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April 11, 2011

HAND DELIVERED

Ms. Ann Cole, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 110001-EI

Dear Ms. Cole:

On September 1, 2010 we submitted Tampa Electric Company's Petition and projection testimonies and exhibits of Tampa Electric witnesses to establish, among other things, the appropriate generating performance incentive factor ("GPIF") targets and ranges for 2011. Targets and ranges were approved for 2011 in Commission Order No. PSC-10-0734-FOF-EI, issued December 20, 2010 in last year's fuel adjustment docket.

Tampa Electric subsequently discovered that, due to measurement errors in bunker quantities that occurred as part of the normal close-out process, coal consumption at Big Bend was understated in 2010. In addition, the MBtu's for the coal units were inadvertently overstated. Both errors have been corrected and controls have been implemented to eliminate the possibility of these errors occurring again. While the corrections to consumption have been made to the A-Schedules and are also reflected in the GPIF True-up Testimony filed in Docket 110001-EI on March 15, 2011, targets and ranges for 2011 need to be revised to reflect these adjustments.

We enclose for filing in this proceeding the original and fifteen (15) copies of revised testimony and Exhibit (BSB-2) of Tampa Electric witness Brian Buckley, which we request be substituted in place of the corresponding testimony and exhibit filed September 1, 2010. In the Petition we will file on September 1, 2011 in this docket we will ask that Tampa Electric's GPIF targets and ranges for 2011 be re-established, based on the corrected revised testimony and exhibit submitted herewith.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

COM 5
APA 1
ECR 10
GCL 1
RAD 1
SSC
ADM
OPC
CLK Ct. RPR

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: All parties of record (w/enc.)

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110001-EI

IN RE: TAMPA ELECTRIC'S

FUEL & PURCHASED POWER COST RECOVERY

AND CAPACITY COST RECOVERY PROJECTIONS

JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY AND EXHIBIT

OF

BRIAN S. BUCKLEY

REVISED: APRIL 11, 2011

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 Manager, Operations Planning.

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, instrumentation and controls, performance planning and asset management. In October 2008, I was promoted to Manager, Operations Planning, where I am currently responsible for unit commitment 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-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2011 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 1, one outage from Big Bend Unit 2, one outage from Big Bend Unit 3 and one outage from Polk Unit 1 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 2011 period. A range of potential improvements and degradations were determined for each of these metrics.

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

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

To give an example for the 2011 period, the projected EUOF for Big Bend Unit 3 is 9.9 percent, and the POF is 6.6 percent. Therefore, the target EAF for Big Bend Unit 3 equals 83.5 percent or:

$$100\% - (9.9\% + 6.6\%) = 83.5\%$$

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 EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Big Bend Unit 3 example:

$$EAF_{MAX} = 1 - [0.8 \ (9.9\%) + 0.95 \ (6.6\%)] = 85.8\%$$

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 3 example,

$$EAF_{MIN} = 1 - [1.40 \ (9.9\%) + 1.10 \ (6.6\%)] = 78.9\%$$

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 2011 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2011; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 2 is scheduled for a planned outage from February 20, 2011 to March 1, 2011 and September 3, 2011 to November 18, 2011. There are 2,089 planned outage hours scheduled for the 2011 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 2 is 23.8 percent or:

$$\frac{2{,}089}{8{,}760} \times 100\% = 23.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 5.8 percent. Big Bend Unit 2 has a POF of 23.8 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 6.0 percent. Bayside Unit 1 has a POF of 21.1 percent, and Bayside Unit 2 has a POF of 3.8 percent.

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

A. For each unit the most current 12-month ending value, June 2011, 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 a EUOF of 9.9 percent for Big Bend Unit 3. The EUOF for Big Bend Unit 3 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:

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

Or

$$EUOF = \frac{(722 + 142)}{8{,}760} \times 100\% = 9.9\%$$

Relative to Big Bend Unit 3, the EUOF of 9.9 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 EUOF for this unit is 26.3 percent. The unit will have a planned outage in 2011, and the POF is 5.8 percent. Therefore, the target equivalent availability for this unit is 67.9 percent.

Big Bend Unit 2

The projected EUOF for this unit is 13.8 percent. The unit will have a planned outage in 2011, and the POF is 23.8 percent. Therefore, the target equivalent availability for this unit is 62.4 percent.

Big Bend Unit 3

The projected EUOF for this unit is 9.9 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 83.5 percent.

Big Bend Unit 4

The projected EUOF for this unit is 15.5 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 77.9 percent.

Polk Unit 1

The projected EUOF for this unit is 5.3 percent. The unit will have a planned outage in 2011, and the POF is 6.0 percent. Therefore, the target equivalent availability for this unit is 88.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 0.7 percent. The unit will have a planned outage in 2011, and the POF is 21.1 percent. Therefore, the target equivalent availability for this unit is 78.2 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.8 percent. The unit will have a planned outage in 2011, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 94.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.5 percent is shown on Page 5 of Document No. 1. This target is greater than the 2007, 2008 and 2009 January through December actual performances.

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 3 on page 16 of Document No. 1. Except for the months of March, April, October and November, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March, April, October and November, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

A. Yes. Rates provide a proper and accurate method of determining 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 31 through 37 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 2011 period.

A. The heat rate target for Big Bend Unit 1 is 10,649 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±474 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,379 Btu/Net kWh with a range of ±354 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,602 Btu/Net kWh, with a range of ±337 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,599 Btu/Net kWh with a range of ±312 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,820 Btu/Net kWh with a range of ±703 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,212 Btu/Net kWh with a range of ±93 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,311 Btu/Net kWh with a range of ±89 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 $872,944,300 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 $28,353,900 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 3, the weighting factor for equivalent availability is 6.47 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 3, page 9, if the unit operates at 85.8 percent equivalent availability, fuel savings would equal $1,833,900, 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 $28,353,900. 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 2011 is $1,902,870,049. This produces the maximum allowed jurisdictional incentive of $7,711,175 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):

$$
\begin{aligned}
GPIP: = (\ & 0.0479\ EAP_{BB1} + 0.0623\ EAP_{BB2} \\
& + 0.0647\ EAP_{BB3} + 0.0825\ EAP_{BB4} \\
& + 0.0070\ EAP_{PK1} + 0.0140\ EAP_{BAY1} \\
& + 0.0033\ EAP_{BAY2} + 0.1309\ HRP_{BB1} \\
& + 0.0871\ HRP_{BB2} + 0.1013\ HRP_{BB3} \\
& + 0.1062\ HRP_{BB4} + 0.1631\ HRP_{PK1} \\
& + 0.0515\ HRP_{BAY1} + 0.0782\ HRP_{BAY2})
\end{aligned}
$$

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 2011 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.

DOCKET NO. 110001-EI
GPIF 2011 PROJECTION FILING
EXHIBIT NO. _____ (BSB-2)
DOCUMENT NO. 1
REVISED 4/11/11

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2011 - DECEMBER 2011

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2011 - DECEMBER 2011
TARGETS
TABLE OF CONTENTS

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2011 - DECEMBER 2011

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	28,353.9	7,711.2
+9	25,518.5	6,940.1
+8	22,683.1	6,168.9
+7	19,847.7	5,397.8
+6	17,012.3	4,626.7
+5	14,176.9	3,855.6
+4	11,341.5	3,084.5
+3	8,506.2	2,313.4
+2	5,670.8	1,542.2
+1	2,835.4	771.1
0	0.0	0.0
-1	(3,280.4)	(771.1)
-2	(6,560.8)	(1,542.2)
-3	(9,841.2)	(2,313.4)
-4	(13,121.6)	(3,084.5)
-5	(16,402.0)	(3,855.6)
-6	(19,682.4)	(4,626.7)
-7	(22,962.8)	(5,397.8)
-8	(26,243.2)	(6,168.9)
-9	(29,523.6)	(6,940.1)
-10	(32,804.0)	(7,711.2)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2011 - DECEMBER 2011

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,876,746,000
Line 2	Month of January	2011	$	1,827,320,000
Line 3	Month of February	2011	$	1,844,451,125
Line 4	Month of March	2011	$	1,861,742,854
Line 5	Month of April	2011	$	1,894,199,839
Line 6	Month of May	2011	$	1,911,957,963
Line 7	Month of June	2011	$	1,929,882,569
Line 8	Month of July	2011	$	1,879,835,503
Line 9	Month of August	2011	$	1,897,458,961
Line 10	Month of September	2011	$	1,915,247,639
Line 11	Month of October	2011	$	1,947,838,015
Line 12	Month of November	2011	$	1,966,098,997
Line 13	Month of December	2011	$	1,984,531,175
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,902,870,049
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.17%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	7,777,432
Line 18	Jurisdictional Sales			18,926,613 MWH
Line 19	Total Sales			19,089,236 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			99.15%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**7,711,175**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2011 - DECEMBER 2011

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	4.79%	67.9	73.5	56.8	1,359.3	(5,657.4)
BIG BEND 2	6.23%	62.4	66.3	54.5	1,765.3	(1,487.8)
BIG BEND 3	6.47%	83.5	85.8	78.9	1,833.9	(1,379.9)
BIG BEND 4	8.25%	77.9	81.3	71.0	2,339.2	(2,354.1)
POLK 1	0.70%	88.6	90.0	85.9	198.3	(455.9)
BAYSIDE 1	1.40%	78.2	79.4	75.9	397.4	(821.4)
BAYSIDE 2	0.33%	94.4	95.0	93.3	93.8	(280.8)
GPIF SYSTEM	28.17%					

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	13.09%	10,649	91.3	10,176	11,123	3,710.3	(3,710.3)
BIG BEND 2	8.71%	10,379	91.2	10,025	10,733	2,469.7	(2,469.7)
BIG BEND 3	10.13%	10,602	86.9	10,265	10,939	2,871.4	(2,871.4)
BIG BEND 4	10.62%	10,599	90.8	10,286	10,911	3,012.5	(3,012.5)
POLK 1	16.31%	9,820	97.5	9,117	10,522	4,624.5	(4,624.5)
BAYSIDE 1	5.15%	7,212	86.6	7,120	7,305	1,459.8	(1,459.8)
BAYSIDE 2	7.82%	7,311	84.7	7,222	7,400	2,218.6	(2,218.6)
GPIF SYSTEM	71.83%						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 11 - DEC 11			ACTUAL PERFORMANCE JAN 09 - DEC 09			ACTUAL PERFORMANCE JAN 08 - DEC 08			ACTUAL PERFORMANCE JAN 07 - DEC 07		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 1	4.79%	17.0%	5.8	26.3	27.9	14.0	30.3	35.3	4.9	19.4	20.4	0.0	23.7	23.7
BIG BEND 2	6.23%	22.1%	23.8	13.8	18.1	26.5	36.7	49.9	10.2	18.8	20.8	2.5	18.0	18.4
BIG BEND 3	6.47%	23.0%	6.6	9.9	10.6	5.0	16.2	17.0	32.4	23.1	34.2	11.8	41.7	47.3
BIG BEND 4	8.25%	29.3%	6.6	15.5	16.6	1.9	18.6	19.0	5.8	21.4	22.7	27.0	19.8	27.0
POLK 1	0.70%	2.5%	6.0	5.3	5.7	14.1	9.4	12.7	3.0	13.8	16.9	4.1	0.0	0.0
BAYSIDE 1	1.40%	5.0%	21.1	0.7	0.9	5.6	1.3	1.4	2.4	2.8	3.1	11.5	3.3	3.9
BAYSIDE 2	0.33%	1.2%	3.8	1.8	1.8	6.8	1.3	1.4	14.5	1.9	2.4	2.0	1.7	1.7
GPIF SYSTEM	**28.17%**	**100.0%**	**10.9**	**14.5**	**16.3**	**10.7**	**22.7**	**26.9**	**12.6**	**19.5**	**23.2**	**11.9**	**23.6**	**27.1**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**74.5**			**66.6**			**67.9**			**64.6**	

3 PERIOD AVERAGE			3 PERIOD AVERAGE
POF	EUOF	EUOR	EAF
11.7	**21.9**	**25.7**	**66.3**

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AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 11 - DEC 11	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 09 - DEC 09	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 08 - DEC 08	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 07 - DEC 07
BIG BEND 1	13.09%	18.2%	10,649	10,471	10,841	10,697
BIG BEND 2	8.71%	12.1%	10,379	10,197	10,588	10,361
BIG BEND 3	10.13%	14.1%	10,602	10,539	10,714	10,530
BIG BEND 4	10.62%	14.8%	10,599	10,507	10,682	10,893
POLK 1	16.31%	22.7%	9,820	9,795	9,527	9,744
BAYSIDE 1	5.15%	7.2%	7,212	7,219	7,190	7,245
BAYSIDE 2	7.82%	10.9%	7,311	7,292	7,305	7,300
GPIF SYSTEM	**71.83%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,804**	**9,720**	**9,824**	**9,828**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2011 - DECEMBER 2011
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	872,944.3	871,585.0	1,359.3	4.79%
EA_2 BIG BEND 2	872,944.3	871,179.0	1,765.3	6.23%
EA_3 BIG BEND 3	872,944.3	871,110.4	1,833.9	6.47%
EA_4 BIG BEND 4	872,944.3	870,605.1	2,339.2	8.25%
EA_7 POLK 1	872,944.3	872,746.0	198.3	0.70%
EA_8 BAYSIDE 1	872,944.3	872,546.9	397.4	1.40%
EA_9 BAYSIDE 2	872,944.3	872,850.5	93.8	0.33%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	872,944.3	869,233.9	3,710.3	13.09%
AHR_2 BIG BEND 2	872,944.3	870,474.6	2,469.7	8.71%
AHR_3 BIG BEND 3	872,944.3	870,072.9	2,871.4	10.13%
AHR_4 BIG BEND 4	872,944.3	869,931.8	3,012.5	10.62%
AHR_7 POLK 1	872,944.3	868,319.7	4,624.5	16.31%
AHR_8 BAYSIDE 1	872,944.3	871,484.5	1,459.8	5.15%
AHR_9 BAYSIDE 2	872,944.3	870,725.7	2,218.6	7.82%
TOTAL SAVINGS			**28,353.9**	**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 2011 - DECEMBER 2011

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	1,359.3	73.5	+10	3,710.3	10,176
+9	1,223.4	72.9	+9	3,339.3	10,216
+8	1,087.4	72.4	+8	2,968.3	10,255
+7	951.5	71.8	+7	2,597.2	10,295
+6	815.6	71.3	+6	2,226.2	10,335
+5	679.6	70.7	+5	1,855.2	10,375
+4	543.7	70.2	+4	1,484.1	10,415
+3	407.8	69.6	+3	1,113.1	10,455
+2	271.9	69.0	+2	742.1	10,495
+1	135.9	68.5	+1	371.0	10,534
					10,574
0	0.0	67.9	0	0.0	10,649
					10,724
-1	(565.7)	66.8	-1	(371.0)	10,764
-2	(1,131.5)	65.7	-2	(742.1)	10,804
-3	(1,697.2)	64.6	-3	(1,113.1)	10,844
-4	(2,262.9)	63.5	-4	(1,484.1)	10,884
-5	(2,828.7)	62.4	-5	(1,855.2)	10,924
-6	(3,394.4)	61.3	-6	(2,226.2)	10,963
-7	(3,960.2)	60.2	-7	(2,597.2)	11,003
-8	(4,525.9)	59.1	-8	(2,968.3)	11,043
-9	(5,091.6)	57.9	-9	(3,339.3)	11,083
-10	(5,657.4)	56.8	-10	(3,710.3)	11,123
	Weighting Factor =	4.79%		Weighting Factor =	13.09%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	1,765.3	66.3	+10	2,469.7	10,025
+9	1,588.8	65.9	+9	2,222.7	10,053
+8	1,412.2	65.5	+8	1,975.7	10,081
+7	1,235.7	65.1	+7	1,728.8	10,109
+6	1,059.2	64.7	+6	1,481.8	10,137
+5	882.7	64.4	+5	1,234.8	10,165
+4	706.1	64.0	+4	987.9	10,193
+3	529.6	63.6	+3	740.9	10,221
+2	353.1	63.2	+2	493.9	10,249
+1	176.5	62.8	+1	247.0	10,276
					10,304
0	0.0	62.4	0	0.0	10,379
					10,454
-1	(148.8)	61.6	-1	(247.0)	10,482
-2	(297.6)	60.8	-2	(493.9)	10,510
-3	(446.3)	60.0	-3	(740.9)	10,538
-4	(595.1)	59.2	-4	(987.9)	10,566
-5	(743.9)	58.4	-5	(1,234.8)	10,594
-6	(892.7)	57.6	-6	(1,481.8)	10,622
-7	(1,041.5)	56.8	-7	(1,728.8)	10,650
-8	(1,190.2)	56.1	-8	(1,975.7)	10,678
-9	(1,339.0)	55.3	-9	(2,222.7)	10,706
-10	(1,487.8)	54.5	-10	(2,469.7)	10,733
	Weighting Factor =	6.23%		Weighting Factor =	8.71%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	1,833.9	85.8	+10	2,871.4	10,265
+9	1,650.5	85.6	+9	2,584.2	10,291
+8	1,467.1	85.4	+8	2,297.1	10,318
+7	1,283.7	85.2	+7	2,009.9	10,344
+6	1,100.3	84.9	+6	1,722.8	10,370
+5	916.9	84.7	+5	1,435.7	10,396
+4	733.6	84.5	+4	1,148.5	10,422
+3	550.2	84.2	+3	861.4	10,448
+2	366.8	84.0	+2	574.3	10,475
+1	183.4	83.8	+1	287.1	10,501
					10,527
0	0.0	83.5	0	0.0	10,602
					10,677
-1	(138.0)	83.1	-1	(287.1)	10,703
-2	(276.0)	82.6	-2	(574.3)	10,729
-3	(414.0)	82.2	-3	(861.4)	10,756
-4	(551.9)	81.7	-4	(1,148.5)	10,782
-5	(689.9)	81.2	-5	(1,435.7)	10,808
-6	(827.9)	80.8	-6	(1,722.8)	10,834
-7	(965.9)	80.3	-7	(2,009.9)	10,860
-8	(1,103.9)	79.9	-8	(2,297.1)	10,886
-9	(1,241.9)	79.4	-9	(2,584.2)	10,913
-10	(1,379.9)	78.9	-10	(2,871.4)	10,939
	Weighting Factor =	6.47%		Weighting Factor =	10.13%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	2,339.2	81.3	+10	3,012.5	10,286
+9	2,105.3	81.0	+9	2,711.3	10,310
+8	1,871.4	80.6	+8	2,410.0	10,334
+7	1,637.4	80.3	+7	2,108.8	10,357
+6	1,403.5	79.9	+6	1,807.5	10,381
+5	1,169.6	79.6	+5	1,506.3	10,405
+4	935.7	79.3	+4	1,205.0	10,429
+3	701.8	78.9	+3	903.8	10,452
+2	467.8	78.6	+2	602.5	10,476
+1	233.9	78.2	+1	301.3	10,500
					10,524
0	0.0	77.9	0	0.0	10,599
					10,674
-1	(235.4)	77.2	-1	(301.3)	10,697
-2	(470.8)	76.5	-2	(602.5)	10,721
-3	(706.2)	75.8	-3	(903.8)	10,745
-4	(941.6)	75.1	-4	(1,205.0)	10,769
-5	(1,177.0)	74.4	-5	(1,506.3)	10,792
-6	(1,412.4)	73.8	-6	(1,807.5)	10,816
-7	(1,647.8)	73.1	-7	(2,108.8)	10,840
-8	(1,883.2)	72.4	-8	(2,410.0)	10,864
-9	(2,118.7)	71.7	-9	(2,711.3)	10,887
-10	(2,354.1)	71.0	-10	(3,012.5)	10,911
	Weighting Factor =	8.25%		Weighting Factor =	10.62%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	198.3	90.0	+10	4,624.5	9,117
+9	178.4	89.9	+9	4,162.1	9,179
+8	158.6	89.7	+8	3,699.6	9,242
+7	138.8	89.6	+7	3,237.2	9,305
+6	119.0	89.5	+6	2,774.7	9,368
+5	99.1	89.3	+5	2,312.3	9,431
+4	79.3	89.2	+4	1,849.8	9,493
+3	59.5	89.1	+3	1,387.4	9,556
+2	39.7	88.9	+2	924.9	9,619
+1	19.8	88.8	+1	462.5	9,682
					9,745
0	0.0	88.6	0	0.0	9,820
					9,895
-1	(45.6)	88.4	-1	(462.5)	9,957
-2	(91.2)	88.1	-2	(924.9)	10,020
-3	(136.8)	87.8	-3	(1,387.4)	10,083
-4	(182.4)	87.6	-4	(1,849.8)	10,146
-5	(227.9)	87.3	-5	(2,312.3)	10,208
-6	(273.5)	87.0	-6	(2,774.7)	10,271
-7	(319.1)	86.7	-7	(3,237.2)	10,334
-8	(364.7)	86.5	-8	(3,699.6)	10,397
-9	(410.3)	86.2	-9	(4,162.1)	10,460
-10	(455.9)	85.9	-10	(4,624.5)	10,522
	Weighting Factor =	0.70%		Weighting Factor =	16.31%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	397.4	79.4	+10	1,459.8	7,120
+9	357.6	79.3	+9	1,313.8	7,121
+8	317.9	79.2	+8	1,167.8	7,123
+7	278.2	79.1	+7	1,021.8	7,125
+6	238.4	78.9	+6	875.9	7,127
+5	198.7	78.8	+5	729.9	7,128
+4	159.0	78.7	+4	583.9	7,130
+3	119.2	78.6	+3	437.9	7,132
+2	79.5	78.5	+2	292.0	7,134
+1	39.7	78.4	+1	146.0	7,136
					7,137
0	0.0	78.2	0	0.0	7,212
					7,287
-1	(82.1)	78.0	-1	(146.0)	7,289
-2	(164.3)	77.8	-2	(292.0)	7,291
-3	(246.4)	77.5	-3	(437.9)	7,293
-4	(328.6)	77.3	-4	(583.9)	7,295
-5	(410.7)	77.0	-5	(729.9)	7,296
-6	(492.9)	76.8	-6	(875.9)	7,298
-7	(575.0)	76.6	-7	(1,021.8)	7,300
-8	(657.1)	76.3	-8	(1,167.8)	7,302
-9	(739.3)	76.1	-9	(1,313.8)	7,304
-10	(821.4)	75.9	-10	(1,459.8)	7,305
	Weighting Factor =	1.40%		Weighting Factor =	5.15%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2011 - DECEMBER 2011

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	93.8	95.0	+10	2,218.6	7,222
+9	84.4	94.9	+9	1,996.7	7,223
+8	75.1	94.8	+8	1,774.8	7,224
+7	65.7	94.8	+7	1,553.0	7,226
+6	56.3	94.7	+6	1,331.1	7,227
+5	46.9	94.7	+5	1,109.3	7,229
+4	37.5	94.6	+4	887.4	7,230
+3	28.1	94.6	+3	665.6	7,231
+2	18.8	94.5	+2	443.7	7,233
+1	9.4	94.5	+1	221.9	7,234
					7,236
0	0.0	94.4	0	0.0	7,311
					7,386
-1	(28.1)	94.3	-1	(221.9)	7,387
-2	(56.2)	94.2	-2	(443.7)	7,388
-3	(84.2)	94.1	-3	(665.6)	7,390
-4	(112.3)	94.0	-4	(887.4)	7,391
-5	(140.4)	93.9	-5	(1,109.3)	7,393
-6	(168.5)	93.8	-6	(1,331.1)	7,394
-7	(196.6)	93.7	-7	(1,553.0)	7,395
-8	(224.7)	93.5	-8	(1,774.8)	7,397
-9	(252.7)	93.4	-9	(1,996.7)	7,398
-10	(280.8)	93.3	-10	(2,218.6)	7,400
	Weighting Factor =	0.33%		Weighting Factor =	7.82%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	72.1	46.3	62.8	72.1	72.1	72.1	72.1	72.1	72.1	55.8	72.1	72.1	67.9
2. POF	0.0	35.7	12.9	0.0	0.0	0.0	0.0	0.0	0.0	22.6	0.0	0.0	5.8
3. EUOF	27.9	17.9	24.3	27.9	27.9	27.9	27.9	27.9	27.9	21.6	27.9	27.9	26.3
4. EUOR	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	673	391	586	651	673	651	673	673	651	521	651	673	7,467
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	71	281	157	69	71	69	71	71	69	223	70	71	1,293
9. POH	0	240	96	0	0	0	0	0	0	168	0	0	504
10. EFOH	135	78	117	130	135	130	135	135	130	104	131	135	1,495
11. EMOH	73	42	63	71	73	71	73	73	71	56	71	73	809
12. OPER BTU (GBTU)	2,537	1,473	2,199	2,450	2,551	2,457	2,562	2,556	2,477	1,944	2,459	2,520	28,188
13. NET GEN (MWH)	237,580	137,900	205,850	230,270	239,990	230,950	241,190	240,530	233,130	182,460	231,260	235,830	2,646,940
14. ANOHR (Btu/kwh)	10,678	10,679	10,684	10,641	10,629	10,637	10,623	10,626	10,624	10,654	10,635	10,688	10,649
15. NOF (%)	89.4	89.3	88.9	91.9	92.6	92.1	93.1	92.8	93.0	91.0	92.3	88.7	91.3
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388

17. ANOHR EQUATION ANOHR = NOF(-14.869) + 12,007

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	81.9	55.6	79.3	81.9	81.9	81.9	81.9	81.9	5.5	0.0	32.7	81.9	62.4
2. POF	0.0	32.1	3.2	0.0	0.0	0.0	0.0	0.0	93.3	100.0	60.1	0.0	23.8
3. EUOF	18.1	12.3	17.5	18.1	18.1	18.1	18.1	18.1	1.2	0.0	7.2	18.1	13.8
4. EUOR	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	0.0	18.1	18.1	18.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	664	407	643	643	664	643	664	664	43	0	257	664	5,956
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	80	265	100	77	80	77	80	80	677	744	464	80	2,804
9. POH	0	216	24	0	0	0	0	0	672	744	433	0	2,089
10. EFOH	117	72	113	114	117	114	117	117	8	0	45	117	1,052
11. EMOH	17	11	17	17	17	17	17	17	1	0	7	17	155
12. OPER BTU (GBTU)	2,473	1,473	2,386	2,358	2,447	2,364	2,431	2,452	131	0	903	2,465	21,881
13. NET GEN (MWH)	238,220	141,490	229,700	227,330	236,030	228,020	234,300	236,620	12,380	0	86,740	237,290	2,108,120
14. ANOHR (Btu/kwh)	10,383	10,412	10,387	10,372	10,367	10,369	10,374	10,365	10,551	0	10,416	10,387	10,379
15. NOF (%)	90.8	88.0	90.4	91.8	92.3	92.1	91.7	92.6	74.8	0.0	87.7	90.5	91.2
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388

17. ANOHR EQUATION ANOHR = NOF(-10.487) + 11,335

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	89.4	89.4	72.1	77.5	89.4	89.4	89.4	89.4	89.4	80.8	56.6	89.4	83.5
2. POF	0.0	0.0	19.4	13.3	0.0	0.0	0.0	0.0	0.0	9.7	36.8	0.0	6.6
3. EUOF	10.6	10.6	8.5	9.2	10.6	10.6	10.6	10.6	10.6	9.5	6.7	10.6	9.9
4. EUOR	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	672	607	542	564	672	651	672	672	651	607	412	672	7,394
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	72	65	201	156	72	69	72	72	69	137	309	72	1,366
9. POH	0	0	144	96	0	0	0	0	0	72	265	0	577
10. EFOH	66	59	53	55	66	64	66	66	64	59	40	66	722
11. EMOH	13	12	10	11	13	12	13	13	12	12	8	13	142
12. OPER BTU (GBTU)	2,202	2,037	1,824	1,785	2,224	2,248	2,309	2,313	2,310	2,126	1,296	2,179	24,858
13. NET GEN (MWH)	207,060	192,120	172,030	167,190	209,420	212,790	218,420	218,830	219,350	201,540	121,290	204,640	2,344,680
14. ANOHR (Btu/kwh)	10,634	10,604	10,601	10,677	10,622	10,567	10,573	10,571	10,530	10,548	10,684	10,647	10,602
15. NOF (%)	84.4	86.7	87.0	81.2	85.4	89.6	89.0	89.2	92.3	91.0	80.7	83.4	86.9
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365
17. ANOHR EQUATION	ANOHR = NOF(	-13.185	) +		11,747								

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	83.4	83.4	56.4	83.4	83.4	83.4	83.4	83.4	83.4	83.4	75.0	53.8	77.9
2. POF	0.0	0.0	32.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	35.5	6.6
3. EUOF	16.6	16.6	11.3	16.6	16.6	16.6	16.6	16.6	16.6	16.6	15.0	10.7	15.5
4. EUOR	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	681	615	462	659	681	659	681	681	659	681	593	440	7,492
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	63	57	281	61	63	61	63	63	61	63	128	304	1,268
9. POH	0	0	240	0	0	0	0	0	0	0	72	264	576
10. EFOH	112	101	76	109	112	109	112	112	109	112	98	72	1,234
11. EMOH	12	11	8	11	12	11	12	12	11	12	10	8	128
12. OPER BTU (GBTU)	2,705	2,511	1,868	2,602	2,739	2,698	2,792	2,786	2,720	2,809	2,379	1,678	30,305
13. NET GEN (MWH)	252,150	236,300	175,270	244,110	258,630	256,510	265,550	264,810	259,440	267,790	224,390	154,370	2,859,320
14. ANOHR (Btu/kwh)	10,728	10,625	10,661	10,661	10,590	10,518	10,513	10,521	10,484	10,488	10,600	10,872	10,599
15. NOF (%)	86.7	90.0	88.8	88.8	91.1	93.3	93.5	93.3	94.4	94.3	90.7	82.2	90.8
16. NPC (MW)	427	427	427	417	417	417	417	417	417	417	417	427	420
17. ANOHR EQUATION	ANOHR = NOF(	-31.682	) +		13,475								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	94.3	37.1	94.3	94.3	94.3	94.3	94.3	94.3	94.3	79.1	94.3	94.3	88.6
2. POF	0.0	60.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.0	0.0	6.0
3. EUOF	5.7	2.2	5.7	5.7	5.7	5.7	5.7	5.7	5.7	4.8	5.7	5.7	5.3
4. EUOR	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	640	248	619	619	640	619	640	640	619	537	619	640	7,080
7. RSH	0	0	0	0	0	0	0	0	0	0	92	0	92
8. UH	104	424	124	101	104	101	104	104	101	207	10	104	1,588
9. POH	0	408	0	0	0	0	0	0	0	120	0	0	528
10. EFOH	40	14	40	39	40	39	40	40	39	34	39	40	446
11. EMOH	2	1	2	2	2	2	2	2	2	2	2	2	20
12. OPER BTU (GBTU)	1,345	522	1,304	1,301	1,347	1,305	1,349	1,349	1,306	1,132	1,303	1,343	14,908
13. NET GEN (MWH)	135,350	52,760	133,390	130,970	137,100	134,020	138,510	138,500	134,980	116,500	132,380	133,750	1,518,210
14. ANOHR (Btu/kwh)	9,940	9,888	9,777	9,936	9,828	9,735	9,739	9,739	9,672	9,717	9,843	10,041	9,820
15. NOF (%)	96.1	96.7	98.0	96.2	97.4	98.4	98.4	98.4	99.1	98.6	97.2	95.0	97.5
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220

17. ANOHR EQUATION ANOHR = NOF(-89.476) + 18,541

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	99.1	99.1	99.1	0.0	0.0	69.4	99.1	99.1	99.1	99.1	76.0	99.1	78.2
2. POF	0.0	0.0	0.0	100.0	100.0	30.0	0.0	0.0	0.0	0.0	23.3	0.0	21.1
3. EUOF	0.9	0.9	0.9	0.0	0.0	0.6	0.9	0.9	0.9	0.9	0.7	0.9	0.7
4. EUOR	0.9	0.9	0.9	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	548	567	581	0	0	225	363	387	441	414	171	594	4,292
7. RSH	190	99	155	0	0	275	375	350	273	324	377	144	2,561
8. UH	6	6	6	720	744	220	6	6	6	6	173	6	1,907
9. POH	0	0	0	720	744	216	0	0	0	0	168	0	1,848
10. EFOH	1	1	1	0	0	1	1	1	1	1	1	1	12
11. EMOH	5	5	5	0	0	3	5	5	5	5	4	5	47
12. OPER BTU (GBTU)	2,259	2,637	2,665	0	0	1,074	1,734	1,843	2,063	1,900	796	2,644	19,599
13. NET GEN (MWH)	310,110	364,290	367,900	0	0	149,810	241,800	256,860	287,280	264,240	110,740	364,350	2,717,380
14. ANOHR (Btu/kwh)	7,285	7,239	7,245	0	0	7,172	7,172	7,174	7,182	7,191	7,185	7,257	7,212
15. NOF (%)	71.5	81.1	79.9	0.0	0.0	95.0	95.0	94.6	92.9	91.1	92.2	77.4	86.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731

17. ANOHR EQUATION ANOHR = NOF(-4.817) + 7,630

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2011 - DECEMBER 2011

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-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011
1. EAF (%)	98.2	98.2	76.0	98.2	98.2	98.2	98.2	98.2	98.2	98.2	98.2	76.0	94.4
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	3.8
3. EUOF	1.8	1.8	1.4	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.4	1.8
4. EUOR	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	96	195	128	473	563	612	634	668	693	709	568	72	5,410
7. RSH	635	465	437	234	168	95	96	63	14	21	140	494	2,861
8. UH	14	12	178	13	14	13	14	14	13	14	13	178	489
9. POH	0	0	168	0	0	0	0	0	0	0	0	168	336
10. EFOH	2	2	2	2	2	2	2	2	2	2	2	2	25
11. EMOH	11	10	9	11	11	11	11	11	11	11	11	9	128
12. OPER BTU (GBTU)	590	1,299	852	2,692	3,376	3,674	3,806	3,998	4,165	4,193	3,294	430	32,449
13. NET GEN (MWH)	80,310	178,020	116,790	367,870	463,510	504,460	522,570	548,840	571,930	575,000	450,890	58,440	4,438,630
14. ANOHR (Btu/kwh)	7,343	7,294	7,291	7,318	7,283	7,283	7,283	7,284	7,282	7,293	7,306	7,360	7,311
15. NOF (%)	80.1	87.1	87.5	83.7	88.7	88.7	88.7	88.5	88.9	87.3	85.4	77.8	84.7
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968

17. ANOHR EQUATION   ANOHR = NOF(-7.036) + 7,907

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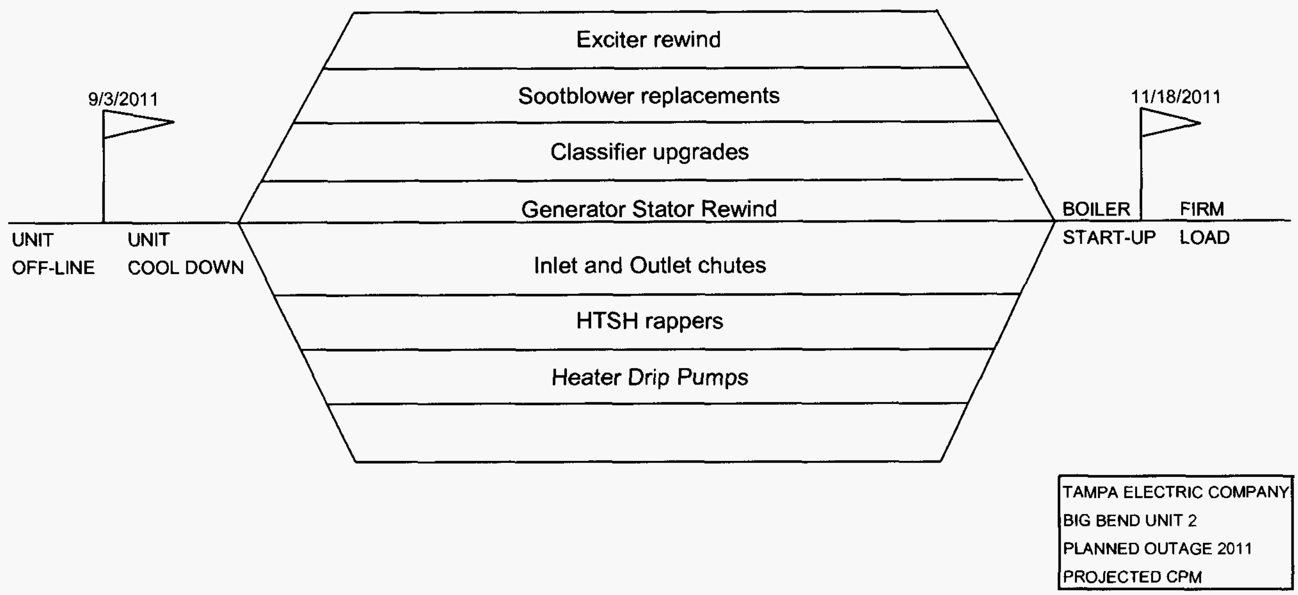
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2011 - DECEMBER 2011

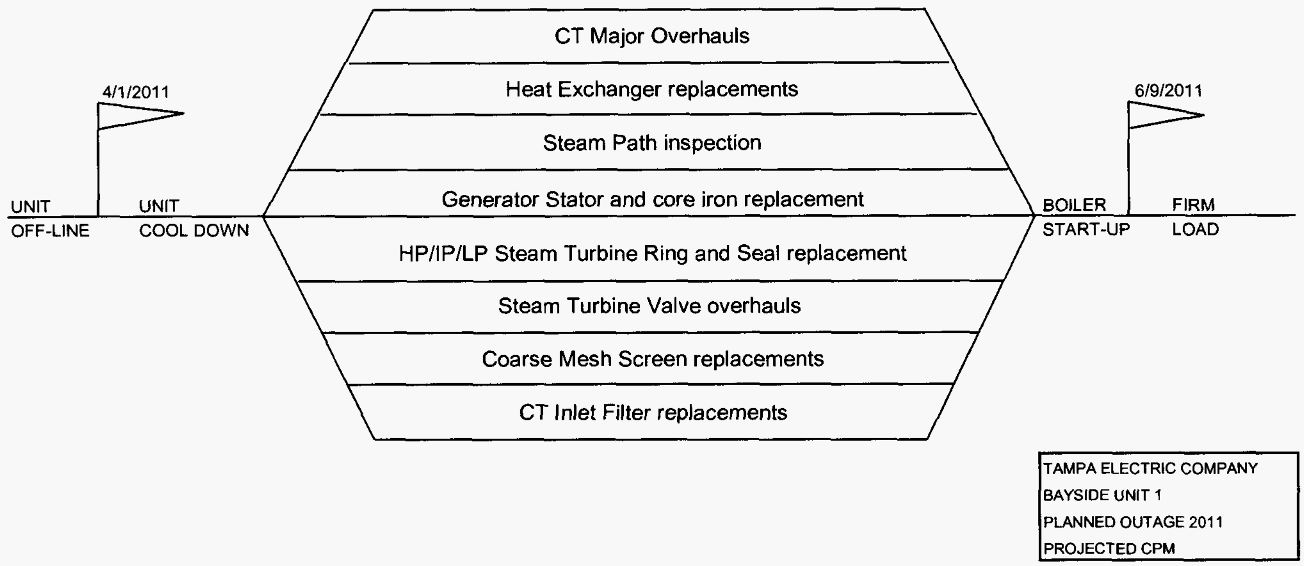
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Feb 19	-	Mar 04	Fuel System Cleanup and Scrubber work
		Oct 15	-	Oct 21	Fuel System Cleanup
+	BIG BEND 2	Feb 20	-	Mar 01	Fuel System Cleanup and Scrubber work
		Sep 03	-	Nov 18	Major outage - Generator Stator Rewind, Classifier upgrades, Inlet and Outlet chutes, Sootblower replacements, Excitier rewind and Heater Drip Pumps
	BIG BEND 3	Mar 26	-	Apr 04	Fuel System Cleanup
		Oct 29	-	Nov 11	Fuel System Cleanup and Scrubber work
	BIG BEND 4	Mar 12	-	Mar 21	Fuel System Cleanup
		Nov 28	-	Dec 11	Fuel System Cleanup and Scrubber work
	POLK 1	Feb 13	-	Feb 26	Gasifier / CT Outage
		Oct 16	-	Oct 20	Gasifier Outage
+	BAYSIDE 1	Apr 01	-	Jun 09	Generator Stator and core iron replacement, Steam Path inspection, HP/IP/LP Steam Turbine Ring and Seal replacements, Steam Turbine Valve overhauls, Heat Exchanger replacements, Coarse Mesh Screen replacements, CT Major Overhauls and CT Inlet Filter replacements
		Nov 14	-	Nov 20	Fuel System Cleanup
	BAYSIDE 2	Mar 05	-	Mar 11	Fuel System Cleanup
		Dec 03	-	Dec 09	Fuel System Cleanup

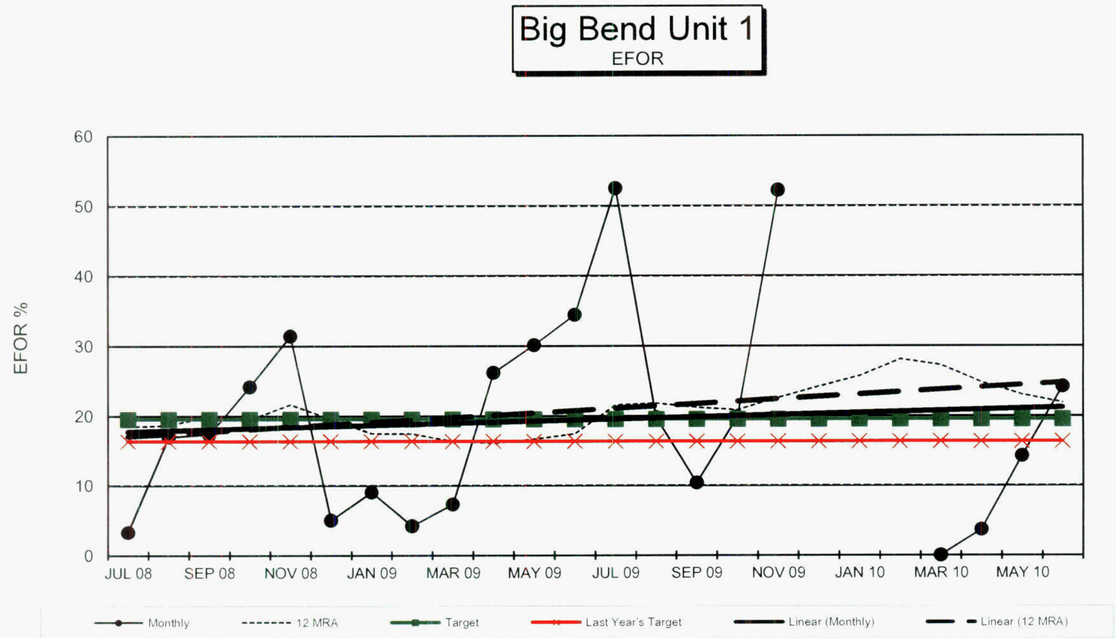
\+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

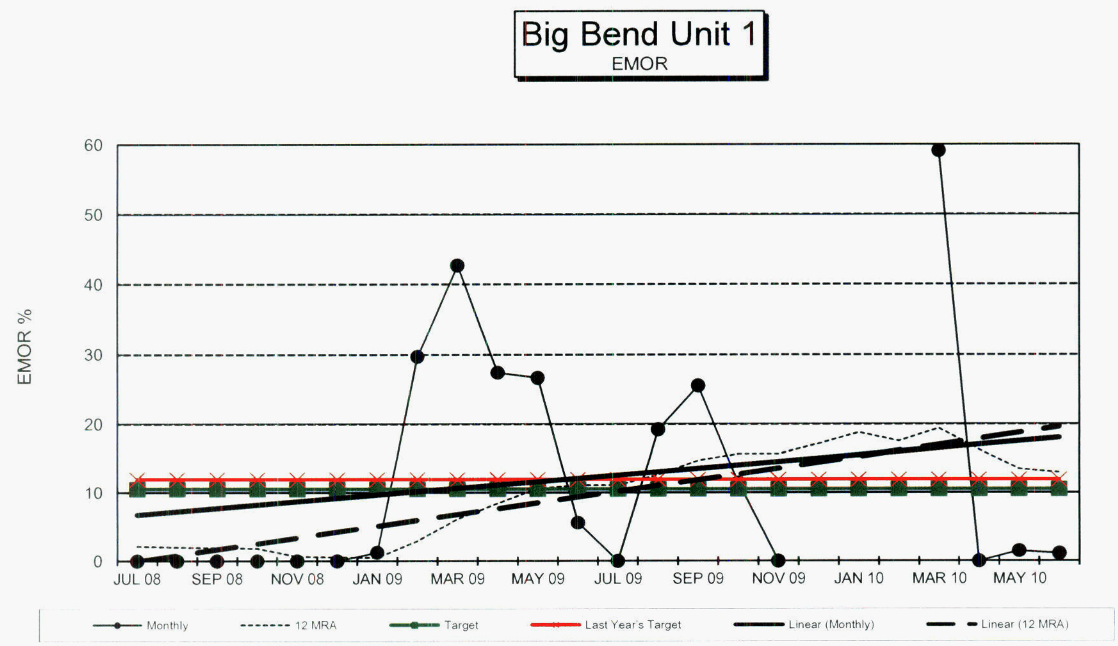
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2011 - DECEMBER 2011



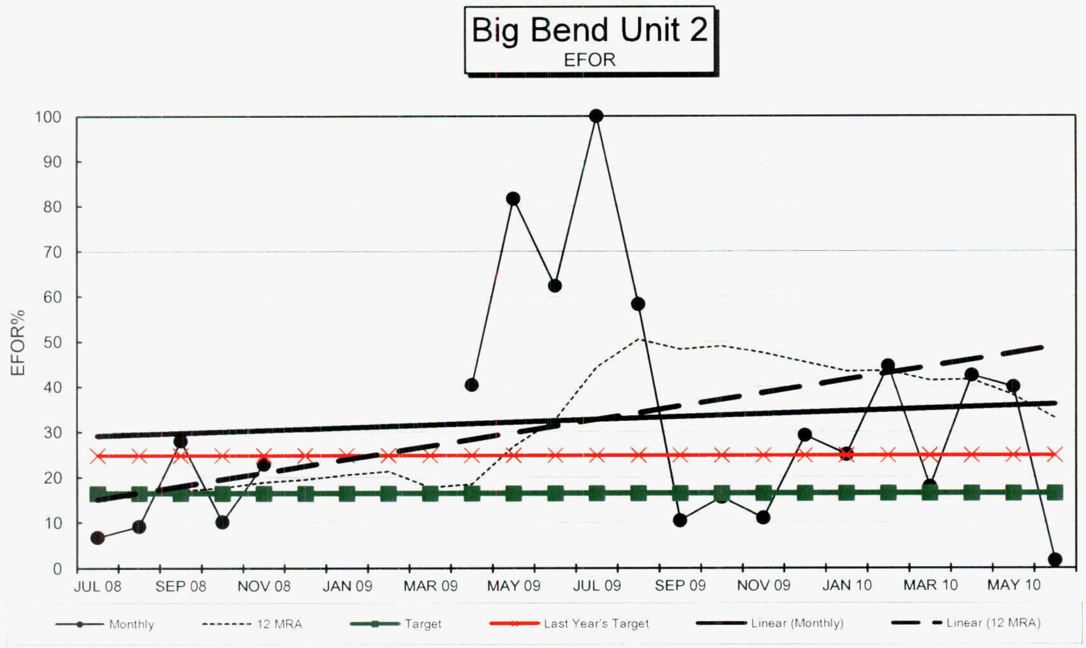
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2011 - DECEMBER 2011

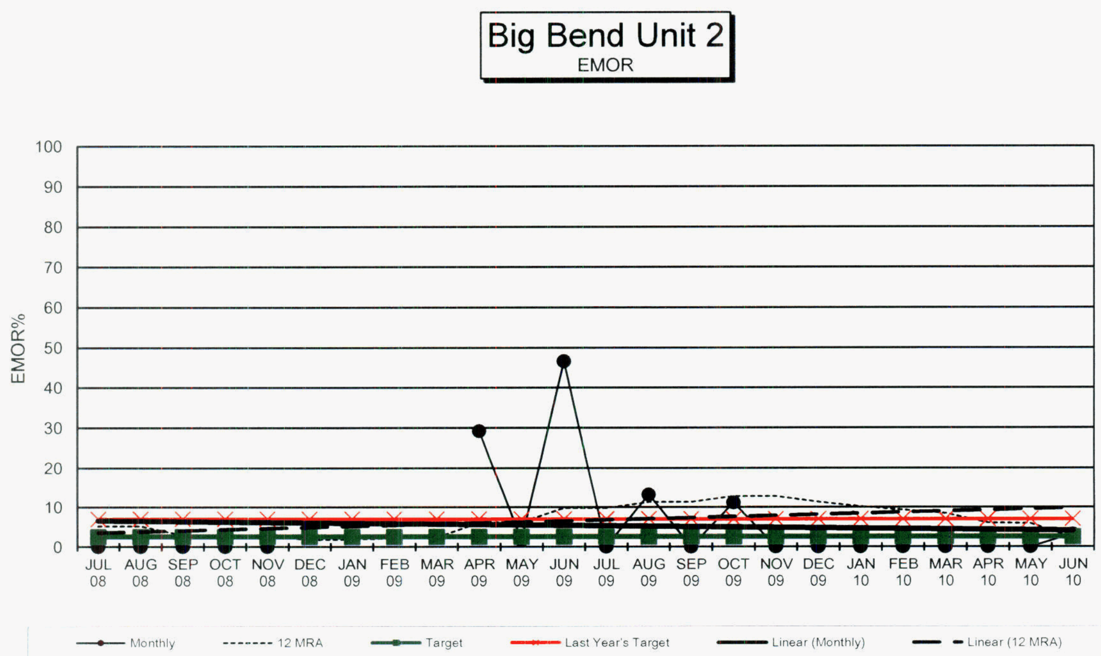




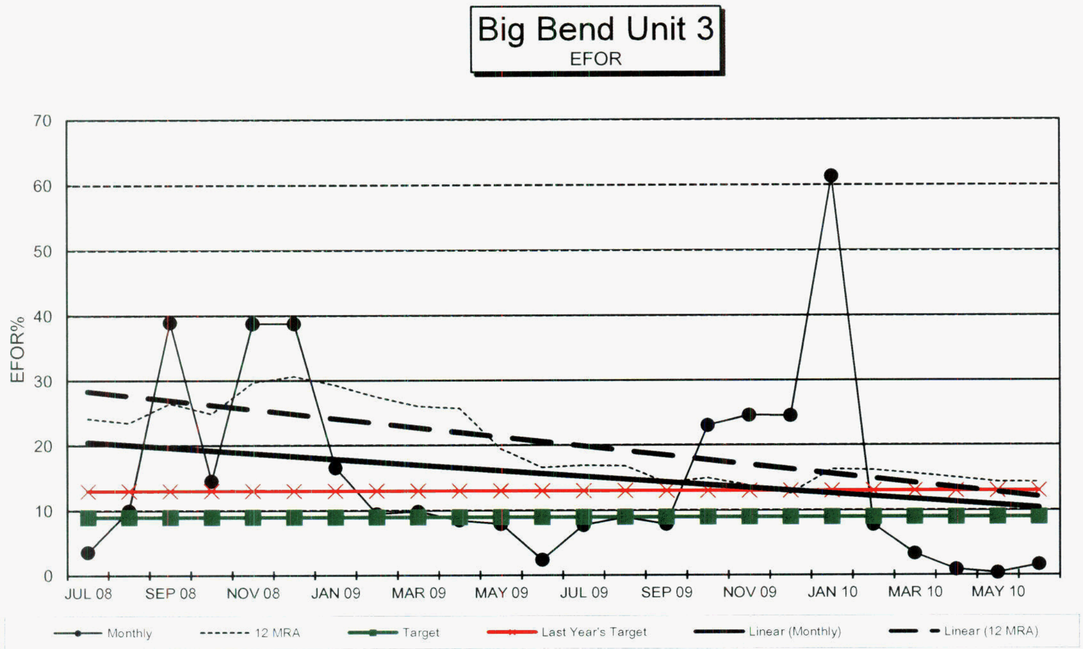


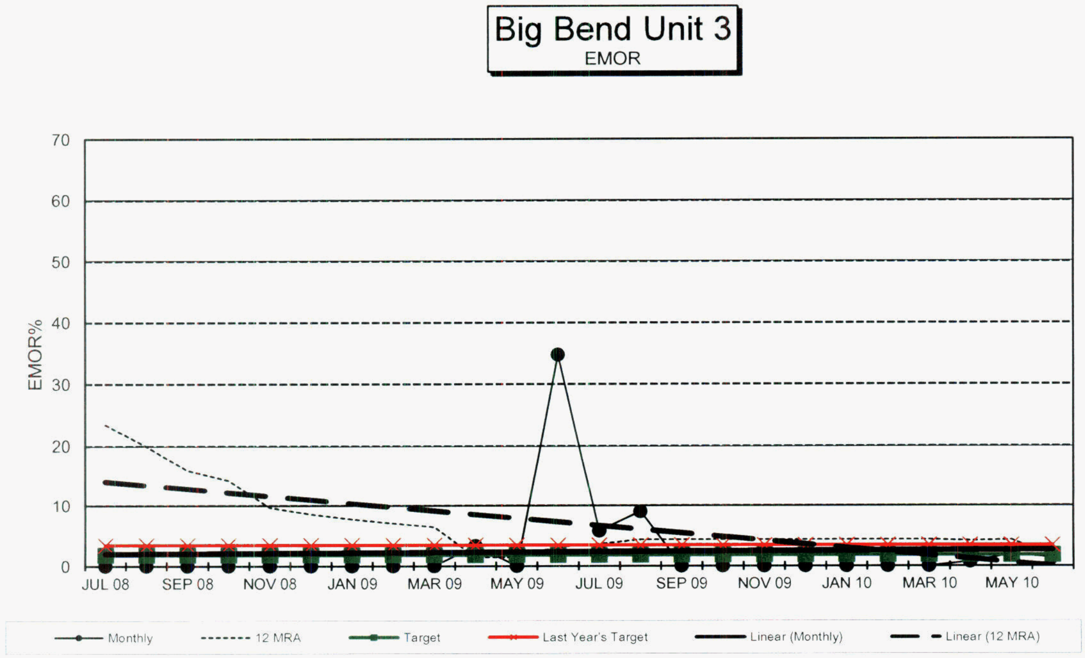
Note: Big Bend Unit 1 was offline for SCR installation from 11/23/2009 to 4/6/2010; therefore, data is not available for this time period.

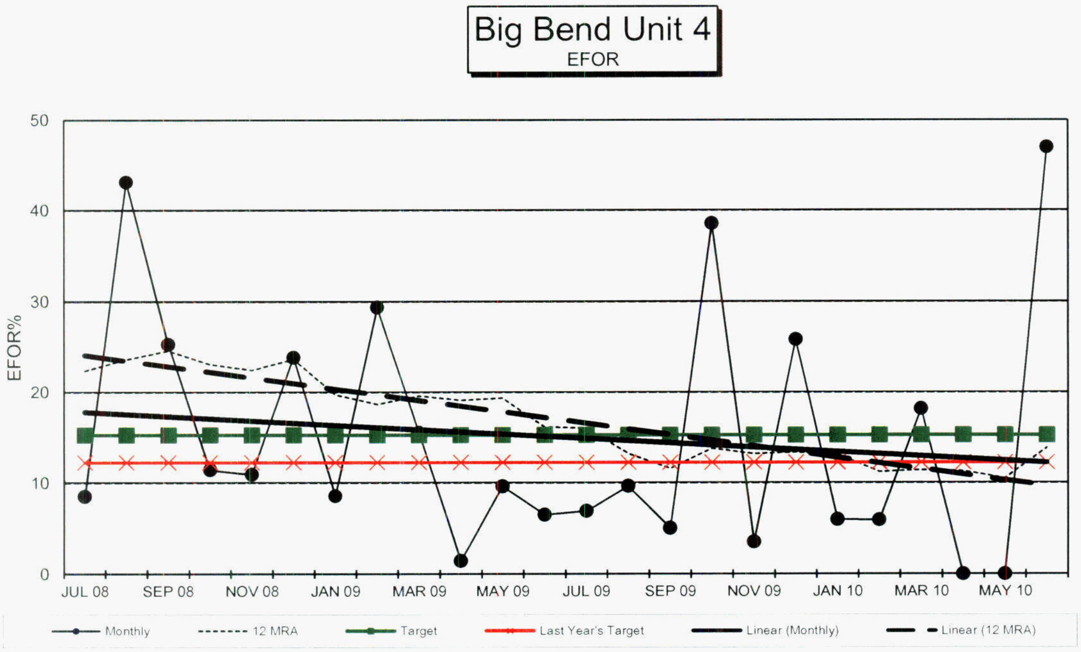




Note: Big Bend Unit 2 was offline for SCR installation from 11/24/2008 to 4/7/2009; therefore, data is not available for this time period.


Big Bend Unit 3
EFOR
70
60
50
40
30
20
10
0
EFOR%
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
EMOR
70
60
50
40
30
20
10
0
EMOR%
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EFOR
EFOR%
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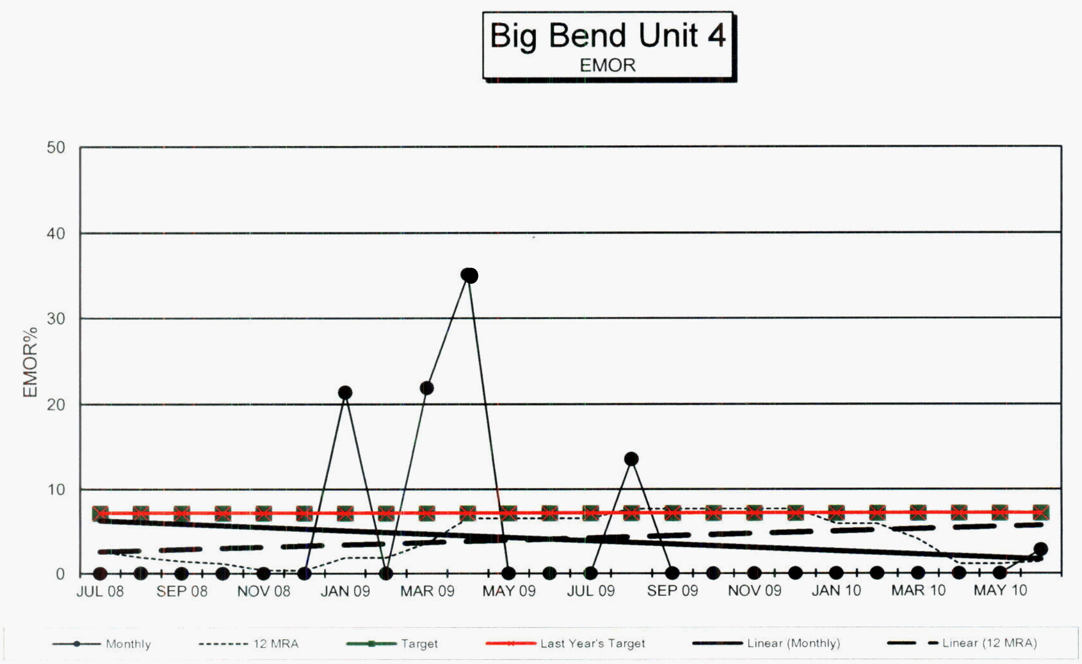
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
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EMOR%
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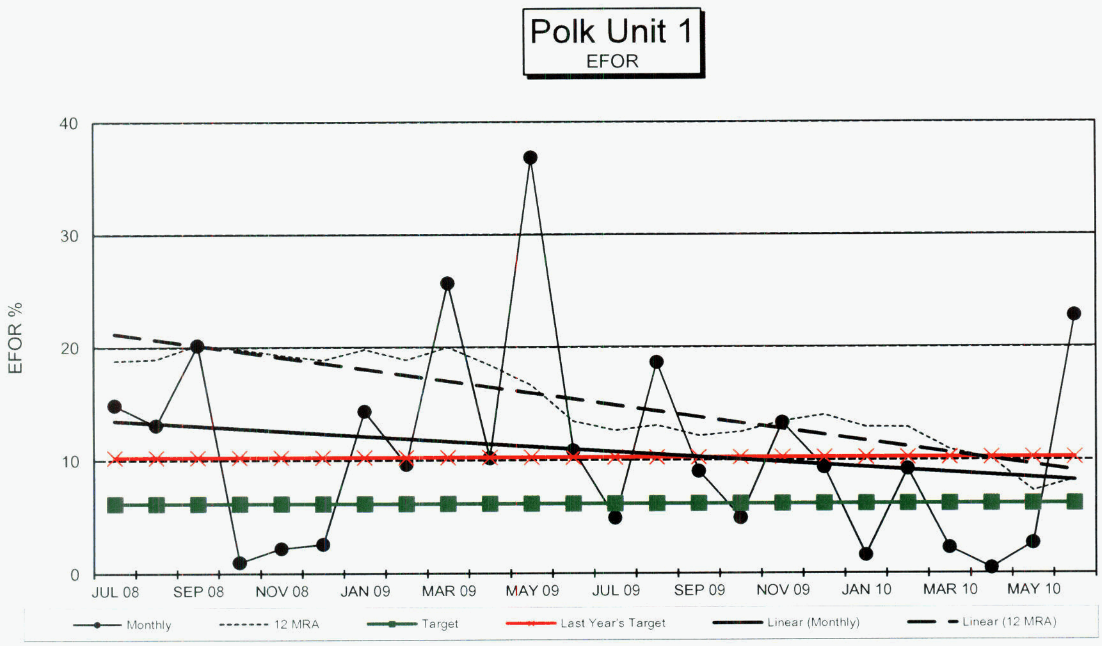
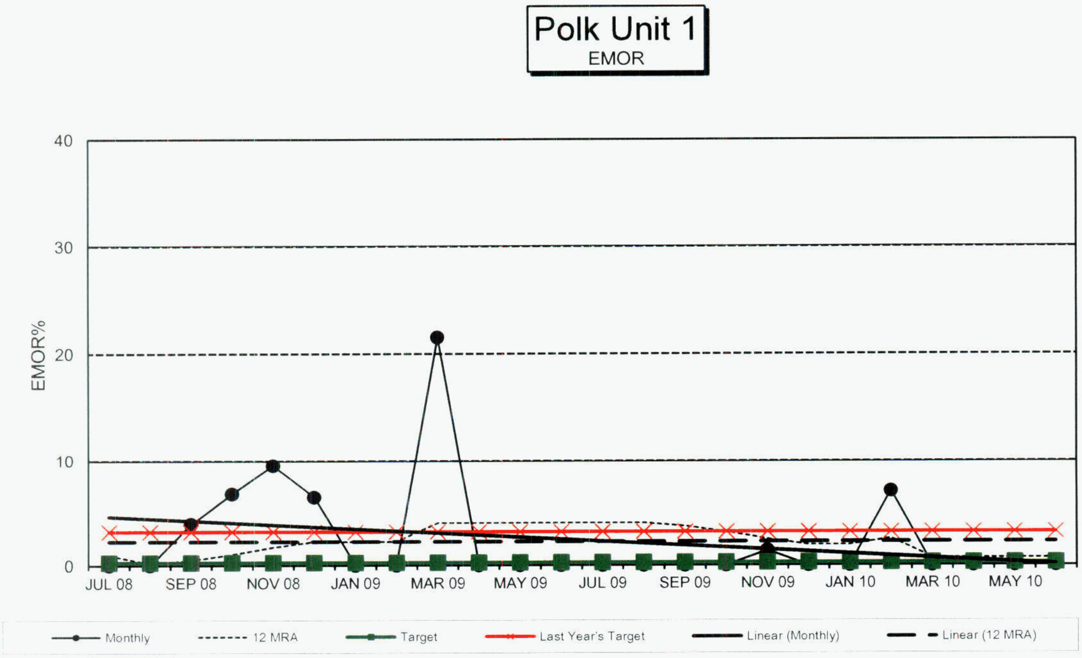
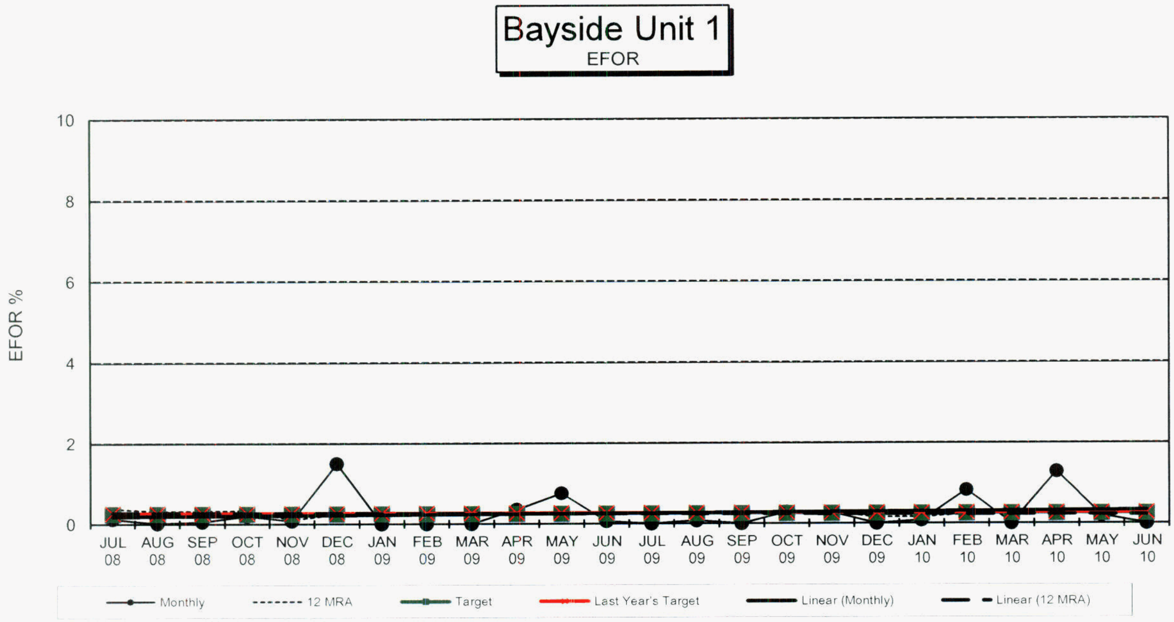
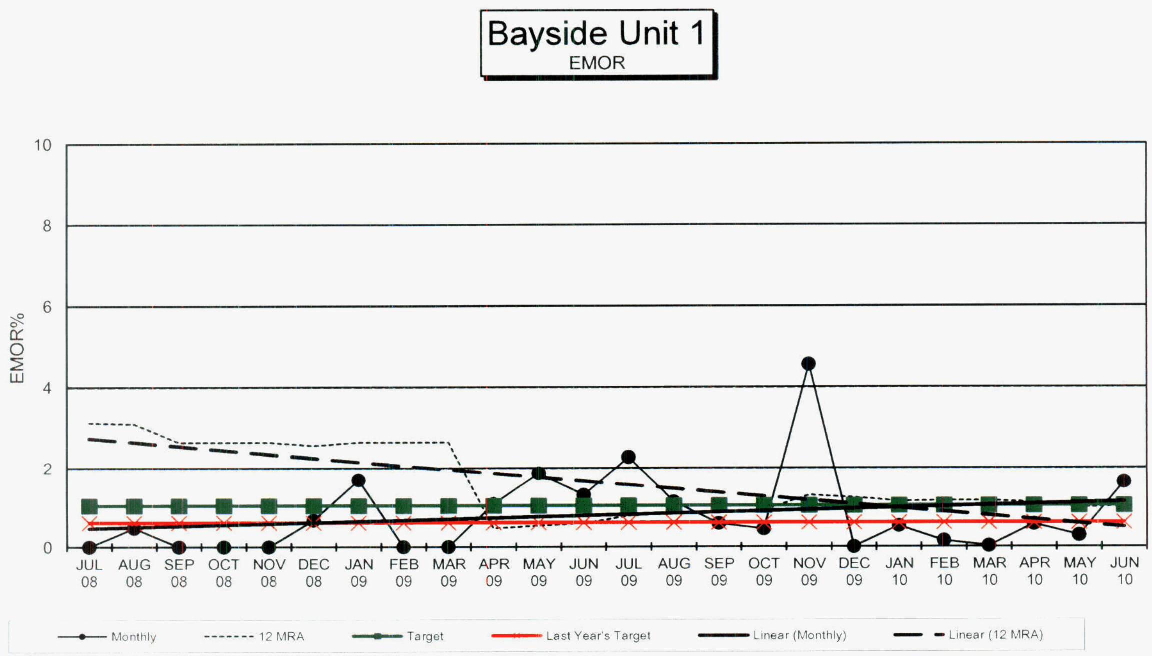
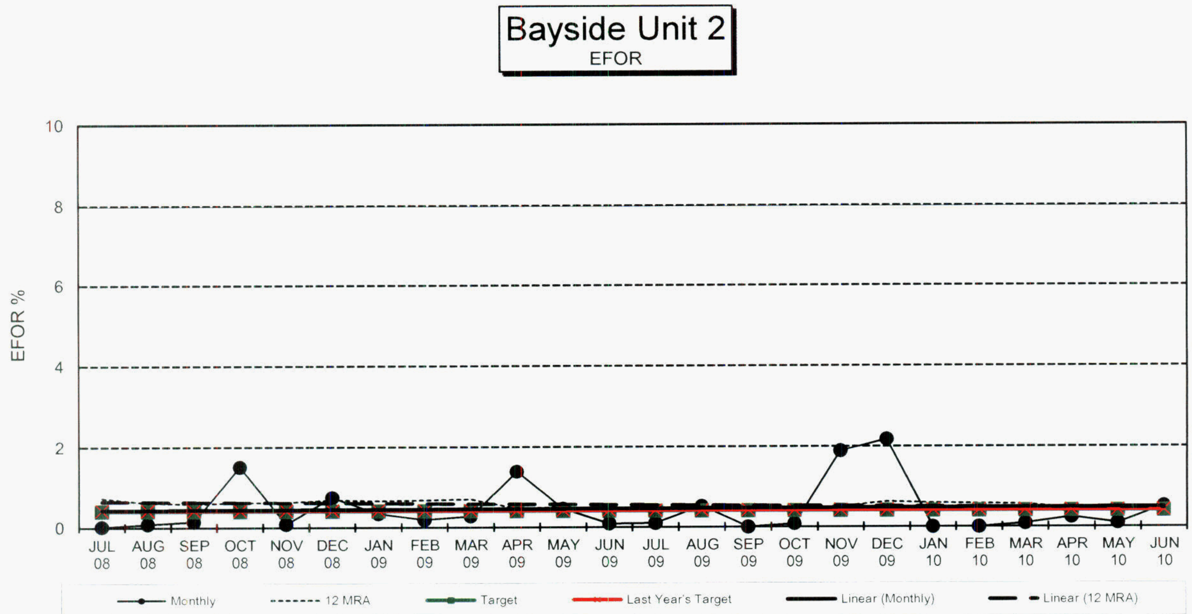
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EFOR
EFOR %
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
40
30
20
10
0
JUL 08
SEP 08
NOV 08
JAN 09
MAR 09
MAY 09
JUL 09
SEP 09
NOV 09
JAN 10
MAR 10
MAY 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
EFOR %
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
EFOR %
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
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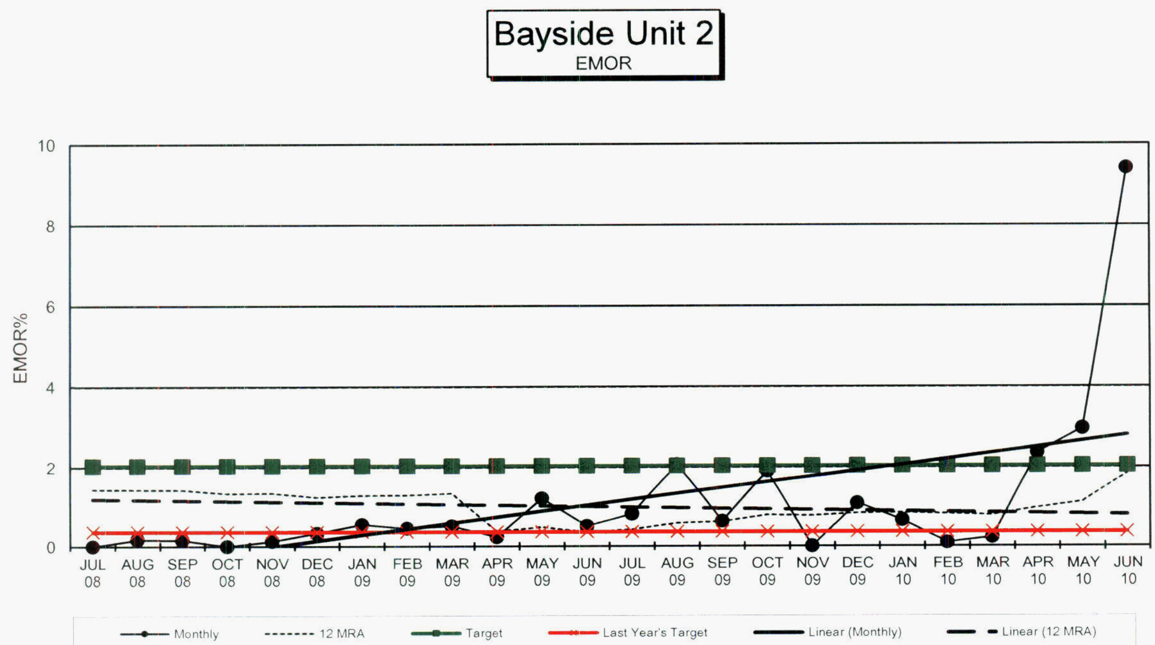
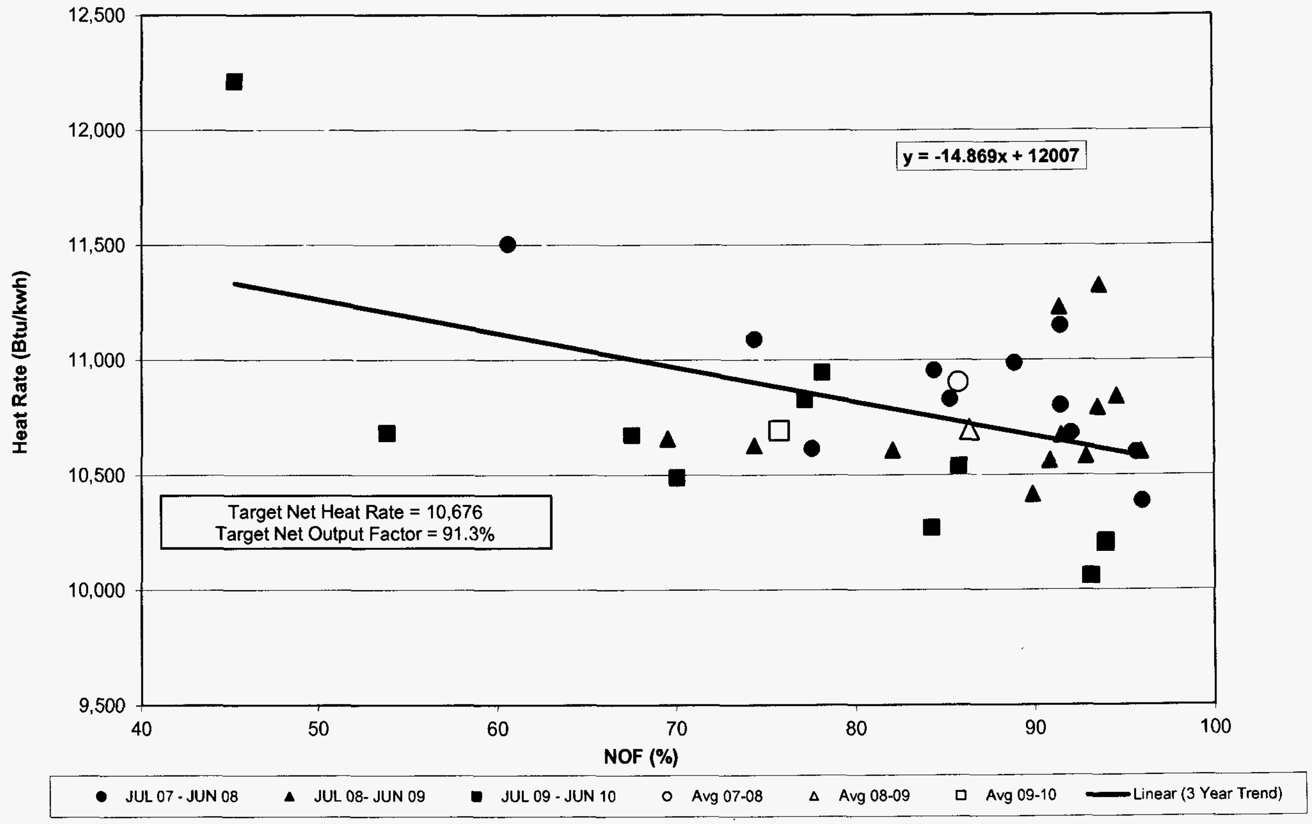
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
10
8
6
4
2
0
JUL 08
AUG 08
SEP 08
OCT 08
NOV 08
DEC 08
JAN 09
FEB 09
MAR 09
APR 09
MAY 09
JUN 09
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

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



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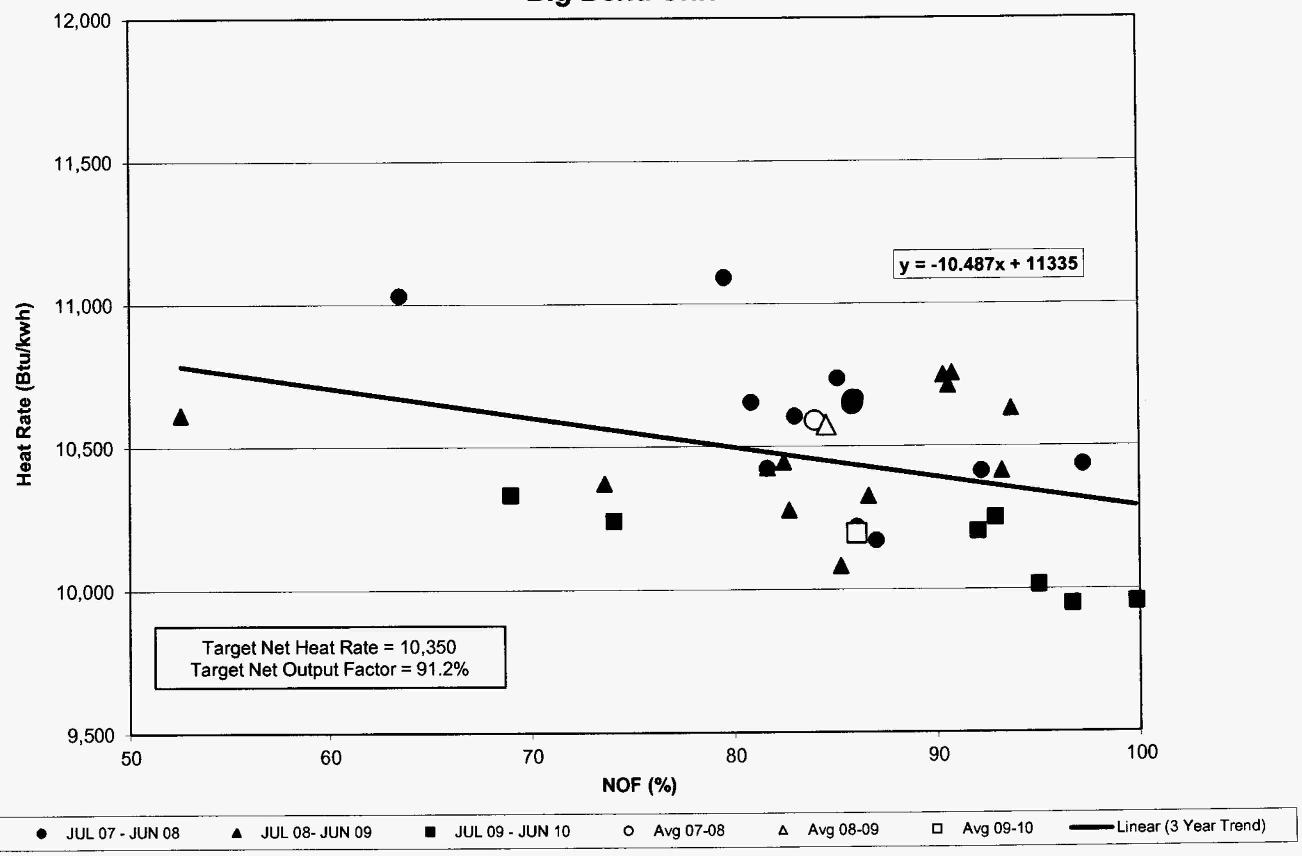
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



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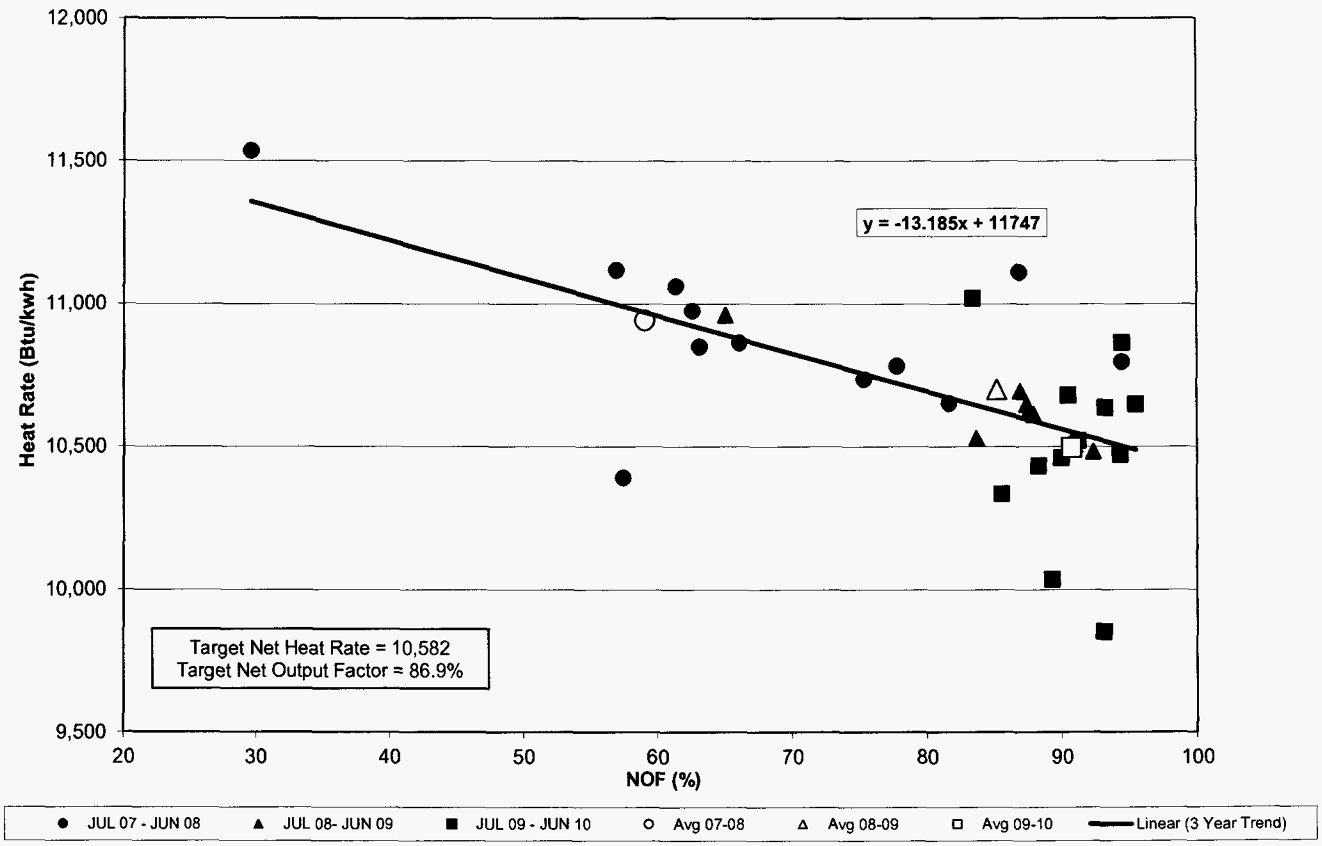
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3



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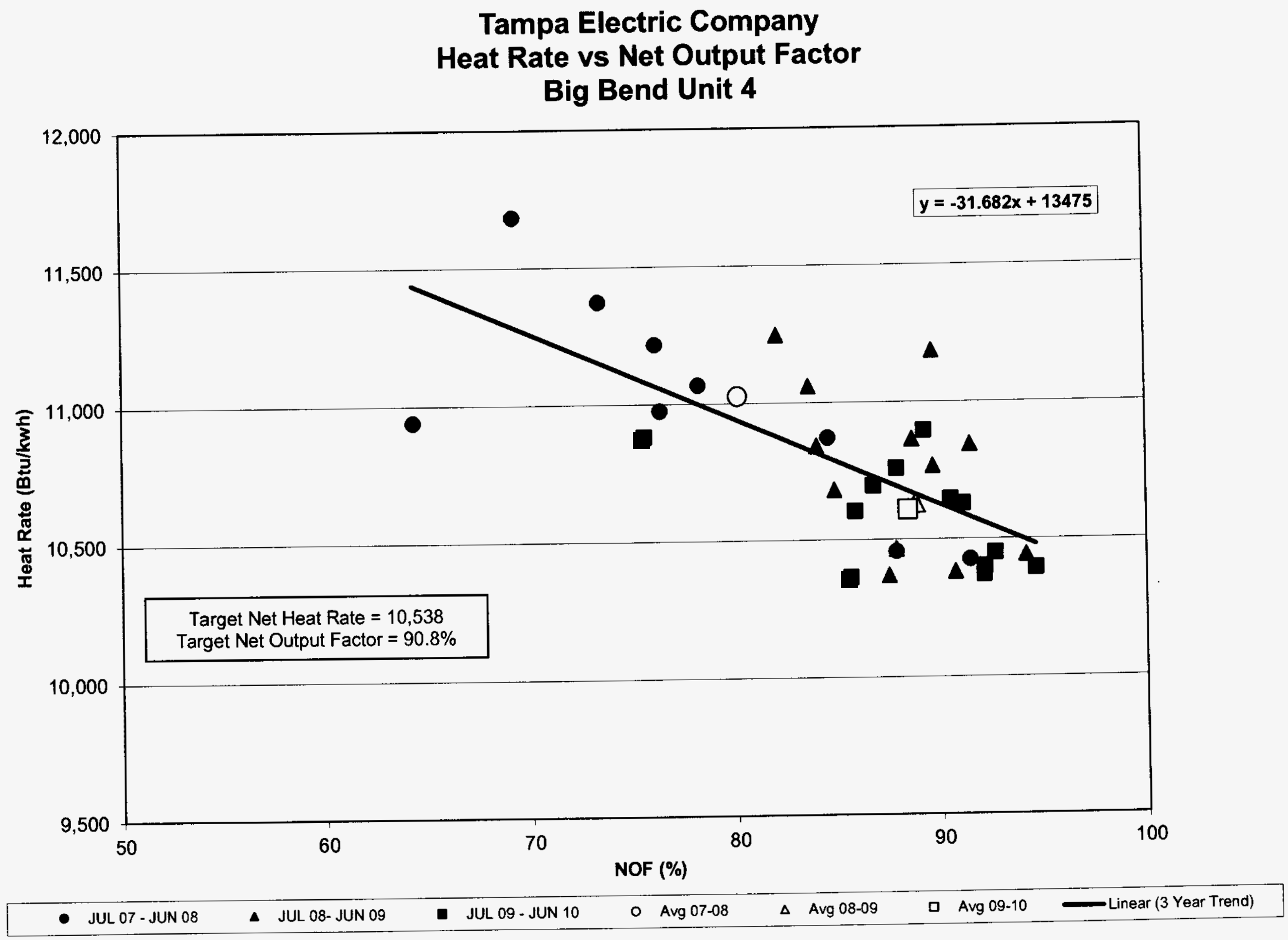

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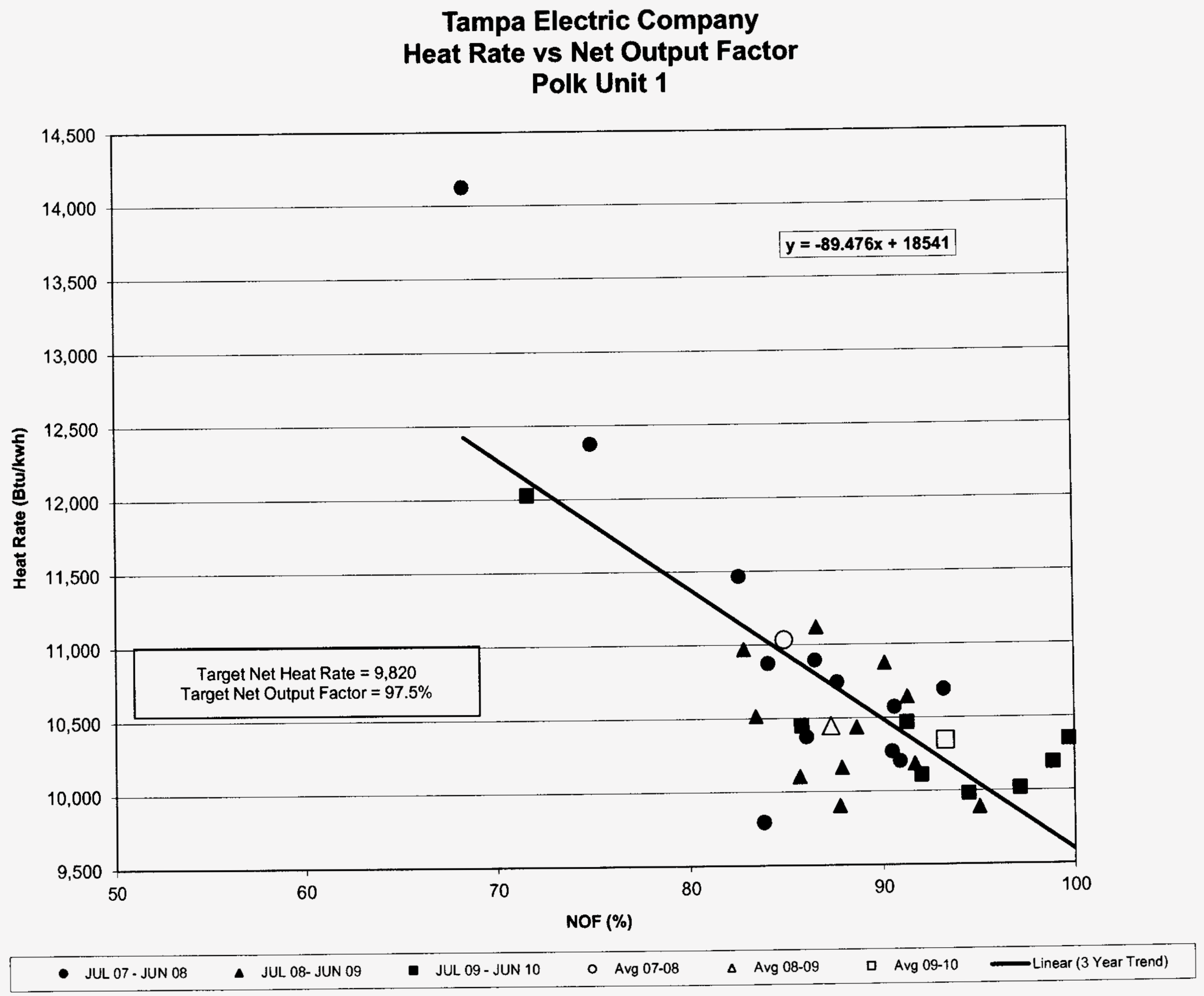

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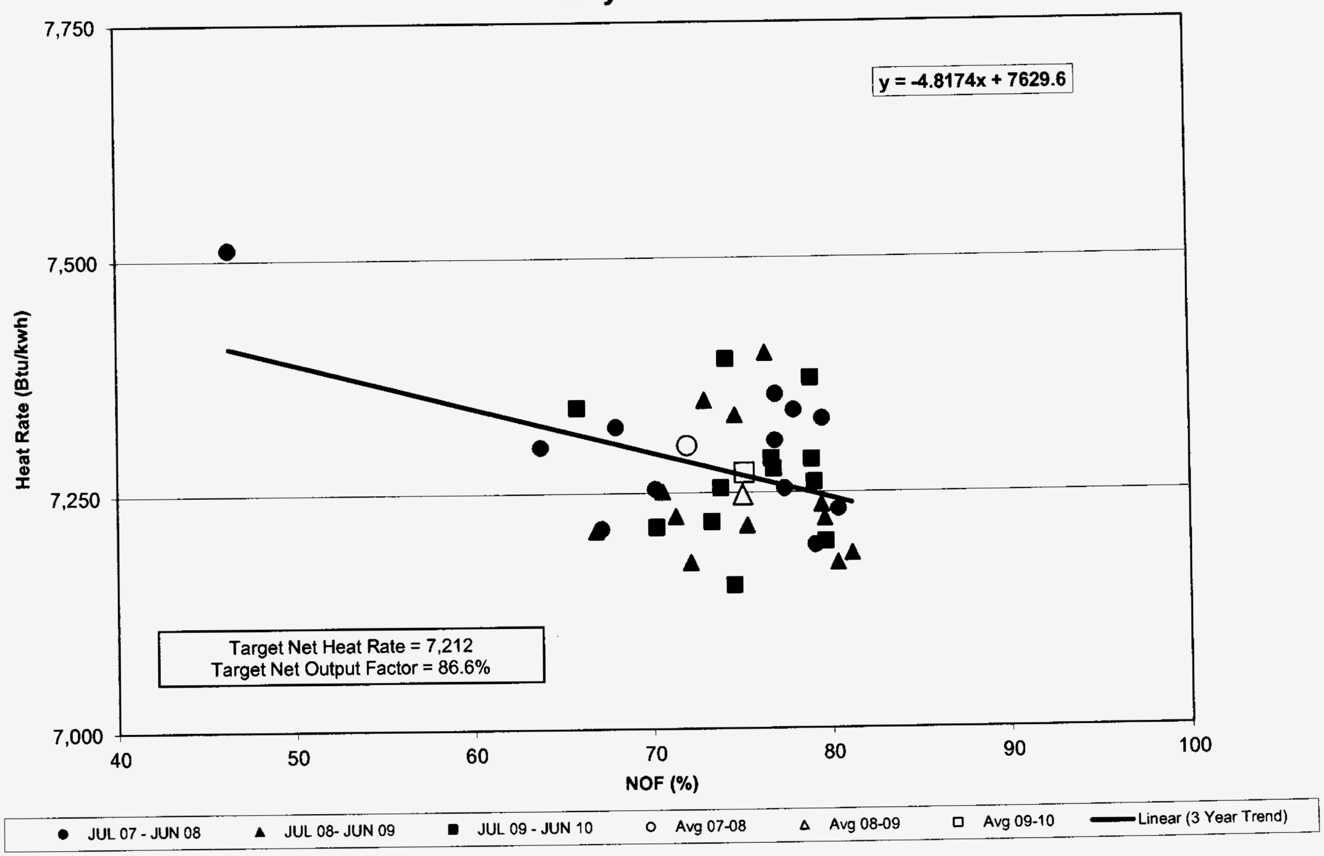
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1



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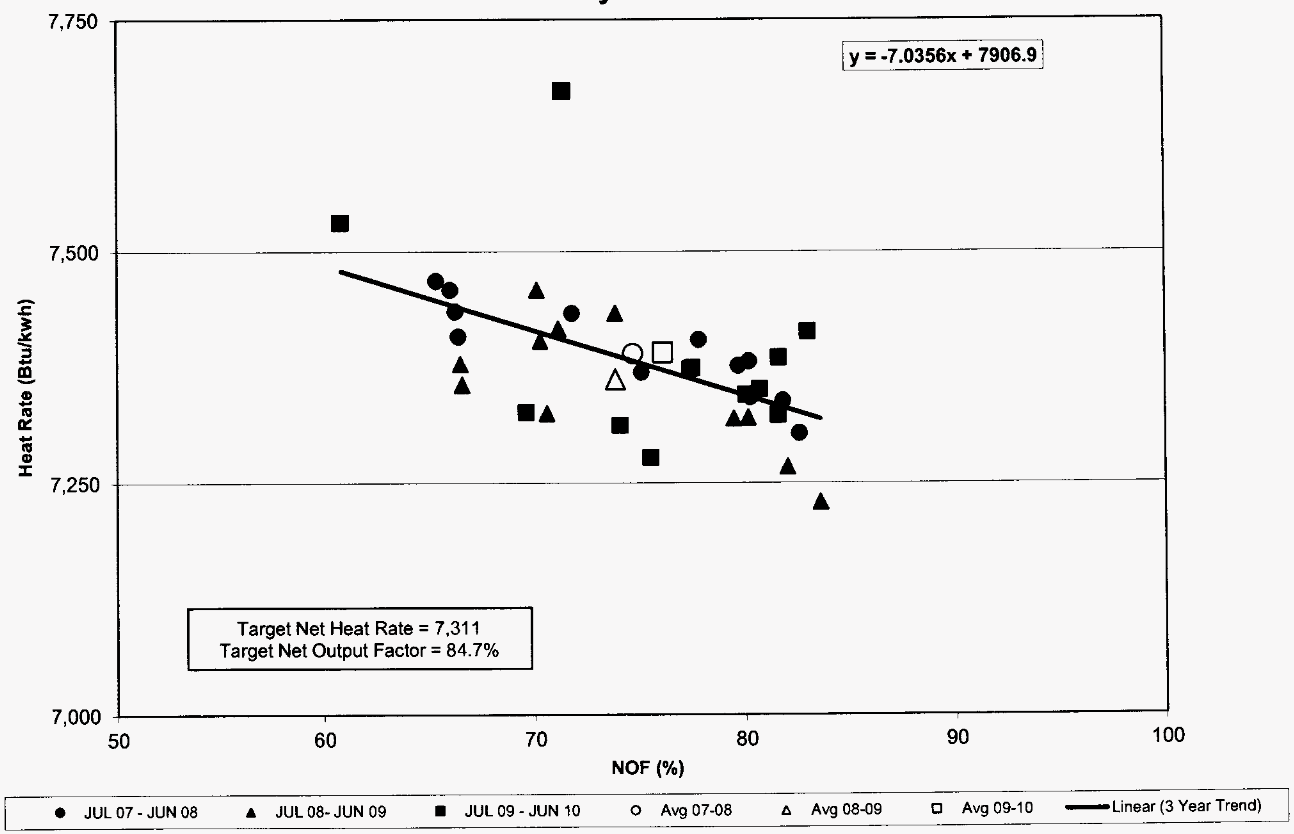
Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



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TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2011 - DECEMBER 2011

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		453	420
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,680	3,482
	SYSTEM TOTAL	**4,624**	**4,417**
	% OF SYSTEM TOTAL	**79.6%**	**78.8%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2011 - DECEMBER 2011

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		453	420
	BIG BEND COAL TOTAL	1,670	1,562
BIG BEND CT4		59	58
	BIG BEND CT TOTAL	59	58
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,624**	**4,417**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2011 - DECEMBER 2011

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,438,630	23.37%	23.37%
BIG BEND	4	2,859,320	15.06%	38.43%
BAYSIDE	1	2,717,380	14.31%	52.74%
BIG BEND	1	2,646,940	13.94%	66.68%
BIG BEND	3	2,344,680	12.35%	79.03%
BIG BEND	2	2,108,120	11.10%	90.13%
POLK	1	1,518,210	7.99%	98.12%
BAYSIDE	5	70,490	0.37%	98.49%
POLK	4	69,380	0.37%	98.86%
BIG BEND CT	4	60,750	0.32%	99.18%
BAYSIDE	6	50,660	0.27%	99.45%
BAYSIDE	3	37,540	0.20%	99.64%
POLK	5	35,780	0.19%	99.83%
BAYSIDE	4	23,430	0.12%	99.96%
POLK	2	6,190	0.03%	99.99%
POLK	3	2,170	0.01%	100.00%
TOTAL GENERATION		18,989,670	100.00%	

GENERATION BY COAL UNITS: 11,477,270 MWH
% GENERATION BY COAL UNIT: 60.44%

GENERATION BY NATURAL GAS UNITS: 7,512,400 MWH
% GENERATION BY NATURAL GAS UNITS: 39.56%

GENERATION BY OIL UNITS: - MWH
% GENERATION BY OIL UNITS: 0.00%

GENERATION BY GPIF UNITS: 18,633,280 MWH
% GENERATION BY GPIF UNITS: 98.12%

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2011 - DECEMBER 2011

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2011 - DECEMBER 2011

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	67.9	5.8	26.3	10,649
Big Bend 2[2]	62.4	23.8	13.8	10,379
Big Bend 3[3]	83.5	6.6	9.9	10,602
Big Bend 4[4]	77.9	6.6	15.5	10,599
Polk 1[5]	88.6	6.0	5.3	9,820
Bayside 1[6]	78.2	21.1	0.7	7,212
Bayside 2[7]	94.4	3.8	1.8	7,311

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