TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS

JANUARY 2007 THROUGH DECEMBER 2007

TESTIMONY AND EXHIBIT
OF
WILLIAM A. SMOTHERMAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

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 WAS-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 2007 period.

GPIF Calculations

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 one natural gas combined cycle unit are included. These are Big Bend Station units 1 through 4, Polk Power Station unit 1 and Bayside unit 1.

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, with the exception of the criterion that the company shall include generating units that will represent at least 80 percent of projected system net generation.

Q. Please explain why does Tampa Electric does not include units that represent 80 percent of projected system net generation?

A. Due to the repowering of Gannon unit 6 to H. L. Culbreath Bayside ("Bayside") unit 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside unit 2 began commercial operation in 2004 the repowered unit is not included in the GPIF calculations because the company does not have the historical operational data required by the GPIF Implementation Manual to set GPIF targets. In addition, Tampa Electric has no other base load generating unit to substitute for Gannon unit 6. Section 3.2 of the GPIF Implementation Manual states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis, and the Commission previously approved this exception for Tampa Electric's projected GPIF filings. Therefore, Tampa Electric requests approval of its

2007 GPIF calculation excluding the repowered Bayside unit 2.

Q. Has Tampa Electric modified its GPIF methodology to account for the concerns expressed in Staff's testimony in the 2006 fuel hearing?

A. Yes. As requested by the Commission, Tampa Electric has worked with the Commission Staff and other interested parties to reach a mutually agreeable alternative proposal.

Q. Please describe the change in methodology.

A. Tampa Electric Company has agreed to remove the outage hours related to any forced outage that is identified as an outlier. The process of identifying outlying outages includes reviewing three years of historical performance and determining the average length (mean) and variation (standard deviation) of all forced outages. If a forced outage within the current sample period (July 2005 through June 2006) is greater than two standard deviations above the three year average outage duration (mean) its associated hours are removed from the GPIF calculations.

Q. As a result of the methodology change, were any outages identified as outliers?

A. Yes. An outage on Big Bend unit 3 was identified as an outlying outage; therefore, its associated forced outage hours were removed from the study.

Q. How will the methodology impact the true-up process?

A. The agreed upon methodology will not impact the true-up process, since no adjustments will be made to exclude outliers.

Q. Is this methodology consistent with the GPIF Implementation Plan?

A. Yes. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers in the calculation.

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 2007 period. A range of potential improvements and degradations were determined for each of these parameters.

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

To give an example for the 2007 period, the projected Equivalent Unplanned Outage Factor for Big Bend unit 2 is 17.74 percent, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability factor for Big Bend unit 2 equals 76.51 percent or:

$$100\% - [(17.74 + 5.75\%)] = 76.51\%$$

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:

$$EAF_{MAX} = 100\% - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

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 2 example:

$$EAF_{MAX} = 100\% - [0.8\ (17.74\%) + 0.95\ (5.75\%)] = 80.34\%$$

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:

$$EAF_{MIN} = 100\% - [1.4\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Big Bend unit 2 example,

$$EAF_{MIN} = 100\% - [1.4\ (17.74\%) + 1.10\ (5.75\%)] = 68.83\%$$

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

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

A. The company's planned outages for January through December 2007 are shown on page 19 of Document No. 1. Three GPIF units have a major outage (28 days or greater) in 2007; therefore, three Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend unit 4 is scheduled for a planned outage from February 1, 2007 to April 30, 2007. There are 2,136 planned outage hours scheduled for the 2006 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend unit 4 is 24.38 percent or:

$$\frac{2,136}{8,760} \times 100 = 24.38\%$$

The factor for each unit is shown on pages 5 and 13 through 18 of Document No. 1. Big Bend unit 1 has a Planned Outage Factor of 3.84 percent. Big Bend unit 2 has a Planned Outage

Factor of 5.75 percent. Big Bend 3 has a Planned Outage Factor of 8.49 percent. Polk unit 1 has a Planned Outage Factor of 3.29 percent and Bayside unit 1 has a Planned Outage Factor of 9.59 percent.

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

A. Graphs for both factors, adjusted for planned outages, versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2006, 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 16.12 percent for Big Bend unit 4. The Equivalent Unplanned Outage Factor for Big Bend unit 4 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{\text{Period Hours}} \times 100$$

Or

$$EUOF = \frac{(1,129 + 284)}{8,760} \times 100 = 16.12\%$$

Relative to Big Bend unit 4, the EUOF of 16.12 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 35.47 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 60.69 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 17.74 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability for this unit is 76.51 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 34.15 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 8.49 percent.

Therefore, the target equivalent availability for this unit is 57.36 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 16.12 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 24.38 percent. Therefore, the target equivalent availability for this unit is 59.50 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 8.36 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 3.29 percent. Therefore, the target equivalent availability for this unit is 88.35 percent.

Bayside Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 9.39 percent. The unit will have a planned outage in 2007, and the Planned Outage Factor is 9.59 percent. Therefore, the target equivalent availability for this unit is 81.02 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 64.3 percent is shown on Page 5 of Document No. 1. This target is similar to the July 2005 through June 2006 GPIF period. Contributing to the system EAF are the planned outages at Big Bend unit 4 to install SCR equipment.

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

A. The adjustment makes the factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since the units in the GPIF are usually base load units, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend unit 4 on page 16 of Document No. 1. During the months of January and May through 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 months of February through April, the Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a 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 parameters, which are subsequently converted to factors. Therefore,

$$FOF + MOF + POF + EAF = 100\%$$

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 29 through 34 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 2007 period.

A. The heat rate target for Big Bend unit 1 is 10,971 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±497 Btu/Net kWh. The heat rate target for Big Bend unit 2 is 10,484 Btu/Net kWh with a range of ±361 Btu/Net kWh. The heat rate target for Big Bend unit 3 is 11,090 Btu/Net kWh, with a range of ±908 Btu/Net kWh. The heat rate target for Big Bend unit 4 is 10,828 Btu/Net kWh with a range of ±651 Btu/Net kWh. The heat rate target for Polk unit 1 is 10,428 Btu/Net kWh with a range of ±1,011 Btu/Net kWh. The heat rate target for Bayside unit 1 is 7,378 Btu/Net kWh with a range of ±277 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 12 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 12. 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 $1,079,796.6 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 $58,301,700 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend unit 1, the weighting factor for equivalent availability is 12.26 percent as shown in the right-hand column on page 6. Pages 7 through 12 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 2, page 8, if the unit operates at 80.3 percent equivalent availability, fuel savings would equal $4,148,500 and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. 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 $58,301,700. 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 2007 is

$1,473,616,457. This produces the maximum allowed jurisdictional incentive of $5,829,646 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 on the GPIF.

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):

$$\begin{aligned} GPIP: = (\ & 0.1226\ EAP_{BB1} + 0.0712\ EAP_{BB2} \\ & + 0.1713\ EAP_{BB3} + 0.1300\ EAP_{BB4} \\ & + 0.0559\ EAP_{PK1} + 0.0040\ EAP_{BAY1} \\ & + 0.0512\ HRP_{BB1} + 0.0408\ HRP_{BB2} \\ & + 0.0730\ HRP_{BB3} + 0.0627\ HRP_{BB4} \\ & + 0.0727\ HRP_{PK} + 0.1446\ HRP_{BAY1}\ ) \end{aligned}$$

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 unit 1.

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2007 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

WILLIAM A. SMOTHERMAN

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2007 - DECEMBER 2007

DOCUMENT NO. 1

GPIF SCHEDULES

EXHIBIT TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2007 - DECEMBER 2007

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2007 - DECEMBER 2007
TARGETS
TABLE OF CONTENTS

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2007 - DECEMBER 2007**

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	58,301.7	5,829.6
+9	52,471.5	5,246.7
+8	46,641.4	4,663.7
+7	40,811.2	4,080.8
+6	34,981.0	3,497.8
+5	29,150.9	2,914.8
+4	23,320.7	2,331.9
+3	17,490.5	1,748.9
+2	11,660.3	1,165.9
+1	5,830.2	583.0
0	0.0	0.0
-1	(7,276.0)	(583.0)
-2	(14,552.0)	(1,165.9)
-3	(21,828.0)	(1,748.9)
-4	(29,104.0)	(2,331.9)
-5	(36,380.0)	(2,914.8)
-6	(43,655.9)	(3,497.8)
-7	(50,931.9)	(4,080.8)
-8	(58,207.9)	(4,663.7)
-9	(65,483.9)	(5,246.7)
-10	(72,759.9)	(5,829.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2007 - DECEMBER 2007

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,450,299,000	
Line 2	Month of January	2007	$	1,415,063,000	
Line 3	Month of February	2007	$	1,428,918,825	
Line 4	Month of March	2007	$	1,442,910,322	
Line 5	Month of April	2007	$	1,464,427,497	
Line 6	Month of May	2007	$	1,478,766,683	
Line 7	Month of June	2007	$	1,493,246,273	
Line 8	Month of July	2007	$	1,457,531,692	
Line 9	Month of August	2007	$	1,471,803,356	
Line 10	Month of September	2007	$	1,486,214,764	
Line 11	Month of October	2007	$	1,507,798,793	
Line 12	Month of November	2007	$	1,522,562,656	
Line 13	Month of December	2007	$	1,537,471,082	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,473,616,457	
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)		$	6,001,946	
Line 18	Jurisdictional Sales			19,970,292	MWH
Line 19	Total Sales			20,560,533	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.13%	
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,829,646**	

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2007 - DECEMBER 2007

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	12.26%	60.7	68.0	46.1	7,147.5	(9,639.5)
BIG BEND 2	7.12%	76.5	80.3	68.8	4,148.5	(4,937.8)
BIG BEND 3	17.13%	57.4	64.6	42.9	9,984.3	(15,386.3)
BIG BEND 4	13.00%	59.5	63.9	50.6	7,576.5	(11,725.7)
POLK 1	5.59%	88.4	90.2	84.7	3,260.8	(2,475.3)
BAYSIDE 1	0.40%	81.0	83.4	76.3	233.5	(2,644.7)
GPIF SYSTEM	**55.49%**					

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	5.12%	10971	71.1	10474	11468	2,986.9	(2,986.9)
BIG BEND 2	4.08%	10484	83.8	10123	10844	2,380.9	(2,380.9)
BIG BEND 3	7.30%	11090	64.2	10182	11998	4,258.0	(4,258.0)
BIG BEND 4	6.27%	10828	82.6	10177	11478	3,657.3	(3,657.3)
POLK 1	7.27%	10428	85.8	9417	11440	4,237.1	(4,237.1)
BAYSIDE1	14.46%	7378	84.7	7101	7655	8,430.3	(8,430.3)
GPIF SYSTEM	**44.51%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 07 - DEC 07 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 05 - DEC 05 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 04 - DEC 04 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN03 - DEC 03 POF	EUOF	EUOR
BIG BEND 1	12.26%	22.1%	3.8	35.5	36.9	8.6	30.4	33.2	7.5	25.9	28.0	0.0	35.3	35.3
BIG BEND 2	7.12%	12.8%	5.8	17.7	18.8	16.0	19.2	22.8	7.4	23.5	25.3	0.0	39.8	39.8
BIG BEND 3	17.13%	30.9%	8.5	34.2	37.3	7.1	41.4	44.6	7.9	25.0	27.1	0.0	37.6	37.6
BIG BEND 4	13.00%	23.4%	24.4	16.1	21.3	7.8	21.5	23.3	0.0	20.7	20.7	10.5	18.2	20.3
POLK 1	5.59%	10.1%	3.3	8.4	8.6	0.0	31.5	31.5	3.2	6.3	6.5	11.1	20.6	23.1
BAYSIDE 1	0.40%	0.7%	9.6	9.4	10.4									
GPIF SYSTEM	**55.49%**	**100.0%**	**10.3**	**25.3**	**28.0**	**8.0**	**30.4**	**32.7**	**5.4**	**22.1**	**23.3**	**3.6**	**31.1**	**31.6**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**64.3**			**61.6**			**72.5**			**65.3**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
5.7	**27.8**	**29.2**	**66.5**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 07 - DEC 07	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 05 - DEC 05	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 04 - DEC 04	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN03 - DEC 03
BIG BEND 1	5.12%	11.5%	10,971	10,943	10,943	11,217
BIG BEND 2	4.08%	9.2%	10,484	10,466	10,466	10,457
BIG BEND 3	7.30%	16.4%	11,090	11,244	11,215	11,121
BIG BEND 4	6.27%	14.1%	10,828	10,729	10,729	10,606
POLK 1	7.27%	16.3%	10,428	10,428	10,420	10,642
BAYSIDE 1	14.46%	32.5%	7,378			
GPIF SYSTEM	**44.51%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**9,670**	**10,782**	**10,773**	**10,824**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2007 - DECEMBER 2007
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	1,079,796.6	1,072,649.1	7,148	12.26%
EA_2 BIG BEND 2	1,079,796.6	1,075,648.1	4,149	7.12%
EA_3 BIG BEND 3	1,079,796.6	1,069,812.3	9,984	17.13%
EA_4 BIG BEND 4	1,079,796.6	1,072,220.1	7,577	13.00%
EA_7 POLK 1	1,079,796.6	1,076,535.8	3,261	5.59%
EA_8 BAYSIDE 1	1,079,796.6	1,079,563.1	234	0.40%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	1,079,796.6	1,076,809.7	2,987	5.12%
AHR_2 BIG BEND 2	1,079,796.6	1,077,415.7	2,381	4.08%
AHR_3 BIG BEND 3	1,079,796.6	1,075,538.6	4,258	7.30%
AHR_4 BIG BEND 4	1,079,796.6	1,076,139.3	3,657	6.27%
AHR_7 POLK 1	1,079,796.6	1,075,559.5	4,237	7.27%
AHR_8 BAYSIDE 1	1,079,796.6	1,071,366.3	8,430	14.46%
TOTAL SAVINGS			**58,301.7**	**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 2007 - DECEMBER 2007

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	7,147.5	68.0	+10	2,986.9	10,474
+9	6,432.8	67.2	+9	2,688.3	10,516
+8	5,718.0	66.5	+8	2,389.6	10,559
+7	5,003.3	65.8	+7	2,090.9	10,601
+6	4,288.5	65.1	+6	1,792.2	10,643
+5	3,573.8	64.3	+5	1,493.5	10,685
+4	2,859.0	63.6	+4	1,194.8	10,727
+3	2,144.3	62.9	+3	896.1	10,770
+2	1,429.5	62.1	+2	597.4	10,812
+1	714.8	61.4	+1	298.7	10,854
					10,896
0	0.0	60.7	0	0.0	10,971
					11,046
-1	(964.0)	59.2	-1	(298.7)	11,088
-2	(1,927.9)	57.8	-2	(597.4)	11,131
-3	(2,891.9)	56.3	-3	(896.1)	11,173
-4	(3,855.8)	54.9	-4	(1,194.8)	11,215
-5	(4,819.8)	53.4	-5	(1,493.5)	11,257
-6	(5,783.7)	51.9	-6	(1,792.2)	11,300
-7	(6,747.7)	50.5	-7	(2,090.9)	11,342
-8	(7,711.6)	49.0	-8	(2,389.6)	11,384
-9	(8,675.6)	47.6	-9	(2,688.3)	11,426
-10	(9,639.5)	46.1	-10	(2,986.9)	11,468
	Weighting Factor =	12.26%		Weighting Factor =	5.12%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2007 - DECEMBER 2007

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	4,148.5	80.3	+10	2,380.9	10,123
+9	3,733.7	80.0	+9	2,142.8	10,152
+8	3,318.8	79.6	+8	1,904.7	10,180
+7	2,904.0	79.2	+7	1,666.6	10,209
+6	2,489.1	78.8	+6	1,428.5	10,238
+5	2,074.3	78.4	+5	1,190.5	10,266
+4	1,659.4	78.0	+4	952.4	10,295
+3	1,244.6	77.7	+3	714.3	10,323
+2	829.7	77.3	+2	476.2	10,352
+1	414.9	76.9	+1	238.1	10,380
					10,409
0	0.0	76.5	0	0.0	10,484
					10,559
-1	(493.8)	75.7	-1	(238.1)	10,587
-2	(987.6)	75.0	-2	(476.2)	10,616
-3	(1,481.3)	74.2	-3	(714.3)	10,644
-4	(1,975.1)	73.4	-4	(952.4)	10,673
-5	(2,468.9)	72.7	-5	(1,190.5)	10,702
-6	(2,962.7)	71.9	-6	(1,428.5)	10,730
-7	(3,456.5)	71.1	-7	(1,666.6)	10,759
-8	(3,950.2)	70.4	-8	(1,904.7)	10,787
-9	(4,444.0)	69.6	-9	(2,142.8)	10,816
-10	(4,937.8)	68.8	-10	(2,380.9)	10,844
	Weighting Factor =	7.12%		Weighting Factor =	4.08%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2007 - DECEMBER 2007

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	9,984.3	64.6	+10	4,258.0	10,182
+9	8,985.9	63.9	+9	3,832.2	10,265
+8	7,987.4	63.2	+8	3,406.4	10,348
+7	6,989.0	62.4	+7	2,980.6	10,432
+6	5,990.6	61.7	+6	2,554.8	10,515
+5	4,992.2	61.0	+5	2,129.0	10,598
+4	3,993.7	60.3	+4	1,703.2	10,682
+3	2,995.3	59.5	+3	1,277.4	10,765
+2	1,996.9	58.8	+2	851.6	10,848
+1	998.4	58.1	+1	425.8	10,932
					11,015
0	0.0	57.4	0	0.0	11,090
					11,165
-1	(1,538.6)	55.9	-1	(425.8)	11,248
-2	(3,077.3)	54.5	-2	(851.6)	11,331
-3	(4,615.9)	53.0	-3	(1,277.4)	11,415
-4	(6,154.5)	51.6	-4	(1,703.2)	11,498
-5	(7,693.1)	50.1	-5	(2,129.0)	11,581
-6	(9,231.8)	48.7	-6	(2,554.8)	11,665
-7	(10,770.4)	47.2	-7	(2,980.6)	11,748
-8	(12,309.0)	45.8	-8	(3,406.4)	11,831
-9	(13,847.7)	44.3	-9	(3,832.2)	11,914
-10	(15,386.3)	42.9	-10	(4,258.0)	11,998
	Weighting Factor =	17.13%		Weighting Factor =	7.30%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2007 - DECEMBER 2007

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	7,576.5	63.9	+10	3,657.3	10,177
+9	6,818.9	63.5	+9	3,291.6	10,235
+8	6,061.2	63.1	+8	2,925.9	10,292
+7	5,303.6	62.6	+7	2,560.1	10,350
+6	4,545.9	62.2	+6	2,194.4	10,408
+5	3,788.3	61.7	+5	1,828.7	10,465
+4	3,030.6	61.3	+4	1,462.9	10,523
+3	2,273.0	60.8	+3	1,097.2	10,580
+2	1,515.3	60.4	+2	731.5	10,638
+1	757.7	59.9	+1	365.7	10,695
					10,753
0	0.0	59.5	0	0.0	10,828
					10,903
-1	(1,172.6)	58.6	-1	(365.7)	10,960
-2	(2,345.1)	57.7	-2	(731.5)	11,018
-3	(3,517.7)	56.8	-3	(1,097.2)	11,076
-4	(4,690.3)	55.9	-4	(1,462.9)	11,133
-5	(5,862.8)	55.1	-5	(1,828.7)	11,191
-6	(7,035.4)	54.2	-6	(2,194.4)	11,248
-7	(8,208.0)	53.3	-7	(2,560.1)	11,306
-8	(9,380.6)	52.4	-8	(2,925.9)	11,363
-9	(10,553.1)	51.5	-9	(3,291.6)	11,421
-10	(11,725.7)	50.6	-10	(3,657.3)	11,478
	Weighting Factor =	13.00%		Weighting Factor =	6.27%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2007 - DECEMBER 2007

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	3,260.8	90.2	+10	4,237.1	9,417
+9	2,934.7	90.0	+9	3,813.4	9,511
+8	2,608.6	89.8	+8	3,389.7	9,604
+7	2,282.6	89.6	+7	2,966.0	9,698
+6	1,956.5	89.5	+6	2,542.2	9,791
+5	1,630.4	89.3	+5	2,118.5	9,885
+4	1,304.3	89.1	+4	1,694.8	9,979
+3	978.2	88.9	+3	1,271.1	10,072
+2	652.2	88.7	+2	847.4	10,166
+1	326.1	88.5	+1	423.7	10,260
					10,353
0	0.0	88.4	0	0.0	10,428
					10,503
-1	(247.5)	88.0	-1	(423.7)	10,597
-2	(495.1)	87.6	-2	(847.4)	10,691
-3	(742.6)	87.2	-3	(1,271.1)	10,784
-4	(990.1)	86.9	-4	(1,694.8)	10,878
-5	(1,237.6)	86.5	-5	(2,118.5)	10,971
-6	(1,485.2)	86.1	-6	(2,542.2)	11,065
-7	(1,732.7)	85.8	-7	(2,966.0)	11,159
-8	(1,980.2)	85.4	-8	(3,389.7)	11,252
-9	(2,227.8)	85.0	-9	(3,813.4)	11,346
-10	(2,475.3)	84.7	-10	(4,237.1)	11,440
	Weighting Factor =	5.59%		Weighting Factor =	7.27%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2007 - DECEMBER 2007

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	233.5	83.4	+10	8,430.3	7,101
+9	210.2	83.1	+9	7,587.3	7,121
+8	186.8	82.9	+8	6,744.3	7,141
+7	163.5	82.7	+7	5,901.2	7,162
+6	140.1	82.4	+6	5,058.2	7,182
+5	116.8	82.2	+5	4,215.2	7,202
+4	93.4	82.0	+4	3,372.1	7,222
+3	70.1	81.7	+3	2,529.1	7,242
+2	46.7	81.5	+2	1,686.1	7,263
+1	23.4	81.3	+1	843.0	7,283
					7,303
0	0.0	81.0	0	0.0	7,378
					7,453
-1	(264.5)	80.6	-1	(843.0)	7,473
-2	(528.9)	80.1	-2	(1,686.1)	7,494
-3	(793.4)	79.6	-3	(2,529.1)	7,514
-4	(1,057.9)	79.1	-4	(3,372.1)	7,534
-5	(1,322.3)	78.7	-5	(4,215.2)	7,554
-6	(1,586.8)	78.2	-6	(5,058.2)	7,574
-7	(1,851.3)	77.7	-7	(5,901.2)	7,595
-8	(2,115.8)	77.3	-8	(6,744.3)	7,615
-9	(2,380.2)	76.8	-9	(7,587.3)	7,635
-10	(2,644.7)	76.3	-10	(8,430.3)	7,655
	Weighting Factor =	0.40%		Weighting Factor =	14.46%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	33.7	63.1	60.69
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.84
3. EUOF	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	19.7	36.9	35.47
4. EUOR	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9	36.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	682	616	682	660	682	660	682	682	660	682	352	682	7718
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	62	56	62	60	62	60	62	62	60	62	368	62	1042
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. FOH & EFOH	242	218	242	234	242	234	242	242	234	242	125	242	2737
11. MOH & EMOH	33	30	33	32	33	32	33	33	32	33	17	33	370
12. OPER BTU (GBTU)	2187	1972	2187	2116	2187	2116	2187	2187	2116	2187	1129	2186	24758
13. NET GEN (MWH)	199,364	179,690	199,335	192,829	199,365	192,882	199,309	199,397	192,901	199,378	102,903	199,263	2,256,616
14. ANOHR (Btu/kwh)	10,971	10,974	10,971	10,972	10,971	10,971	10,971	10,970	10,971	10,971	10,971	10,972	10,971
15. NOF (%)	71.2	71.0	71.2	71.1	71.2	71.1	71.1	71.2	71.2	71.2	71.2	71.1	71.1
16. NPC (MW)	411	411	411	411	411	411	411	411	411	411	411	411	411
17. ANOHR EQUATION	ANOHR = NOF(		-25.102	) +	12757								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	81.2	81.2	81.2	81.2	31.4	75.8	81.2	81.2	81.2	81.2	81.2	81.2	76.50
2. POF	0.0	0.0	0.0	0.0	61.3	6.7	0.0	0.0	0.0	0.0	0.0	0.0	5.75
3. EUOF	18.8	18.8	18.8	18.8	7.3	17.6	18.8	18.8	18.8	18.8	18.8	18.8	17.74
4. EUOR	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	692	625	692	670	246	647	692	692	670	692	670	692	7681
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	52	47	52	50	498	73	52	52	50	52	50	52	1079
9. POH	0	0	0	0	456	48	0	0	0	0	0	0	504
10. FOH & EFOH	114	103	114	111	44	103	114	114	111	114	111	114	1270
11. MOH & EMOH	26	23	26	25	10	23	26	26	25	26	25	26	285
12. OPER BTU (GBTU)	2379	2148	2379	2302	845	2224	2379	2379	2302	2379	2302	2379	26396
13. NET GEN (MWH)	226,893	204,918	226,892	219,568	80,585	212,178	226,891	226,893	219,572	226,893	219,574	226,891	2,517,748
14. ANOHR (Btu/kwh)	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484	10,484
15. NOF (%)	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8
16. NPC (MW)	391	391	391	391	391	391	391	391	391	391	391	391	391
17. ANOHR EQUATION	ANOHR = NOF(	-19.503	) +		12119								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	62.7	62.7	62.7	62.7	62.7	62.7	62.7	62.7	62.7	62.7	62.7	0.0	57.36
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	8.49
3. EUOF	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	0.0	34.15
4. EUOR	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	0.0	37.3
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	598	540	598	578	598	578	598	598	578	598	578	20	6459
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	146	132	146	142	146	142	146	146	142	146	142	724	2301
9. POH	0	0	0	0	0	0	0	0	0	0	0	744	744
10. FOH & EFOH	245	221	245	237	245	237	245	245	237	245	237	0	2641
11. MOH & EMOH	33	29	33	31	33	31	33	33	31	33	31	0	350
12. OPER BTU (GBTU)	1766	1620	1813	1728	1796	1734	1788	1805	1737	1771	1760	60	19394
13. NET GEN (MWH)	156,961	144,799	162,532	156,615	163,068	157,356	162,158	164,264	157,769	159,966	158,026	5,337	1,748,851
14. ANOHR (Btu/kwh)	11,249	11,191	11,152	11,035	11,012	11,021	11,029	10,990	11,013	11,069	11,139	11,175	11,090
15. NOF (%)	60.7	61.9	62.8	65.4	65.9	65.7	65.5	66.4	65.9	64.6	63.1	62.3	64.2
16. NPC (MW)	433	433	433	414	414	414	414	414	414	414	433	433	422
17. ANOHR EQUATION	ANOHR = NOF(		-45.088	) +	13984								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	78.7	0.0	0.0	0.0	78.7	78.7	78.7	78.7	78.7	78.7	78.7	78.7	59.49
2. POF	0.0	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.38
3. EUOF	21.3	0.0	0.0	0.0	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	16.12
4. EUOR	21.3	0.0	0.0	0.0	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	620	0	0	40	620	600	620	620	600	620	600	620	5562
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	124	672	744	680	124	120	124	124	120	124	120	124	3198
9. POH	0	672	744	720	0	0	0	0	0	0	0	0	2136
10. FOH & EFOH	127	0	0	0	127	123	127	127	123	127	123	127	1129
11. MOH & EMOH	32	0	0	0	32	31	32	32	31	32	31	32	284
12. OPER BTU (GBTU)	2634.93	0.00	0.00	100.09	2219.93	2487.83	2568.54	2582.52	2503.15	2638.18	2490.68	2587.57	22823.75
13. NET GEN (MWH)	244,102	0	0	8,890	202,371	230,125	237,568	239,003	231,698	244,736	230,144	239,236	2,107,873
14. ANOHR (Btu/kwh)	10,794	11,877	11,877	11,259	10,970	10,811	10,812	10,805	10,804	10,780	10,822	10,816	10,828
15. NOF (%)	85.2	0.0	0.0	48.6	71.4	83.9	83.8	84.3	84.5	86.4	83.0	83.5	82.6
16. NPC (MW)	462	462	462	457	457	457	457	457	457	457	462	462	459
17. ANOHR EQUATION	ANOHR = NOF(	-12.70629064) +		11876.88211									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	91.4	91.4	91.4	70.0	91.4	91.4	91.4	91.4	91.4	76.6	91.4	91.4	88.35
2. POF	0.0	0.0	0.0	23.3	0.0	0.0	0.0	0.0	0.0	16.1	0.0	0.0	3.29
3. EUOF	8.6	8.6	8.6	6.6	8.6	8.6	8.6	8.6	8.6	7.3	8.6	8.6	8.36
4. EUOR	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	708	639	708	525	708	685	708	708	685	594	685	708	8059
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	36	33	36	195	36	35	36	36	35	150	35	36	701
9. POH	0	0	0	168	0	0	0	0	0	120	0	0	288
10. FOH & EFOH	45	40	45	33	45	43	45	45	43	37	43	45	507
11. MOH & EMOH	20	18	20	15	20	19	20	20	19	17	19	20	226
12. OPER BTU (GBTU)	1678.62	1516.17	1669.08	1156.73	1580.38	1529.40	1580.38	1580.38	1566.54	1400.88	1624.47	1678.62	18562.26
13. NET GEN (MWH)	161,240	145,636	160,244	110,605	151,281	146,401	151,281	151,281	150,256	134,495	156,038	161,240	1,779,998
14. ANOHR (Btu/kwh)	10,411	10,411	10,416	10,458	10,447	10,447	10,447	10,447	10,426	10,416	10,411	10,411	10,428
15. NOF (%)	87.6	87.6	87.1	82.6	83.8	83.8	83.8	83.8	86.0	87.1	87.6	87.6	85.8
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	257

17. ANOHR EQUATION ANOHR = NOF(-9.460055341) + 11239.71057

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2007 - DECEMBER 2007

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-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007
1. EAF (%)	89.6	89.6	69.4	89.6	89.6	89.6	89.6	89.6	89.6	34.7	62.7	89.6	81.0
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	61.3	30.0	0.0	9.6
3. EUOF	10.4	10.4	8.0	10.4	10.4	10.4	10.4	10.4	10.4	4.0	7.3	10.4	9.4
4. EUOR	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	488	521	438	497	517	487	515	510	476	217	359	553	5579
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	256	151	306	223	227	233	229	234	244	527	361	191	3181
9. POH	0	0	168	0	0	0	0	0	0	456	216	0	840
10. FOH & EFOH	4	3	3	3	4	3	4	4	3	1	2	4	38
11. MOH & EMOH	74	67	57	71	74	71	74	74	71	29	50	74	784
12. OPER BTU (GBTU)	1893.7	2313.7	2116.0	2257.9	2453.2	2271.6	2399.6	2386.2	2228.9	1064.0	1721.7	2432.8	25539.0
13. NET GEN (MWH)	256,806	313,672	286,818	305,997	332,424	307,842	325,185	323,365	302,044	144,168	233,305	329,827	3,461,453
14. ANOHR (Btu/kwh)	7,374	7,376	7,378	7,379	7,380	7,379	7,379	7,379	7,379	7,380	7,380	7,376	7,378
15. NOF (%)	66.3	76.0	82.5	87.8	91.6	90.0	89.9	90.3	90.3	94.6	92.6	75.2	84.7
16. NPC (MW)	793	793	793	702	702	702	702	702	702	702	702	793	732
17. ANOHR EQUATION	ANOHR = NOF(		0.22	) +	7360								

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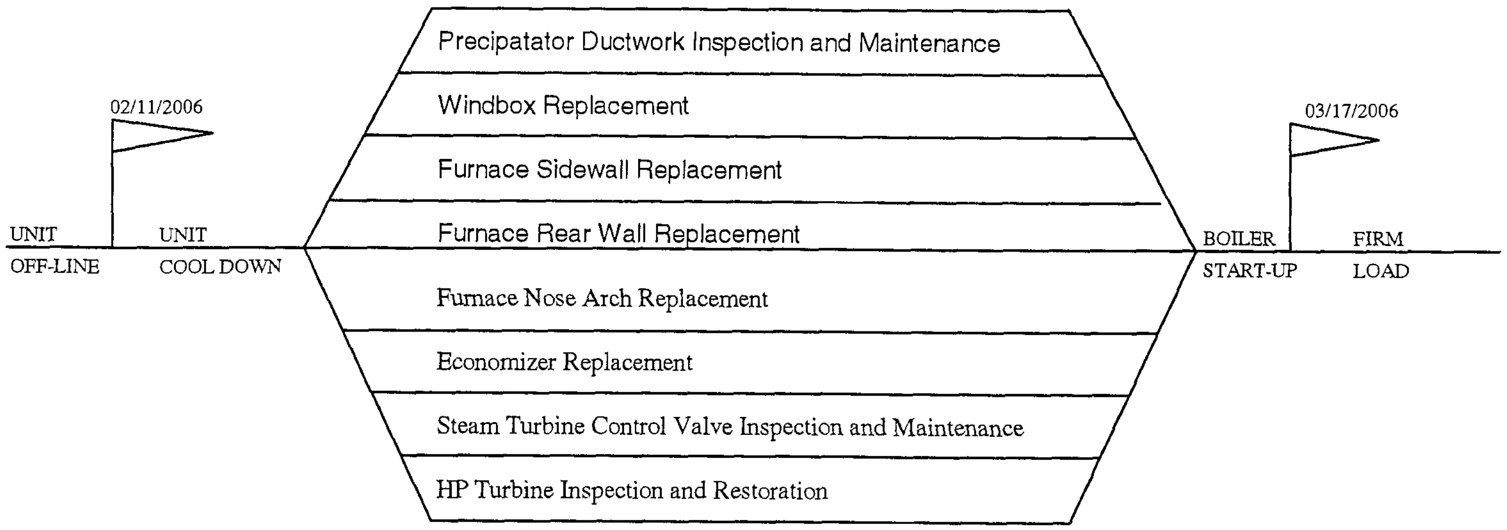
TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2007 - DECEMBER 2007

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Nov 03	-	Nov 16	Fuel System Clean-up
	BIG BEND 2	May 13	-	Jun 02	Fuel System Clean-up
+	BIG BEND 3	Dec 01		Dec 31	Duct Work Outage *
+	BIG BEND 4	Feb 01	-	Apr 30	SCR Outage *
	POLK 1	Apr 02	-	Apr 08	Gasifier / CT Outage
		Oct 21	-	Oct 25	Gasifier Outage
+	BAYSIDE 1	Mar 17	-	Mar 23	Combustion Path Inspection
		Oct 13	-	Nov 09	Steam Turbine Overhaul *

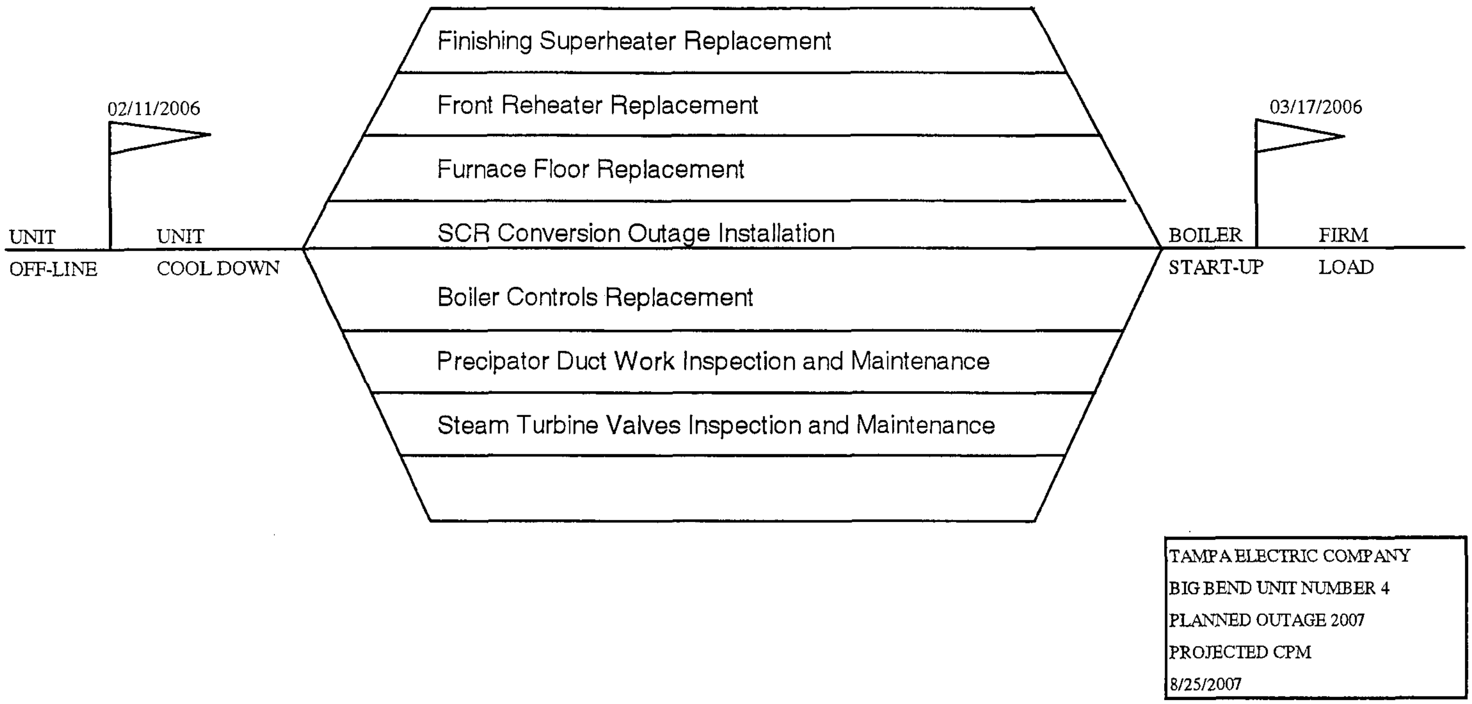
\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2007 - DECEMBER 2007

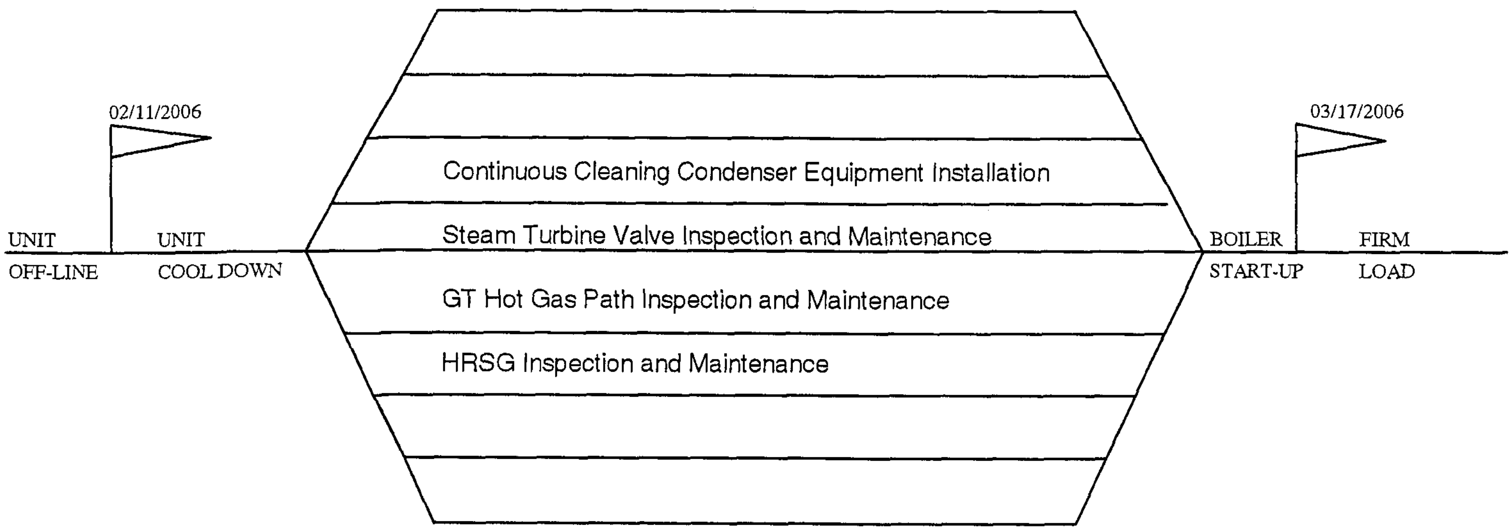


TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 3
PLANNED OUTAGE 2007
PROJECTED CPM
8/25/2007

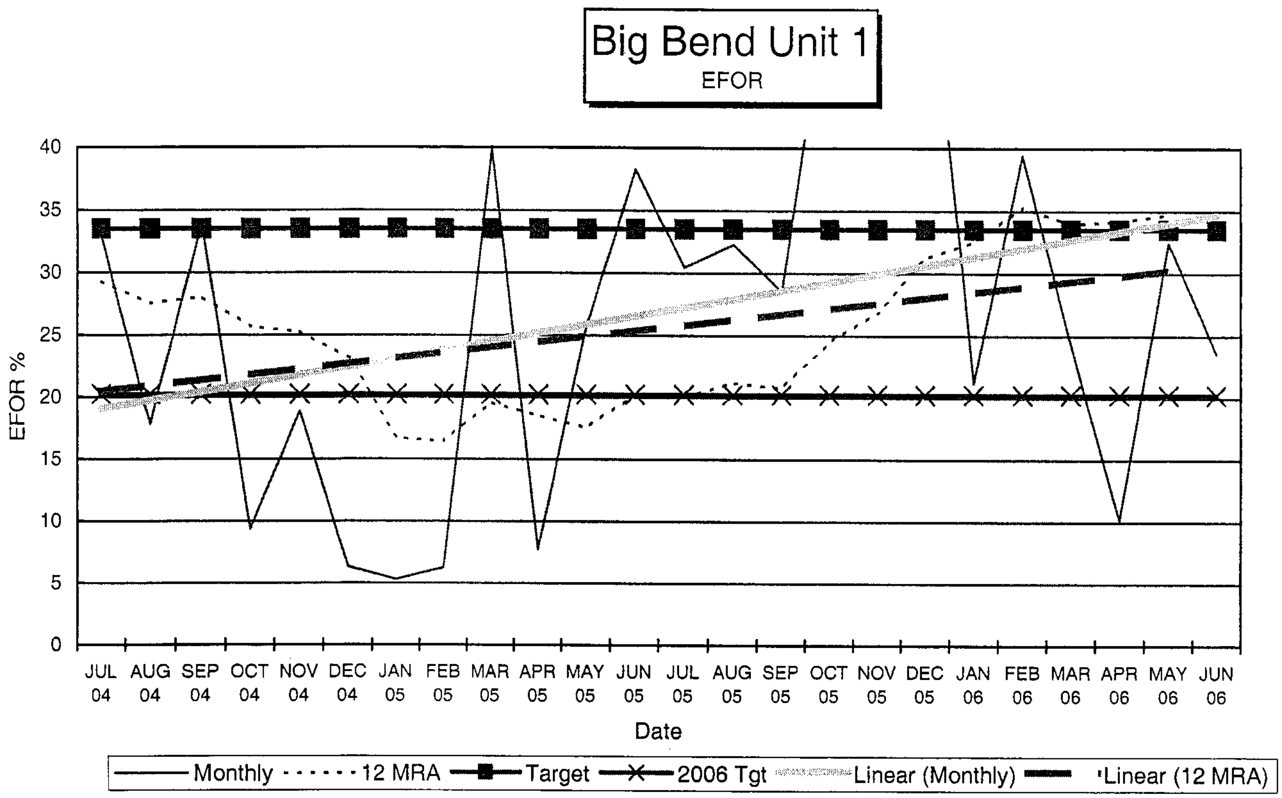
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2007 - DECEMBER 2007

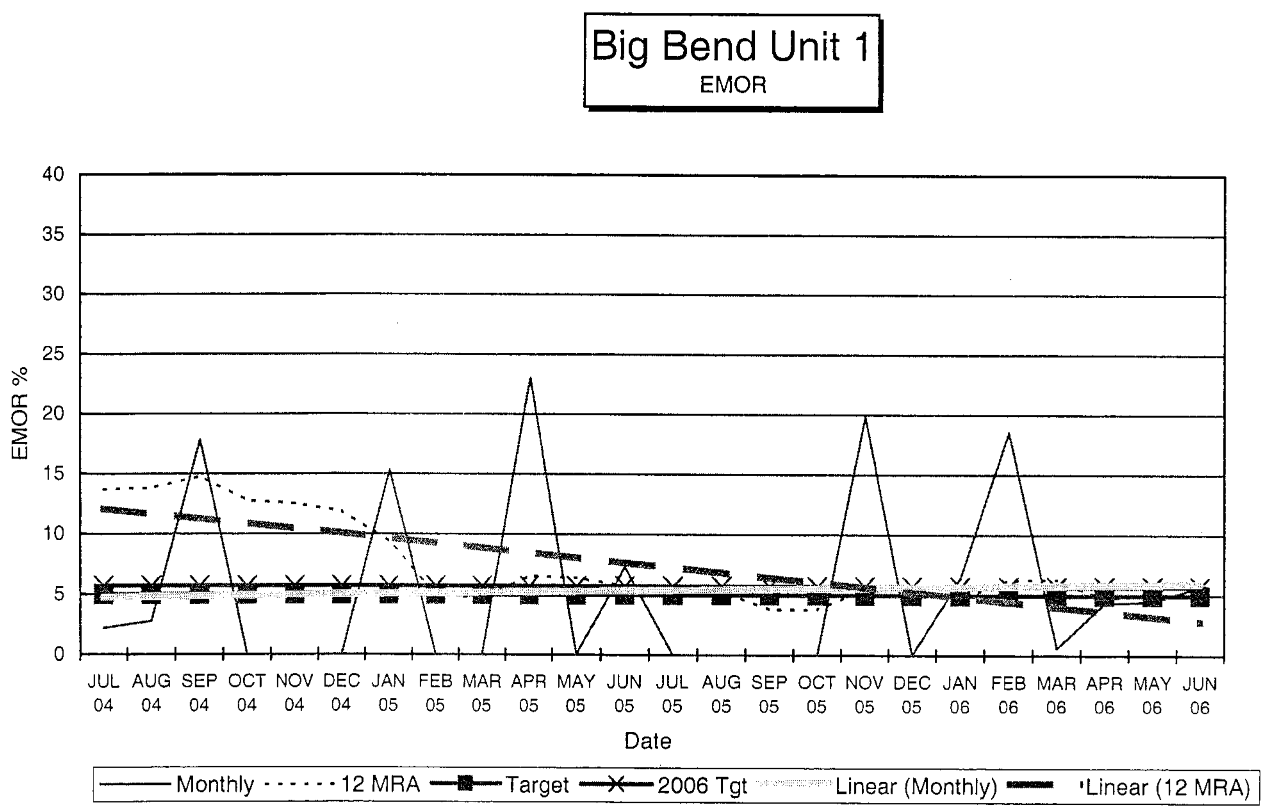


TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2007 - DECEMBER 2007



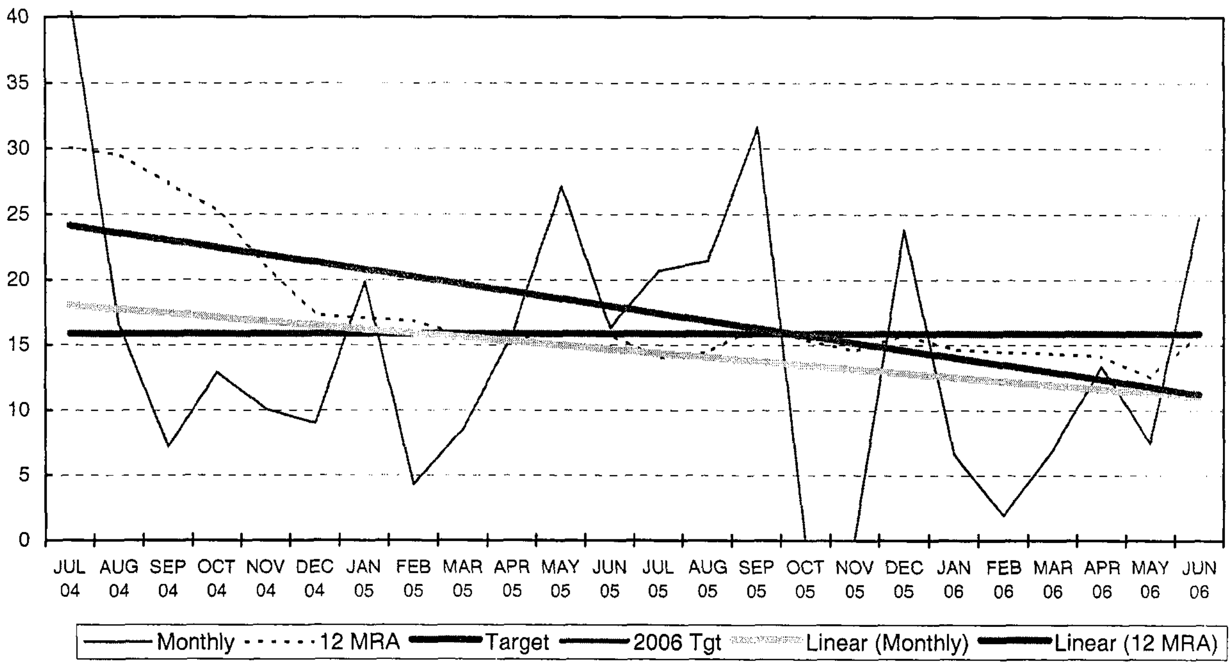
TAMPA ELECTRIC COMPANY
BAYSIDE UNIT # 1
PLANNED OUTAGE 2007
PROJECTED CPM
8/25/2007



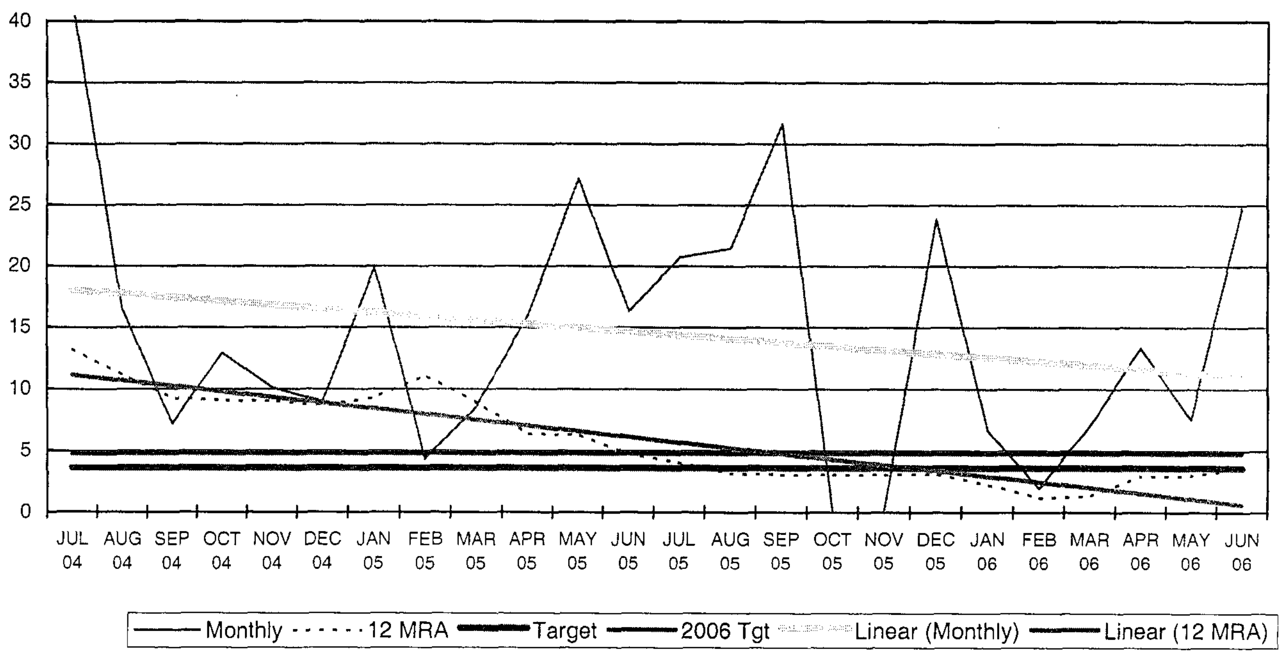


12 MRA = 12 Month Rolling Average

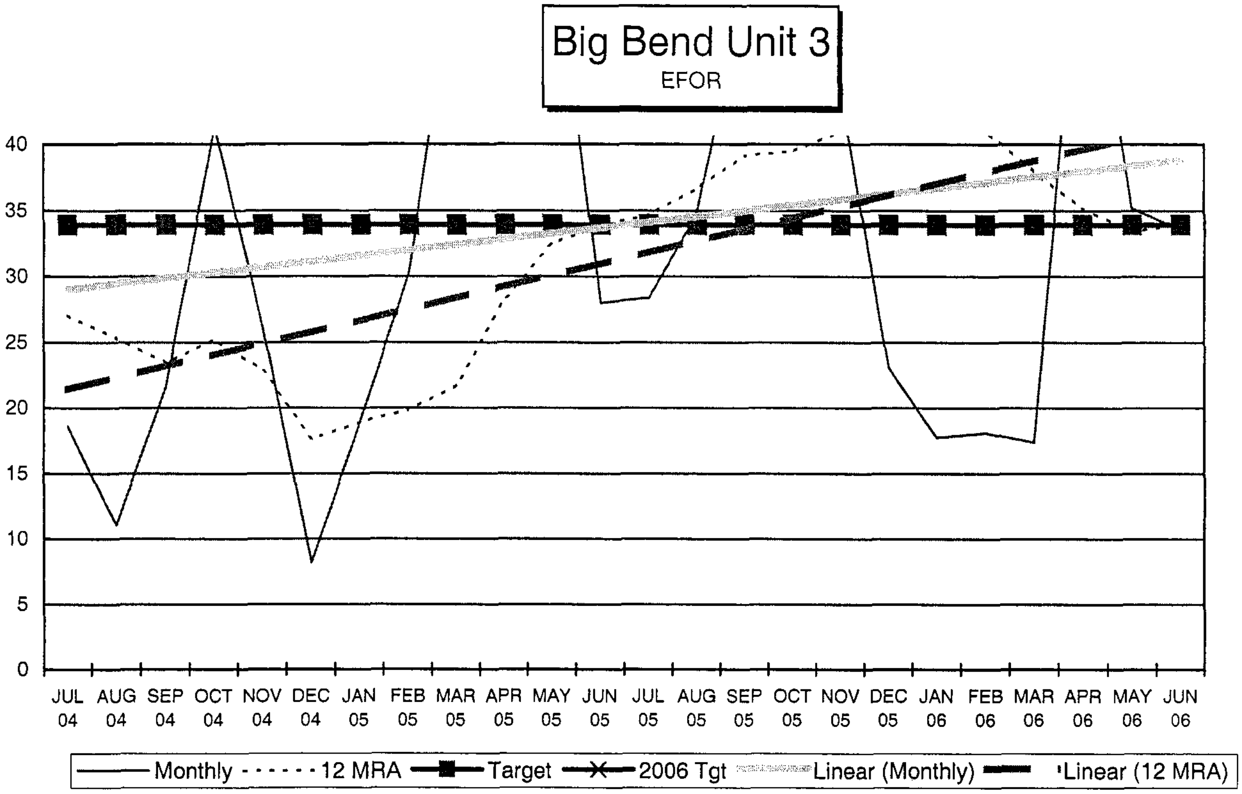
Big Bend Unit 2
EFOR

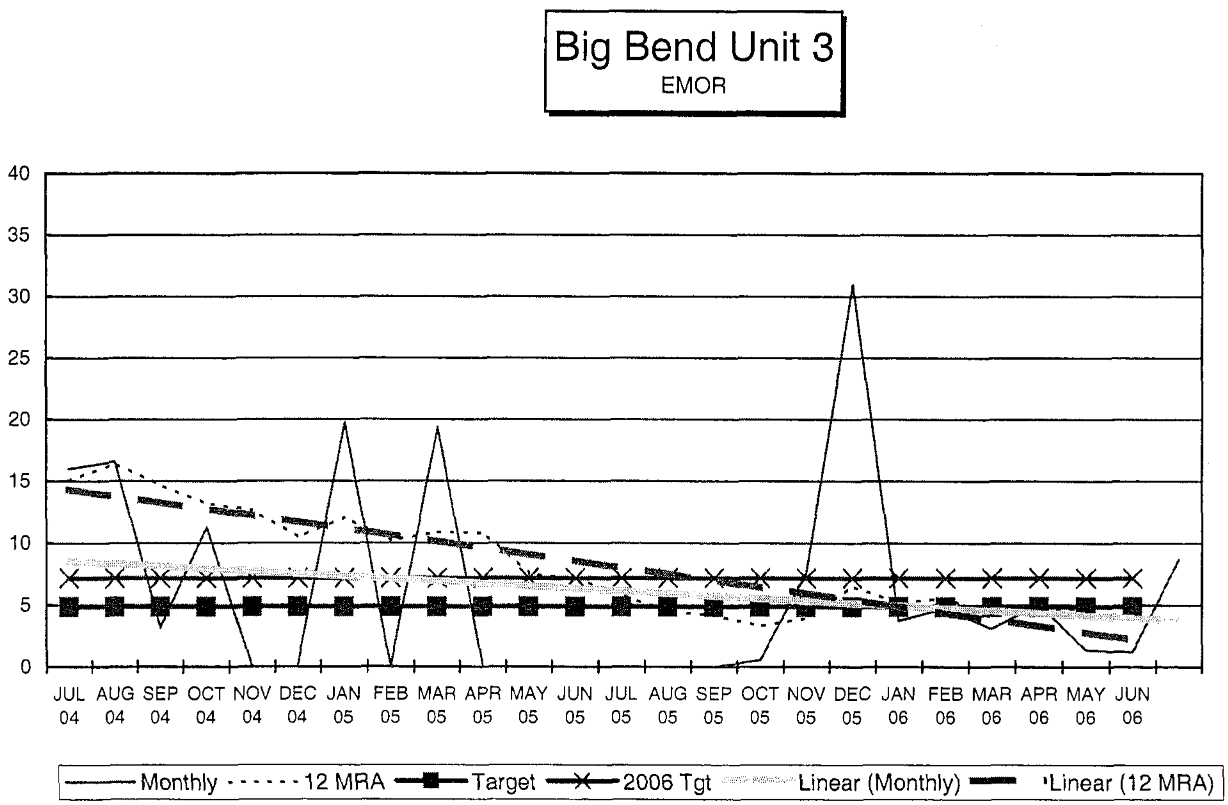


Big Bend Unit 2
EMOR

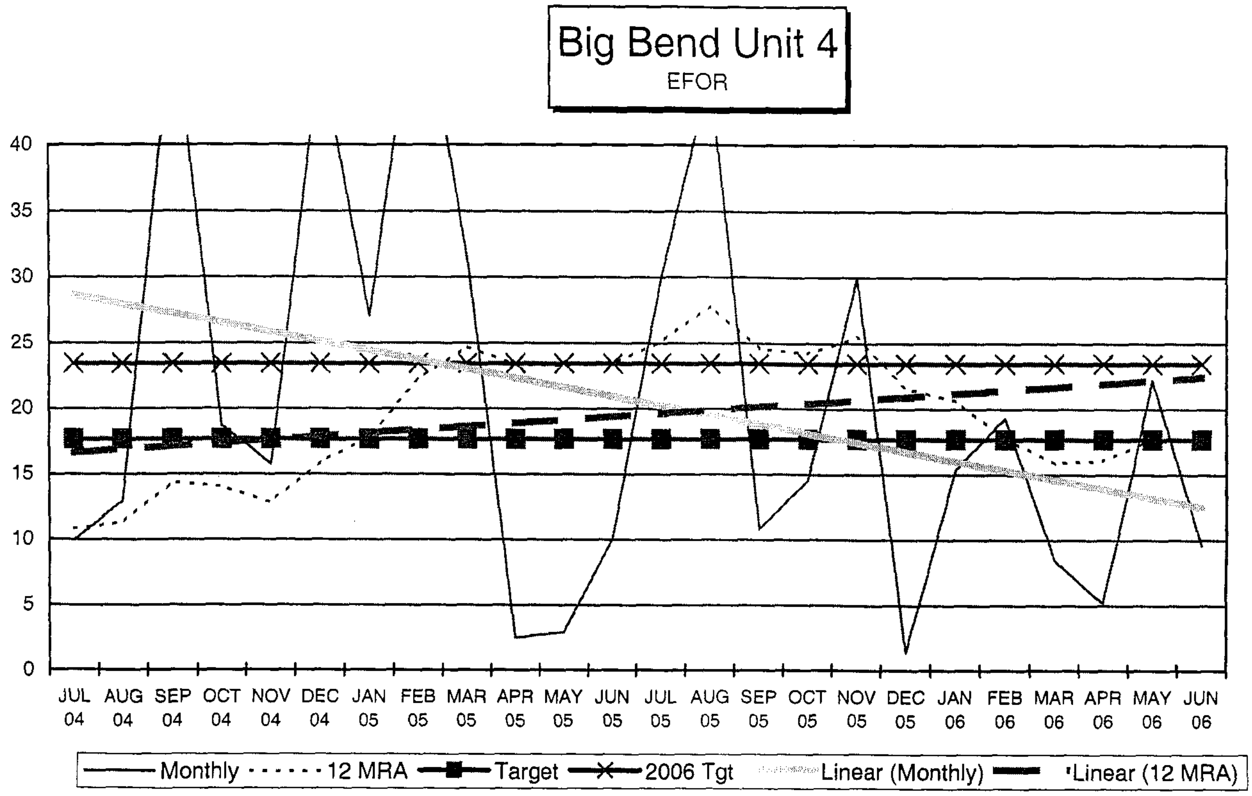


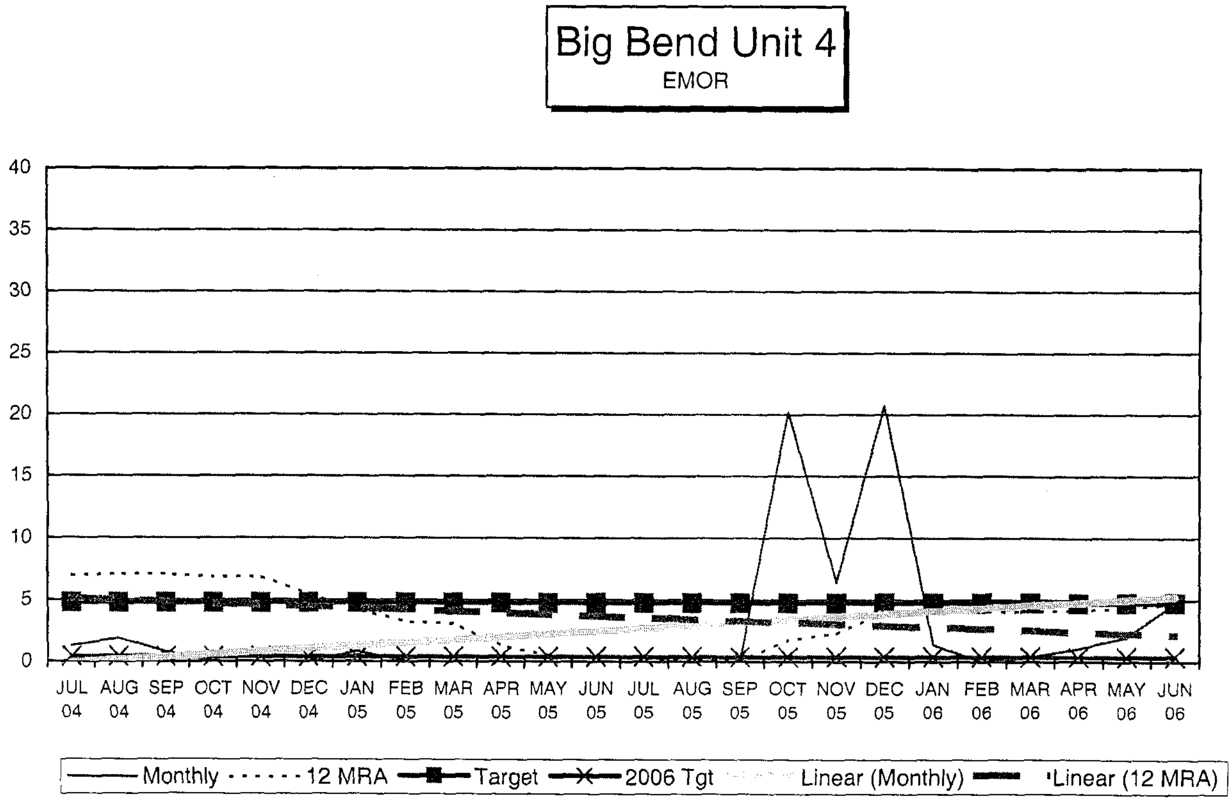
12 MRA = 12 Month Rolling Average



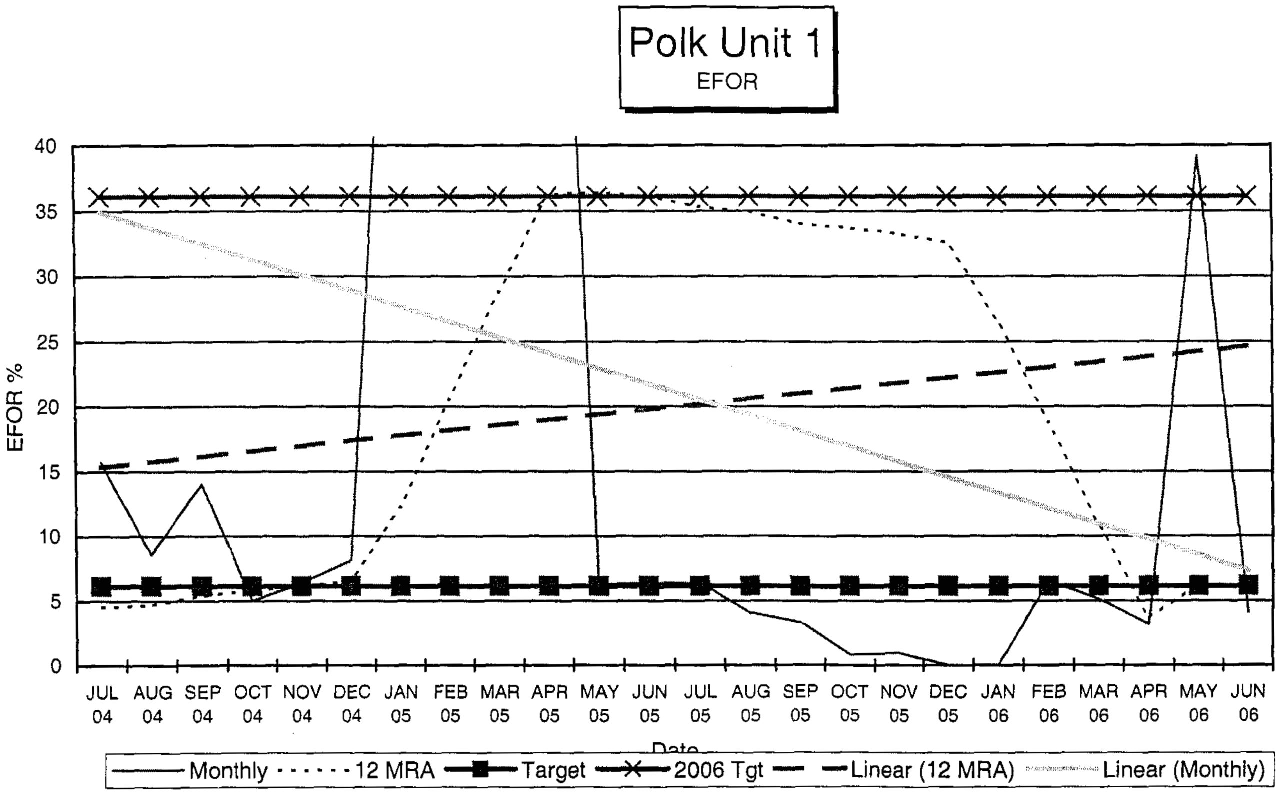


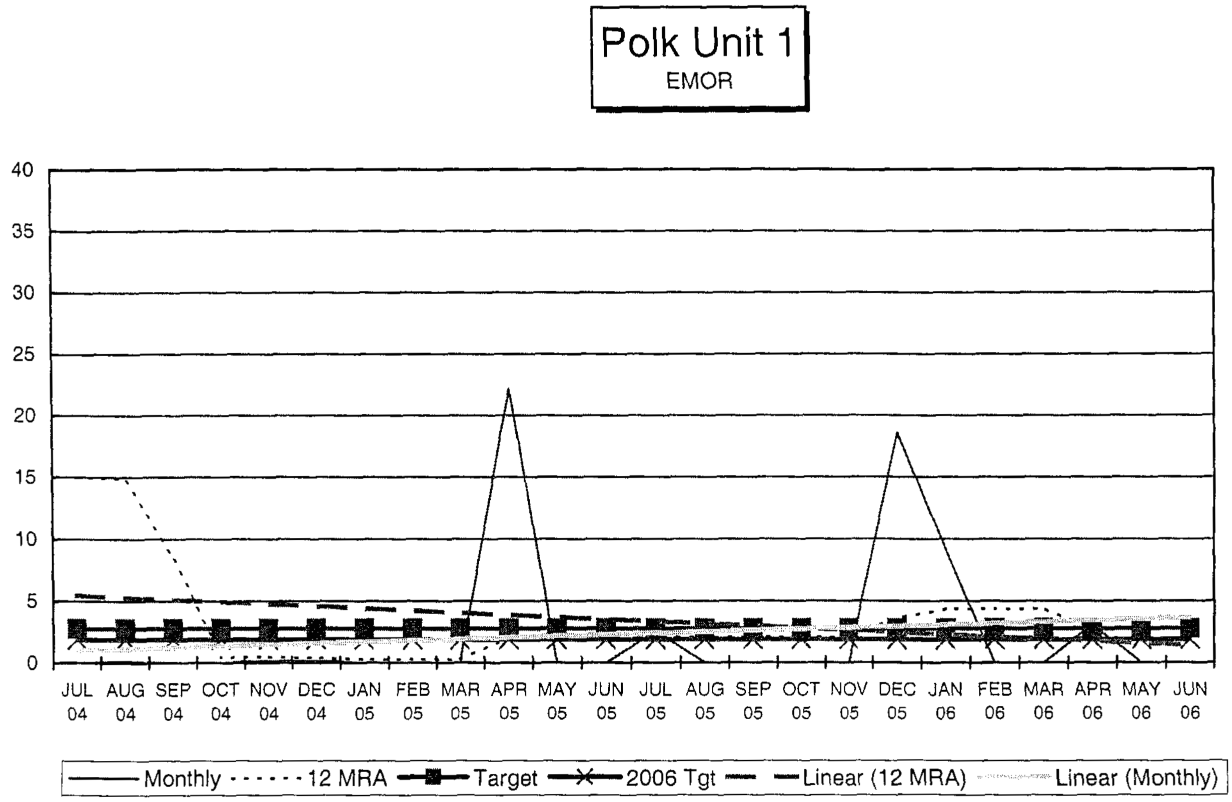
12 MRA = 12 Month Rolling Average



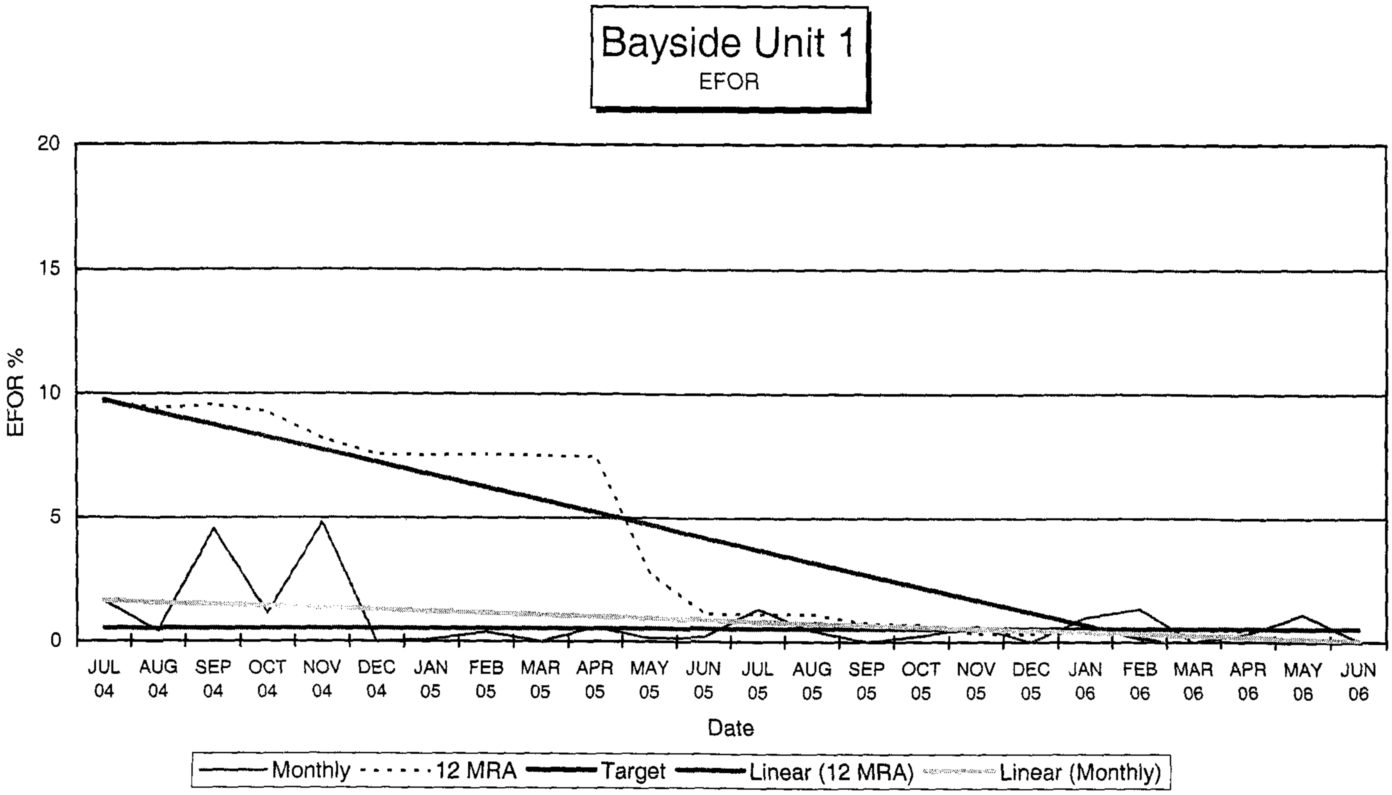


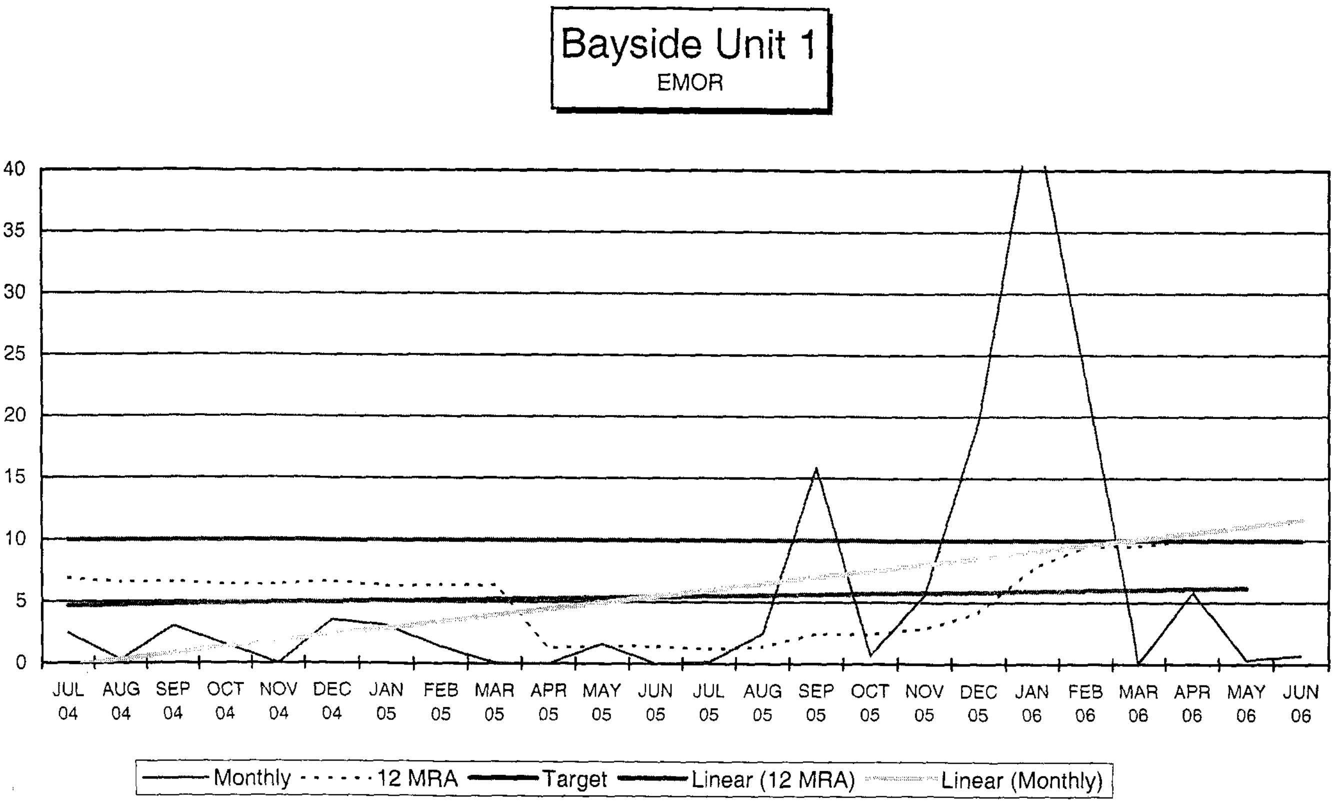
12 MRA = 12 Month Rolling Average





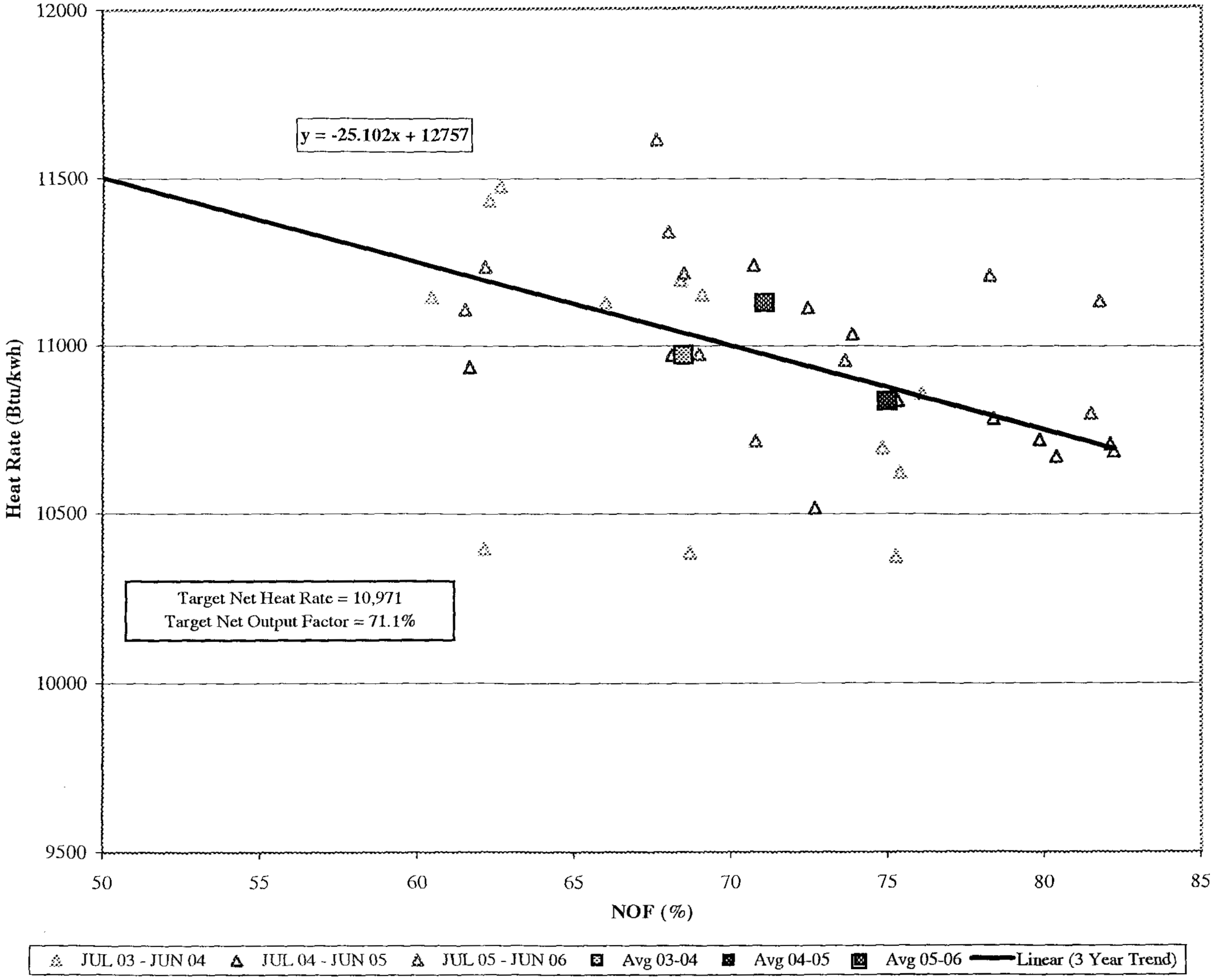
12 MRA = 12 Month Rolling Avreage

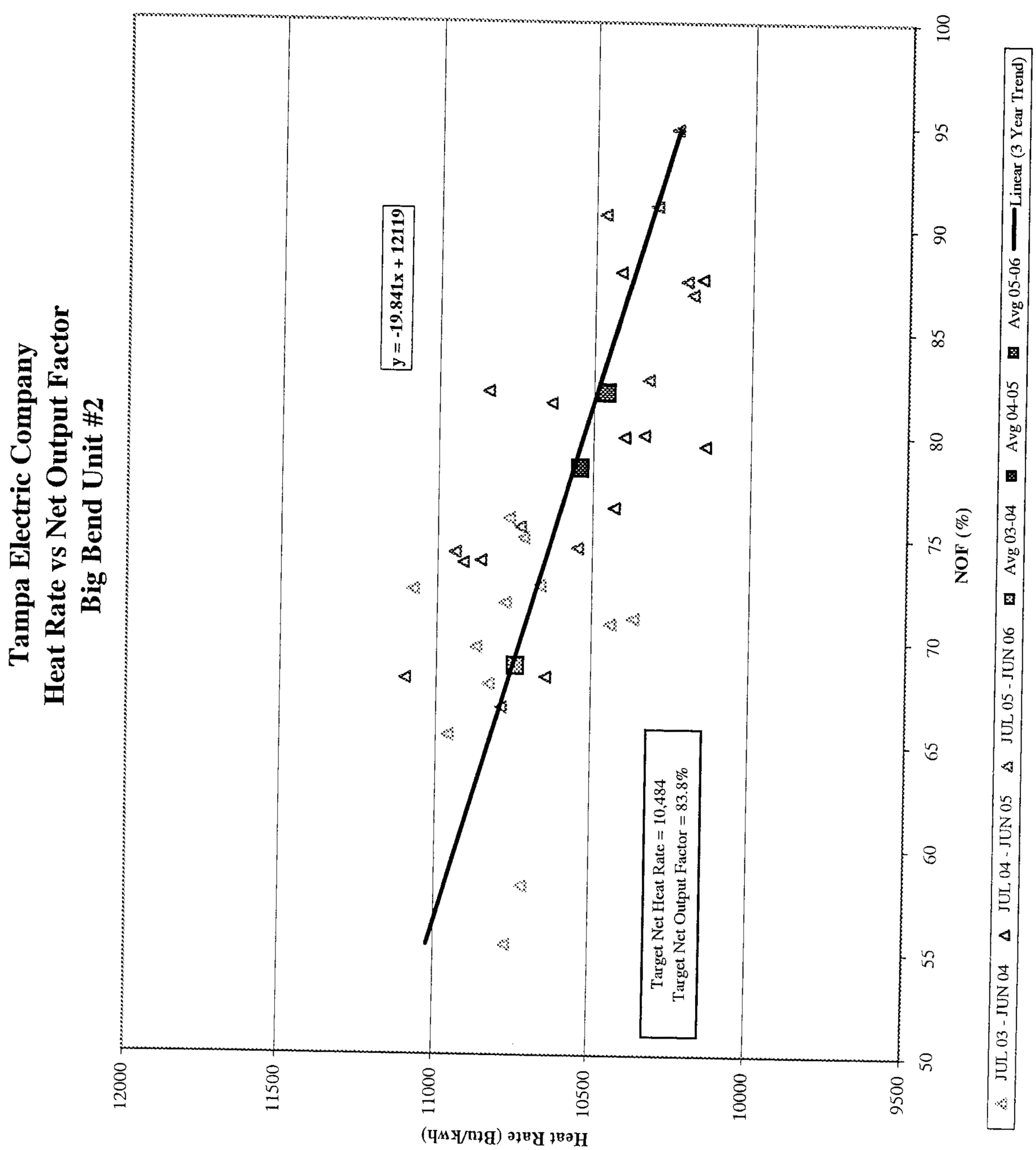




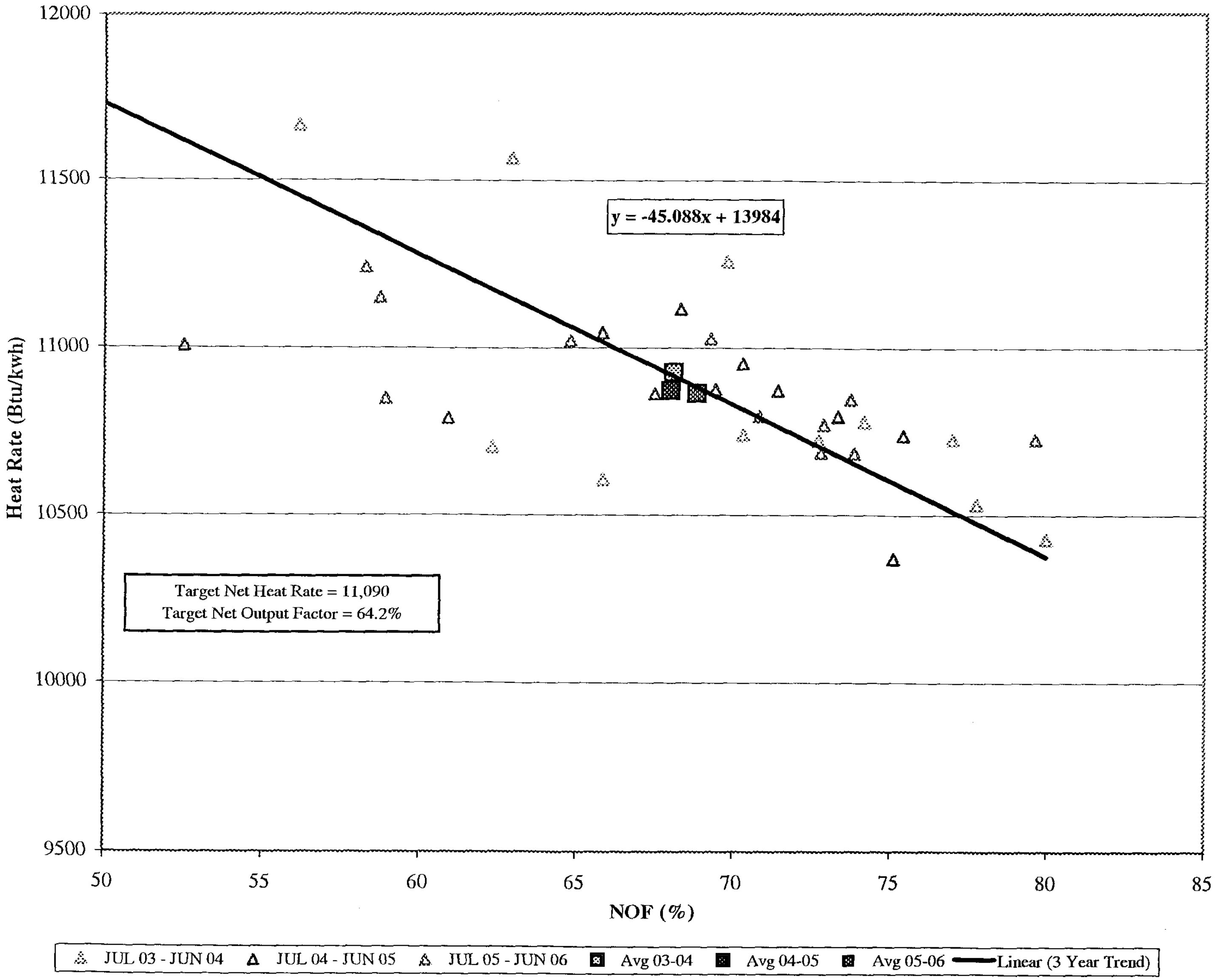
12 MRA = 12 Month Rolling Avreage

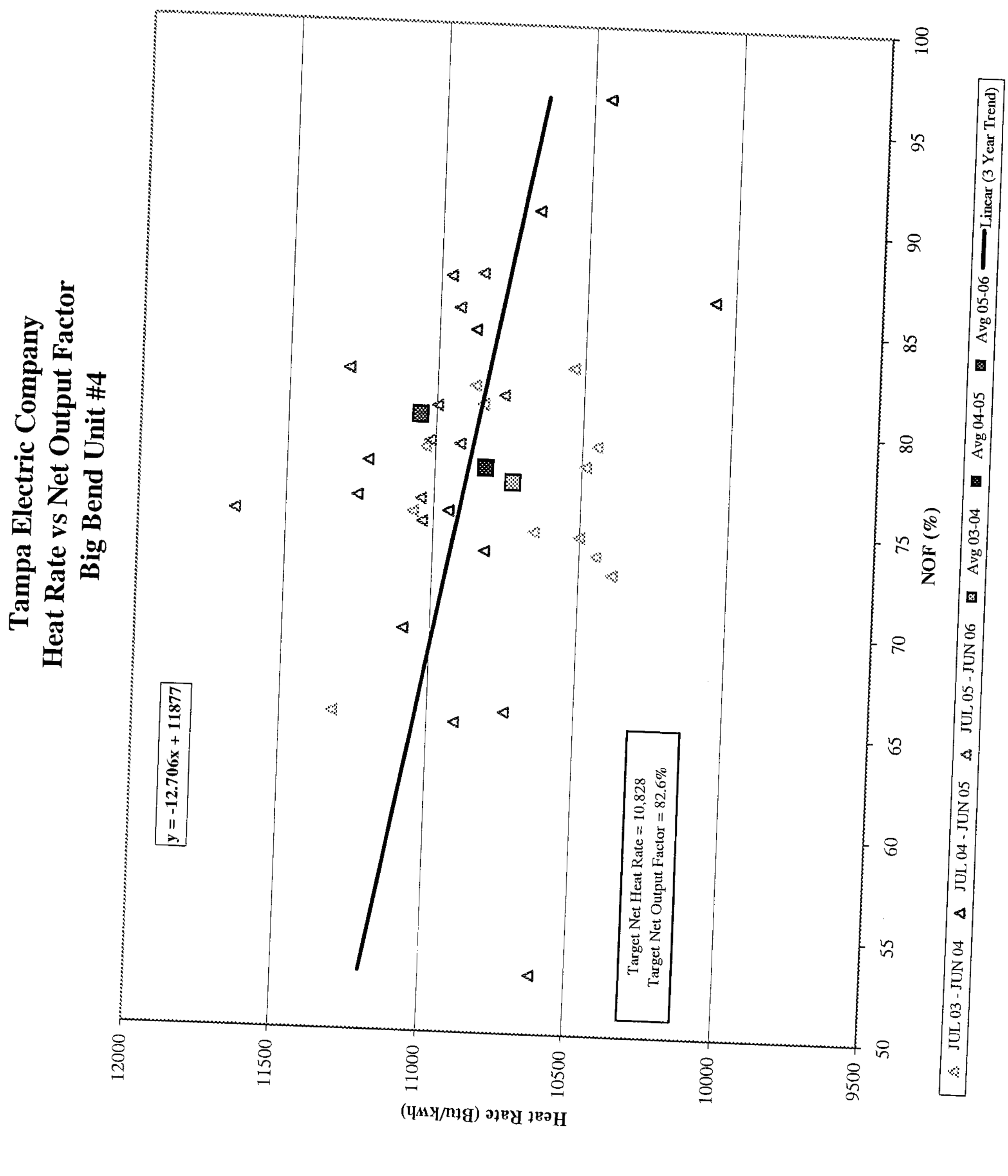
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



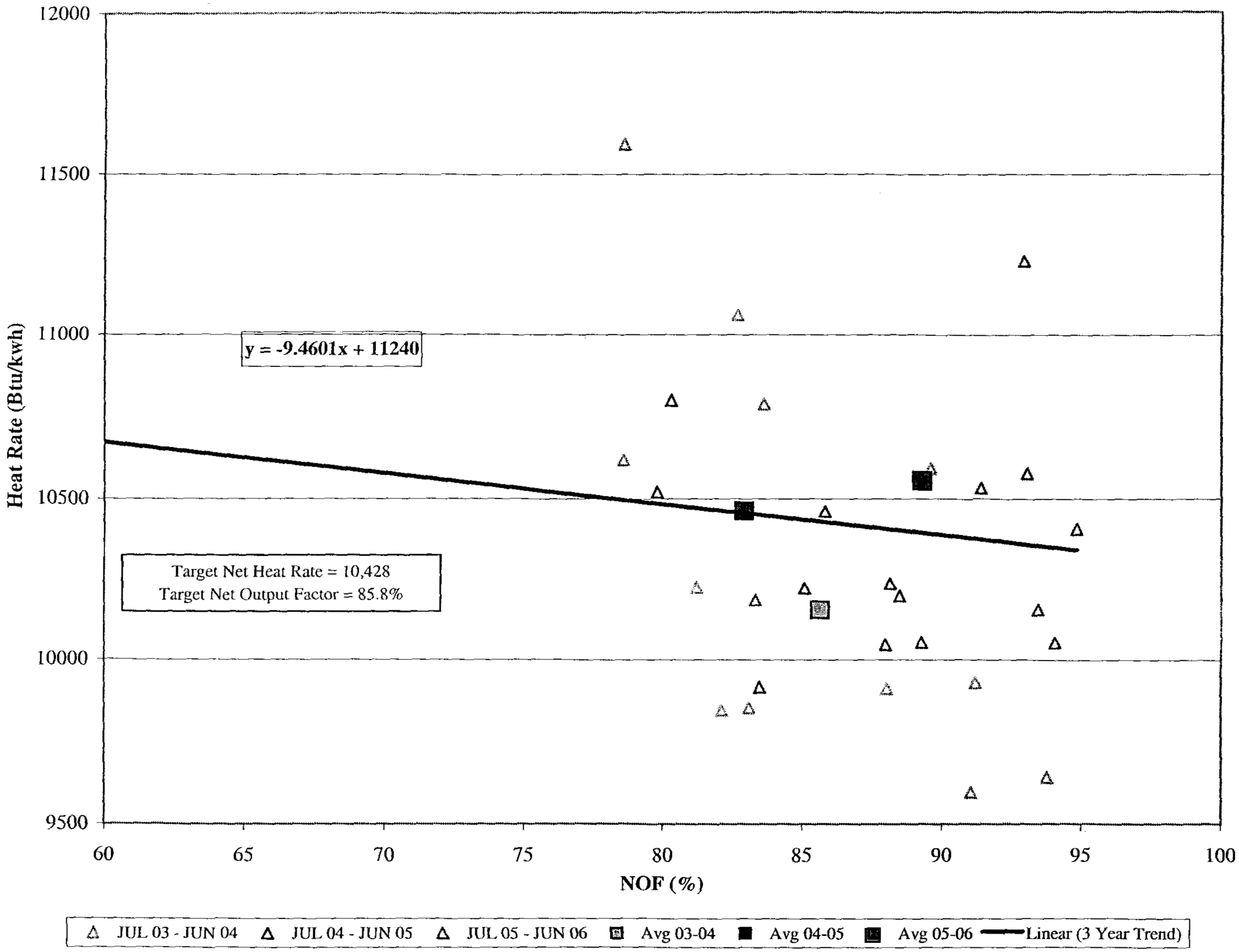

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2
y = -19.841x + 12119
Target Net Heat Rate = 10,484
Target Net Output Factor = 83.8%
Heat Rate (Btu/Kwh)
12000
11500
11000
10500
10000
9500
50
55
60
65
70
75
80
85
90
95
100
NOF (%)
JUL 03 - JUN 04
JUL 04 - JUN 05
JUL 05 - JUN 06
Avg 03-04
Avg 04-05
Avg 05-06
Linear (3 Year Trend)

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3




Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4
y = -12.706x + 11877
Target Net Heat Rate = 10,828
Target Net Output Factor = 82.6%
Heat Rate (Btu/kwh)
12000
11500
11000
10500
10000
9500
50
55
60
65
70
75
80
85
90
95
100
NOF (%)
JUL 03 - JUN 04
JUL 04 - JUN 05
JUL 05 - JUN 06
Avg 03-04
Avg 04-05
Avg 05-06
Linear (3 Year Trend)

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



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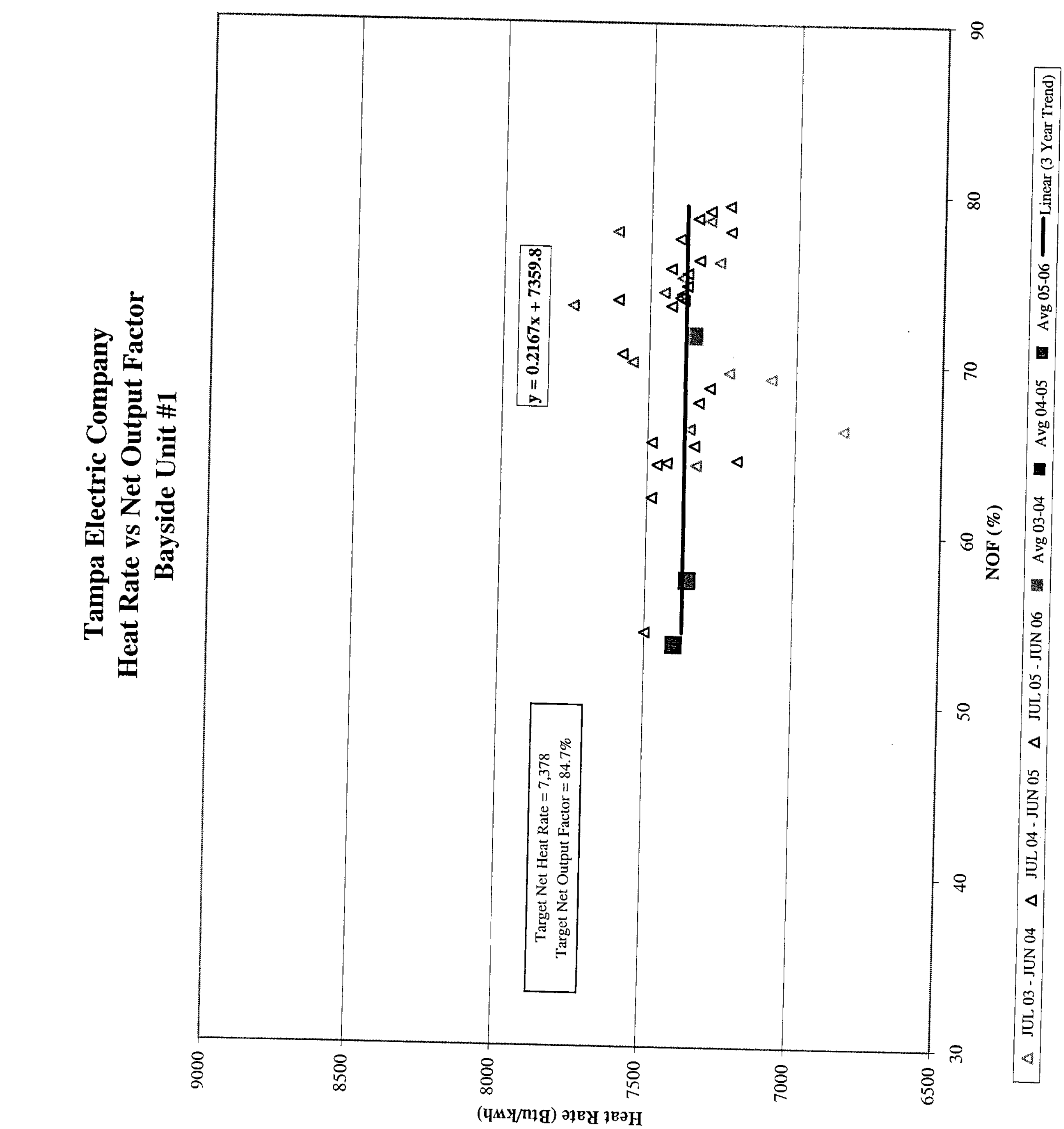
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit #1
Heat Rate (Btu/kwh)
9000
8500
8000
7500
7000
6500
30
40
50
60
70
80
90
NOF (%)
Target Net Heat Rate = 7,378
Target Net Output Factor = 84.7%
y = 0.2167x + 7359.8
JUL 03 - JUN 04
JUL 04 - JUN 05
JUL 05 - JUN 06
Avg 03-04
Avg 04-05
Avg 05-06
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2007 - DECEMBER 2007

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		411.0	411.0
BIG BEND 2		391.0	391.0
BIG BEND 3		433.0	423.5
BIG BEND 4		462.0	459.5
POLK 1		260.0	257.5
BAYSIDE 1		793.0	747.5
	GPIF TOTAL	2750.0	2690.0
	SYSTEM TOTAL	**4745.0**	**4562.5**
	% OF SYSTEM TOTAL	**57.96%**	**58.96%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2007 - DECEMBER 2007

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		411.0	411.0
BIG BEND 2		391.0	391.0
BIG BEND 3		433.0	423.5
BIG BEND 4		462.0	459.5
	BIG BEND TOTAL	1697.0	1685.0
BIG BEND CT1		15.0	14.5
BIG BEND CT2		80.0	73.0
BIG BEND CT3		80.0	73.0
	CT TOTAL	175.0	160.5
PHILLIPS 1		18.0	17.5
PHILLIPS 2		18.0	17.5
	PHILLIPS TOTAL	36.0	35.0
POLK 1		260.0	257.5
POLK 2		184.0	172.0
POLK 3		184.0	172.0
POLK 4		184.0	172.0
POLK 5		184.0	172.0
	POLK TOTAL	996.0	945.5
BAYSIDE 1		793.0	747.5
BAYSIDE 2		1048.0	989.0
	BAYSIDE TOTAL	1841.0	1736.5
	SYSTEM TOTAL	**4745.0**	**4562.5**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2007 - DECEMBER 2007

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,305,127	23.39%	23.39%
BAYSIDE	1	3,461,453	18.81%	42.20%
BIG BEND	2	2,517,748	13.68%	55.88%
BIG BEND	1	2,256,616	12.26%	68.14%
BIG BEND	4	2,107,873	11.45%	79.59%
POLK	1	1,779,998	9.67%	89.26%
BIG BEND	3	1,748,851	9.50%	98.77%
POLK	4	100,322	0.55%	99.31%
POLK	5	55,797	0.30%	99.61%
POLK	2	35,465	0.19%	99.81%
POLK	3	18,680	0.10%	99.91%
PHILLIPS	2	9,050	0.05%	99.96%
PHILLIPS	1	7,146	0.04%	100.00%
BIG BEND CT	2	347	0.00%	100.00%
BIG BEND CT	3	282	0.00%	100.00%
BIG BEND CT	1	28	0.00%	100.00%
TOTAL GENERATION		18,404,783	100.00%	

GENERATION BY COAL UNITS: 10,411,086 MWH

% GENERATION BY COAL UNITS: 56.57%

GENERATION BY NATURAL GAS UNITS: 7,976,844 MWH

% GENERATION BY NATURAL GAS UNITS: 43.34%

GENERATION BY OIL UNITS: 16,853 MWH

% GENERATION BY OIL UNITS: 0.09%

GENERATION BY GPIF UNITS: 13,872,539 MWH

% GENERATION BY GPIF UNITS: 75.37%