TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080001-EI

IN RE: TAMPA ELECTRIC'S

FUEL & PURCHASED POWER COST RECOVERY

AND CAPACITY COST RECOVERY PROJECTIONS

JANUARY 2009 THROUGH DECEMBER 2009

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. 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 Supervisor, Performance Planning & Analysis in the Resource Planning Department.

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 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Asset Management. In August 2007, I was promoted to Supervisor, Performance Planning and Analysis in the Resource Planning department, where I am currently responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents 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 any exhibits to support your testimony?

A. Yes, Exhibit No. ____ (BSB-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2009 period.

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

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. 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. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One outage from Big Bend Unit 2, one outage from Big Bend Unit 3, and one outage from Big Bend Unit 4 were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2009 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 or POF and the Equivalent Unplanned Outage Factor or EUOF were subtracted from 100 percent to determine the target Equivalent Availability Factor or EAF. The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2009 period, the projected

Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 18.2 percent, and the Planned Outage Factor is 9.3 percent. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 72.5 percent or:

$$100\% - (18.2\% + 9.3\%) = 72.5\%$$

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 by using the following formula:

$$EAF_{MAX} = 1 - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 1 - [0.8\ (18.2\%) + 0.95\ (9.3\%)] = 76.6\%$$

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 with the Big Bend Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (18.2\%) + 1.10\ (9.3\%)] = 64.3\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2009 are shown on page 21 of Document No. 1. Four GPIF units have a major outage of 28 days or greater in 2009; therefore, four Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage from November 28, 2009 to December 31, 2009. There are 816 planned outage hours scheduled for the 2009 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend Unit 1 is 9.3 percent or:

$$\frac{816}{8{,}760} \times 100\% = 9.3\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a Planned Outage Factor of 9.3 percent. Big Bend Unit 2 has a Planned Outage Factor of 32.6 percent. Big Bend Unit 3 has a Planned Outage Factor of 3.8 percent. Big Bend Unit 4 has a Planned Outage Factor of 15.3 percent.

Polk Unit 1 has a Planned Outage Factor of 9.8 percent. Bayside Unit 1 has a Planned Outage Factor of 3.8 percent, and Bayside Unit 2 has a Planned Outage Factor of 3.8 percent.

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

A. For each unit the most current 12-month ending value, June 2008, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 18.2 percent for Big Bend Unit 1. The Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 14, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(1,368 + 224)}{8,760} \times 100\% = 18.2\%$$

Relative to Big Bend Unit 1, the EUOF of 18.2 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

The projected Equivalent Unplanned Outage Factor for this unit is 18.2 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 9.3 percent. Therefore, the target equivalent availability for this unit is 72.5 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 11.3 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 32.6 percent. Therefore, the target equivalent availability for this unit is 56.1 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 41.8 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8 percent. Therefore, the target equivalent availability for this unit is 54.3 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 17.2 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 15.3 percent. Therefore, the target equivalent availability for this unit is 67.5 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 10.6 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 9.8 percent. Therefore, the target equivalent availability for this unit is 79.7 percent.

Bayside Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 2.8 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.4 percent.

Bayside Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 2.0 percent. The unit will have a planned outage in 2009, and the Planned Outage Factor is 3.8

percent. Therefore, the target equivalent availability for this unit is 94.1 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 62.7 percent is shown on Page 5 of Document No. 1. This target is comparable to the 2007 January through December actual performance.

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 will not 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 1 on page 14 of Document No. 1. During the months of January through October and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the month of November, the

Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to a scheduled planned outage. 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 the unit metrics, which are subsequently converted to factors. Therefore,

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

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

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

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of 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 periods 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 33 through 39 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 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.

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 2009 period.

A. The heat rate target for Big Bend Unit 1 is 10,774 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±302 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,396 Btu/Net kWh with a range of ±291 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,751 Btu/Net kWh, with a range of ±293 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,598 Btu/Net kWh with a range of ±454 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,707 Btu/Net kWh with a range of ±753 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,264

Btu/Net kWh with a range of ±102 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,378 Btu/Net kWh with a range of ±101 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. 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 $1,492,425.10 is shown on page 6, column 2.

Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $60,487,101 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 1, the weighting factor for equivalent availability is 8.9 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 1, page 7, if the unit operates at 76.6 percent equivalent availability, fuel savings would equal $5,381,600, and 10 equivalent availability points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. 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 $60,487,101. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2009 is $2,071,043,308. This produces the maximum allowed jurisdictional incentive of $8,123,043 shown on line 21.

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. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your 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):

$$\begin{aligned} GPIP: = (\ & 0.0890\ EAP_{BB1} + 0.0704\ EAP_{BB2} \\ & + 0.2222\ EAP_{BB3} + 0.1042\ EAP_{BB4} \\ & + 0.0309\ EAP_{PK1} + 0.0067\ EAP_{BAY1} \\ & + 0.0070\ EAP_{BAY2} + 0.0451\ HRP_{BB1} \\ & + 0.0329\ HRP_{BB2} + 0.0342\ HRP_{BB3} \\ & + 0.0711\ HRP_{BB4} + 0.1081\ HRP_{PK1} \\ & + 0.0906\ HRP_{BAY1} + 0.0876\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2009 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 testimony?

A. Yes.

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2009 - DECEMBER 2009

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2009 - DECEMBER 2009
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2009 - DECEMBER 2009

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	60,487.1	8,123.0
+9	54,438.4	7,310.7
+8	48,389.7	6,498.4
+7	42,341.0	5,686.1
+6	36,292.3	4,873.8
+5	30,243.6	4,061.5
+4	24,194.8	3,249.2
+3	18,146.1	2,436.9
+2	12,097.4	1,624.6
+1	6,048.7	812.3
0	0.0	0.0
-1	(10,975.5)	(812.3)
-2	(21,950.9)	(1,624.6)
-3	(32,926.4)	(2,436.9)
-4	(43,901.9)	(3,249.2)
-5	(54,877.4)	(4,061.5)
-6	(65,852.8)	(4,873.8)
-7	(76,828.3)	(5,686.1)
-8	(87,803.8)	(6,498.4)
-9	(98,779.2)	(7,310.7)
-10	(109,754.7)	(8,123.0)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2009 - DECEMBER 2009

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,884,283,000	
Line 2	Month of January	2009	$	1,956,933,000	
Line 3	Month of February	2009	$	1,977,816,000	
Line 4	Month of March	2009	$	2,022,168,000	
Line 5	Month of April	2009	$	2,048,958,000	
Line 6	Month of May	2009	$	2,060,785,000	
Line 7	Month of June	2009	$	2,097,586,000	
Line 8	Month of July	2009	$	2,114,125,000	
Line 9	Month of August	2009	$	2,133,572,000	
Line 10	Month of September	2009	$	2,168,532,000	
Line 11	Month of October	2009	$	2,148,509,000	
Line 12	Month of November	2009	$	2,153,373,000	
Line 13	Month of December	2009	$	2,156,923,000	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,071,043,308	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.38%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	8,435,228	
Line 18	Jurisdictional Sales			19,991,680	MWH
Line 19	Total Sales			20,760,002	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			96.30%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**8,123,043**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2009 - DECEMBER 2009

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	8.90%	72.5	76.6	64.3	5,381.6	(13,607.0)
BIG BEND 2	7.04%	56.1	60.0	48.4	4,256.1	(10,743.9)
BIG BEND 3	22.22%	54.3	62.9	37.2	13,438.2	(34,614.0)
BIG BEND 4	10.42%	67.5	71.7	59.1	6,305.2	(15,453.2)
POLK 1	3.09%	79.7	82.3	74.6	1,866.1	(4,526.3)
BAYSIDE 1	0.67%	93.4	94.1	91.9	405.7	(1,190.9)
BAYSIDE 2	0.70%	94.1	94.7	92.9	423.0	(1,208.2)
GPIF SYSTEM	53.03%					

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 1	4.51%	10,774	90.9	10,472	11,077	2,730.6	(2,730.6)
BIG BEND 2	3.29%	10,396	90.5	10,105	10,688	1,990.2	(1,990.2)
BIG BEND 3	3.42%	10,751	77.3	10,458	11,044	2,071.3	(2,071.3)
BIG BEND 4	7.11%	10,598	90.1	10,144	11,052	4,299.7	(4,299.7)
POLK 1	10.81%	10,707	86.9	9,955	11,460	6,540.5	(6,540.5)
BAYSIDE 1	9.06%	7,264	84.4	7,163	7,366	5,480.0	(5,480.0)
BAYSIDE 2	8.76%	7,378	77.7	7,277	7,479	5,298.9	(5,298.9)
GPIF SYSTEM	46.97%						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 09 - DEC 09 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 07 - DEC 07 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 06 - DEC 06 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 05 - DEC 05 POF	EUOF	EUOR
BIG BEND 1	8.90%	16.8%	9.3	18.2	20.0	0.0	23.7	23.7	18.5	26.3	32.2	8.6	30.4	33.2
BIG BEND 2	7.04%	13.3%	32.6	11.3	16.7	2.5	16.0	18.4	0.0	17.2	17.2	16.0	19.2	22.8
BIG BEND 3	22.22%	41.9%	3.8	41.8	43.5	11.8	41.7	47.3	7.9	30.2	32.8	7.1	41.4	44.6
BIG BEND 4	10.42%	19.7%	15.3	17.2	20.3	27.0	19.8	27.0	8.3	17.0	18.6	7.8	21.5	23.3
POLK 1	3.09%	5.8%	9.6	10.6	11.7	4.1	11.0	12.8	12.0	9.2	10.7	0.0	31.5	33.4
BAYSIDE 1	0.67%	1.3%	3.8	2.8	2.9	11.5	3.3	3.9	2.5	10.3	11.1	3.1	4.4	4.6
BAYSIDE 2	0.70%	1.3%	3.8	2.0	2.1	2.0	1.7	1.7	10.0	1.4	1.6	2.9	4.2	4.2
GPIF SYSTEM	53.03%	100.0%	11.2	26.1	28.5	11.0	28.4	32.4	8.9	23.4	25.8	8.2	31.2	33.9
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				62.7			60.6			67.7			60.7	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
9.4	27.7	30.7	63.0

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 09 - DEC 09	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 07 - DEC 07	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 06 - DEC 06	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 05 - DEC 05
BIG BEND 1	4.51%	9.6%	10,774	10,681	10,749	10,663
BIG BEND 2	3.29%	7.0%	10,396	10,350	10,344	10,409
BIG BEND 3	3.42%	7.3%	10,751	10,693	10,787	10,838
BIG BEND 4	7.11%	15.1%	10,598	10,603	10,576	10,431
POLK 1	10.81%	23.0%	10,707	10,697	10,454	10,520
BAYSIDE 1	9.06%	19.3%	7,264	7,310	7,329	7,405
BAYSIDE 2	8.76%	18.7%	7,378	7,378	7,428	7,388
GPIF SYSTEM	46.97%	100.0%				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			9,394	9,384	9,350	9,351

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2009 - DECEMBER 2009
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	1,492,425.1	1,487,043.5	5,381.6	8.90%
EA_2 BIG BEND 2	1,492,425.1	1,488,169.0	4,256.1	7.04%
EA_3 BIG BEND 3	1,492,425.1	1,478,986.9	13,438.2	22.22%
EA_4 BIG BEND 4	1,492,425.1	1,486,119.9	6,305.2	10.42%
EA_7 POLK 1	1,492,425.1	1,490,559.0	1,866.1	3.09%
EA_8 BAYSIDE 1	1,492,425.1	1,492,019.4	405.7	0.67%
EA_9 BAYSIDE 2	1,492,425.1	1,492,002.1	423.0	0.70%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	1,492,425.1	1,489,694.5	2,730.6	4.51%
AHR_2 BIG BEND 2	1,492,425.1	1,490,434.9	1,990.2	3.29%
AHR_3 BIG BEND 3	1,492,425.1	1,490,353.8	2,071.3	3.42%
AHR_4 BIG BEND 4	1,492,425.1	1,488,125.4	4,299.7	7.11%
AHR_7 POLK 1	1,492,425.1	1,485,884.6	6,540.5	10.81%
AHR_8 BAYSIDE 1	1,492,425.1	1,486,945.1	5,480.0	9.06%
AHR_9 BAYSIDE 2	1,492,425.1	1,487,126.2	5,298.9	8.76%
TOTAL SAVINGS			60,487.101	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 2009 - DECEMBER 2009

BIG BEND 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	5,381.6	76.6	+10	2,730.6	10,472
+9	4,843.4	76.2	+9	2,457.5	10,495
+8	4,305.3	75.8	+8	2,184.5	10,518
+7	3,767.1	75.4	+7	1,911.4	10,540
+6	3,229.0	75.0	+6	1,638.4	10,563
+5	2,690.8	74.6	+5	1,365.3	10,586
+4	2,152.6	74.1	+4	1,092.2	10,608
+3	1,614.5	73.7	+3	819.2	10,631
+2	1,076.3	73.3	+2	546.1	10,654
+1	538.2	72.9	+1	273.1	10,677
					10,699
0	0.0	72.5	0	0.0	10,774
					10,849
-1	(1,360.7)	71.7	-1	(273.1)	10,872
-2	(2,721.4)	70.9	-2	(546.1)	10,895
-3	(4,082.1)	70.0	-3	(819.2)	10,918
-4	(5,442.8)	69.2	-4	(1,092.2)	10,940
-5	(6,803.5)	68.4	-5	(1,365.3)	10,963
-6	(8,164.2)	67.6	-6	(1,638.4)	10,986
-7	(9,524.9)	66.8	-7	(1,911.4)	11,009
-8	(10,885.6)	65.9	-8	(2,184.5)	11,031
-9	(12,246.3)	65.1	-9	(2,457.5)	11,054
-10	(13,607.0)	64.3	-10	(2,730.6)	11,077
	Weighting Factor =	8.90%		Weighting Factor =	4.51%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

BIG BEND 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	4,256.1	60.0	+10	1,990.2	10,105
+9	3,830.5	59.6	+9	1,791.1	10,126
+8	3,404.9	59.2	+8	1,592.1	10,148
+7	2,979.3	58.8	+7	1,393.1	10,170
+6	2,553.7	58.4	+6	1,194.1	10,191
+5	2,128.1	58.1	+5	995.1	10,213
+4	1,702.4	57.7	+4	796.1	10,235
+3	1,276.8	57.3	+3	597.0	10,256
+2	851.2	56.9	+2	398.0	10,278
+1	425.6	56.5	+1	199.0	10,300
					10,321
0	0.0	56.1	0	0.0	10,396
					10,471
-1	(1,074.4)	55.3	-1	(199.0)	10,493
-2	(2,148.8)	54.6	-2	(398.0)	10,514
-3	(3,223.2)	53.8	-3	(597.0)	10,536
-4	(4,297.6)	53.0	-4	(796.1)	10,558
-5	(5,371.9)	52.2	-5	(995.1)	10,579
-6	(6,446.3)	51.5	-6	(1,194.1)	10,601
-7	(7,520.7)	50.7	-7	(1,393.1)	10,623
-8	(8,595.1)	49.9	-8	(1,592.1)	10,644
-9	(9,669.5)	49.1	-9	(1,791.1)	10,666
-10	(10,743.9)	48.4	-10	(1,990.2)	10,688
	Weighting Factor =	7.04%		Weighting Factor =	3.29%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

BIG BEND 3

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	13,438.2	62.9	+10	2,071.3	10,458
+9	12,094.4	62.0	+9	1,864.2	10,480
+8	10,750.6	61.2	+8	1,657.0	10,502
+7	9,406.7	60.3	+7	1,449.9	10,523
+6	8,062.9	59.5	+6	1,242.8	10,545
+5	6,719.1	58.6	+5	1,035.7	10,567
+4	5,375.3	57.8	+4	828.5	10,589
+3	4,031.5	56.9	+3	621.4	10,611
+2	2,687.6	56.0	+2	414.3	10,632
+1	1,343.8	55.2	+1	207.1	10,654
					10,676
0	0.0	54.3	0	0.0	10,751
					10,826
-1	(3,461.4)	52.6	-1	(207.1)	10,848
-2	(6,922.8)	50.9	-2	(414.3)	10,870
-3	(10,384.2)	49.2	-3	(621.4)	10,892
-4	(13,845.6)	47.5	-4	(828.5)	10,913
-5	(17,307.0)	45.8	-5	(1,035.7)	10,935
-6	(20,768.4)	44.1	-6	(1,242.8)	10,957
-7	(24,229.8)	42.4	-7	(1,449.9)	10,979
-8	(27,691.2)	40.6	-8	(1,657.0)	11,001
-9	(31,152.6)	38.9	-9	(1,864.2)	11,023
-10	(34,614.0)	37.2	-10	(2,071.3)	11,044
	Weighting Factor =	22.22%		Weighting Factor =	3.42%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

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	6,305.2	71.7	+10	4,299.7	10,144
+9	5,674.7	71.2	+9	3,869.7	10,182
+8	5,044.2	70.8	+8	3,439.7	10,220
+7	4,413.6	70.4	+7	3,009.8	10,258
+6	3,783.1	70.0	+6	2,579.8	10,296
+5	3,152.6	69.6	+5	2,149.8	10,334
+4	2,522.1	69.1	+4	1,719.9	10,372
+3	1,891.6	68.7	+3	1,289.9	10,410
+2	1,261.0	68.3	+2	859.9	10,447
+1	630.5	67.9	+1	430.0	10,485
					10,523
0	0.0	67.5	0	0.0	10,598
					10,673
-1	(1,545.3)	66.6	-1	(430.0)	10,711
-2	(3,090.6)	65.8	-2	(859.9)	10,749
-3	(4,636.0)	64.9	-3	(1,289.9)	10,787
-4	(6,181.3)	64.1	-4	(1,719.9)	10,825
-5	(7,726.6)	63.3	-5	(2,149.8)	10,863
-6	(9,271.9)	62.4	-6	(2,579.8)	10,900
-7	(10,817.2)	61.6	-7	(3,009.8)	10,938
-8	(12,362.6)	60.7	-8	(3,439.7)	10,976
-9	(13,907.9)	59.9	-9	(3,869.7)	11,014
-10	(15,453.2)	59.1	-10	(4,299.7)	11,052
	Weighting Factor =	10.42%		Weighting Factor =	7.11%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

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	1,866.1	82.3	+10	6,540.5	9,955
+9	1,679.5	82.1	+9	5,886.4	10,022
+8	1,492.9	81.8	+8	5,232.4	10,090
+7	1,306.3	81.5	+7	4,578.3	10,158
+6	1,119.7	81.3	+6	3,924.3	10,226
+5	933.1	81.0	+5	3,270.2	10,294
+4	746.4	80.8	+4	2,616.2	10,361
+3	559.8	80.5	+3	1,962.1	10,429
+2	373.2	80.2	+2	1,308.1	10,497
+1	186.6	80.0	+1	654.0	10,565
					10,632
0	0.0	79.7	0	0.0	10,707
					10,782
-1	(452.6)	79.2	-1	(654.0)	10,850
-2	(905.3)	78.7	-2	(1,308.1)	10,918
-3	(1,357.9)	78.1	-3	(1,962.1)	10,986
-4	(1,810.5)	77.6	-4	(2,616.2)	11,054
-5	(2,263.1)	77.1	-5	(3,270.2)	11,121
-6	(2,715.8)	76.6	-6	(3,924.3)	11,189
-7	(3,168.4)	76.1	-7	(4,578.3)	11,257
-8	(3,621.0)	75.6	-8	(5,232.4)	11,325
-9	(4,073.7)	75.1	-9	(5,886.4)	11,392
-10	(4,526.3)	74.6	-10	(6,540.5)	11,460
	Weighting Factor =	3.09%		Weighting Factor =	10.81%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

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	405.7	94.1	+10	5,480.0	7,163
+9	365.1	94.0	+9	4,932.0	7,165
+8	324.6	94.0	+8	4,384.0	7,168
+7	284.0	93.9	+7	3,836.0	7,171
+6	243.4	93.8	+6	3,288.0	7,173
+5	202.9	93.7	+5	2,740.0	7,176
+4	162.3	93.7	+4	2,192.0	7,179
+3	121.7	93.6	+3	1,644.0	7,181
+2	81.1	93.5	+2	1,096.0	7,184
+1	40.6	93.4	+1	548.0	7,187
					7,189
0	0.0	93.4	0	0.0	7,264
					7,339
-1	(119.1)	93.2	-1	(548.0)	7,342
-2	(238.2)	93.1	-2	(1,096.0)	7,345
-3	(357.3)	92.9	-3	(1,644.0)	7,347
-4	(476.4)	92.8	-4	(2,192.0)	7,350
-5	(595.4)	92.6	-5	(2,740.0)	7,352
-6	(714.5)	92.5	-6	(3,288.0)	7,355
-7	(833.6)	92.3	-7	(3,836.0)	7,358
-8	(952.7)	92.2	-8	(4,384.0)	7,360
-9	(1,071.8)	92.0	-9	(4,932.0)	7,363
-10	(1,190.9)	91.9	-10	(5,480.0)	7,366
	Weighting Factor =	0.67%		Weighting Factor =	9.06%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2009 - DECEMBER 2009

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	423.0	94.7	+10	5,298.9	7,277
+9	380.7	94.7	+9	4,769.0	7,279
+8	338.4	94.6	+8	4,239.1	7,282
+7	296.1	94.5	+7	3,709.3	7,285
+6	253.8	94.5	+6	3,179.4	7,287
+5	211.5	94.4	+5	2,649.5	7,290
+4	169.2	94.4	+4	2,119.6	7,292
+3	126.9	94.3	+3	1,589.7	7,295
+2	84.6	94.2	+2	1,059.8	7,298
+1	42.3	94.2	+1	529.9	7,300
					7,303
0	0.0	94.1	0	0.0	7,378
					7,453
-1	(120.8)	94.0	-1	(529.9)	7,455
-2	(241.6)	93.9	-2	(1,059.8)	7,458
-3	(362.5)	93.8	-3	(1,589.7)	7,461
-4	(483.3)	93.7	-4	(2,119.6)	7,463
-5	(604.1)	93.5	-5	(2,649.5)	7,466
-6	(724.9)	93.4	-6	(3,179.4)	7,468
-7	(845.7)	93.3	-7	(3,709.3)	7,471
-8	(966.6)	93.2	-8	(4,239.1)	7,474
-9	(1,087.4)	93.1	-9	(4,769.0)	7,476
-10	(1,208.2)	92.9	-10	(5,298.9)	7,479
	Weighting Factor =	0.70%		Weighting Factor =	8.76%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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 1	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	72.0	0.0	72.5
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	100.0	9.3
3. EUOF	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	18.0	0.0	18.2
4. EUOR	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	0.0	20.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	649	586	649	628	649	628	649	649	628	649	565	0	6,925
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	95	86	95	92	95	92	95	95	92	95	155	744	1835
9. POH	0	0	0	0	0	0	0	0	0	0	72	744	816
10. EFOH	128	116	128	124	128	124	128	128	124	128	112	0	1,368
11. EMOH	21	19	21	20	21	20	21	21	20	21	18	0	224
12. OPER BTU (GBTU)	2,484	2,237	2,487	2,348	2,440	2,367	2,446	2,443	2,361	2,445	2,125	0	26,192
13. NET GEN (MWH)	230,369	207,327	230,692	217,874	226,585	219,971	227,300	226,994	219,301	227,241	197,291	0	2,430,945
14. ANOHR (Btu/kwh)	10,784	10,791	10,782	10,779	10,767	10,761	10,761	10,764	10,767	10,762	10,769	0	10,774
15. NOF (%)	90.4	90.1	90.5	90.6	91.2	91.5	91.5	91.4	91.2	91.5	91.1	0.0	90.9
16. NPC (MW)	393	393	393	383	383	383	383	383	383	383	383	393	386
17. ANOHR EQUATION	ANOHR = NOF(	-20.702	) +		12,655								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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 2	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	0.0	0.0	0.0	61.1	83.3	83.3	83.3	83.3	83.3	83.3	80.5	29.5	56.1
2. POF	100.0	100.0	100.0	26.7	0.0	0.0	0.0	0.0	0.0	0.0	3.3	64.5	32.6
3. EUOF	0.0	0.0	0.0	12.3	16.7	16.7	16.7	16.7	16.7	16.7	16.2	5.9	11.3
4. EUOR	0.0	0.0	0.0	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	0	0	0	486	686	664	686	686	664	686	641	244	5,441
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	744	672	744	234	58	56	58	58	56	58	79	500	3,319
9. POH	744	672	744	192	0	0	0	0	0	0	24	480	2,856
10. EFOH	0	0	0	60	85	82	85	85	82	85	79	30	674
11. EMOH	0	0	0	28	40	38	40	40	38	40	37	14	314
12. OPER BTU (GBTU)	0	0	0	1,743	2,462	2,383	2,462	2,462	2,383	2,462	2,302	891	19,579
13. NET GEN (MWH)	0	0	0	167,830	237,197	229,579	237,231	237,231	229,548	237,226	221,753	85,687	1,883,282
14. ANOHR (Btu/kwh)	0	0	0	10,383	10,380	10,380	10,380	10,380	10,380	10,380	10,380	10,395	10,396
15. NOF (%)	0.0	0.0	0.0	91.3	91.5	91.5	91.5	91.5	91.5	91.5	91.5	90.6	90.5
16. NPC (MW)	393	393	393	378	378	378	378	378	378	378	378	388	383

17. ANOHR EQUATION ANOHR = NOF(-15.533) + 11,802

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ORIGINAL SHEET NO. 8.401.09E

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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 3	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	31.0	56.5	56.5	54.3
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	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	23.9	43.5	43.5	41.8
4. EUOR	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	549	496	549	531	549	531	549	549	531	301	531	549	6,214
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	195	176	195	189	195	189	195	195	189	443	189	195	2,546
9. POH	0	0	0	0	0	0	0	0	0	336	0	0	336
10. EFOH	208	187	208	201	208	201	208	208	201	114	201	208	2,350
11. EMOH	116	105	116	112	116	112	116	116	112	64	112	116	1,314
12. OPER BTU (GBTU)	1,763	1,572	1,775	1,672	1,762	1,718	1,775	1,770	1,707	973	1,702	1,765	19,953
13. NET GEN (MWH)	163,764	145,861	164,986	155,359	163,964	160,006	165,339	164,817	158,865	90,597	158,375	163,953	1,855,886
14. ANOHR (Btu/kwh)	10,764	10,774	10,759	10,760	10,745	10,738	10,738	10,741	10,744	10,739	10,746	10,763	10,751
15. NOF (%)	75.9	74.9	76.5	76.4	78.0	78.7	78.7	78.4	78.1	78.6	77.9	76.0	77.3
16. NPC (MW)	393	393	393	383	383	383	383	383	383	383	383	393	386
17. ANOHR EQUATION	ANOHR = NOF(		-9.516	) +	11,487								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	79.7	79.7	79.7	8.0	5.1	79.7	79.7	79.7	79.7	79.7	79.7	79.7	67.5
2. POF	0.0	0.0	0.0	90.0	93.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
3. EUOF	20.3	20.3	20.3	2.0	1.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	17.2
4. EUOR	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	656	593	656	64	42	635	656	656	635	656	635	656	6,542
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	88	79	88	656	702	85	88	88	85	88	85	88	2,218
9. POH	0	0	0	648	696	0	0	0	0	0	0	0	1,344
10. EFOH	131	118	131	13	8	127	131	131	127	131	127	131	1,306
11. EMOH	20	18	20	2	1	19	20	20	19	20	19	20	200
12. OPER BTU (GBTU)	2,716	2,445	2,718	261	175	2,634	2,722	2,719	2,627	2,721	2,625	2,762	27,133
13. NET GEN (MWH)	258,660	232,238	259,006	24,403	16,474	248,202	256,480	255,929	247,014	256,304	246,692	258,738	2,560,140
14. ANOHR (Btu/kwh)	10,501	10,528	10,494	10,693	10,629	10,614	10,614	10,623	10,636	10,617	10,641	10,677	10,598
15. NOF (%)	92.1	91.5	92.2	88.3	89.5	89.8	89.8	89.6	89.4	89.8	89.3	88.6	90.1
16. NPC (MW)	428	428	428	435	435	435	435	435	435	435	435	445	434

17. ANOHR EQUATION ANOHR = NOF(-50.422) + 15.144

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	88.3	0.0	68.4	88.3	88.3	88.3	88.3	88.3	88.3	88.3	86.6	88.3	79.7
2. POF	0.0	100.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	9.8
3. EUOF	11.7	0.0	9.1	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.5	11.7	10.6
4. EUOR	11.7	0.0	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	722	0	559	698	722	698	722	722	698	722	582	722	7,564
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	22	672	185	22	22	22	22	22	22	22	138	22	1,196
9. POH	0	672	168	0	0	0	0	0	0	0	14	0	854
10. EFOH	80	0	62	78	80	78	80	80	78	80	76	80	853
11. EMOH	7	0	5	7	7	7	7	7	7	7	6	7	72
12. OPER BTU (GBTU)	1,655	0	1,313	1,530	1,583	1,533	1,584	1,583	1,531	1,584	1,276	1,613	16,910
13. NET GEN (MWH)	139,476	0	117,700	144,920	151,687	147,941	152,921	152,157	146,365	152,607	121,696	151,847	1,579,317
14. ANOHR (Btu/kwh)	11,868	0	11,152	10,555	10,435	10,362	10,359	10,406	10,463	10,378	10,482	10,621	10,707
15. NOF (%)	75.8	0.0	82.6	88.3	89.5	90.2	90.2	89.7	89.2	90.0	89.0	87.7	86.9
16. NPC (MW)	255	255	255	235	235	235	235	235	235	235	235	240	240
17. ANOHR EQUATION	ANOHR = NOF(		-104.957	)+	19,824								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

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-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	97.1	97.1	75.2	97.1	97.1	97.1	97.1	97.1	97.1	75.2	97.1	97.1	93.4
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	22.6	0.0	0.0	3.8
3. EUOF	2.9	2.9	2.3	2.9	2.9	2.9	2.9	2.9	2.9	2.3	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	695	646	542	572	616	668	696	697	680	424	601	716	7,553
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	49	26	202	148	128	52	48	47	40	320	119	28	1,207
9. POH	0	0	168	0	0	0	0	0	0	168	0	0	336
10. EFOH	2	2	2	2	2	2	2	2	2	2	2	2	23
11. EMOH	20	18	15	19	20	19	20	20	19	15	19	20	222
12. OPER BTU (GBTU)	2,756	3,058	2,550	2,489	2,813	2,958	3,113	3,134	3,017	1,938	2,415	3,556	33,804
13. NET GEN (MWH)	375,128	420,310	350,370	342,977	388,777	407,976	429,681	432,788	416,211	267,844	331,139	490,330	4,653,531
14. ANOHR (Btu/kwh)	7,346	7,275	7,278	7,258	7,235	7,250	7,245	7,242	7,249	7,235	7,293	7,253	7,264
15. NOF (%)	68.2	82.2	81.7	85.6	90.2	87.2	88.2	88.8	87.4	90.2	78.7	86.6	84.4
16. NPC (MW)	791	791	791	700	700	700	700	700	700	700	700	791	730
17. ANOHR EQUATION	ANOHR = NOF(		-5.067	) +	7,692								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2009 - DECEMBER 2009

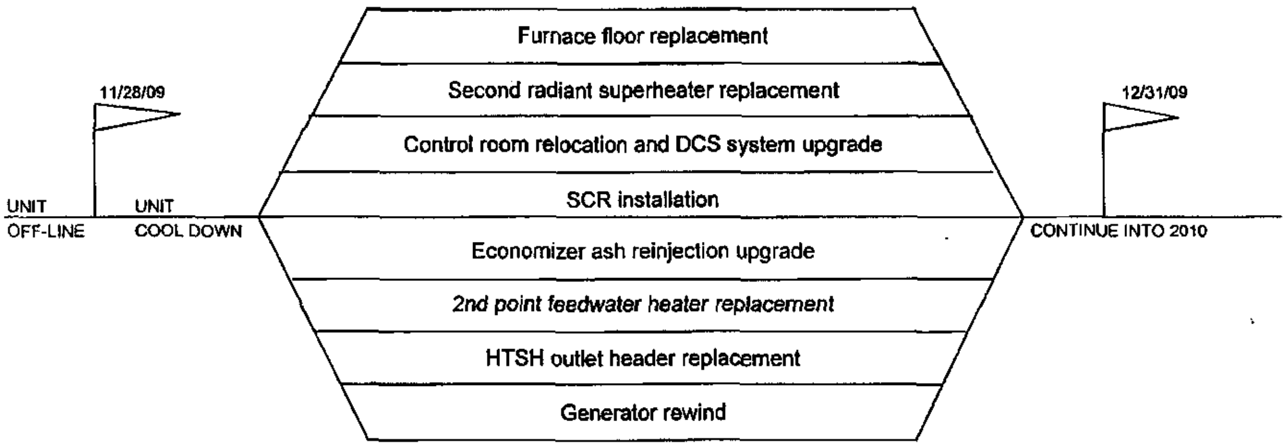
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009
1. EAF (%)	97.9	97.9	75.8	97.9	97.9	97.9	97.9	97.9	97.9	75.8	97.9	97.9	94.1
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	22.6	0.0	0.0	3.8
3. EUOF	2.1	2.1	1.6	2.1	2.1	2.1	2.1	2.1	2.1	1.6	2.1	2.1	2.0
4. EUOR	2.1	2.1	2.1	2.1	0.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	438	475	411	587	661	510	543	546	516	586	250	562	6,086
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	306	197	333	133	83	210	201	198	204	158	470	182	2,674
9. POH	0	0	168	0	0	0	0	0	0	168	0	0	336
10. EFOH	6	6	5	6	6	6	6	6	6	5	6	6	70
11. EMOH	10	9	7	9	10	9	10	10	9	7	9	10	109
12. OPER BTU (GBTU)	2,055	2,471	2,376	3,106	3,944	2,959	3,191	3,236	2,926	3,319	1,249	2,898	33,746
13. NET GEN (MWH)	276,759	333,595	321,767	420,869	536,555	402,166	433,917	440,102	397,339	450,672	169,039	391,208	4,573,988
14. ANOHR (Btu/kwh)	7,425	7,407	7,386	7,379	7,351	7,358	7,355	7,353	7,364	7,364	7,391	7,408	7,378
15. NOF (%)	60.4	67.1	74.8	77.2	87.5	84.9	86.1	86.9	82.9	82.9	72.7	66.6	77.7
16. NPC (MW)	1,046	1,046	1,046	928	928	928	928	928	928	928	928	1,046	967
17. ANOHR EQUATION	ANOHR = NOF(		-2.713	) +	7,589								

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2009 - DECEMBER 2009

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Nov 28	-	Dec 31	SCR Outage
+	BIG BEND 2	Jan 01	-	Apr 08	SCR Outage
		Nov 30		Dec 20	FGD Scrubber Outage
+	BIG BEND 3	Oct 03	-	Oct 16	Fuel System Clean-up
	BIG BEND 4	Apr 04	-	May 29	Major Outage
+	POLK 1	Feb 01	-	Mar 07	Gasifier / CT Outage
		Nov 08	-	Nov 12	Gasifier Outage
+	BAYSIDE 1	Mar 21	-	Mar 27	Fuel System Clean-up
		Oct 17	-	Oct 23	Fuel System Clean-up
+	BAYSIDE 2	Mar 08	-	Mar 14	Combustion Path Inspection & Steam Turbine
		Oct 31	-	Nov 06	Fuel System Clean-up

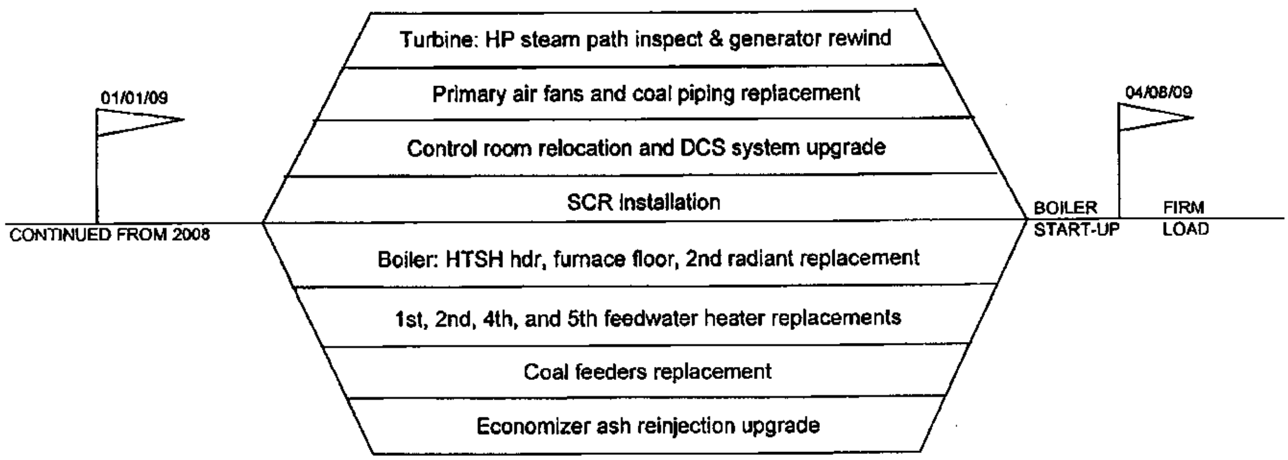
\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2009 - DECEMBER 2009



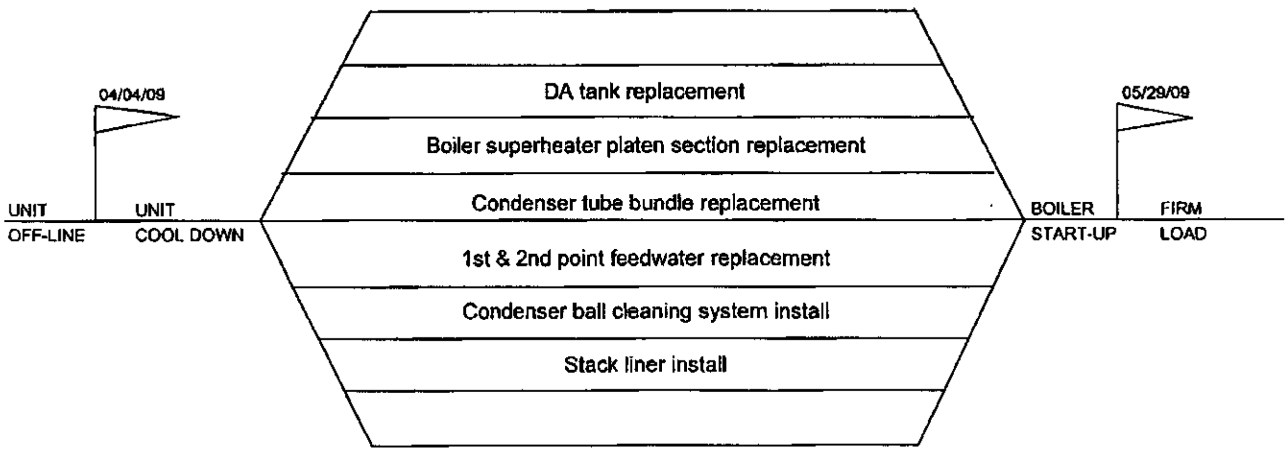
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 1
PLANNED OUTAGE 2009
PROJECTED CPM
08/01/08

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2009 - DECEMBER 2009



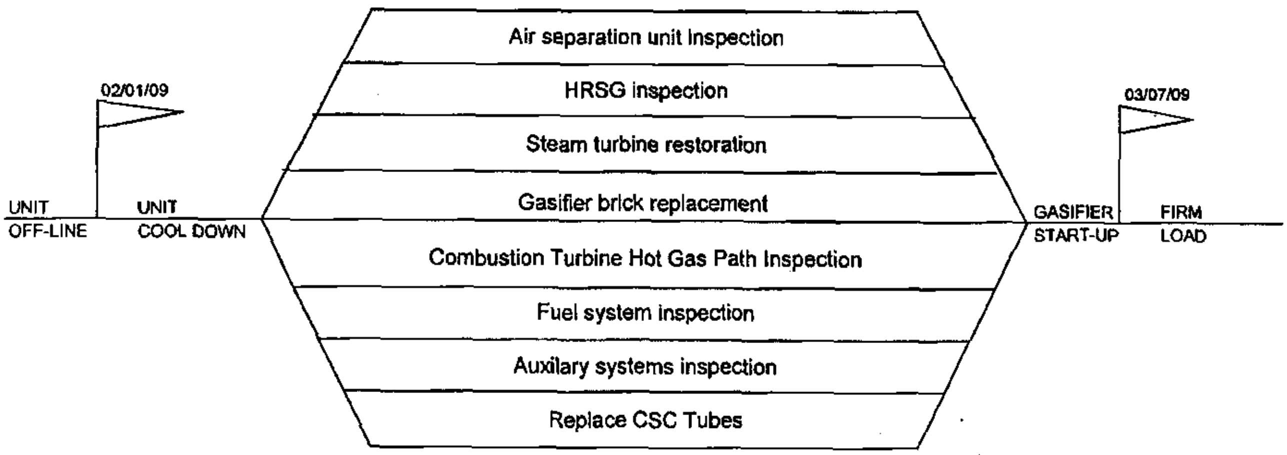
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 2
PLANNED OUTAGE 2009
PROJECTED CPM
08/01/08

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2009 - DECEMBER 2009



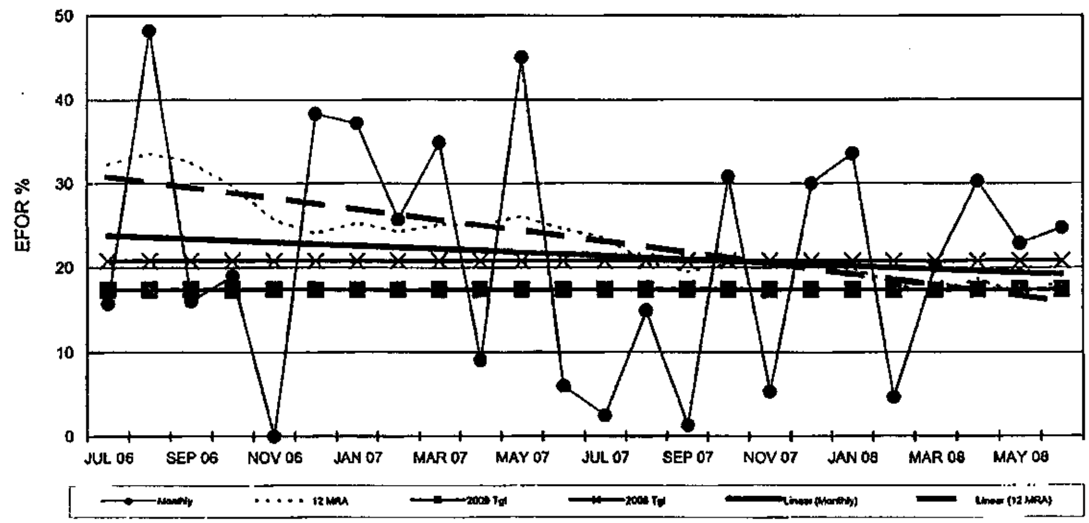
TAMPA ELECTRIC COMPANY
BIG BEND UNIT 4
PLANNED OUTAGE 2009
PROJECTED CPM
08/01/08

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2009 - DECEMBER 2009

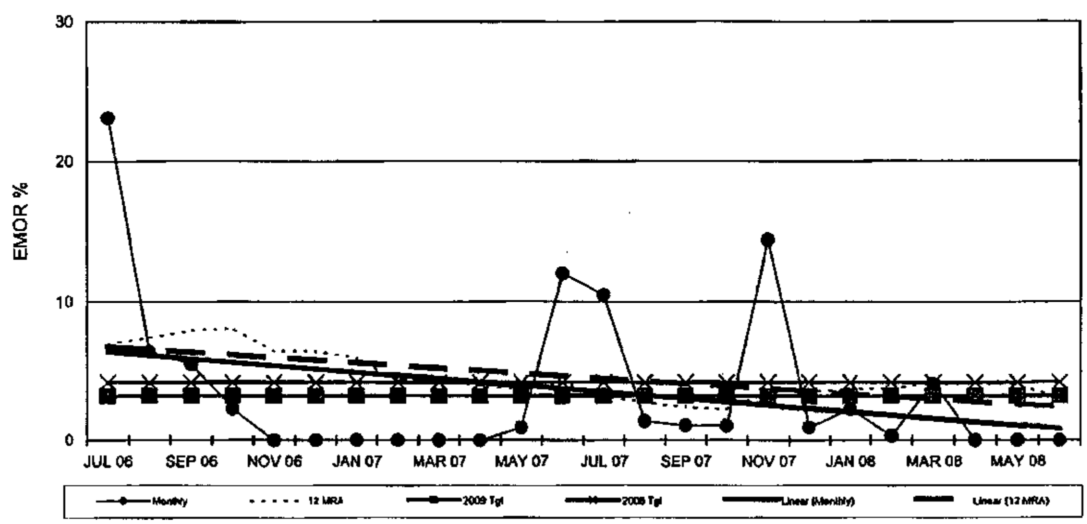


TAMPA ELECTRIC COMPANY
POLK 1
PLANNED OUTAGE 2008
PROJECTED CPM
08/01/08

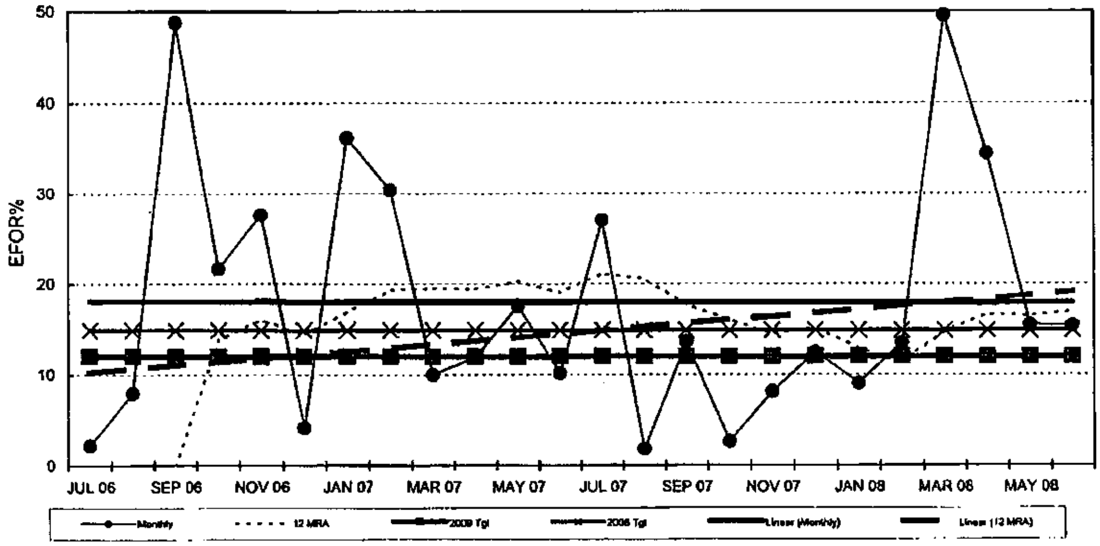
Big Bend Unit 1
EFOR



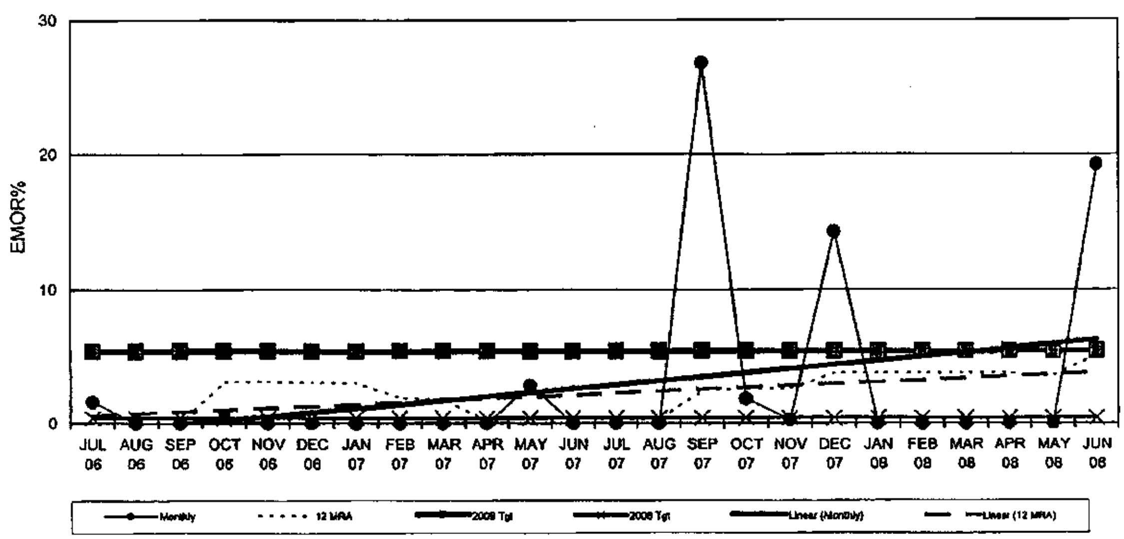
Big Bend Unit 1
EMOR

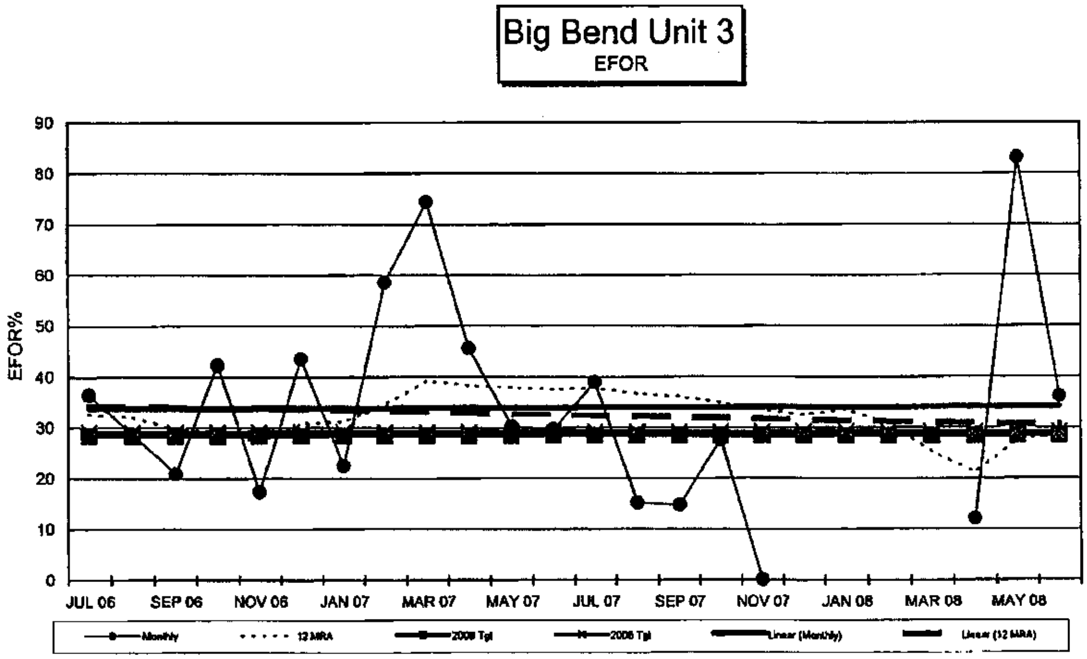


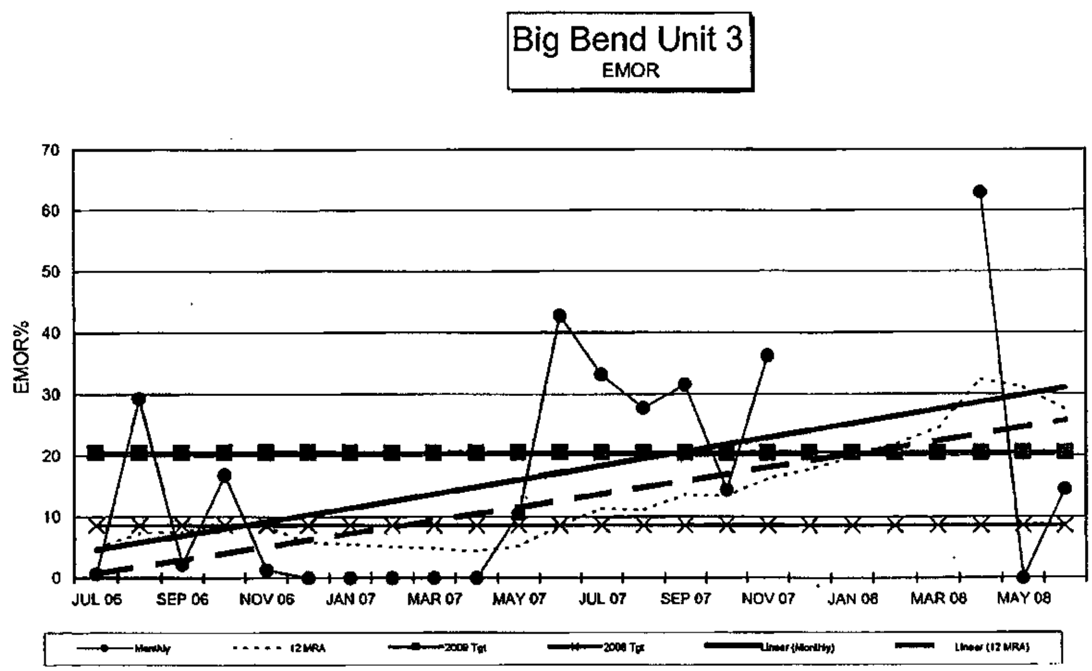
Big Bend Unit 2
EFOR



Big Bend Unit 2
EMOR

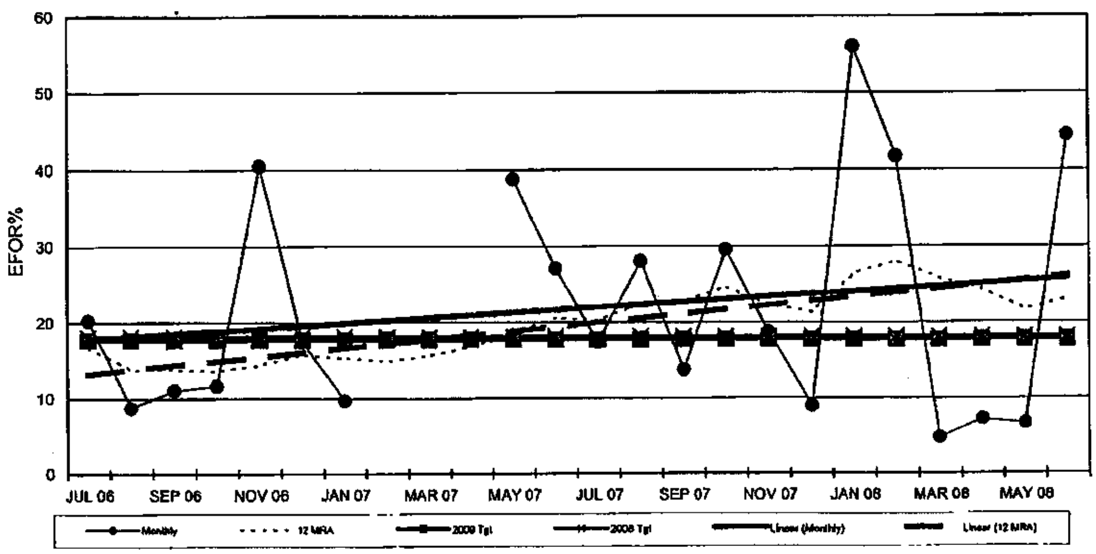




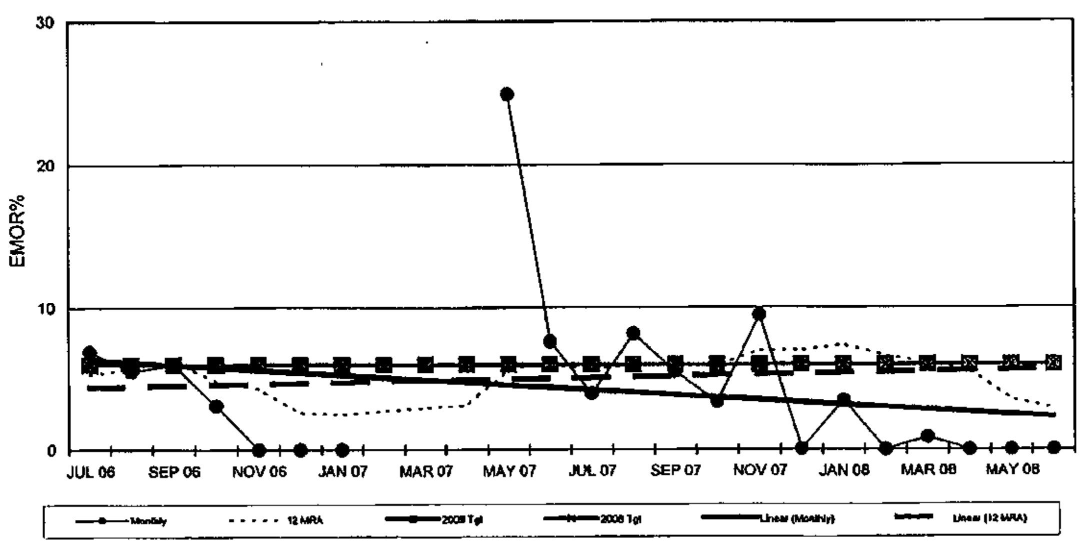


Note: Big Bend Unit 3 was offline for SCR installation from 11/18/2007 to 4/28/2008; therefore, data is not available for this time period.

Big Bend Unit 4
EFOR

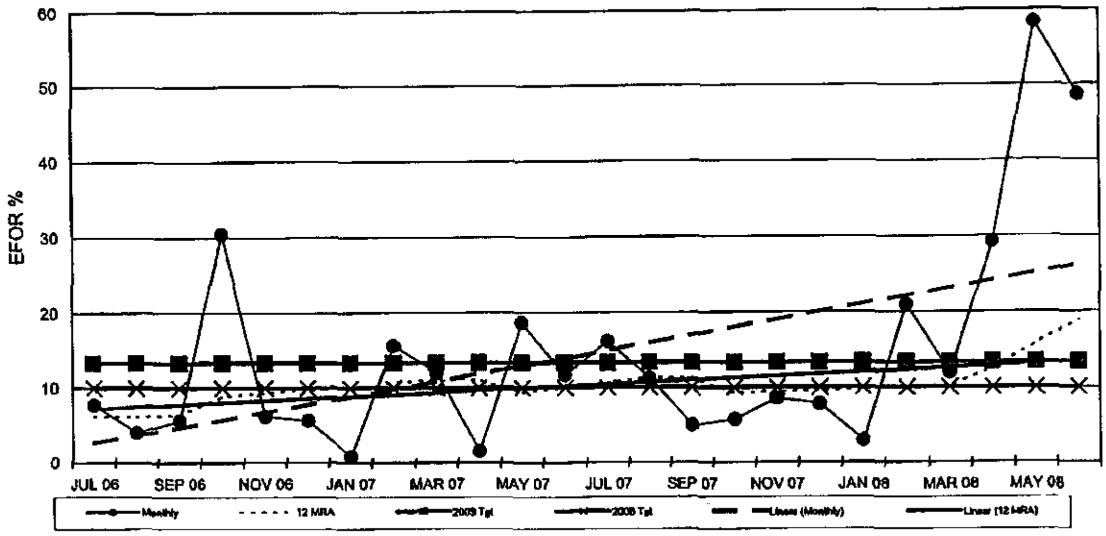


Big Bend Unit 4
EMOR

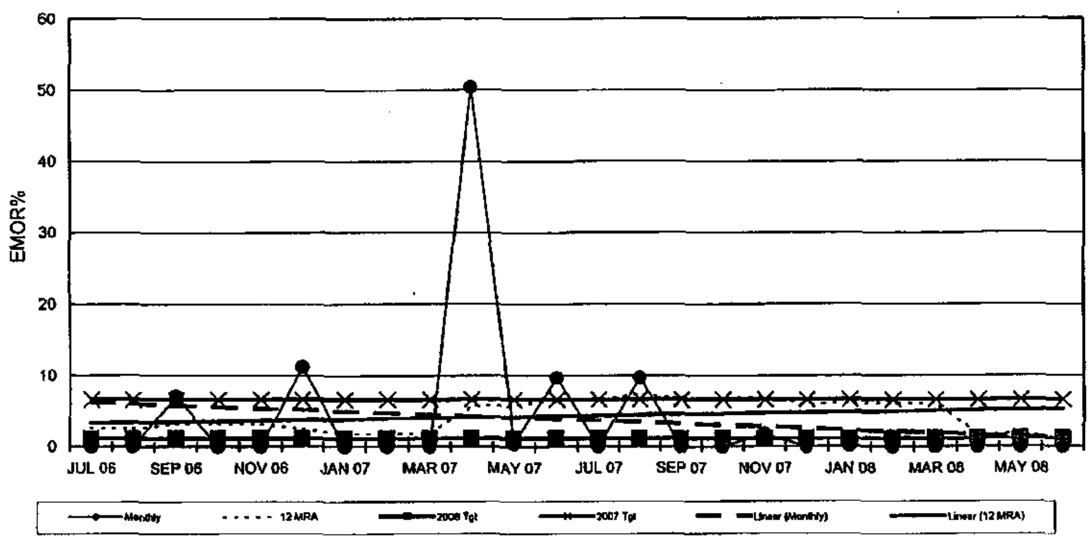


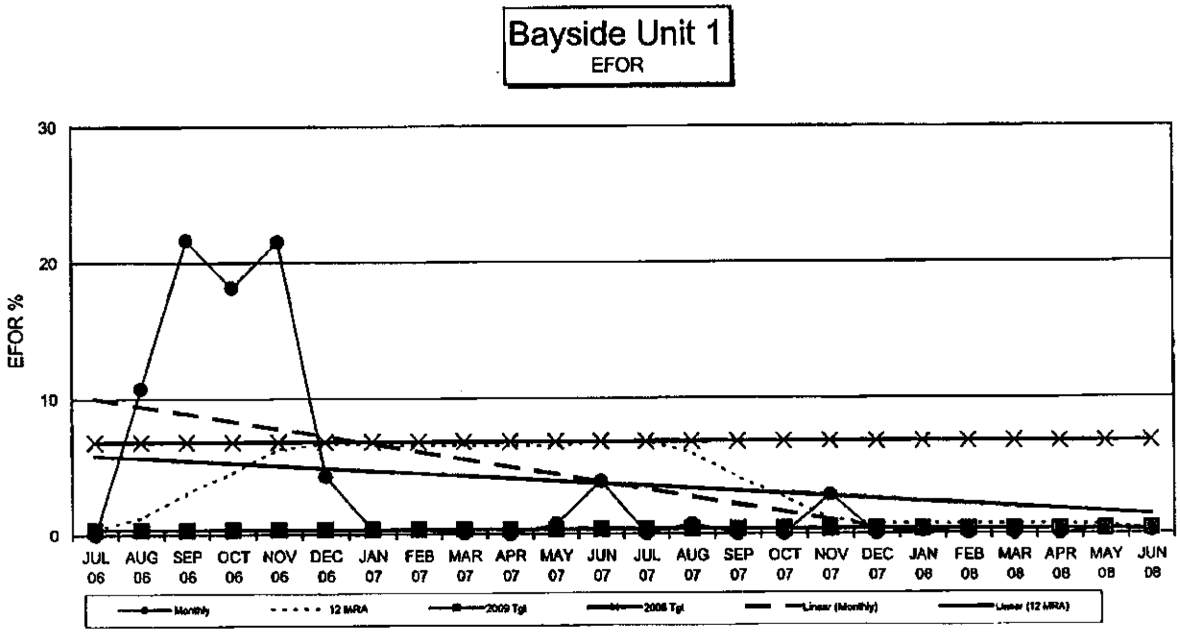
Note: Big Bend Unit 4 was offline for SCR installation from 2/1/2007 to 5/19/2007; therefore, data is not available for this time period.

Polk Unit 1
EFOR



Polk Unit 1
EMOR




Bayside Unit 1
EFOR
EFOR %
30
20
10
0
JUL 06
AUG 06
SEP 06
OCT 06
NOV 06
DEC 06
JAN 07
FEB 07
MAR 07
APR 07
MAY 07
JUN 07
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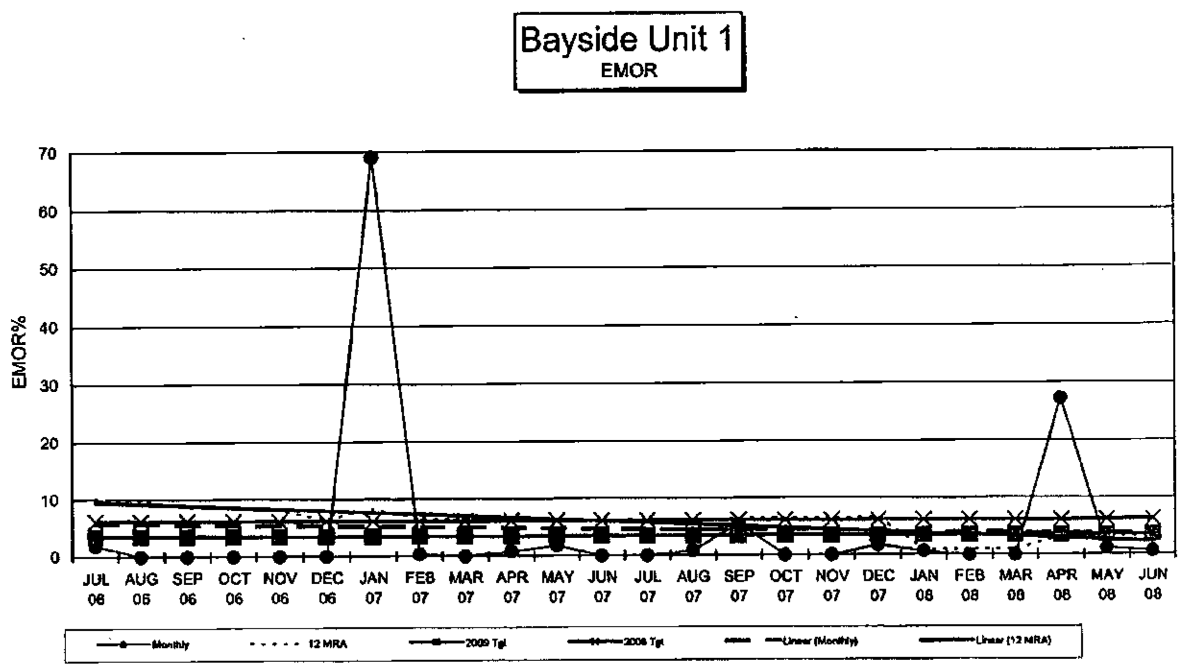
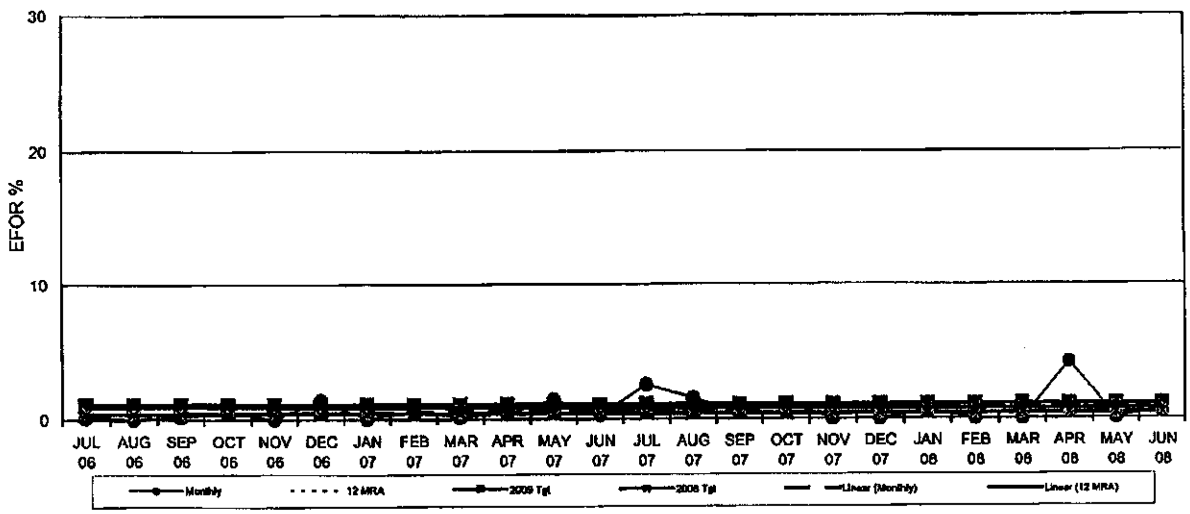
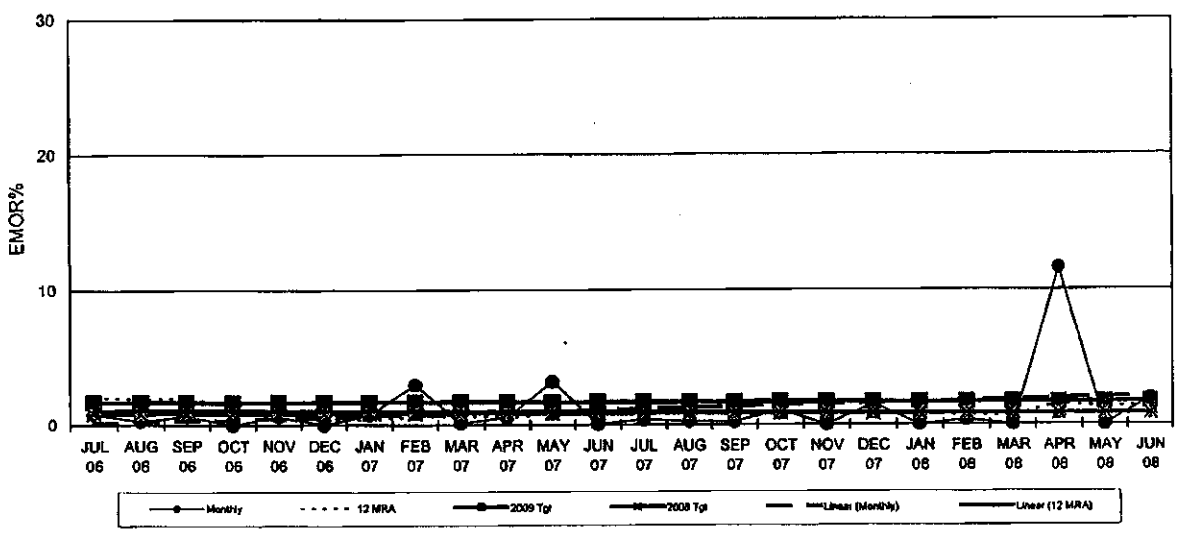
FEB 08
MAR 08
APR 08
MAY 08
JUN 08

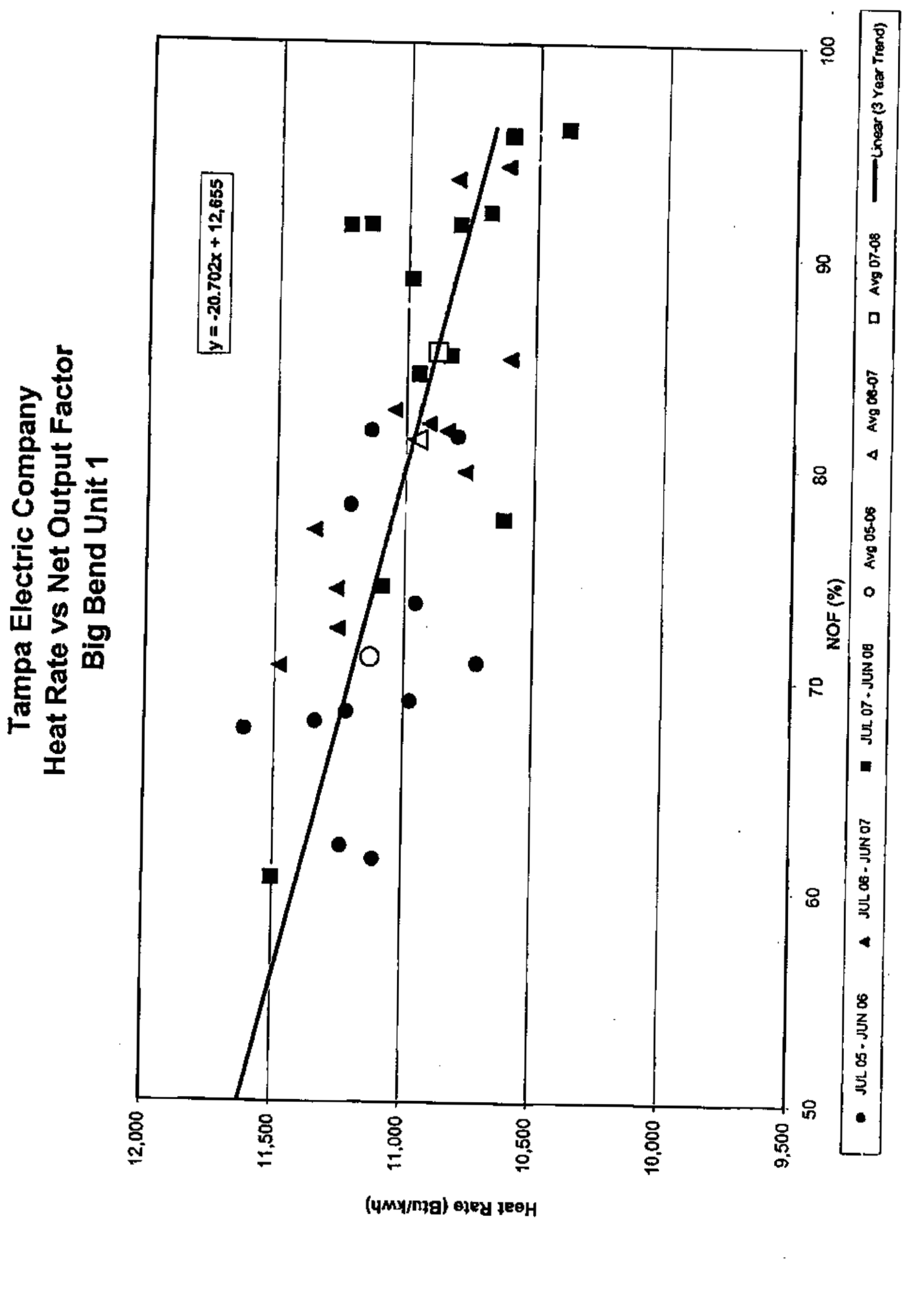

Bayside Unit 1
EMOR
EMOR%
70
60
50
40
30
20
10
0
JUL 06
AUG 06
SEP 06
OCT 06
NOV 06
DEC 06
JAN 07
FEB 07
MAR 07
APR 07
MAY 07
JUN 07
JUL 07
AUG 07
SEP 07
OCT 07
NOV 07
DEC 07
JAN 08
FEB 08
MAR 08
APR 08
MAY 08
JUN 08
12 MRA

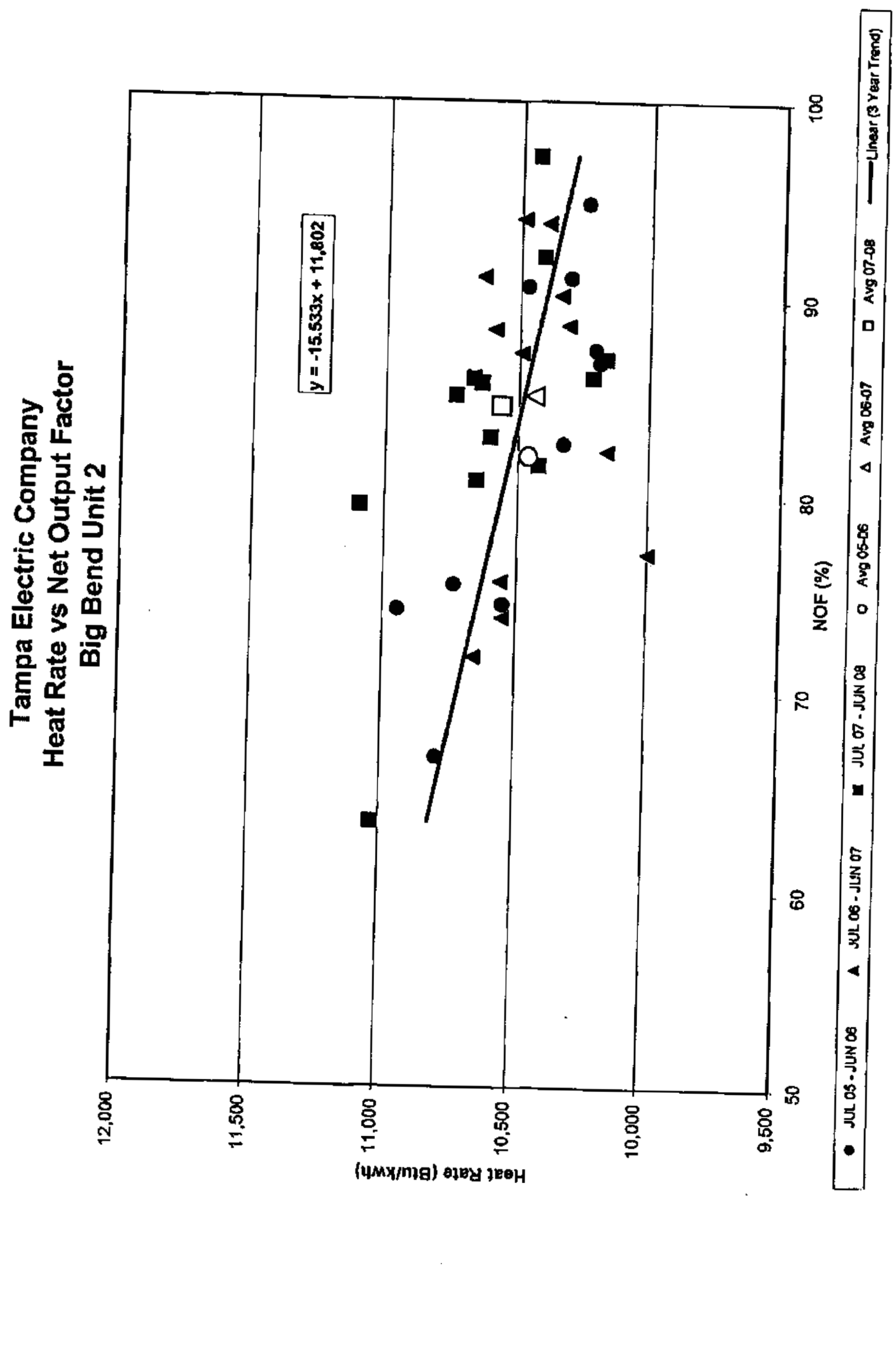
Bayside Unit 2
EFOR

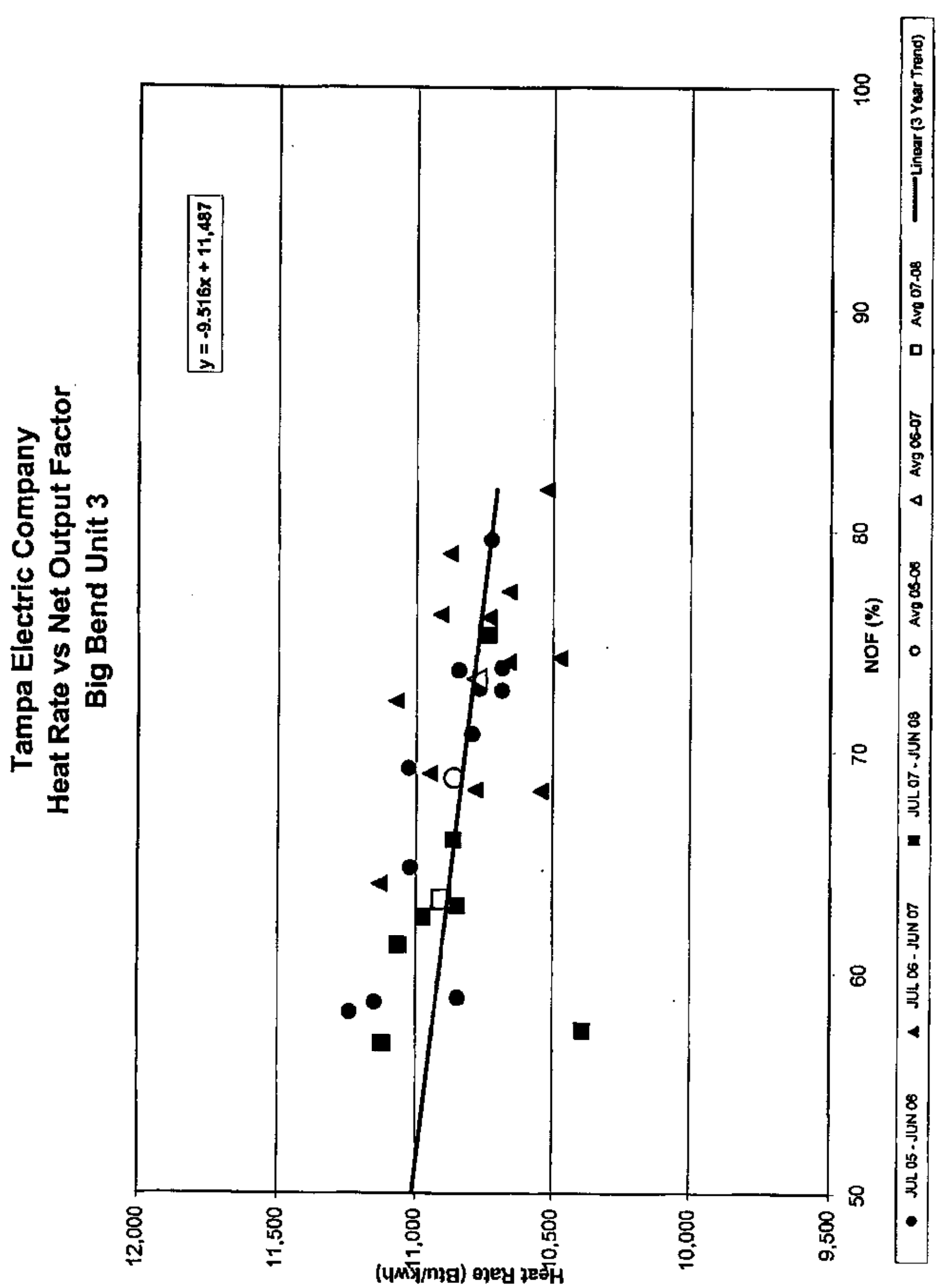


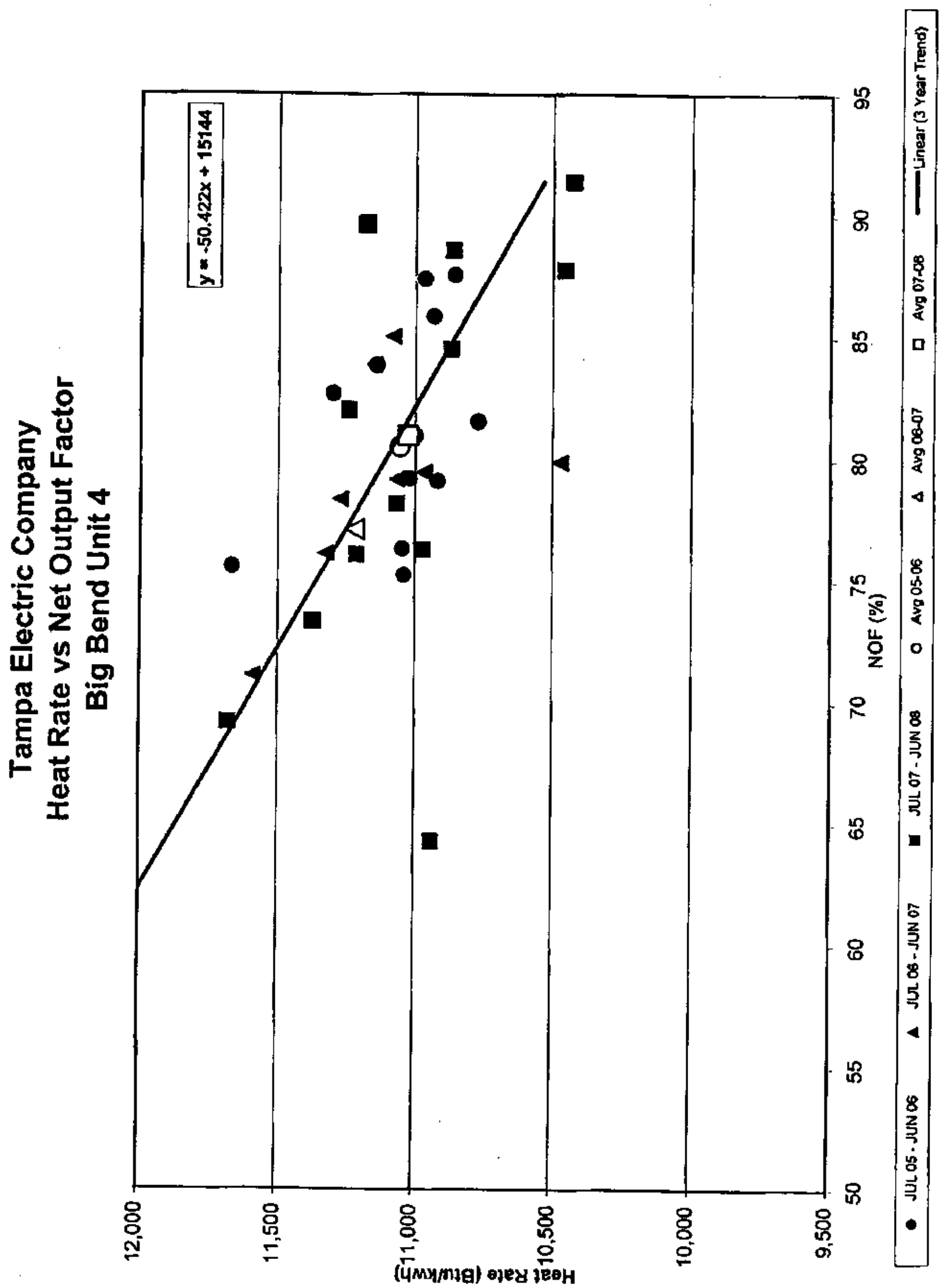
Bayside Unit 2
EMOR



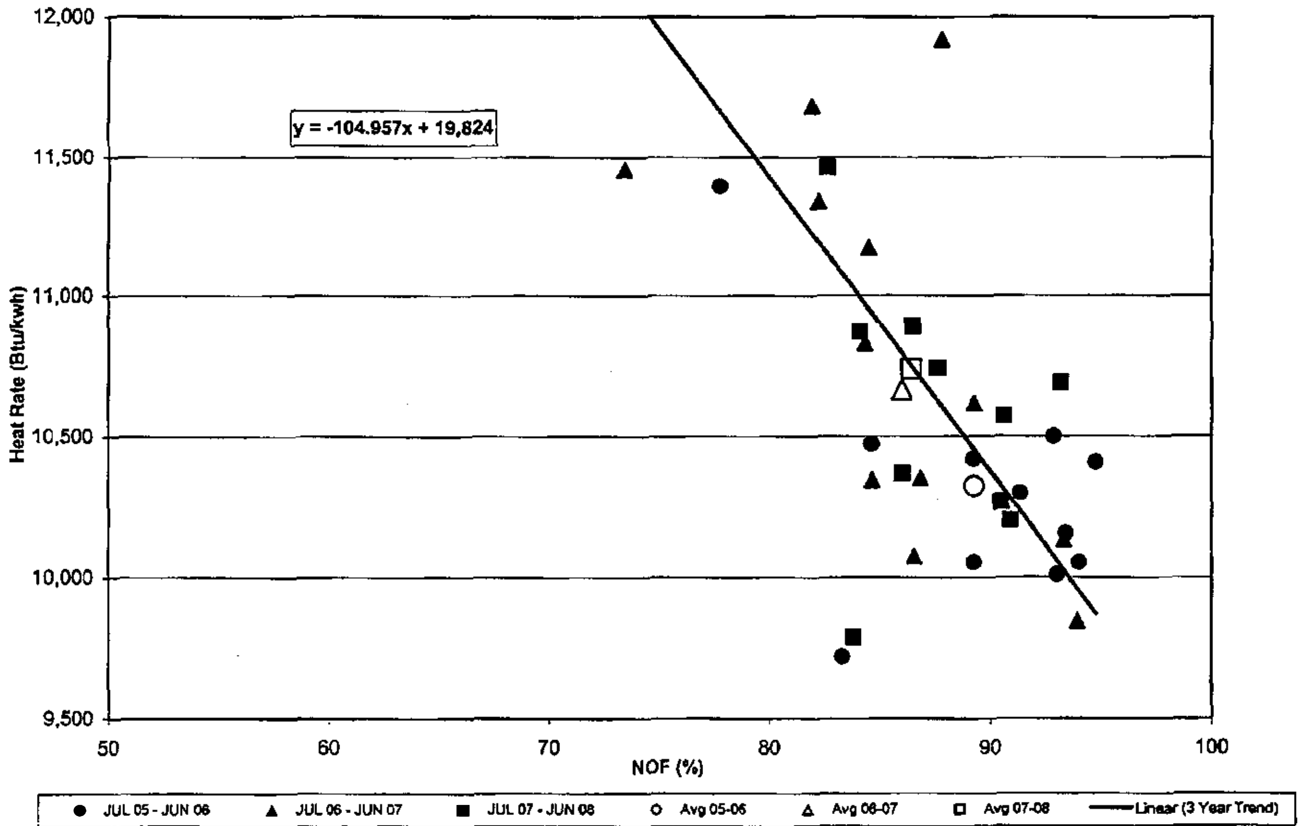

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1
y = -20.702x + 12,655
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
50
60
70
80
90
100
NOF (%)
JUL 05 - JUN 06
JUL 06 - JUN 07
JUL 07 - JUN 08
Avg 05-06
Avg 06-07
Avg 07-08
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
y = -15.533x + 11,802
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
50
60
70
80
90
100
NOF (%)
JUL 05 - JUN 06
JUL 06 - JUN 07
JUL 07 - JUN 08
Avg 05-06
Avg 06-07
Avg 07-08
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
y = -9.516x + 11,487
Heat Rate (Btu/kWh)
12,000
11,500
11,000
10,500
10,000
9,500
NOF (%)
50
60
70
80
90
100
JUL 05 - JUN 06
JUL 06 - JUN 07
JUL 07 - JUN 08
Avg 05-06
Avg 06-07
Avg 07-08
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4
y = -50.422x + 15144
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
50
55
60
65
70
75
80
85
90
95
NOF (%)
JUL 05 - JUN 06
JUL 06 - JUN 07
JUL 07 - JUN 08
Avg 05-06
Avg 06-07
Avg 07-08
Linear (3 Year Trend)

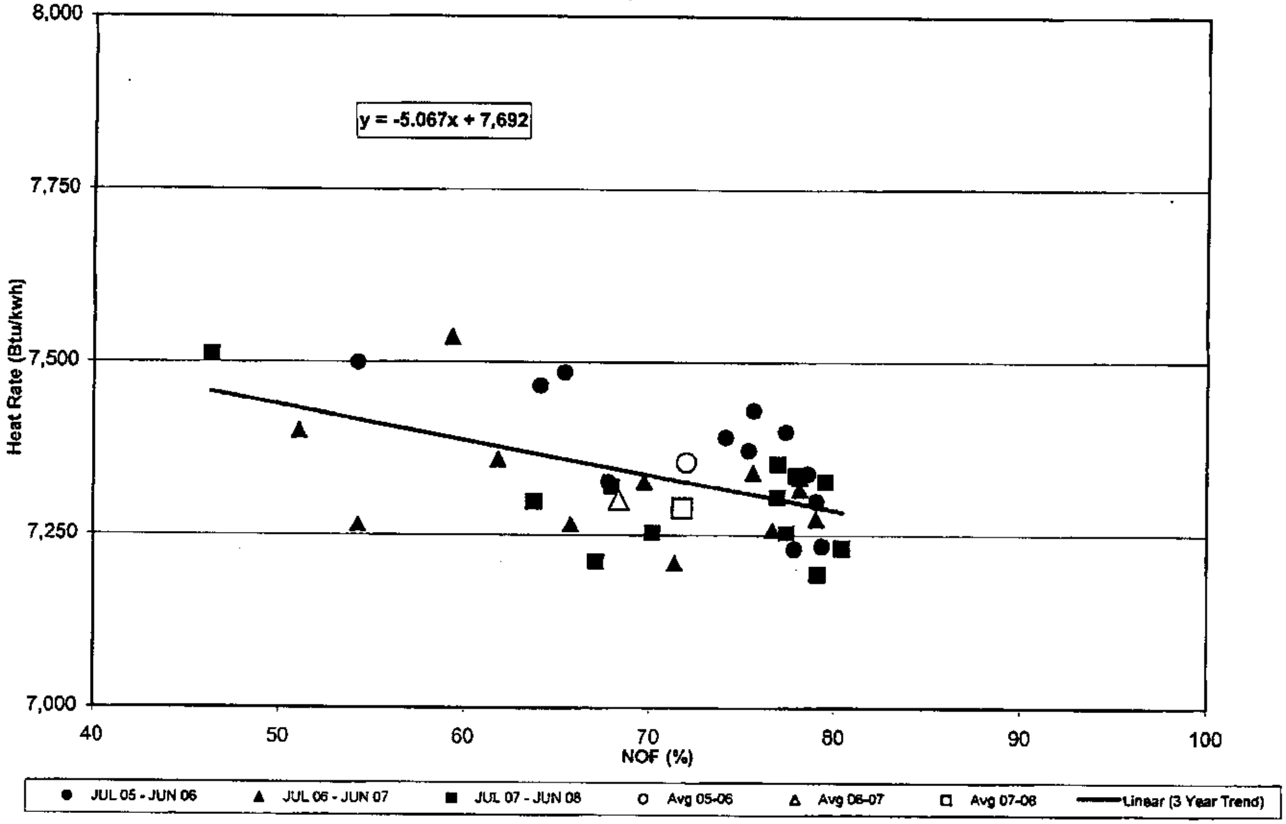
Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1

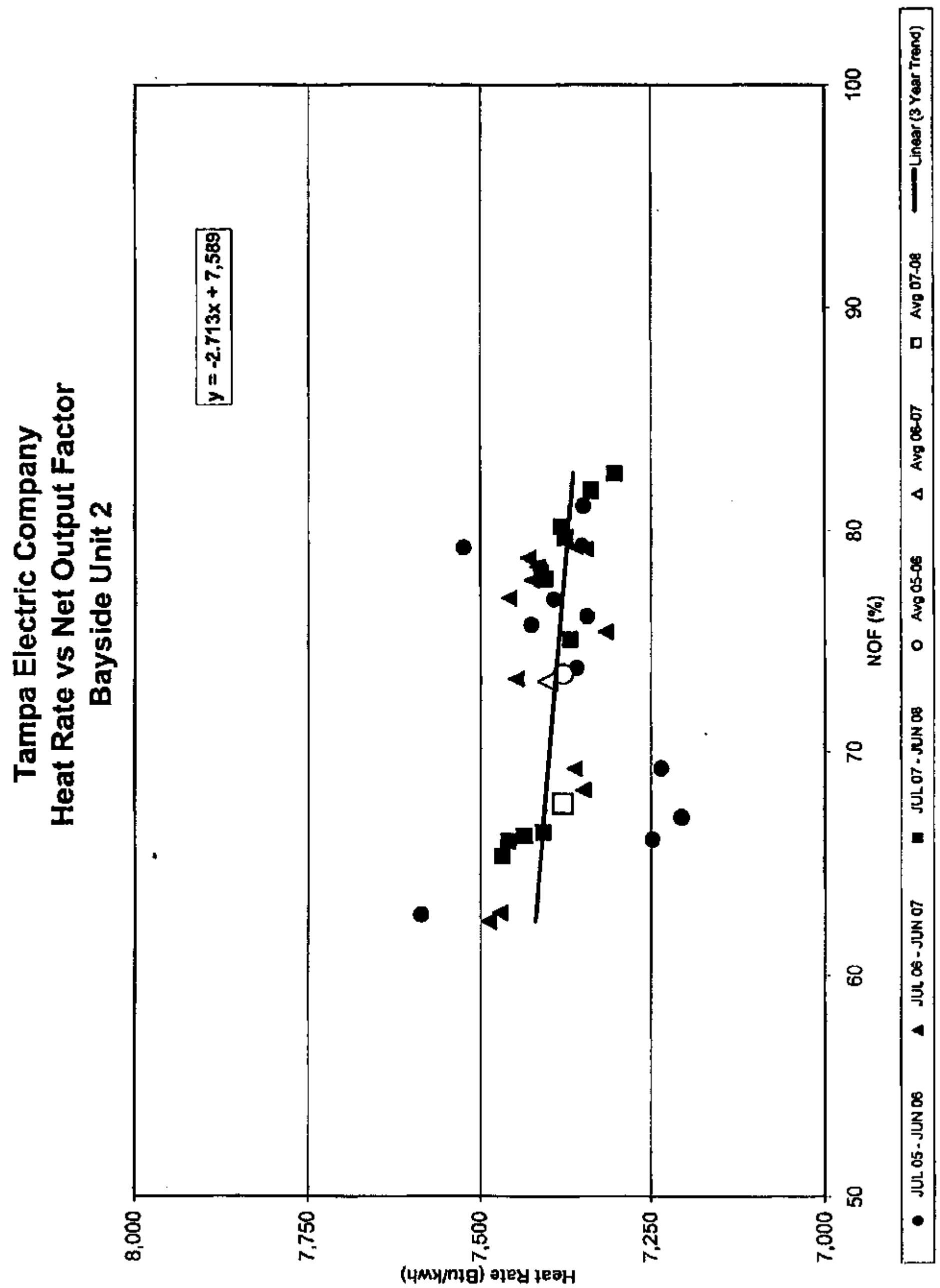


57

58

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




Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -2.713x + 7,589
Heat Rate (Btu/kwh)
8,000
7,750
7,500
7,250
7,000
50
60
70
80
90
100
NOF (%)
JUL 05 - JUN 06
JUL 06 - JUN 07
JUL 07 - JUN 08
Avg 05-06
Avg 06-07
Avg 07-08
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2009 - DECEMBER 2009

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		401	386
BIG BEND 2		404	383
BIG BEND 3		409	386
BIG BEND 4		466	434
POLK 1		310	240
BAYSIDE 1		740	730
BAYSIDE 2		979	967
	GPIF TOTAL	3,710	3,527
	SYSTEM TOTAL	**4,647**	**4,454**
	% OF SYSTEM TOTAL	**79.8%**	**79.2%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2009 - DECEMBER 2009

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	730
BAYSIDE 2		979	967
BAYSIDE 3		44	43
BAYSIDE 4		44	43
BAYSIDE 5		44	43
BAYSIDE 6		44	43
	BAYSIDE TOTAL	1,895	1,870
BIG BEND 1		401	386
BIG BEND 2		404	383
BIG BEND 3		409	386
BIG BEND 4		466	434
	BIG BEND COAL TOTAL	1,680	1,589
BIG BEND CT1		11	10
BIG BEND CT4		44	43
	BIG BEND CT TOTAL	55	54
COT 1		3	3
COT 2		3	3
	COT TOTAL	6	6
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	35
POLK 1		310	240
POLK 2		168	167
POLK 3		172	171
POLK 4		162	161
POLK 5		162	161
	POLK TOTAL	974	900
	SYSTEM TOTAL	4,647	4,454

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2009 - DECEMBER 2009

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,653,531	23.31%	23.31%
BAYSIDE	1	4,573,988	22.91%	46.23%
BIG BEND	4	2,560,140	12.83%	59.05%
BIG BEND	1	2,430,945	12.18%	71.23%
BIG BEND	2	1,883,282	9.43%	80.66%
POLK	1	1,855,886	9.30%	89.96%
BIG BEND	3	1,579,317	7.91%	97.87%
POLK	4	119,515	0.60%	98.47%
POLK	5	80,572	0.40%	98.87%
POLK	3	53,545	0.27%	99.14%
BAYSIDE	5	50,069	0.25%	99.39%
BAYSIDE	6	48,525	0.24%	99.64%
POLK	2	45,781	0.23%	99.87%
BAYSIDE	3	10,605	0.05%	99.92%
BAYSIDE	4	9,512	0.05%	99.97%
BIG BEND CT	4	3,834	0.02%	99.99%
PHILLIPS	2	1,347	0.01%	99.99%
PHILLIPS	1	1,336	0.01%	100.00%
BIG BEND CT	1	19	0.00%	100.00%
TOTAL GENERATION		19,961,749	100.00%	

GENERATION BY COAL UNITS:	10,309,570 MWH	GENERATION BY NATURAL GAS UNITS:	9,649,477 MWH
% GENERATION BY COAL UNITS:	51.65%	% GENERATION BY NATURAL GAS UNITS:	48.34%
GENERATION BY OIL UNITS:	2,702 MWH	GENERATION BY GPIF UNITS:	19,537,089 MWH
% GENERATION BY OIL UNITS:	0.01%	% GENERATION BY GPIF UNITS:	97.87%

DOCKET NO. 080001-EI
GPIF 2009 PROJECTION FILING
EXHIBIT NO. ____ (BSB-1)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2009 - DECEMBER 2009

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2009 - DECEMBER 2009

	Availability			Net
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Big Bend 1[1]	72.5	9.3	18.2	10,774
Big Bend 2[2]	56.1	32.6	11.3	10,396
Big Bend 3[3]	54.3	3.8	41.8	10,751
Big Bend 4[4]	67.5	15.3	17.2	10,598
Polk 1[5]	79.7	9.8	10.6	10,707
Bayside 1[6]	93.4	3.8	2.8	7,264
Bayside 2[7]	94.1	3.8	2.0	7,378

[1] Original Sheet 8.401.09E, Page 14

[2] Original Sheet 8.401.09E, Page 15

[3] Original Sheet 8.401.09E, Page 16

[4] Original Sheet 8.401.09E, Page 17

[5] Original Sheet 8.401.09E, Page 18

[6] Original Sheet 8.401.09E, Page 19

[7] Original Sheet 8.401.09E, Page 20