+10	2,964.0	7,334
+9	303.9	88.7	+9	2,667.6	7,349
+8	270.1	88.5	+8	2,371.2	7,364
+7	236.4	88.4	+7	2,074.8	7,379
+6	202.6	88.3	+6	1,778.4	7,395
+5	168.8	88.1	+5	1,482.0	7,410
+4	135.1	88.0	+4	1,185.6	7,425
+3	101.3	87.9	+3	889.2	7,441
+2	67.5	87.7	+2	592.8	7,456
+1	33.8	87.6	+1	296.4	7,471
					7,486
0	0.0	87.4	0	0.0	7,561
					7,636
-1	(77.4)	87.2	-1	(296.4)	7,652
-2	(154.7)	86.9	-2	(592.8)	7,667
-3	(232.1)	86.6	-3	(889.2)	7,682
-4	(309.5)	86.4	-4	(1,185.6)	7,698
-5	(386.8)	86.1	-5	(1,482.0)	7,713
-6	(464.2)	85.8	-6	(1,778.4)	7,728
-7	(541.6)	85.5	-7	(2,074.8)	7,743
-8	(618.9)	85.3	-8	(2,371.2)	7,759
-9	(696.3)	85.0	-9	(2,667.6)	7,774
-10	(773.7)	84.7	-10	(2,964.0)	7,789

Weighting Factor = 3.12%

Weighting Factor = 27.35%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 19 - DEC 19 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 19 - DEC 19 POF	EUOF	EUOR
POLK 1	5.1%	45.3%	8.2	8.5	9.2	4.8	15.4	16.2
POLK 2	1.9%	17.0%	6.6	2.5	2.7	4.5	2.9	3.0
BAYSIDE 1	1.1%	9.9%	7.1	1.9	2.0	11.1	3.7	4.1
BAYSIDE 2	3.1%	27.8%	7.7	4.9	5.3	11.4	3.2	3.6
GPIF SYSTEM	**11.2%**	**100.0%**	**7.7**	**5.8**	**6.3**	**7.2**	**8.7**	**9.2**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%				**86.5**			**84.1**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
7.7	**15.6**	**16.7**	**76.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 19 - DEC 19	ADJUSTED ACTUAL HEAT RATE JAN 19 - DEC 19
POLK 1	10.57%	11.9%	10,124	8,880
POLK 2	36.89%	41.5%	6,904	6,469
BAYSIDE 1	14.00%	15.8%	7,400	7,344
BAYSIDE 2	27.35%	30.8%	7,561	7,438
GPIF SYSTEM	**88.8%**	**100.0%**		
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**7,568**	**7,192**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2019 - DECEMBER 2019

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i \left(EAP_i \right) + e_i \left(AHRP_i \right) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	5.07%	*	(PK 1 EAP)	+	1.90%	*	(PK 2 EAP)	+	1.11%	*	(BAY 1 EAP)
+	3.12%	*	(BAY 2 EAP)	+	10.57%	*	(PK 1 AHRP)	+	36.89%	*	(PK 2 AHRP)
+	14.00%	*	(BAY 1 AHRP)	+	27.35%	*	(BAY 2 AHRP)				

GPIP =	5.07%	*	-10.000	+	1.90%	*	-1.742	+	1.11%	*	-10.000
+	3.12%	*	10.000	+	10.57%	*	10.000	+	36.89%	*	10.000
+	14.00%	*	0.000	+	27.35%	*	3.170				

GPIP =	-0.507	+	-0.033	+	-0.111
+	0.312	+	1.057	+	3.689
+	0.000	+	0.867		

GPIP = 5.274 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = $2,858,056

EXHIBIT TO THE TESTIMONY OF

JEREMY B. CAIN

DOCKET NO. 20200001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2019 - DECEMBER 2019

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	61.1	18.0	81.8	100.0	68.9	98.5	98.8	100.0	100.0	43.7	86.9	82.9	78.9
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	192.7	53.0	458.1	692.0	509.0	667.2	319.9	409.9	465.6	133.8	358.1	173.9	4,433.2
4. Reserve Shutdown Hours	RSH	322.9	0.0	179.0	28.0	3.4	42.0	415.5	334.1	254.4	191.2	279.3	443.1	2,492.9
5. Unavailable Hours	UH	213.9	539.6	106.9	0.0	231.6	10.8	8.6	0.0	0.0	419.0	82.6	127.0	1,740.0
6. Planned Outage Hours	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	419.0	0.0	0.0	419.0
7. Forced Outage Hours	FOH	19.6	539.6	0.0	0.0	41.5	8.7	0.0	0.0	0.0	0.0	0.0	0.0	609.4
8. Maintenance Outage Hours	MOH	208.8	0.0	106.9	0.0	190.1	2.1	8.6	0.0	0.0	0.0	82.6	127.0	726.1
9a. Partial Planned Outage Hours	PPOH	744.0	493.0	30.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,267.9
9b. Load Reduction Partial Planned (MW)	LRPP	20.0	5.0	65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
10a. Partial Forced Outage Hours	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	372.2	0.0	372.2
10b. Load Reduction Partial Forced (MW)	LRPF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	7.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.0
12. Net Summer Continuous Rating (MW)	NSC	235	235	235	235	235	235	235	235	235	235	235	235	235
13. Operating British Thermal Units (GBTU)	OPR BTU	247.0	62.5	551.9	884.0	657.3	872.8	386.1	475.2	515.6	181.6	493.7	249.7	5,577.4
14. Net Generation (MWH)	NETGEN	23,968.3	4,295.0	61,112.0	103,624.0	75,289.0	101,034.8	40,693.3	51,490.0	55,151.1	19,059.4	59,836.1	26,913.0	622,466.0
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	10,304.7	14,559.0	9,032.0	8,531.0	8,731.0	8,639.0	9,789.0	9,229.0	9,348.0	9,529.0	8,251.0	9,279.0	8,960.2
16. Net Output Factor (%)	NOF	50.8	32.9	55.1	64.5	62.9	64.4	54.1	53.5	50.4	60.6	71.1	63.9	59.0

EXHIBIT NO._____ (JBC-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20200001-EI
DOCUMENT NO. 2
PAGE 1 OF 4

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 2		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	98.7	95.3	99.5	64.2	99.4	80.4	97.0	99.5	99.3	99.9	71.7	93.0	92.6
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	742.3	643.0	741.8	396.0	744.0	643.1	730.9	740.3	715.1	743.4	569.2	713.4	8,122.5
4. Reserve Shutdown Hours	RSH	0.0	0.0	0.0	66.5	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	67.5
5. Unavailable Hours	UH	1.7	29.0	2.2	257.5	0.0	76.9	12.1	3.7	4.9	0.6	150.8	30.6	570.0
6. Planned Outage Hours	POH	0.0	0.0	0.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	120.7	25.7	391.4
7. Forced Outage Hours	FOH	1.7	29.0	2.2	10.1	0.0	76.9	2.5	0.1	0.3	0.6	16.6	0.2	140.2
8. Maintenance Outage Hours	MOH	0.0	0.0	0.0	2.4	0.0	0.0	9.6	3.6	4.7	0.0	13.5	4.7	38.5
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	5.0	8.4	5.8	0.0	18.3	237.6	7.6	0.0	0.0	1.7	51.0	0.4	335.8
10b. Load Reduction Partial Forced (MW)	LRPF	34.0	298.6	97.0	0.0	138.0	125.2	124.9	0.0	0.0	124.5	125.0	123.4	128.3
11a. Partial Maintenance Outage Hours	PMOH	32.3	0.0	0.0	0.0	0.0	0.0	29.7	0.0	0.0	0.0	135.7	81.1	278.8
11b. Load Reduction Partial Maintenance (MW)	LRPM	300.0	0.0	0.0	0.0	0.0	0.0	125.0	0.0	0.0	0.0	132.5	125.0	148.9
12. Net Summer Continuous Rating (MW)	NSC	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061
13. Operating British Thermal Units (GBTU)	OPR BTU	4,703.9	2,665.0	3,704.2	1,627.1	3,689.5	3,213.4	4,270.8	4,669.9	4,373.8	4,680.8	2,949.5	4,228.1	44,776.0
14. Net Generation (MWH)	NETGEN	682,239.1	377,898.0	527,688.0	213,900.0	517,263.0	449,778.0	592,883.0	673,696.0	658,273.7	676,742.0	417,852.0	611,288.0	6,399,500.8
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	6,894.7	7,052.0	7,020.0	7,607.0	7,134.0	7,144.0	7,204.0	6,932.0	6,912.0	6,917.0	7,050.0	6,917.0	6,996.8
16. Net Output Factor (%)	NOF	76.6	49.0	59.1	50.6	65.5	58.9	75.1	85.3	86.3	85.7	66.0	68.5	71.2

EXHIBIT NO._____ (JBC-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20200001-EI
DOCUMENT NO. 2
PAGE 2 OF 4

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	99.9	87.8	23.1	87.9	93.9	95.4	86.7	96.8	97.5	78.1	67.5	98.6	85.1
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	744.0	597.1	0.0	586.9	714.1	700.1	672.5	728.2	708.2	602.7	467.8	736.3	7,257.9
4. Reserve Shutdown Hours	RSH	0.0	0.0	171.9	46.5	0.0	0.0	0.0	0.0	0.0	0.0	23.6	0.0	242.0
5. Unavailable Hours	UH	0.0	74.9	572.1	86.6	29.9	19.9	71.5	15.8	11.8	141.3	228.6	7.7	1,260.1
6. Planned Outage Hours	POH	0.0	74.9	572.1	8.5	0.0	0.0	0.0	0.0	0.0	114.4	203.7	0.0	973.6
7. Forced Outage Hours	FOH	0.0	0.0	0.0	78.1	0.0	19.9	68.5	10.8	10.2	24.7	14.0	7.7	233.9
8. Maintenance Outage Hours	MOH	0.0	0.0	0.0	0.0	29.9	0.0	3.0	5.0	1.6	2.2	10.8	0.0	52.5
9a. Partial Planned Outage Hours	PPOH	0.0	48.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.5
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	117.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.4
10a. Partial Forced Outage Hours	PFOH	2.1	0.0	0.0	0.9	0.0	39.7	81.7	16.1	12.8	36.9	16.8	10.0	217.0
10b. Load Reduction Partial Forced (MW)	LRPF	263.8	0.0	0.0	77.4	0.0	94.2	79.0	79.0	145.3	72.3	79.0	71.0	86.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	0.0	0.0	44.6	7.7	0.0	7.4	2.4	20.3	0.0	0.0	82.5
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	0.0	0.0	79.0	75.0	0.0	79.0	79.0	118.1	0.0	0.0	88.3
12. Net Summer Continuous Rating (MW)	NSC	701	701	701	701	701	701	701	701	701	701	701	701	701
13. Operating British Thermal Units (GBTU)	OPR BTU	2,153.7	1,975.7	0.0	2,092.3	2,623.6	2,709.4	2,338.2	2,555.4	2,098.8	1,848.1	1,146.7	2,090.2	23,632.0
14. Net Generation (MWH)	NETGEN	281,105.8	268,363.3	-489.0	285,493.0	357,594.0	371,287.2	316,400.6	340,370.5	282,565.0	249,882.7	153,636.9	286,572.2	3,192,782.2
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	7,661.4	7,362.0	0.0	7,329.0	7,337.0	7,297.0	7,390.0	7,508.0	7,428.0	7,396.0	7,464.0	7,294.0	7,401.7
16. Net Output Factor (%)	NOF	47.7	56.8	0.0	69.4	68.6	73.6	64.1	65.3	56.0	55.1	46.8	48.6	60.2

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2019 - DECEMBER 2019

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2		JAN 19	FEB 19	MAR 19	APR 19	MAY 19	JUN 19	JUL 19	AUG 19	SEP 19	OCT 19	NOV 19	DEC 19	2019
1. Equivalent Availability Factor (%)	EAF	33.7	80.8	99.5	94.1	99.6	99.3	100.0	92.1	97.4	100.0	71.8	46.1	85.5
2. Period Hours	PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
3. Service Hours	SH	241.8	594.0	740.6	691.2	742.1	717.2	743.0	685.1	707.6	744.0	597.6	155.5	7,359.7
4. Reserve Shutdown Hours	RSH	24.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	212.4	237.4
5. Unavailable Hours	UH	478.2	78.0	3.4	28.8	1.9	2.8	0.0	58.9	12.4	0.0	122.4	376.1	1,162.9
6. Planned Outage Hours	POH	445.0	58.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.4	372.6	998.0
7. Forced Outage Hours	FOH	33.2	0.0	3.4	28.8	0.5	2.8	0.0	0.0	0.0	0.0	0.0	3.5	72.2
8. Maintenance Outage Hours	MOH	0.0	20.0	0.0	0.0	1.4	0.0	0.0	58.9	12.4	0.0	0.0	0.0	92.9
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	0.7	383.8	0.2	53.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	445.1
10b. Load Reduction Partial Forced (MW)	LRPF	261.8	138.4	78.8	77.0	77.5	0.0	0.0	0.0	0.0	0.0	0.0	79.0	130.3
11a. Partial Maintenance Outage Hours	PMOH	59.9	0.0	0.0	0.0	2.7	8.3	0.0	0.0	24.2	0.0	164.2	41.9	301.2
11b. Load Reduction Partial Maintenance (MW)	LRPM	261.8	0.0	0.0	0.0	77.1	85.0	0.0	0.0	77.0	0.0	149.2	174.2	166.9
12. Net Summer Continuous Rating (MW)	NSC	929	929	929	929	929	929	929	929	929	929	929	929	929
13. Operating British Thermal Units (GBTU)	OPR BTU	661.3	2,265.6	4,330.1	3,601.5	4,030.2	3,898.4	3,798.3	3,042.7	2,946.1	3,292.3	2,204.7	365.9	34,437.1
14. Net Generation (MWH)	NETGEN	80,708.2	305,544.7	572,174.0	492,205.4	551,479.2	538,434.7	520,587.5	405,685.4	397,926.0	448,016.3	297,089.0	38,648.7	4,648,499.1
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	8,193.5	7,415.0	7,568.0	7,317.0	7,308.0	7,240.0	7,296.0	7,500.0	7,404.0	7,349.0	7,421.0	9,469.0	7,408.2
16. Net Output Factor (%)	NOF	31.9	49.1	86.9	73.6	77.5	80.5	75.3	63.7	59.5	64.8	44.4	23.7	64.9