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 2012 THROUGH DECEMBER 2012

TESTIMONY AND EXHIBIT
OF
BRIAN S. BUCKLEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of 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-3), 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 2012 period.

Q. Please describe any corrections you made to your testimony and Exhibit (BSB-2), originally filed on

September 1, 2010 in last year's fuel docket.

A. My testimony and Exhibit (BSB-2), originally filed on September 1, 2010, was re-filed in revised form on April 11, 2011, to correct certain errors detected in coal bunker quantities that resulted in an understatement of coal consumption in 2010 at Big Bend Station. That revised testimony also corrected an inadvertent understatement of the fuel consumption for the coal units. Those corrections necessitate a recalculation of Tampa Electric's GPIF targets and ranges for 2011 that were approved in Commission Order No. PSC-10-0734-FOF-EI, issued December 20, 2010 in last year's fuel adjustment docket. Tampa Electric's petition requests the Commission to re-establish the GPIF targets and ranges for 2011 based on the corrected information contained in my revised testimony and exhibit filed on April 11, 2011.

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 4 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 2012 period. A range of potential improvements and degradations were determined for each of these metrics.

On April 11, 2011 Tampa Electric submitted revised and corrected testimony and Exhibit (BSB-2) of Tampa Electric witness Brian Buckley, correcting certain errors that had been inadvertently included in Mr. Buckley's testimony and exhibit as originally filed September 1, 2010. The correction of those errors necessitates re-establishment of the company's GPIF targets and ranges for 2011 from those approved in Commission Order No. PSC-10-0734-FOF-EI, issued December 20, 2010 in last year's fuel adjustment docket. The correct 2011 GPIF targets and ranges for Tampa Electric are set forth in Mr. Buckley's revised Exhibit (BSB-2), at page 4, filed April 11, 2011. The company requests that the corrected 2011 targets and ranges be approved in place of the targets and ranges approved in the December 20, 2010 order in Docket No. 100001-EI.

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 2012 period, the projected EUOF for Big Bend Unit 3 is 13.5 percent, and the POF is 6.6 percent. Therefore, the target EAF for Big Bend Unit 3 equals 79.98 percent or:

$$100\% - (13.5\% + 6.6\%) = 79.9\%$$

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:

$$EAF_{MAX} = 1 - [0.799 \ (EUOF_T) + 0.95 \ (POF_T)]$$

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:

$$EAF_{MAX} = 1 - [0.799 \ (13.5\%) + 0.95 \ (6.6\%)] = 83.0\%$$

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,

$$EAF_{MIN} = 1 - [1.40 \ (13.5\%) + 1.10 \ (6.6\%)] = 73.84\%$$

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 2012 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2012; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Polk Unit 1 is scheduled for a planned outage from April 22, 2012 to May 26, 2012 and November 11, 2012 to November 15, 2012. There are 960 planned outage hours scheduled for the 2012 period, and a total of 8,784 hours during this 12-month period. Consequently, the POF for Polk Unit 1 is 10.9 percent or:

$$\frac{960}{8,784} \times 100\% = 10.9\%$$

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 5.7 percent. Big Bend Unit 2 has a POF of 5.7 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 10.9 percent. Bayside Unit 1 has a POF of 3.8 percent, and Bayside Unit 2 has a POF of 17.2 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 13.46 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

$$EUOF = \frac{(975 + 208)}{8,784} \times 100\% = 13.47\%$$

Relative to Big Bend Unit 3, the EUOF of 13.47 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 12.4 percent. The unit will have a planned outage in 2012, and the POF is 5.7 percent. Therefore, the target equivalent availability for this unit is 81.9 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.1 percent. The unit will have a planned outage in 2012, and the POF is 5.7 percent. Therefore, the target equivalent availability for this unit is 76.2 percent.

Big Bend Unit 3

The projected EUOF for this unit is 13.5 percent. The unit will have a planned outage in 2012, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 80.0 percent.

Big Bend Unit 4

The projected EUOF for this unit is 16.0 percent. The unit will have a planned outage in 2012, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 77.4 percent.

Polk Unit 1

The projected EUOF for this unit is 3.6 percent. The unit will have a planned outage in 2012, and the POF is 10.9 percent. Therefore, the target equivalent availability for this unit is 85.5 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.4 percent. The unit will have a planned outage in 2012, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 94.8 percent.

Bayside Unit 2

The projected EUOF for this unit is 2.8 percent. The unit will have a planned outage in 2012, and the POF is 17.2 percent. Therefore, the target equivalent availability for this unit is 80.0 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 75.81 percent is shown on Page 5 of Document No. 1. This target is greater than the 2008, 2009 and 2010 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 and September, 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 and September, 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 2012 period.

A. The heat rate target for Big Bend Unit 1 is 10,468 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±633 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,272 Btu/Net kWh with a range of ±410 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,614 Btu/Net kWh, with a range of ±404 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,549 Btu/Net kWh with a range of ±392 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,220 Btu/Net kWh with a range of ±305 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,248 Btu/Net kWh with a range of ±129 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,316 Btu/Net kWh with a range of ±127 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 $842,493,200 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 $29,723,500 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 9.79 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 83.0 percent equivalent availability, fuel savings would equal $3,576,100 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 $30,848,200. 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 2012 is $1,955,104,745. This produces the maximum allowed jurisdictional incentive of $7,982,556 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):

$$GPIP: = (0.0030\ EAP_{BB1} + 0.0509\ EAP_{BB2} + 0.0920\ EAP_{BB3} + 0.0650\ EAP_{BB4} + 0.0081\ EAP_{PK1} + 0.0135\ EAP_{BAY1} + 0.0095\ EAP_{BAY2} + 0.1920\ HRP_{BB1} + 0.1241\ HRP_{BB2} + 0.1203\ HRP_{BB3} + 0.1177\ HRP_{BB4} + 0.0681\ HRP_{PK1} + 0.0686\ HRP_{BAY1} + 0.0673\ HRP_{BAY2})$$

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 2012 PROJECTION FILING
EXHIBIT NO. ____ (BSB-3)
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2012 - DECEMBER 2012

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2012 - DECEMBER 2012
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2012 - DECEMBER 2012

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,723.5	7,982.6
+9	26,751.2	7,184.3
+8	23,778.8	6,386.0
+7	20,806.5	5,587.8
+6	17,834.1	4,789.5
+5	14,861.8	3,991.3
+4	11,889.4	3,193.0
+3	8,917.1	2,394.8
+2	5,944.7	1,596.5
+1	2,972.4	798.3
0	0.0	0.0
-1	(2,880.4)	(798.3)
-2	(5,760.8)	(1,596.5)
-3	(8,641.1)	(2,394.8)
-4	(11,521.5)	(3,193.0)
-5	(14,401.9)	(3,991.3)
-6	(17,282.3)	(4,789.5)
-7	(20,162.7)	(5,587.8)
-8	(23,043.0)	(6,386.0)
-9	(25,923.4)	(7,184.3)
-10	(28,803.8)	(7,982.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2012 - DECEMBER 2012

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,927,561,000
Line 2	Month of January	2012	$	1,878,290,000
Line 3	Month of February	2012	$	1,895,898,969
Line 4	Month of March	2012	$	1,913,673,022
Line 5	Month of April	2012	$	1,945,501,685
Line 6	Month of May	2012	$	1,963,740,763
Line 7	Month of June	2012	$	1,982,150,833
Line 8	Month of July	2012	$	1,932,255,686
Line 9	Month of August	2012	$	1,950,370,583
Line 10	Month of September	2012	$	1,968,655,307
Line 11	Month of October	2012	$	2,000,606,976
Line 12	Month of November	2012	$	2,019,362,666
Line 13	Month of December	2012	$	2,038,294,191
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,955,104,745
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)		$	7,990,926
Line 18	Jurisdictional Sales			19,044,253 MWH
Line 19	Total Sales			19,064,222 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			99.90%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**7,982,556**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2012 - DECEMBER 2012

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	0.30%	81.9	84.6	76.3	89.3	(936.3)
BIG BEND 2	5.09%	76.2	80.1	68.4	1,512.2	(122.3)
BIG BEND 3	9.20%	80.0	83.0	73.9	2,734.4	(1,685.0)
BIG BEND 4	6.50%	77.4	80.9	70.3	1,932.3	(1,553.3)
POLK 1	0.81%	85.5	86.8	83.0	241.1	(84.9)
BAYSIDE 1	1.35%	94.8	95.2	93.8	401.1	(1,665.7)
BAYSIDE 2	0.95%	80.0	81.4	77.1	280.9	(224.1)
GPIF SYSTEM	**24.19%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR TARGET Btu/kwh	ANOHR TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	19.20%	10,468	92.9	9,836	11,101	5,705.6	(5,705.6)
BIG BEND 2	12.41%	10,272	92.9	9,862	10,682	3,688.3	(3,688.3)
BIG BEND 3	12.03%	10,614	86.1	10,209	11,018	3,576.1	(3,576.1)
BIG BEND 4	11.77%	10,549	88.0	10,157	10,941	3,499.1	(3,499.1)
POLK 1	6.81%	10,220	94.2	9,915	10,525	2,023.9	(2,023.9)
BAYSIDE 1	6.86%	7,248	82.6	7,120	7,377	2,040.2	(2,040.2)
BAYSIDE 2	6.73%	7,316	83.2	7,189	7,442	1,998.9	(1,998.9)
GPIF SYSTEM	**75.81%**						

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

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 12 - DEC 12 POF	TARGET PERIOD JAN 12 - DEC 12 EUOF	TARGET PERIOD JAN 12 - DEC 12 EUOR	ACTUAL PERFORMANCE JAN 10 - DEC 10 POF	ACTUAL PERFORMANCE JAN 10 - DEC 10 EUOF	ACTUAL PERFORMANCE JAN 10 - DEC 10 EUOR	ACTUAL PERFORMANCE JAN 09 - DEC 09 POF	ACTUAL PERFORMANCE JAN 09 - DEC 09 EUOF	ACTUAL PERFORMANCE JAN 09 - DEC 09 EUOR	ACTUAL PERFORMANCE JAN 08 - DEC 08 POF	ACTUAL PERFORMANCE JAN 08 - DEC 08 EUOF	ACTUAL PERFORMANCE JAN 08 - DEC 08 EUOR
BIG BEND 1	0.30%	1.2%	5.7	12.4	13.2	24.5	15.1	19.9	14.0	30.3	21.5	4.9	19.4	20.4
BIG BEND 2	5.09%	21.0%	5.7	18.1	19.2	5.5	26.1	27.6	26.5	36.7	42.0	10.2	18.8	20.8
BIG BEND 3	9.20%	38.0%	6.6	13.5	14.4	8.4	11.9	13.1	5.0	16.2	12.2	32.4	23.1	34.2
BIG BEND 4	6.50%	26.9%	6.6	16.0	17.2	19.3	14.2	17.5	1.9	18.6	12.9	5.8	21.4	22.7
POLK 1	0.81%	3.4%	10.9	3.6	4.0	4.8	5.2	5.7	5.6	1.3	0.2	3.0	13.8	16.9
BAYSIDE 1	1.35%	5.6%	3.8	1.4	1.5	5.0	1.1	1.1	6.8	1.3	0.6	2.4	2.8	3.1
BAYSIDE 2	0.95%	3.9%	17.2	2.8	3.4	8.7	1.8	1.9	14.1	9.4	11.4	14.5	1.9	2.4
GPIF SYSTEM	**24.19%**	**100.0%**	**6.8**	**13.7**	**14.6**	**10.6**	**14.3**	**16.1**	**9.3**	**19.7**	**17.7**	**16.9**	**19.4**	**24.5**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**79.5**			**75.1**			**71.0**			**63.7**	

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
12.3	17.8	19.4	69.9

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 10 - DEC 10	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 09 - DEC 09	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 08 - DEC 08
BIG BEND 1	19.20%	25.3%	10,468	10,182	10,394	10,793
BIG BEND 2	12.41%	16.4%	10,272	10,078	10,555	10,595
BIG BEND 3	12.03%	15.9%	10,614	10,707	10,713	10,670
BIG BEND 4	11.77%	15.5%	10,549	10,373	10,686	10,773
POLK 1	6.81%	9.0%	10,220	10,207	10,288	10,206
BAYSIDE 1	6.86%	9.1%	7,248	7,237	7,253	7,226
BAYSIDE 2	6.73%	8.9%	7,316	7,313	7,293	7,304
GPIF SYSTEM	**75.81%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,878**	**9,759**	**9,947**	**10,053**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2012 - DECEMBER 2012
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	842,493.2	842,403.9	89.3	0.30%
EA_2 BIG BEND 2	842,493.2	840,981.1	1,512.2	5.09%
EA_3 BIG BEND 3	842,493.2	839,758.8	2,734.4	9.20%
EA_4 BIG BEND 4	842,493.2	840,561.0	1,932.3	6.50%
EA_7 POLK 1	842,493.2	842,252.2	241.1	0.81%
EA_8 BAYSIDE 1	842,493.2	842,092.1	401.1	1.35%
EA_9 BAYSIDE 2	842,493.2	842,212.3	280.9	0.95%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	842,493.2	836,787.6	5,705.6	19.20%
AHR_2 BIG BEND 2	842,493.2	838,804.9	3,688.3	12.41%
AHR_3 BIG BEND 3	842,493.2	838,917.1	3,576.1	12.03%
AHR_4 BIG BEND 4	842,493.2	838,994.1	3,499.1	11.77%
AHR_7 POLK 1	842,493.2	840,469.3	2,023.9	6.81%
AHR_8 BAYSIDE 1	842,493.2	840,453.0	2,040.2	6.86%
AHR_9 BAYSIDE 2	842,493.2	840,494.3	1,998.9	6.73%
TOTAL SAVINGS			**29,723.5**	**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 2012 - DECEMBER 2012

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	89.3	84.6	+10	5,705.6	9,836
+9	80.4	84.4	+9	5,135.1	9,891
+8	71.4	84.1	+8	4,564.5	9,947
+7	62.5	83.8	+7	3,994.0	10,003
+6	53.6	83.5	+6	3,423.4	10,059
+5	44.7	83.2	+5	2,852.8	10,114
+4	35.7	83.0	+4	2,282.3	10,170
+3	26.8	82.7	+3	1,711.7	10,226
+2	17.9	82.4	+2	1,141.1	10,282
+1	8.9	82.1	+1	570.6	10,337
					10,393
0	0.0	81.9	0	0.0	10,468
					10,543
-1	(93.6)	81.3	-1	(570.6)	10,599
-2	(187.3)	80.8	-2	(1,141.1)	10,655
-3	(280.9)	80.2	-3	(1,711.7)	10,710
-4	(374.5)	79.7	-4	(2,282.3)	10,766
-5	(468.1)	79.1	-5	(2,852.8)	10,822
-6	(561.8)	78.5	-6	(3,423.4)	10,878
-7	(655.4)	78.0	-7	(3,994.0)	10,933
-8	(749.0)	77.4	-8	(4,564.5)	10,989
-9	(842.7)	76.9	-9	(5,135.1)	11,045
-10	(936.3)	76.3	-10	(5,705.6)	11,101
	Weighting Factor =	0.30%		Weighting Factor =	19.20%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	1,512.2	80.1	+10	3,688.3	9,862
+9	1,360.9	79.7	+9	3,319.5	9,895
+8	1,209.7	79.3	+8	2,950.7	9,929
+7	1,058.5	78.9	+7	2,581.8	9,962
+6	907.3	78.5	+6	2,213.0	9,996
+5	756.1	78.1	+5	1,844.2	10,029
+4	604.9	77.7	+4	1,475.3	10,063
+3	453.6	77.4	+3	1,106.5	10,096
+2	302.4	77.0	+2	737.7	10,130
+1	151.2	76.6	+1	368.8	10,163
					10,197
0	0.0	76.2	0	0.0	10,272
					10,347
-1	(12.2)	75.4	-1	(368.8)	10,380
-2	(24.5)	74.6	-2	(737.7)	10,414
-3	(36.7)	73.8	-3	(1,106.5)	10,448
-4	(48.9)	73.1	-4	(1,475.3)	10,481
-5	(61.1)	72.3	-5	(1,844.2)	10,515
-6	(73.4)	71.5	-6	(2,213.0)	10,548
-7	(85.6)	70.7	-7	(2,581.8)	10,582
-8	(97.8)	69.9	-8	(2,950.7)	10,615
-9	(110.0)	69.2	-9	(3,319.5)	10,649
-10	(122.3)	68.4	-10	(3,688.3)	10,682
	Weighting Factor =	5.09%		Weighting Factor =	12.41%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	2,734.4	83.0	+10	3,576.1	10,209
+9	2,461.0	82.7	+9	3,218.5	10,242
+8	2,187.5	82.4	+8	2,860.9	10,275
+7	1,914.1	82.1	+7	2,503.3	10,308
+6	1,640.6	81.8	+6	2,145.7	10,341
+5	1,367.2	81.5	+5	1,788.1	10,374
+4	1,093.8	81.2	+4	1,430.5	10,407
+3	820.3	80.9	+3	1,072.8	10,440
+2	546.9	80.6	+2	715.2	10,473
+1	273.4	80.3	+1	357.6	10,506
					10,539
0	0.0	80.0	0	0.0	10,614
					10,689
-1	(168.5)	79.4	-1	(357.6)	10,722
-2	(337.0)	78.8	-2	(715.2)	10,755
-3	(505.5)	78.2	-3	(1,072.8)	10,788
-4	(674.0)	77.6	-4	(1,430.5)	10,820
-5	(842.5)	77.0	-5	(1,788.1)	10,853
-6	(1,011.0)	76.4	-6	(2,145.7)	10,886
-7	(1,179.5)	75.8	-7	(2,503.3)	10,919
-8	(1,348.0)	75.1	-8	(2,860.9)	10,952
-9	(1,516.5)	74.5	-9	(3,218.5)	10,985
-10	(1,685.0)	73.9	-10	(3,576.1)	11,018
	Weighting Factor =	9.20%		Weighting Factor =	12.03%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	1,932.3	80.9	+10	3,499.1	10,157
+9	1,739.1	80.6	+9	3,149.2	10,188
+8	1,545.8	80.2	+8	2,799.3	10,220
+7	1,352.6	79.9	+7	2,449.4	10,252
+6	1,159.4	79.5	+6	2,099.5	10,283
+5	966.1	79.2	+5	1,749.5	10,315
+4	772.9	78.8	+4	1,399.6	10,347
+3	579.7	78.5	+3	1,049.7	10,379
+2	386.5	78.1	+2	699.8	10,410
+1	193.2	77.8	+1	349.9	10,442
					10,474
0	0.0	77.4	0	0.0	10,549
					10,624
-1	(155.3)	76.7	-1	(349.9)	10,656
-2	(310.7)	76.0	-2	(699.8)	10,687
-3	(466.0)	75.3	-3	(1,049.7)	10,719
-4	(621.3)	74.6	-4	(1,399.6)	10,751
-5	(776.6)	73.9	-5	(1,749.5)	10,782
-6	(932.0)	73.2	-6	(2,099.5)	10,814
-7	(1,087.3)	72.5	-7	(2,449.4)	10,846
-8	(1,242.6)	71.8	-8	(2,799.3)	10,878
-9	(1,397.9)	71.0	-9	(3,149.2)	10,909
-10	(1,553.3)	70.3	-10	(3,499.1)	10,941
	Weighting Factor =	6.50%		Weighting Factor =	11.77%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	241.1	86.8	+10	2,023.9	9,915
+9	217.0	86.6	+9	1,821.5	9,938
+8	192.9	86.5	+8	1,619.1	9,961
+7	168.7	86.4	+7	1,416.7	9,984
+6	144.6	86.3	+6	1,214.4	10,007
+5	120.5	86.1	+5	1,012.0	10,030
+4	96.4	86.0	+4	809.6	10,053
+3	72.3	85.9	+3	607.2	10,076
+2	48.2	85.8	+2	404.8	10,099
+1	24.1	85.6	+1	202.4	10,122
					10,145
0	0.0	85.5	0	0.0	10,220
					10,295
-1	(8.5)	85.2	-1	(202.4)	10,318
-2	(17.0)	85.0	-2	(404.8)	10,341
-3	(25.5)	84.7	-3	(607.2)	10,364
-4	(33.9)	84.5	-4	(809.6)	10,387
-5	(42.4)	84.2	-5	(1,012.0)	10,410
-6	(50.9)	84.0	-6	(1,214.4)	10,433
-7	(59.4)	83.7	-7	(1,416.7)	10,456
-8	(67.9)	83.5	-8	(1,619.1)	10,479
-9	(76.4)	83.2	-9	(1,821.5)	10,502
-10	(84.9)	83.0	-10	(2,023.9)	10,525
	Weighting Factor =	0.81%		Weighting Factor =	6.81%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	401.1	95.2	+10	2,040.2	7,120
+9	361.0	95.2	+9	1,836.2	7,125
+8	320.9	95.1	+8	1,632.2	7,130
+7	280.8	95.1	+7	1,428.2	7,136
+6	240.7	95.1	+6	1,224.1	7,141
+5	200.6	95.0	+5	1,020.1	7,146
+4	160.4	95.0	+4	816.1	7,152
+3	120.3	94.9	+3	612.1	7,157
+2	80.2	94.9	+2	408.0	7,163
+1	40.1	94.8	+1	204.0	7,168
					7,173
0	0.0	94.8	0	0.0	7,248
					7,323
-1	(166.6)	94.7	-1	(204.0)	7,329
-2	(333.1)	94.6	-2	(408.0)	7,334
-3	(499.7)	94.5	-3	(612.1)	7,339
-4	(666.3)	94.4	-4	(816.1)	7,345
-5	(832.8)	94.3	-5	(1,020.1)	7,350
-6	(999.4)	94.2	-6	(1,224.1)	7,355
-7	(1,166.0)	94.1	-7	(1,428.2)	7,361
-8	(1,332.6)	94.0	-8	(1,632.2)	7,366
-9	(1,499.1)	93.9	-9	(1,836.2)	7,371
-10	(1,665.7)	93.8	-10	(2,040.2)	7,377
	Weighting Factor =	1.35%		Weighting Factor =	6.86%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2012 - DECEMBER 2012

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	280.9	81.4	+10	1,998.9	7,189
+9	252.8	81.2	+9	1,799.1	7,194
+8	224.7	81.1	+8	1,599.2	7,199
+7	196.6	81.0	+7	1,399.3	7,205
+6	168.5	80.8	+6	1,199.4	7,210
+5	140.5	80.7	+5	999.5	7,215
+4	112.4	80.5	+4	799.6	7,220
+3	84.3	80.4	+3	599.7	7,225
+2	56.2	80.2	+2	399.8	7,230
+1	28.1	80.1	+1	199.9	7,236
					7,241
0	0.0	80.0	0	0.0	7,316
					7,391
-1	(22.4)	79.7	-1	(199.9)	7,396
-2	(44.8)	79.4	-2	(399.8)	7,401
-3	(67.2)	79.1	-3	(599.7)	7,406
-4	(89.7)	78.8	-4	(799.6)	7,411
-5	(112.1)	78.5	-5	(999.5)	7,417
-6	(134.5)	78.2	-6	(1,199.4)	7,422
-7	(156.9)	78.0	-7	(1,399.3)	7,427
-8	(179.3)	77.7	-8	(1,599.2)	7,432
-9	(201.7)	77.4	-9	(1,799.1)	7,437
-10	(224.1)	77.1	-10	(1,998.9)	7,442
	Weighting Factor =	0.95%		Weighting Factor =	6.73%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	86.8	86.8	86.8	46.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	67.2	81.9
2. POF	0.0	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	5.7
3. EUOF	13.2	13.2	13.2	7.0	13.2	13.2	13.2	13.2	13.2	13.2	13.2	10.2	12.4
4. EUOR	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	668	625	668	345	668	646	668	668	646	668	646	517	7,433
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	76	71	75	375	76	74	76	76	74	76	75	227	1,351
9. POH	0	0	0	336	0	0	0	0	0	0	0	168	504
10. EFOH	73	69	73	38	73	71	73	73	71	73	71	57	817
11. EMOH	24	23	24	13	24	24	24	24	24	24	24	19	272
12. OPER BTU (GBTU)	2,532	2,357	2,572	1,233	2,547	2,465	2,547	2,507	2,464	2,513	2,429	1,913	28,080
13. NET GEN (MWH)	241,210	224,340	245,800	116,700	244,210	236,370	244,140	239,600	236,180	240,320	232,170	181,410	2,682,450
14. ANOHR (Btu/kwh)	10,496	10,506	10,464	10,562	10,431	10,429	10,431	10,464	10,431	10,459	10,461	10,544	10,468
15. NOF (%)	91.4	90.9	93.2	87.9	95.0	95.0	94.9	93.2	95.0	93.4	93.3	88.8	92.9
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	-18.440	) +	12,182									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	80.8	80.8	80.8	43.1	80.8	80.8	80.8	80.8	80.8	80.8	80.8	62.6	76.2
2. POF	0.0	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	5.7
3. EUOF	19.2	19.2	19.2	10.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	14.8	18.1
4. EUOR	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2	19.2
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	633	592	633	327	633	613	633	633	613	633	613	490	7,046
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	111	104	110	393	111	107	111	111	107	111	108	254	1,738
9. POH	0	0	0	336	0	0	0	0	0	0	0	168	504
10. EFOH	132	123	132	68	132	127	132	132	127	132	128	102	1,466
11. EMOH	11	10	11	6	11	11	11	11	11	11	11	8	122
12. OPER BTU (GBTU)	2,382	2,208	2,396	1,181	2,314	2,275	2,350	2,347	2,273	2,332	2,263	1,784	26,104
13. NET GEN (MWH)	231,860	214,760	233,370	114,830	225,210	221,630	228,980	228,620	221,400	227,040	220,410	173,220	2,541,330
14. ANOHR (Btu/kwh)	10,273	10,280	10,268	10,284	10,275	10,264	10,264	10,265	10,265	10,270	10,268	10,297	10,272
15. NOF (%)	92.7	91.8	93.3	91.2	92.4	93.9	94.0	93.8	93.8	93.2	93.4	89.5	92.9
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		-7.525	) +	10,971								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	85.6	85.6	57.9	85.6	85.6	85.6	85.6	85.6	45.6	85.6	85.6	85.6	80.0
2. POF	0.0	0.0	32.3	0.0	0.0	0.0	0.0	0.0	46.7	0.0	0.0	0.0	6.6
3. EUOF	14.4	14.4	9.8	14.4	14.4	14.4	14.4	14.4	7.7	14.4	14.4	14.4	13.5
4. EUOR	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	661	619	448	640	661	640	661	661	342	661	640	661	7,295
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	83	77	295	80	83	80	83	83	378	83	81	83	1,489
9. POH	0	0	240	0	0	0	0	0	336	0	0	0	576
10. EFOH	88	83	60	85	88	85	88	88	46	88	86	88	975
11. EMOH	19	18	13	18	19	18	19	19	10	19	18	19	208
12. OPER BTU (GBTU)	2,224	2,023	1,495	2,215	2,205	2,200	2,239	2,216	1,097	2,193	2,038	2,187	24,336
13. NET GEN (MWH)	209,910	189,800	140,860	210,250	207,750	208,610	211,660	209,000	102,550	206,430	190,290	205,750	2,292,860
14. ANOHR (Btu/kwh)	10,595	10,657	10,613	10,533	10,614	10,548	10,580	10,603	10,696	10,625	10,710	10,631	10,614
15. NOF (%)	87.0	84.0	86.1	90.0	86.1	89.3	87.7	86.6	82.2	85.6	81.5	85.3	86.1
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365
17. ANOHR EQUATION	ANOHR = NOF(	-20.706	) +	12,397									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	82.8	54.3	82.8	82.8	82.8	82.8	82.8	82.8	82.8	50.8	77.3	82.8	77.4
2. POF	0.0	34.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.7	6.7	0.0	6.6
3. EUOF	17.2	11.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	10.5	16.0	17.2	16.0
4. EUOR	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	647	397	647	627	647	627	647	647	627	397	585	647	7,142
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	97	299	96	93	97	93	97	97	93	347	136	97	1,642
9. POH	0	240	0	0	0	0	0	0	0	288	48	0	576
10. EFOH	101	62	101	97	101	97	101	101	97	62	91	101	1,111
11. EMOH	27	17	27	26	27	26	27	27	26	17	24	27	297
12. OPER BTU (GBTU)	2,557	1,411	2,599	2,473	2,537	2,510	2,561	2,562	2,501	1,525	2,175	2,426	27,853
13. NET GEN (MWH)	242,130	129,360	247,550	236,010	241,640	240,830	244,730	244,830	239,770	144,210	203,460	225,900	2,640,420
14. ANOHR (Btu/kwh)	10,558	10,909	10,498	10,477	10,499	10,420	10,464	10,463	10,433	10,575	10,689	10,740	10,549
15. NOF (%)	87.6	76.3	89.6	90.3	89.6	92.1	90.7	90.7	91.7	87.1	83.4	81.8	88.0
16. NPC (MW)	427	427	427	417	417	417	417	417	417	417	417	427	420
17. ANOHR EQUATION	ANOHR = NOF(		-30.914	) +	13,268								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	96.0	96.0	96.0	67.2	15.5	96.0	96.0	96.0	96.0	96.0	80.0	96.0	85.5
2. POF	0.0	0.0	0.0	30.0	83.9	0.0	0.0	0.0	0.0	0.0	16.6	0.0	10.9
3. EUOF	4.0	4.0	4.0	2.8	0.6	4.0	4.0	4.0	4.0	4.0	3.3	4.0	3.6
4. EUOR	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	724	677	724	490	117	700	724	724	700	724	584	724	7,612
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	20	19	19	230	627	20	20	20	20	20	137	20	1,172
9. POH	0	0	0	216	624	0	0	0	0	0	120	0	960
10. EFOH	17	16	17	11	3	16	17	17	16	17	14	17	178
11. EMOH	13	12	13	9	2	13	13	13	13	13	10	13	136
12. OPER BTU (GBTU)	1,525	1,428	1,524	1,037	244	1,479	1,523	1,549	1,504	1,540	1,231	1,535	16,120
13. NET GEN (MWH)	148,600	139,260	148,470	101,500	23,560	144,560	148,290	152,770	148,750	151,200	120,000	150,400	1,577,360
14. ANOHR (Btu/kwh)	10,260	10,251	10,264	10,221	10,341	10,234	10,269	10,141	10,110	10,186	10,256	10,209	10,220
15. NOF (%)	93.3	93.5	93.2	94.2	91.5	93.9	93.1	95.9	96.6	94.9	93.4	94.4	94.2
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(		-45.481	) +	14,504								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	98.5	98.5	76.3	98.5	98.5	98.5	98.5	98.5	98.5	76.3	98.5	98.5	94.8
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	22.6	0.0	0.0	3.8
3. EUOF	1.5	1.5	1.1	1.5	1.5	1.5	1.5	1.5	1.5	1.1	1.5	1.5	1.4
4. EUOR	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	448	527	436	415	432	445	474	493	470	257	371	511	5,279
7. RSH	285	158	131	294	301	264	259	240	239	311	339	222	3,045
8. UH	11	10	176	11	11	11	11	11	11	176	11	11	459
9. POH	0	0	168	0	0	0	0	0	0	168	0	0	336
10. EFOH	3	3	2	3	3	3	3	3	3	2	3	3	31
11. EMOH	8	8	6	8	8	8	8	8	8	6	8	8	93
12. OPER BTU (GBTU)	1,831	2,330	2,008	1,764	1,905	1,991	2,138	2,243	2,124	1,053	1,515	2,220	23,125
13. NET GEN (MWH)	251,490	320,680	276,800	243,520	263,220	275,350	295,710	310,350	293,850	145,130	208,890	305,440	3,190,430
14. ANOHR (Btu/kwh)	7,282	7,265	7,255	7,245	7,236	7,232	7,230	7,228	7,230	7,254	7,255	7,268	7,248
15. NOF (%)	70.8	76.8	80.2	83.6	87.0	88.3	89.0	89.7	89.2	80.6	80.3	75.5	82.6
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-2.816	) +		7,481							

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

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-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012
1. EAF (%)	96.6	33.3	0.0	77.3	96.6	96.6	96.6	96.6	96.6	96.6	74.1	96.6	80.0
2. POF	0.0	65.5	100.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	17.2
3. EUOF	3.4	1.2	0.0	2.7	3.4	3.4	3.4	3.4	3.4	3.4	2.6	3.4	2.8
4. EUOR	3.4	3.4	0.0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	232	65	0	505	611	604	641	647	631	602	303	304	5,144
7. RSH	487	167	0	51	108	92	78	71	65	116	231	414	1,880
8. UH	26	464	743	164	26	25	26	26	25	26	187	26	1,760
9. POH	0	456	743	144	0	0	0	0	0	0	168	0	1,511
10. EFOH	1	0	0	1	1	1	1	1	1	1	1	1	9
11. EMOH	25	8	0	19	25	24	25	25	24	25	18	25	241
12. OPER BTU (GBTU)	1,360	385	0	2,883	3,595	3,565	3,772	3,854	3,785	3,471	1,652	1,898	30,304
13. NET GEN (MWH)	184,350	52,170	0	394,460	493,670	489,650	517,980	529,900	520,780	475,410	224,950	258,930	4,142,250
14. ANOHR (Btu/kwh)	7,377	7,373	0	7,308	7,283	7,280	7,283	7,273	7,267	7,300	7,343	7,331	7,316
15. NOF (%)	76.0	76.4	0.0	84.0	87.0	87.3	87.0	88.2	88.9	85.0	79.9	81.4	83.2
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(		-8.469	) +		8,020							

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ORIGINAL SHEET NO. 8.401.12E

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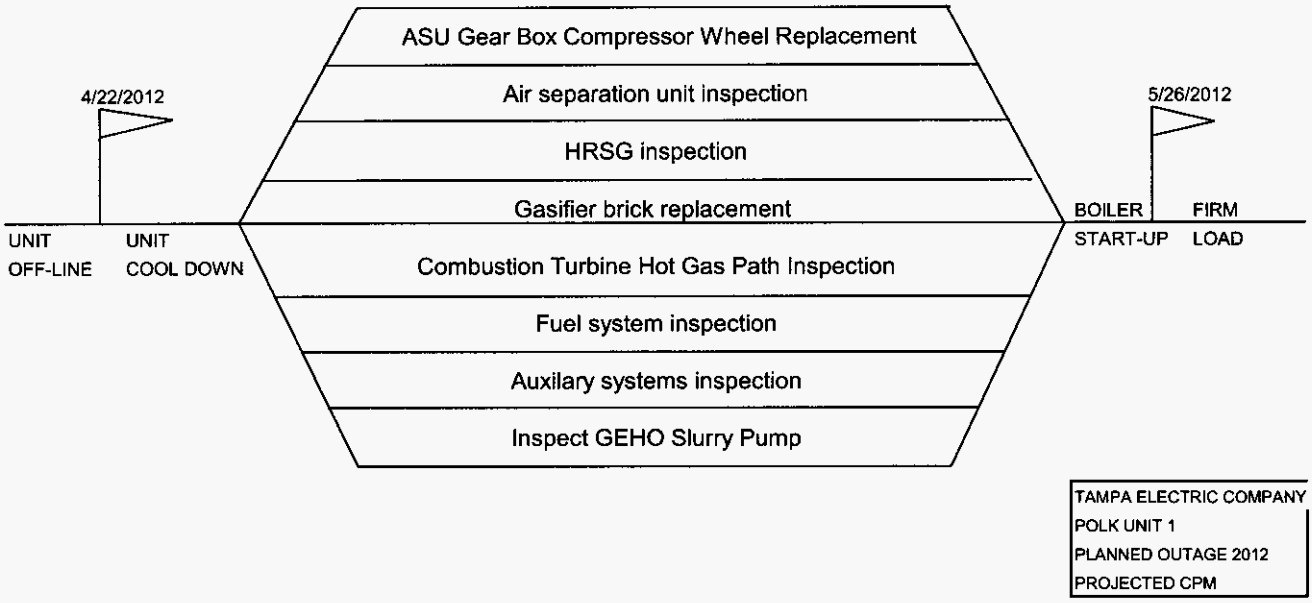
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2012 - DECEMBER 2012

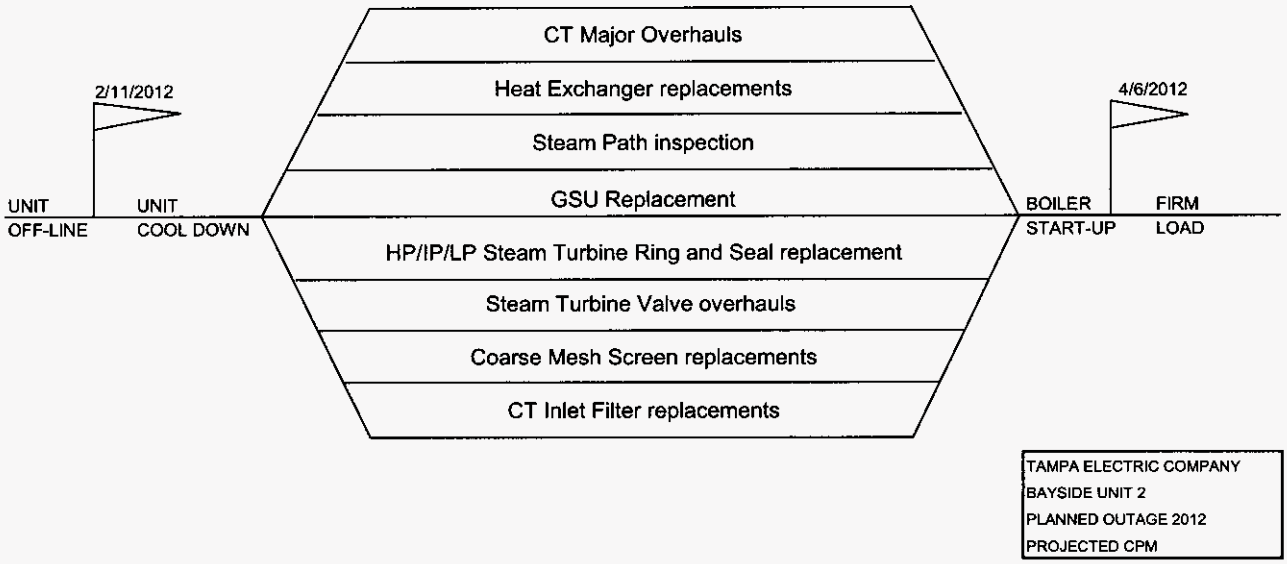
	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
	BIG BEND 1	Apr 08 - Apr 21	Fuel System Cleanup and Scrubber work
		Dec 02 - Dec 08	Fuel System Cleanup
	BIG BEND 2	Apr 07 - Apr 20	Fuel System Cleanup and Scrubber work
		Dec 03 - Dec 09	Fuel System Cleanup
	BIG BEND 3	Mar 11 - Mar 20	Fuel System Cleanup
		Sep 15 - Sep 28	Fuel System Cleanup and Scrubber work
	BIG BEND 4	Feb 04 - Feb 13	Fuel System Cleanup
		Oct 20 - Nov 02	Fuel System Cleanup and Scrubber work
+	POLK 1	Apr 22 - May 26	Gasifier / CT Outage, HRSG Inspection, Air Separation Unit (ASU) Inspection and Gearbox Compressor Wheel Replacement, Gassifier Brick Replacement, CT Hot Gas Path Inspection, Fuel System Inspection, Aux System Inspection, GEHO Slurry Pump Repair
		Nov 11 - Nov 15	Gasifier Outage
	BAYSIDE 1	Mar 01 - Mar 09	Fuel System Cleanup
		Oct 04 - Oct 12	Fuel System Cleanup
+	BAYSIDE 2	Feb 06 - Apr 06	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 23	Fuel System Cleanup

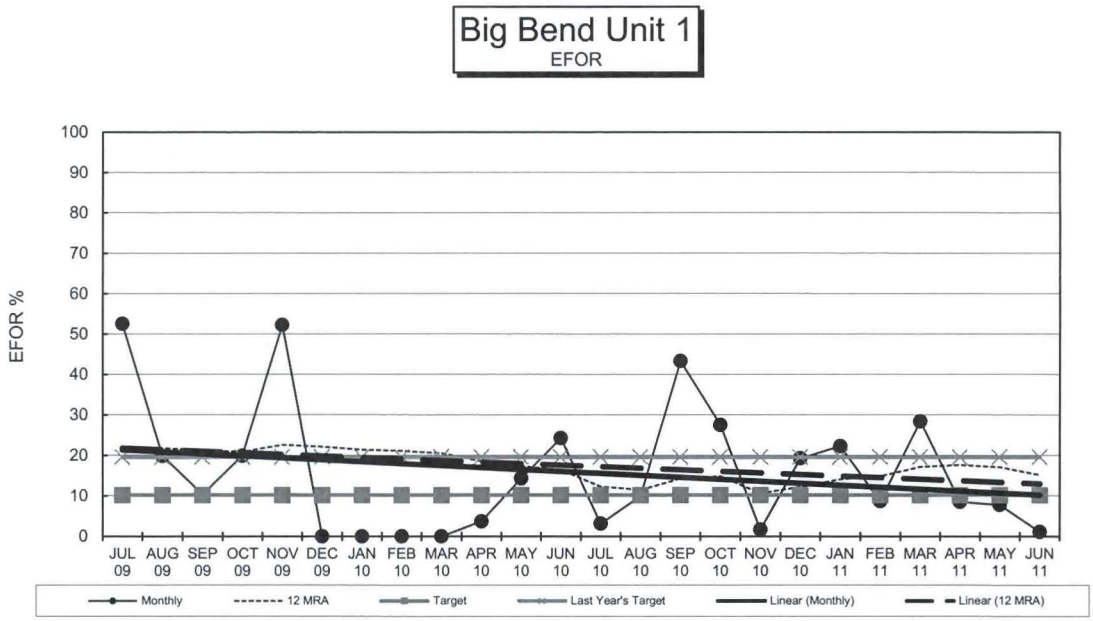
+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2012 - DECEMBER 2012



TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2012 - DECEMBER 2012




Big Bend Unit 1
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EFOR %
100
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JUL 09
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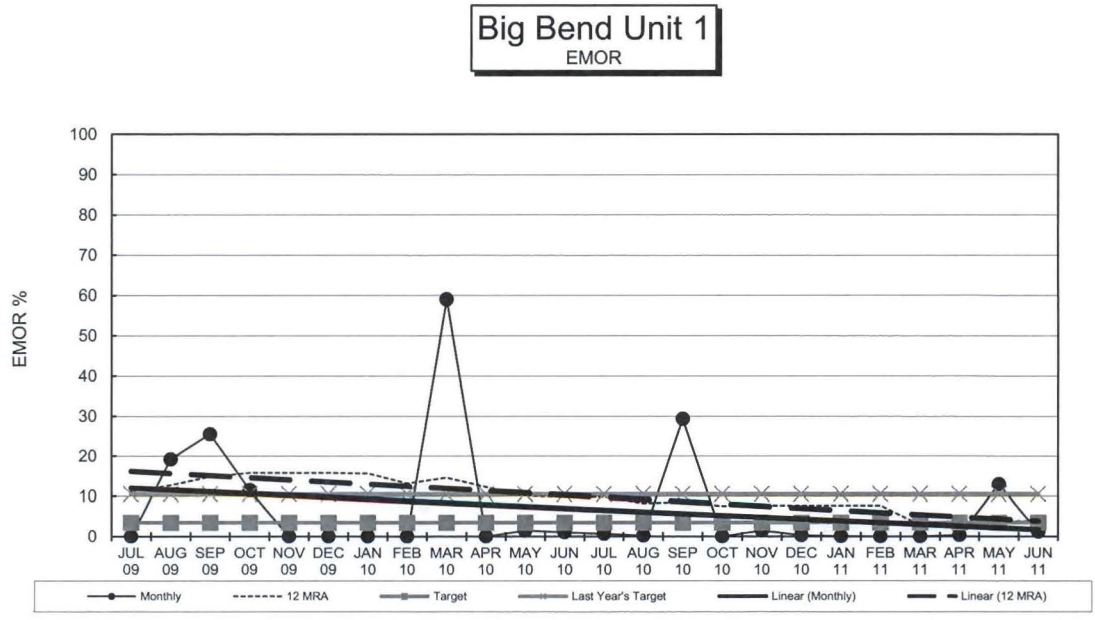
MAY 11
JUN 11
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EMOR %
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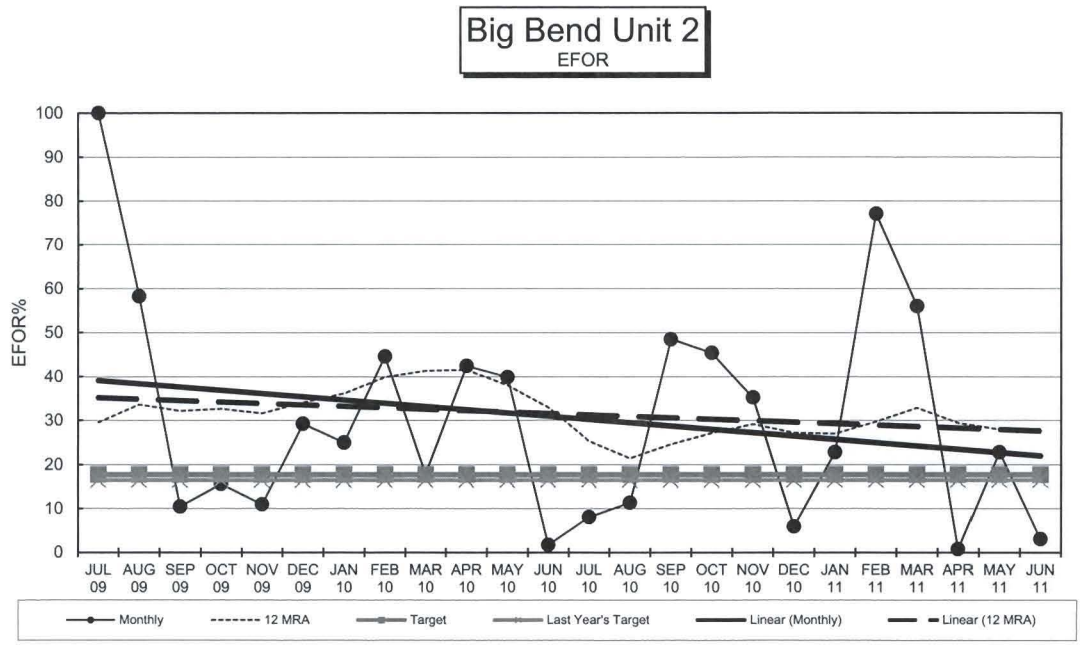
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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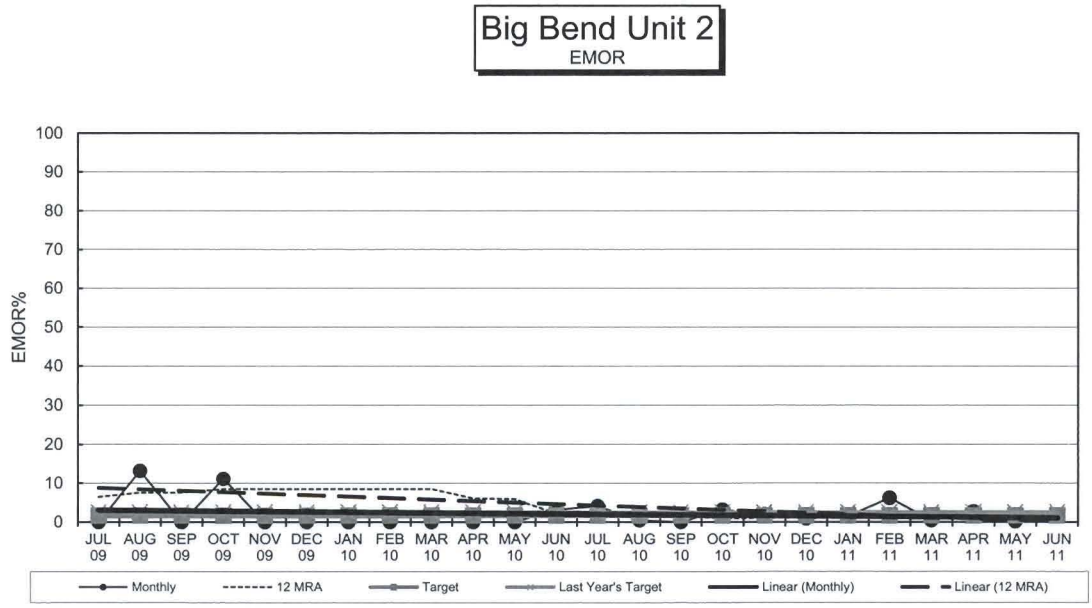
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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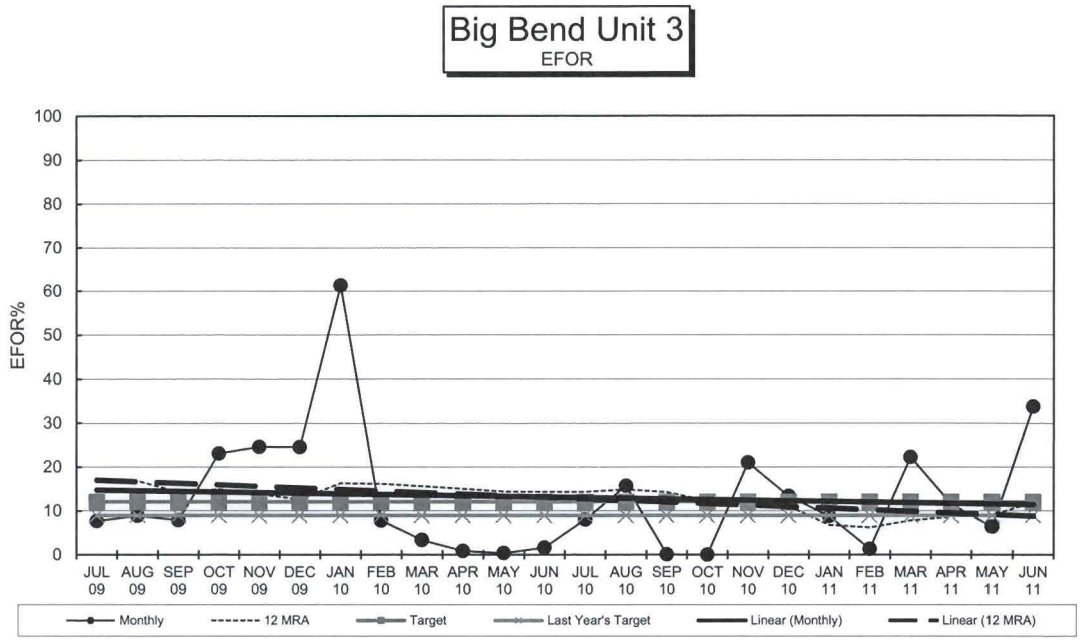
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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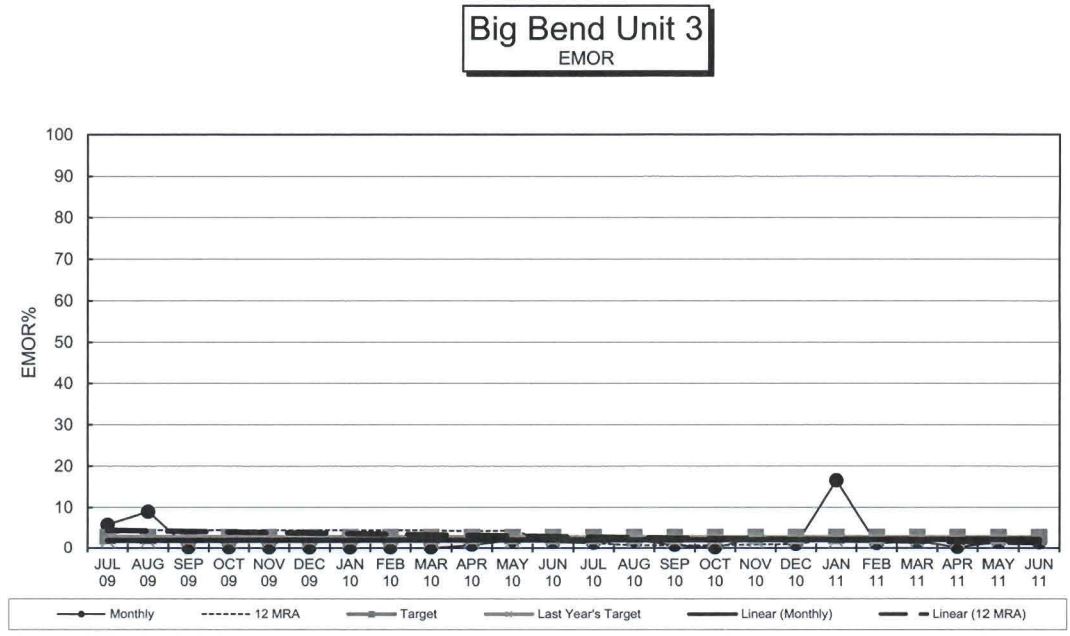
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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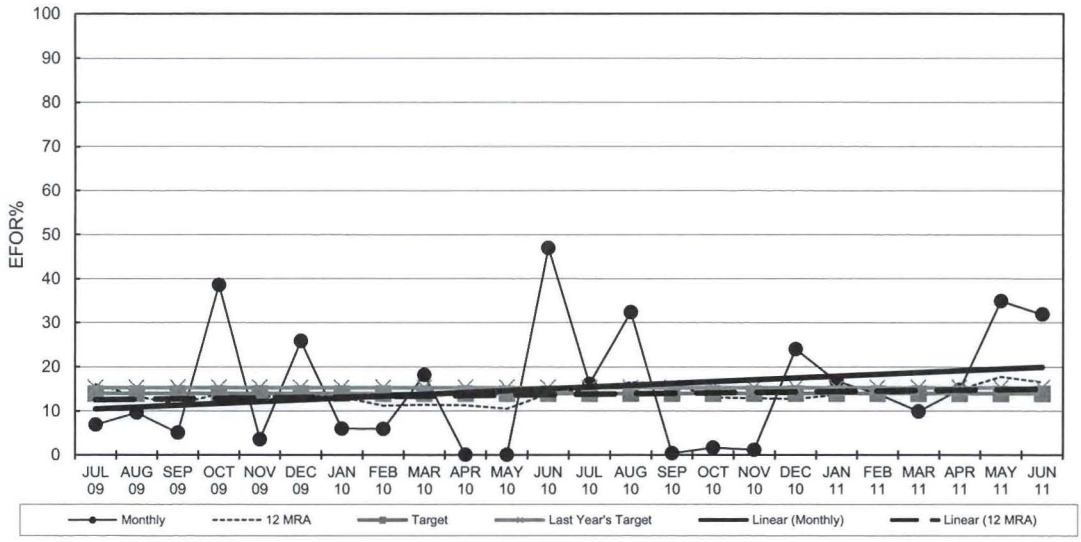
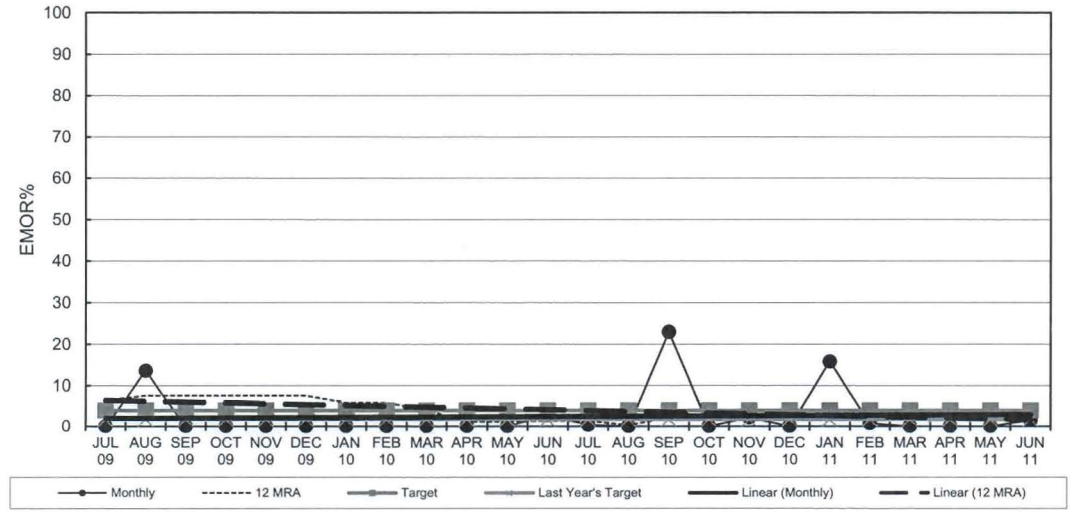
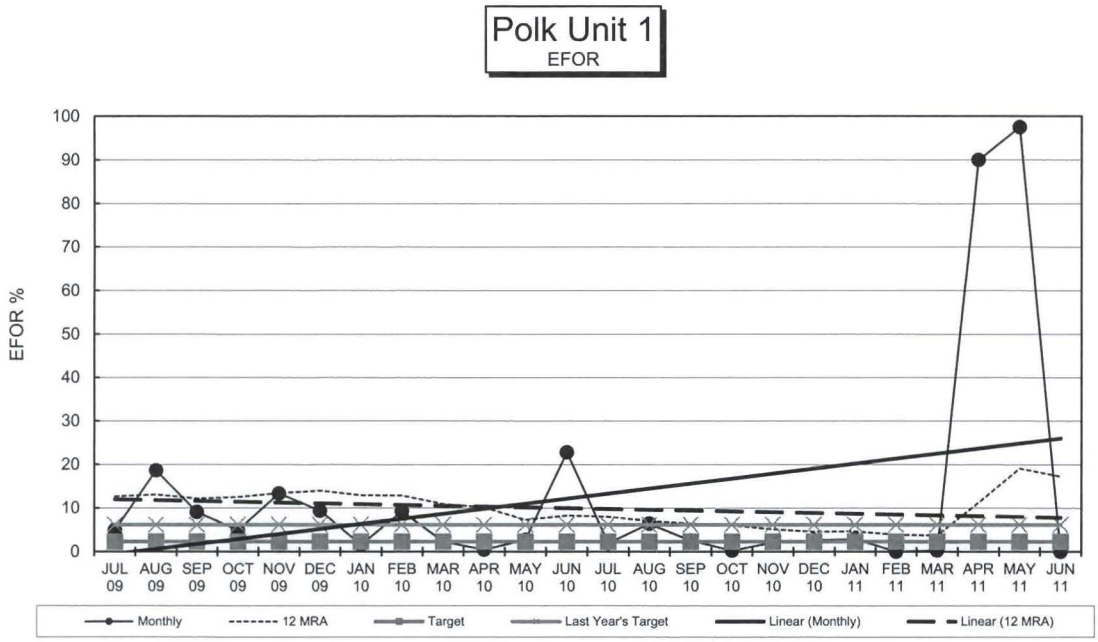
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Big Bend Unit 4
EFOR



Big Bend Unit 4
EMOR

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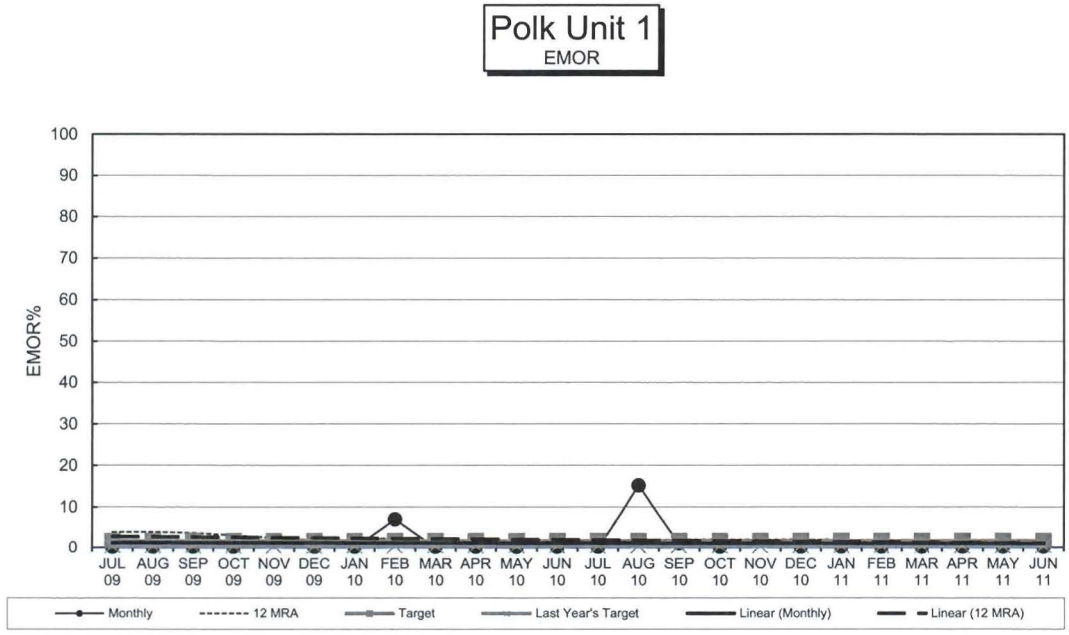
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
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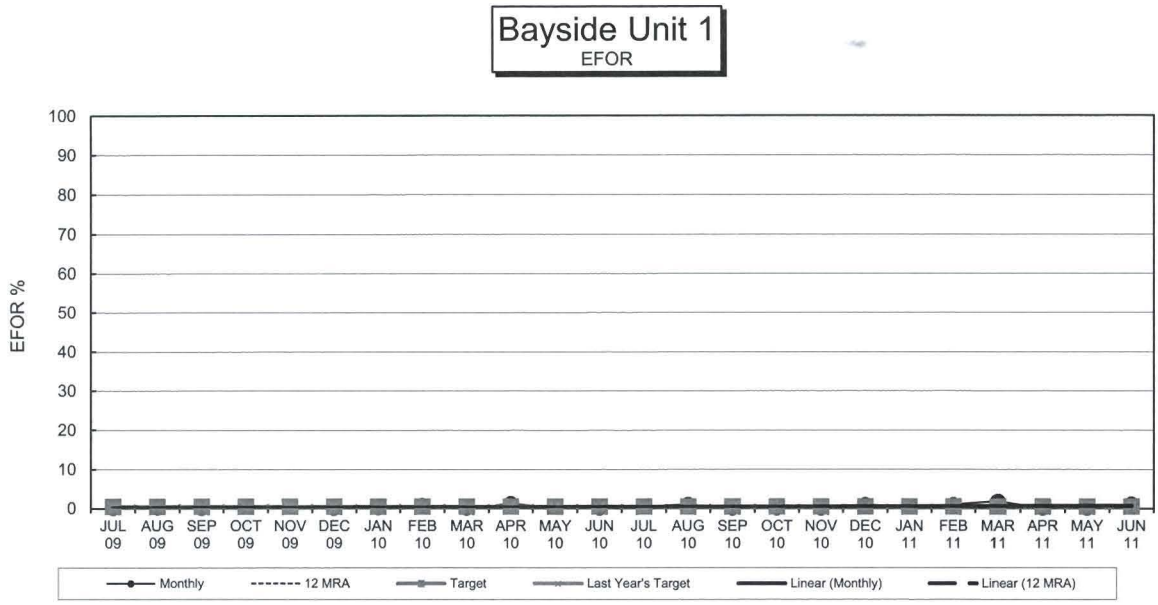
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
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EFOR %
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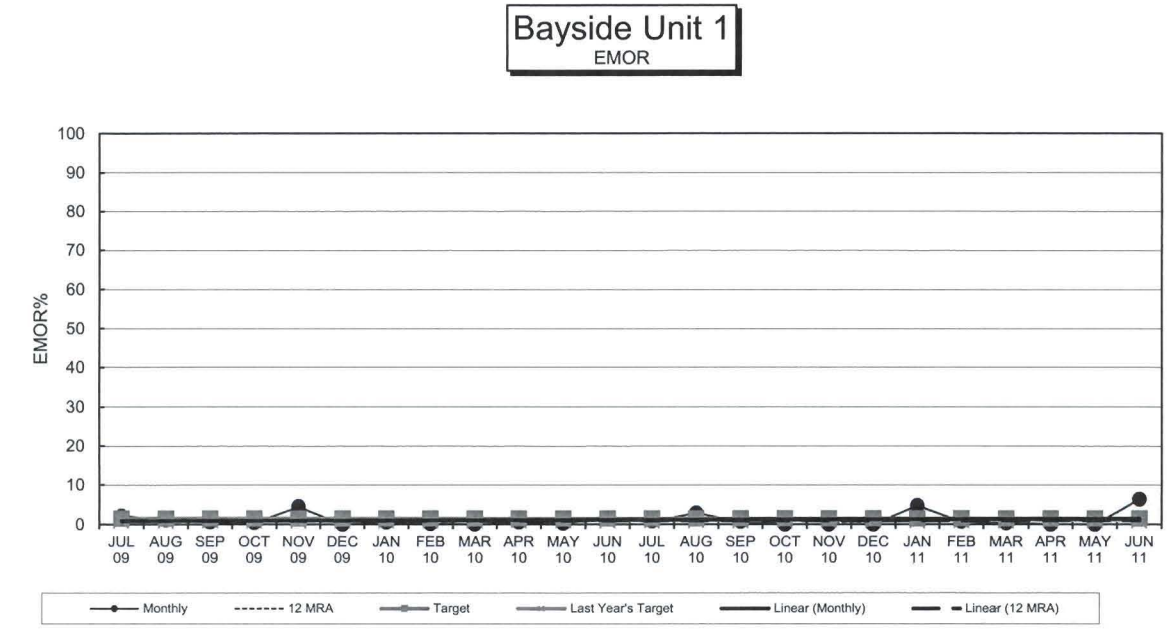
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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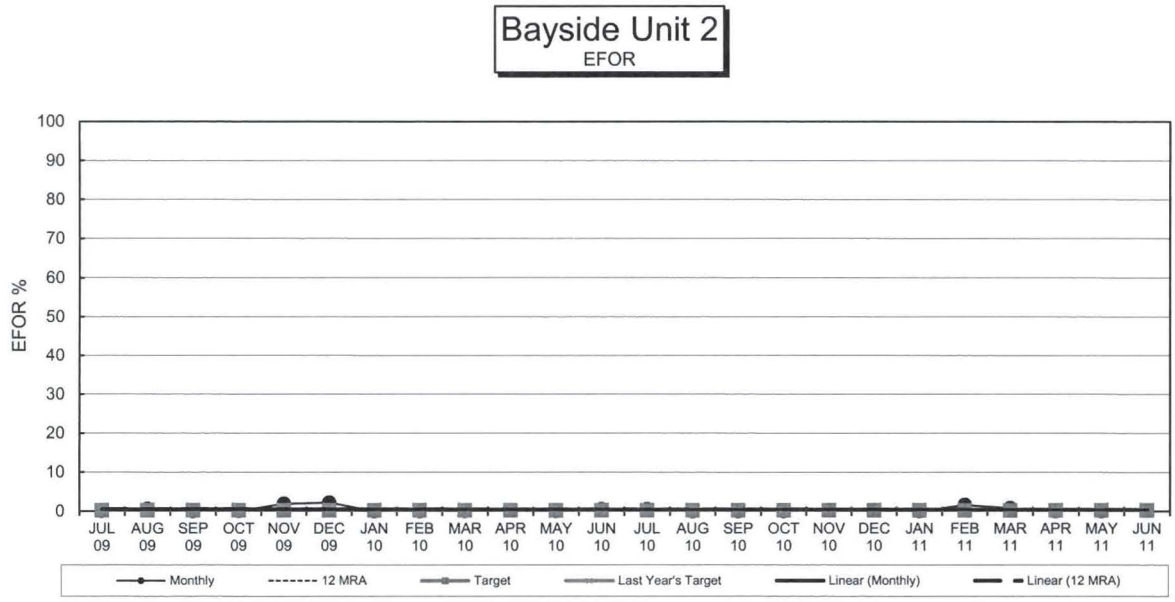
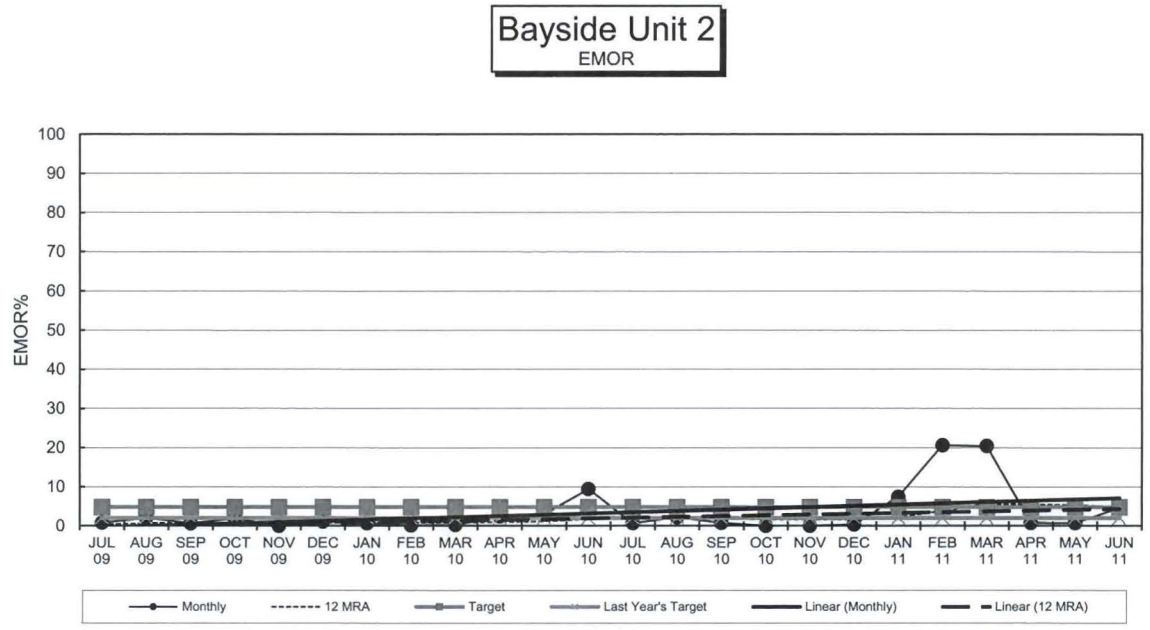
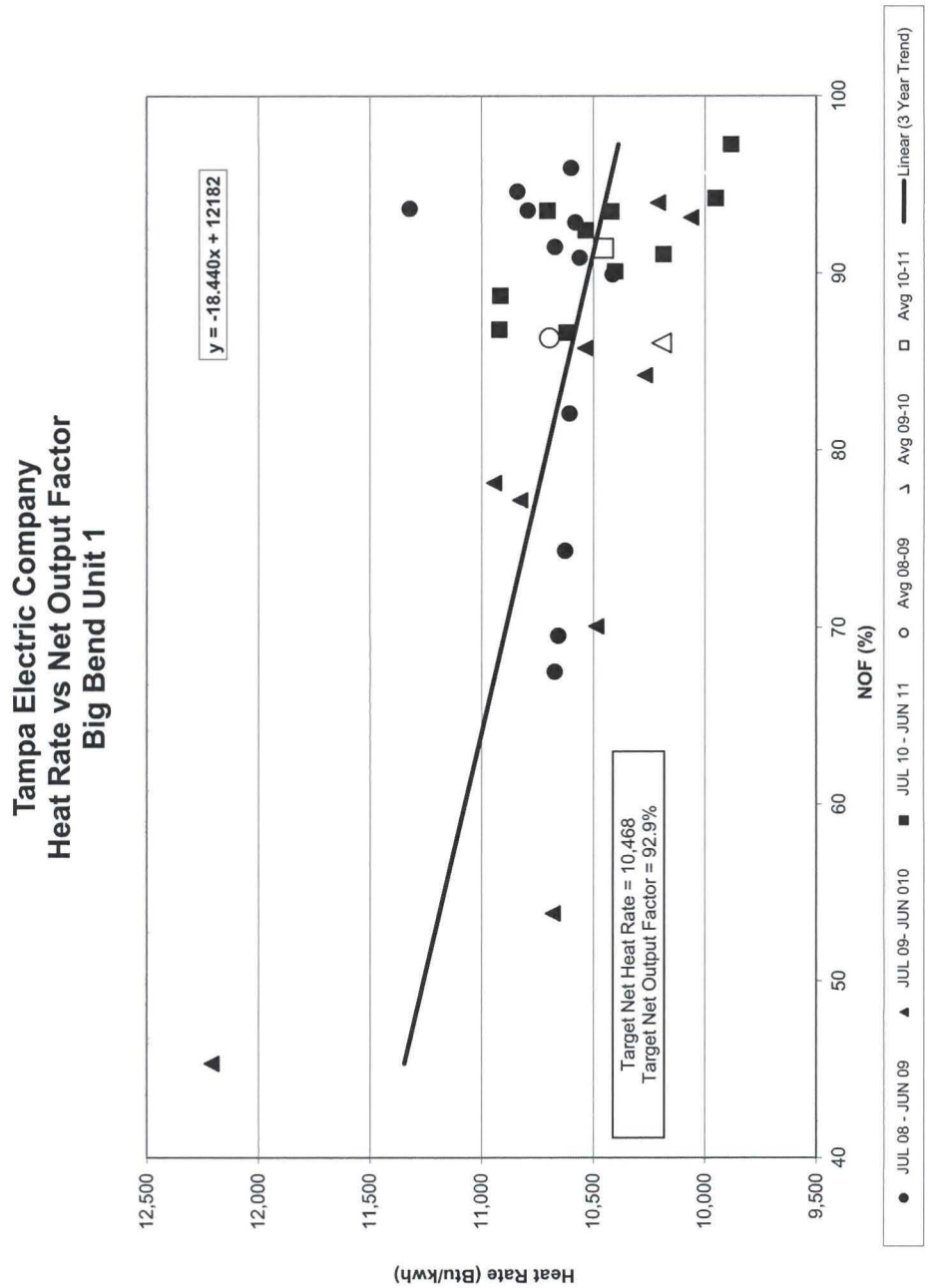
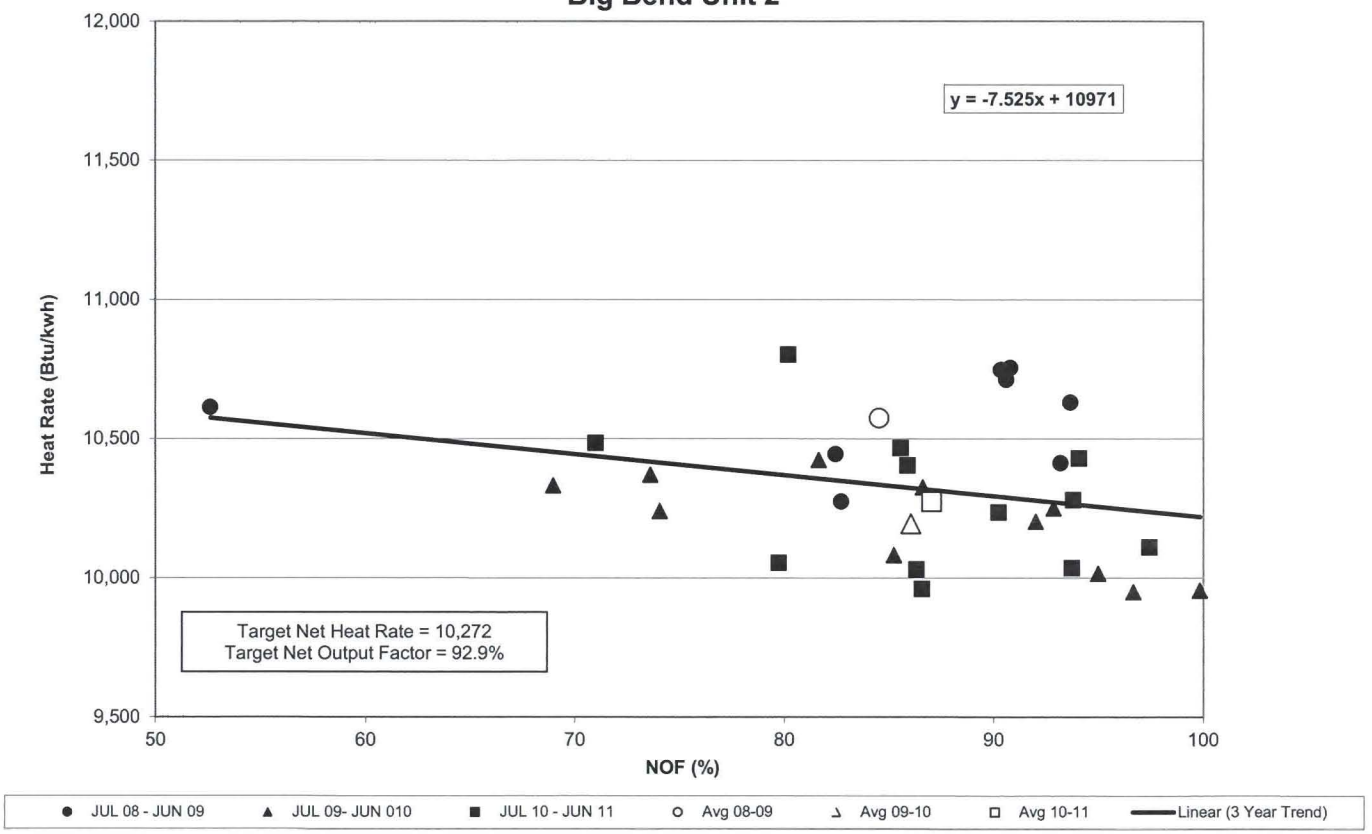
0
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

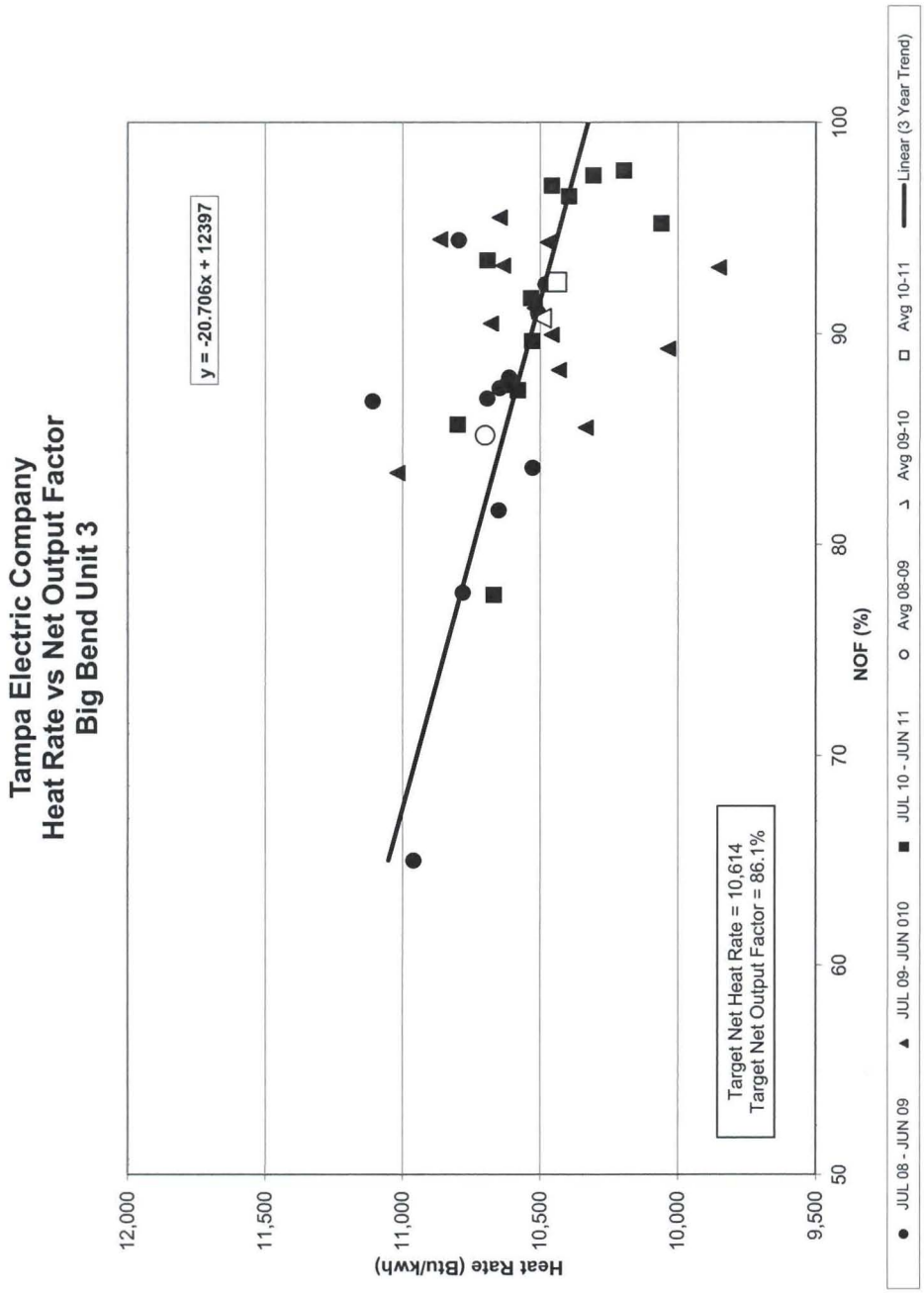

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 09
AUG 09
SEP 09
OCT 09
NOV 09
DEC 09
JAN 10
FEB 10
MAR 10
APR 10
MAY 10
JUN 10
JUL 10
AUG 10
SEP 10
OCT 10
NOV 10
DEC 10
JAN 11
FEB 11
MAR 11
APR 11
MAY 11
JUN 11
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

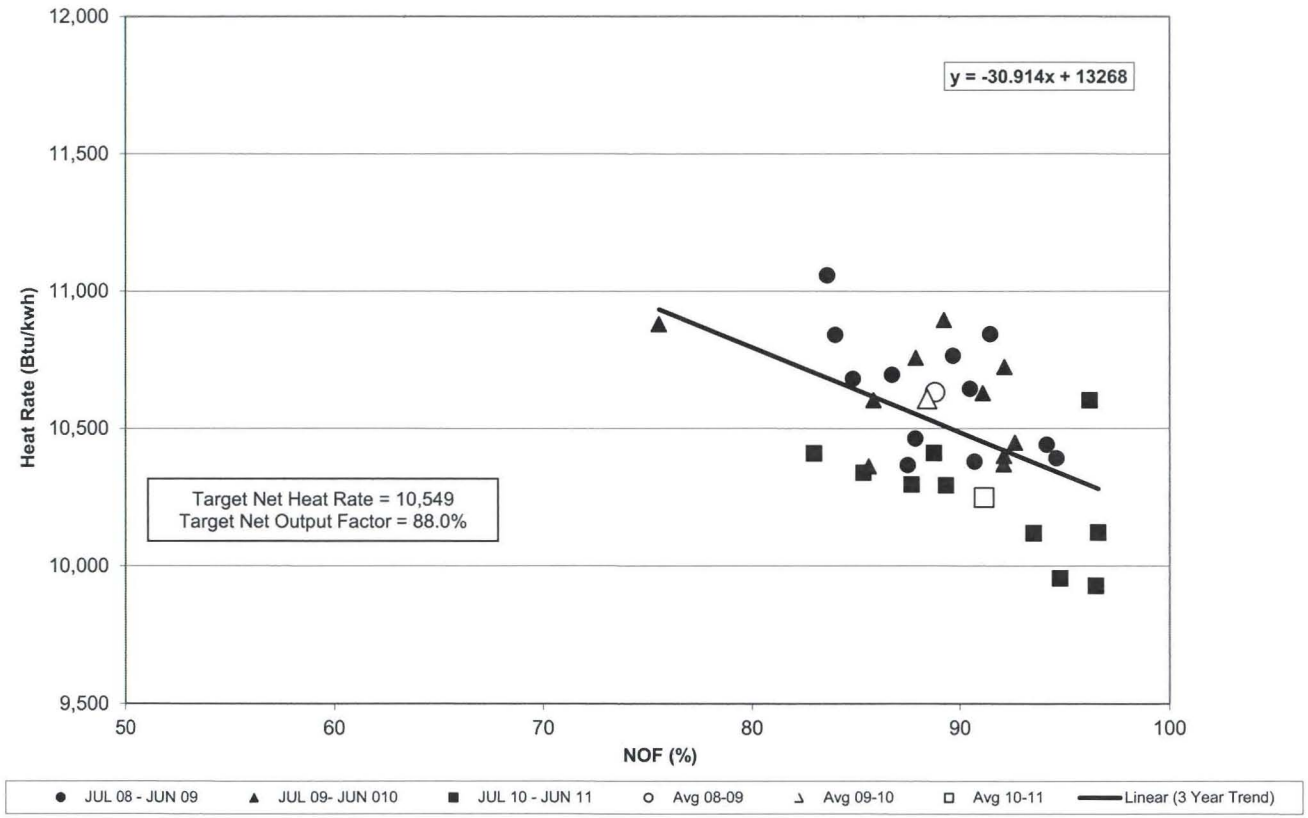

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1
y = -18.440x + 12182
Target Net Heat Rate = 10,468
Target Net Output Factor = 92.9%
Heat Rate (Btu/kwh)
NOF (%)
12,500
12,000
11,500
11,000
10,500
10,000
9,500
40
50
60
70
80
90
100
JUL 08 - JUN 09
JUL 09- JUN 010
JUL 10 - JUN 11
Avg 08-09
Avg 09-10
Avg 10-11
Linear (3 Year Trend)

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

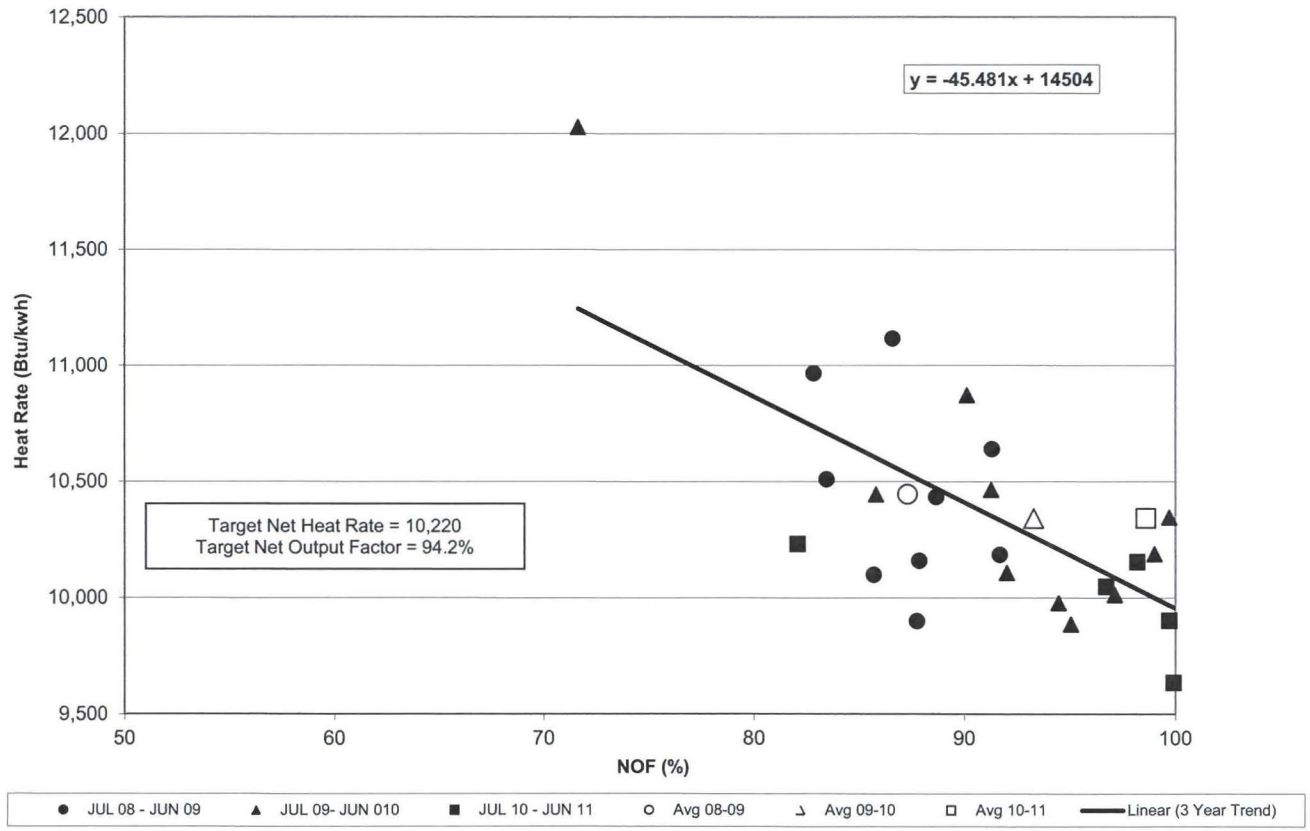


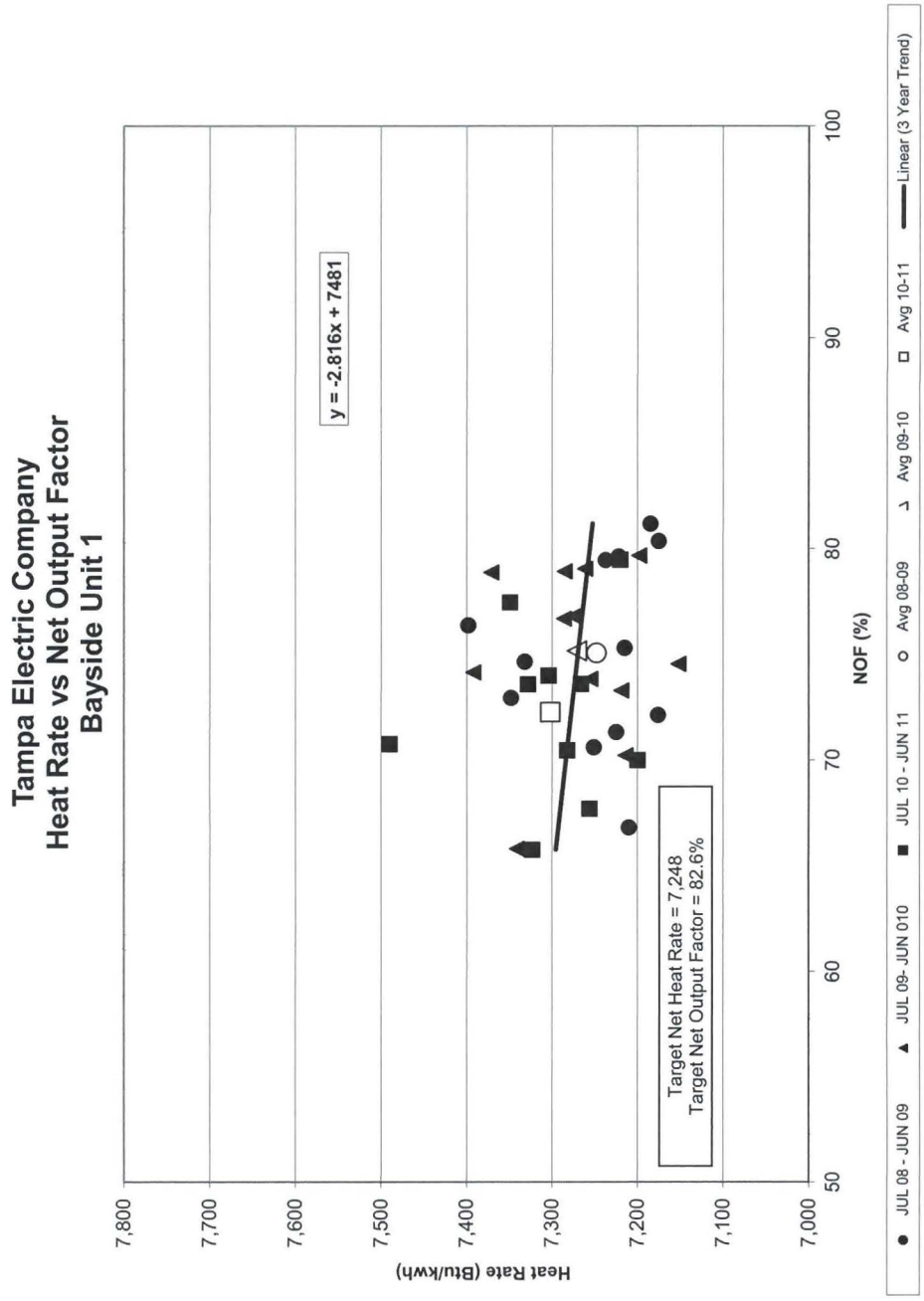

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
y = -20.706x + 12397
Target Net Heat Rate = 10,614
Target Net Output Factor = 86.1%
Heat Rate (Btu/kwh)
12,000
11,500
11,000
10,500
10,000
9,500
NOF (%)
50
60
70
80
90
100
JUL 08 - JUN 09
JUL 09- JUN 010
JUL 10 - JUN 11
Avg 08-09
Avg 09-10
Avg 10-11
Linear (3 Year Trend)

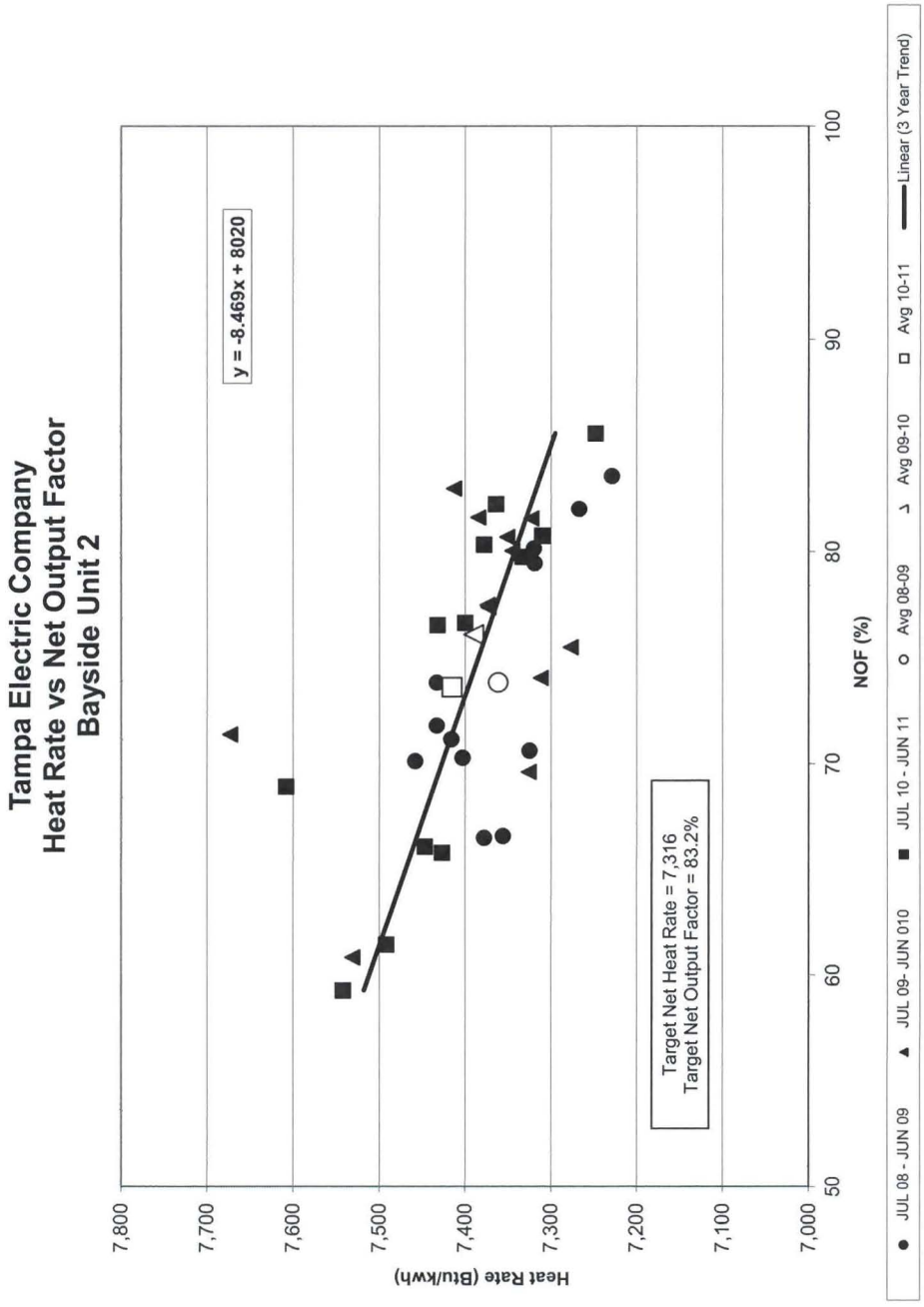
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4



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




Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
y = -2.816x + 7481
Target Net Heat Rate = 7,248
Target Net Output Factor = 82.6%
Heat Rate (Btu/kwh)
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
NOF (%)
50
60
70
80
90
100
JUL 08 - JUN 09
JUL 09- JUN 010
JUL 10 - JUN 11
Avg 08-09
Avg 09-10
Avg 10-11
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -8.469x + 8020
Target Net Heat Rate = 7,316
Target Net Output Factor = 83.2%
Heat Rate (Btu/kwh)
NOF (%)
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
50
60
70
80
90
100
JUL 08 - JUN 09
JUL 09- JUN 010
JUL 10 - JUN 11
Avg 08-09
Avg 09-10
Avg 10-11
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2012 - DECEMBER 2012

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 2012 - DECEMBER 2012

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 2012 - DECEMBER 2012

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,142,250	21.49%	21.49%
BAYSIDE	1	3,190,430	16.56%	38.05%
BIG BEND	1	2,682,450	13.92%	51.97%
BIG BEND	4	2,640,420	13.70%	65.67%
BIG BEND	2	2,541,330	13.19%	78.86%
BIG BEND	3	2,292,860	11.90%	90.76%
POLK	1	1,577,360	8.19%	98.94%
POLK	4	94,320	0.49%	99.43%
POLK	5	52,490	0.27%	99.70%
BAYSIDE	5	23,910	0.12%	99.83%
BAYSIDE	6	13,670	0.07%	99.90%
BAYSIDE	3	7,210	0.04%	99.94%
BAYSIDE	4	4,920	0.03%	99.96%
POLK	2	4,380	0.02%	99.98%
BIG BEND CT	4	2,070	0.01%	100.00%
POLK	3	870	0.00%	100.00%
TOTAL GENERATION		19,270,940	100.00%	

GENERATION BY COAL UNITS: 11,734,420 MWH
% GENERATION BY COAL UNITS: 60.89%
GENERATION BY NATURAL GAS UNITS: 7,536,520 MWH
% GENERATION BY NATURAL GAS UNITS: 39.11%

GENERATION BY OIL UNITS: - MWH
% GENERATION BY OIL UNITS: 0.00%
GENERATION BY GPIF UNITS: 19,067,100 MWH
% GENERATION BY GPIF UNITS: 98.94%

DOCKET NO. 110001-EI
GPIF 2012 PROJECTION FILING
EXHIBIT NO. ____ (BSB-3)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2012 - DECEMBER 2012

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2012 - DECEMBER 2012

Unit	Availability			Net Heat Rate
	EAF	POF	EUOF	
Big Bend 1[1]	81.9	5.7	12.4	10,468
Big Bend 2[2]	76.2	5.7	18.1	10,272
Big Bend 3[3]	80.0	6.6	13.5	10,614
Big Bend 4[4]	77.4	6.6	16.0	10,549
Polk 1[5]	85.5	10.9	3.6	10,220
Bayside 1[6]	94.8	3.8	1.4	7,248
Bayside 2[7]	80.0	17.2	2.8	7,316

1 Original Sheet 8.401.12E, Page 14

2 Original Sheet 8.401.12E, Page 15

3 Original Sheet 8.401.12E, Page 16

4 Original Sheet 8.401.12E, Page 17

5 Original Sheet 8.401.12E, Page 18

6 Original Sheet 8.401.12E, Page 19

7 Original Sheet 8.401.12E, Page 20