BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	)))))	DOCKET NO. 060001-EI May 30, 2006

DIRECT TESTIMONY OF
JAMES A. ROSS

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of the State of Florida

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 060001-EI May 30, 2006

PREPARED DIRECT TESTIMONY AND EXHIBITS OF

JAMES A. ROSS

ON BEHALF OF THE

FLORIDA OFFICE OF PUBLIC COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060001-EI

DIRECT TESTIMONY OF
JAMES A. ROSS

INTRODUCATION AND SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is James A. Ross. I am a member of the consulting firm of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 500 Chesterfield Center, Suite 320, Chesterfield, Missouri 63017. A statement of my qualifications is attached as Appendix A (Exhibit ____).

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. RCS was engaged by the Florida Office of Public Counsel to evaluate whether, from the perspective of the electric utilities' ratepayers, time and experience have proven the Generating Performance Incentive Factor (GPIF) mechanism, adopted by the Florida Public Service Commission (Commission) in 1980, to be effective and equitable and, if not, to recommend steps needed to ensure the GPIF operates in a manner that is consistent with ratepayers' interests. The purpose of my testimony is to convey my conclusions and my recommendations.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATION.

A. My conclusions and recommendations are summarized as follows:

- In general, the investor-owned utilities on a whole have received significantly more rewards than penalties. The cumulative **net** payments (i.e., rewards less penalties) to Florida Power & Light Company (FP&L), Progress Energy Florida, Inc. (PEF, formerly Florida Power Corporation or FPC), and Gulf Power Company (Gulf) have, for the period April 1983 through December 2004, been about $120 million.

- The publicly available data indicate that, despite the incentive mechanism that resulted in the payment of (net) $120 million over time, the GPIF process has not prompted universal improvement in individual unit performance or in system-wide performance. The most striking example is the decline in TECO's system availablilty and heat rate performance for the period October 1989 throught December 2004.

- A review of the publicly available individual unit data for each of the utilities indicates that individual unit performance varies from year to year. The actual availability and heat rate performance for the individual units for the most part shows mixed improvement and, in some circumstances, degradation over time. The data also indicate that the availability and heat rate performance for many units was higher in past periods than in more recent periods.

- Fundamentally, a regulated utility has an obligation to operate efficiently. Any incentive mechanism should take this tenet into account, and reward only performance that demonstrates material and meaningful improvements. Importantly, the incentive mechanism should not result in rewards for performance that shows no exemplary gains or even long-term declines.

- Based on my review of publicly available data, I recommend that the Commission revise the GPIF process to treat ratepayers more equitably. This can be accomplished by imposing a Generating Performance Incentive Points (GPIP) dead-band. Establishing a GPIP dead-band for effectuating rewards and penalties is a modification that will require only minimal changes to the GPIF methodology as a whole.

- The GPIP dead-band would simply be applied in the last step of the GPIF methodology; thus, all other aspects of the current GPIF would be unaffected. In other words, the utilities would continue to calculate the GPIF components as currently defined in the methodology, including the GPIP.

- In addition to the GPIP dead-band modification, the Commission can address the problem of a consistent decline in system performance over time (as in the case of TECO) by establishing absolute system weighted EAF and HR numbers that would preclude any reward payment for actual performance below these established minimum performance levels.

BACKGROUND

Q. WHAT IS THE GENERATING PERFORMANCE INCENTIVE FACTOR?

A. The Generating Performance Incentive Factor, or GPIF, is a reward/penalty mechanism that the Commission prescribed in 1980. The stated purpose of the Generating Performance Incentive Factor is to encourage utilities to improve the productivity of their baseload generating units.

Q. HOW DOES THE GPIF ASSESS THE EFFICIENCY OF GENERATING UNITS?

A. The GPIF focuses on two aspects of generating efficiency over which the Commission has determined the utilities can exercise some control.

The first aspect is the "heat rate" of a generating unit. The heat rate quantifies the amount of fuel that must be consumed to produce a unit of electricity and is expressed in British thermal units (Btu's) per kilowatthour (kWh). A reduction in the heat rate of a unit signifies an improvement in efficiency, because the generating unit requires less fuel to generate a kilowatthour of electricity.

The second aspect that the GPIF mechanism takes into account is the availability of a unit. A unit is deemed available if it is able and ready to generate electricity when called upon. If a unit is unavailable at a time when it would be the most economical unit to operate, the utility must operate a more expensive unit and incur higher fuel costs. An increase in a unit's availability rating signifies an improvement in unit performance.

Q. DESCRIBE HOW THE GPIF MEASURES HEAT RATE AND AVAILABILITY FOR THE PURPOSE OF ESTABLISHING REWARDS AND PENALTIES.

A. The generating units that are the subjects of the mechanism are identified at the outset of the period during which performance will be measured. For each such unit the utility owner submits, for Commission approval, targets for heat rate and availability that will be effective during a projection period. At the end of the period, the actual operating data are compared to the utility's targets. The comparisons are translated into a score measured in terms of Generating Performance Incentive Points (GPIP). If a utility earns a positive score (between 1 and 10 GPIP), it receives a reward. If the utility's score is negative, it is penalized.

Q. HOW DOES THE GPIF QUANTIFY THE POSSIBLE RANGE OF REWARDS AND PENALTIES?

A. The maximum reward or penalty is measured in terms of 25 basis points on the utility's average equity for the period. These limits become the extreme points of the scale that is divided into 10 positive GPIP points and 10 negative GPIP points.

Q. PLEASE ILLUSTRATE THE CALCULATIONS NECESSARY TO DETERMINE THE REWARD OR PENALTY THAT A UTILITY RECEIVES UNDER THE GPIF.

A. The calculation of the maximum reward/penalty allowed in the GPIF methodology is illustrated hypothetically in Schedule 1 of Exhibit______ (JAR-1). Page 1 of Schedule 1 shows that the maximum allowed incentive is a function of the revenue associated with 25 basis points (0.25%) return on average jurisdictional common equity for the evaluation period. The calculation of the GPIF requires complex simulations of the utility's system dispatch. It also involves and a projection of an individual generating unit's overall availability, after taking into account full and partial planned and unplanned outages (equivalent availability factor, or EAF), and average heat rate (i.e., the determination of specific "targets"). For each unit, a target and a maximum reasonable attainable range of potential improvement (as well as provision for degradation) is determined, along with a "weighting factor" to reflect the percent contribution to total system fuel savings. Page 2 of Schedule 1 illustrates the results of this aspect of the calculation for a typical evaluation period.

As illustrated on Page 3 of Schedule 1 to Exhibit______ (JAR-1), the individual unit data are consolidated to generate a utility system reward/penalty table associated with the Generating Performance Incentive Points (GPIP) ranging from -10 to +10. At the end of the evaluation period, actual unit EAF and average heat rates are compared to the pre-established targets. Based on this comparison, a total system GPIP is determined which corresponds to a monetary reward/penalty based on the deviation of individual unit performances from their targets.

Q. WHAT GOVERNS THE CALCULATION OF THE GPIP?

A. The Commission prescribed the methodology in the form of a formula, which appears in the GPIF manual that accompanied the order adopting the GPIF. The formula for computing the GPIP is presented below:

4.2.3 **<u>Generating Performance Incentive Points</u>**

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

Where:

GPIP = Generating performance incentive points

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

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

EAP_i = Equivalent availability points awarded/deducted for unit i

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

Q. FOR WHAT PERIODS DOES THE COMMISSION REVIEW GENERATING PERFORMANCE FOR PURPOSES OF THE GPIF?

A. Initially, the Commission determined that the utilities' GPIF's would be subject to six-month review periods. These six-month periods ranged from April through September in a given calendar year and from October in one calendar year through March of the following calendar year. Thus, the review period and subsequent Commission GPIF determinations reflected six-month reward/penalty data and six-month individual unit data for the periods "April through September" and "October through March".

This six-month review was continued until 1999. Beginning with calendar year 1999, each utility's GPIF review was performed on a calendar year basis. Data from Commission decisions and utility filings with the Commission beginning in calendar year 1999 forward are presented on a 12-month calendar year basis. (The Commission determined that since performance targets are set prospectively, the GPIF methodology allows for adjustments to the EAF and HR performance indicators where such adjustments are determined to be appropriate by the Commission.)

Q. PLEASE DESCRIBE YOUR REVIEW OF THE GPIF DATA.

A. I reviewed publicly available utility reward/penalty data, individual unit target performance data, and individual unit adjusted actual performance data that was obtained from Commission decisions and GPIF data filed with the Commission. The reward/penalty data was obtained for the period April 1983 through December 2004. Individual unit data was obtained for the period October 1989 through December 2004. This represents the most comprehensive period for which data was obtainable from the public record, although there is a limited amount of data during these periods could not be gleaned from the documents.

Q. DID YOU ADJUST ANY OF THE DATA THAT YOU RECEIVED?

A. Yes. Due to the nature of utility operations (e.g., planned maintenance), the comparison of both individual unit and system performance data over time is best evaluated on a 12-month basis. Accordingly, I annualized the six-month data for reward/penalty and unit performance. In general, I annualized the reward/penalty data by combining (i.e., adding) the six-month period "April through September" with the six-month period "October through March" for an annualized "April through March" period. (Some deviation from the general application was necessitated by differences in individual utility data availability and the transition to calendar year GPIF reviews beginning with calendar year 1999.)

With respect to the individual unit performance data, the annualized data was calculated by combining (i.e., averaging) the six-month EAF and HR data for only those units that were included in two consecutive six-month periods beginning with the period "October through March" (i.e., resulting in a consecutive 12-month period of "October through September"). For purposes of trend analysis, units with less than three annual periods of data were also excluded from the unit database.

Additionally, I developed system target and actual EAFs and HR's for selected annual periods. The system weighted performance data was calculated by normalizing the EAF and heat rate weighting percentages and applying those normalized percentages to calculate a weighted system EAF or heat rate number. For periods prior to the "calendar year GPIF reviews" (i.e., calendar year 1999), the system weighted EAF and heat rate numbers reflect an average of the two six-month weighted system numbers.

Q. WHAT DID YOU LEARN REGARDING THE REWARDS AND PENALTIES THAT HAVE BEEN PAID/IMPOSED OVER TIME?

A. In general, the investor-owned utilities in the aggregate have received significantly more rewards than penalties. The cumulative **net** payments (i.e., rewards less penalties) to Florida Power & Light Company, Progress Energy Florida, Inc. , and Gulf Power Company, for the period April 1983 through December 2004, totaled approximately $120 million.

Schedule 2 to Exhibit __ (JAR-1) presents the annualized reward/penalties for FP&L, PEF, Gulf and TECO for the period April 1983 through December 2004. Each of the investor-owned utilities has been assessed different rewards/penalties under the GPIF methodology. Each individual utility's reward/penalty is detailed in following sections of the testimony.

Q. HOW HAS FPL FARED UNDER THE GPIF?

A. On an absolute dollar basis, FPL has received the greatest monetary reward. FPL received a cumulative **net payment** on the order of $92 million during the period. Page 1 of Schedule 2 to Exhibit __ (JAR-1). presents the FPL reward/penalty beginning with April 1983 and concluding with calendar year 2004 (note that the graph excludes the period April 1997 through September 1997 for FPL because this information was not obtained). The FPL reward/penalty presented on Page 1 of Schedule 2 demonstrates that FPL has consistently received rewards in excess of penalties during the period evaluated.

Q. PLEASE DESCRIBE PEF'S HISTORY OF GPIF-RELATED REWARDS AND PENALTIES.

A On an absolute dollar basis, PEF is a distant second behind FP&L in receiving net monetary rewards under the GPIF methodology. PEF received a cumulative **net payment** on the order of $27 million. Page 2 of Schedule 2 to Exhibit ___ (JAR-1) shows this information in table format.

Q. PLEASE PROVIDE CORRESPONDING INFORMATION FOR GULF POWER.

A. Gulf received a cumulative **net payment** on the order of $3 million. Page 3 of Schedule 2 presents the Gulf reward/penalty beginning with April 1983 and concluding with calendar year 2004.

Q. PLEASE TURN TO TECO.

A. Page 4 of Schedule 2 to Exhibit __ (JAR-1) shows (Column 2 at Line 22) that TECO is the only utility that has experienced a cumulative **net penalty** under the GPIF methodology for the period annualized. TECO's cumulative **net penalty**, however, is only about $2.3 million. The penalties incurred by TECO in calendar years 2002 and 2003 were significant in comparison to past annualized periods. Nevertheless, Page 2 of Schedule 2 shows, at Line 20, that even factoring in the calendar year 2002 penalty, ratepayers had made a cumulative net payment to TECO through year 2002.

Q. WHAT IS THE SIGNIFICANCE OF THIS OBSERVATION?

A. As discussed in more detail below, the publicly available data indicates that TECO's system-wide performance has been on a declining trend since the 1990's.

Thus, any assumed correlation between enhanced system performance and the GPIF incentive is, at best, suspect.

Q. WHAT DID YOU CONCLUDE FROM YOUR ANALYSIS OF HISTORICAL DATA?

A. A review of the publicly available data indicates that the GPIF process has not prompted universal improvement in individual unit performance or in system-wide performance.

The most striking example is the TECO system EAF and HR performance, shown graphically in Schedule 3 to Exhibit __ (JAR-1) Figure 1 of Schedule 3 shows the system-related target and actual EAF for the period October 1989 through December 2004. The actual EAF linear trend line presented in this exhibit shows a significant downward trend in the EAF, which indicates a decline in performance.

Similarly, Figure 2 of Schedule 3 presents the system-related target and actual HR for the period October 1989 through December 2004. The linear trend line presented on Figure 2 shows a significant upward trend in the HR, which indicates a decline in performance (i.e., the higher the average heat rate, the more fuel consumed, and the greater the cost to generate a kWh of electricity). In short, over a period when the EAF and HR performance has declined, the utility continued to receive rewards under the GPIF.

Q. WHAT DID YOU OBSERVE REGARDING THE SETTING OF TARGETS OVER TIME?

A. A review of recent calendar year TECO system weighted EAF and HR data shows a decline (reduction in required performance) in the performance targets. Less demanding targets allow poorer system performance to either receive reward payments or incur reduced penalties relative to targets requiring better performance. Schedule 4 of Exhibit______ (JAR-1) shows the TECO target and actual adjusted EAF and HR data for calendar years 2001 through 2004. Note that the EAF target in 2004 reflected a 4.49% lower performance than the 2001 target, and the decline (deterioration) in the HR target for the same period was 2.66%. The result is that in calendar year 2004, TECO received a $729,534 reward payment from ratepayers for actual adjusted EAF and HR performance that was 2.21% and 1.21% poorer, respectively, than calendar year 2001 (a period for which TECO received a $831,029 **penalty**).

Q. IS THIS PHENOMENON UNIQUE TO TECO?

A. No. The circumstance of receiving a reward in a year where the system performance declined from that exhibited in an earlier year is not limited to TECO. A review of recent calendar year data shows that PEF also had declining target standards such that poorer performance resulted in rewards in comparison to a period where the system exhibited higher performance. Schedule 5 of Exhibit __ (JAR-1) compares the actual adjusted EAF, HR and reward data for calendar years 2001 and 2002. The actual adjusted EAF and HR performance for calendar year 2002 shows a decline in performance of 2.19% and 2.93%, respectively, from calendar year 2001. Nevertheless, PEF was awarded $2,781,223 in 2002 compared to $608,057 in 2001.

Q. WHAT ABOUT GULF POWER?

A. Schedule 6 of Exhibit______ (JAR-1) presents a similar example of two recent calendar years where a decline in Gulf's system performance in comparison to a prior year still resulted in a $441,988 reward.

Q. IN YOUR REVIEW, DID YOU DETECT AN OVERALL PATTERN TO THE PERFORMANCE DATA OF INDIVIDUAL UNITS?

A No. There was a general absence of sustained trends of improvement. The individual unit performance data for each of the utilities vary from year to year. Based on the historical range of variation, there is no indication that the prospect of GPIF rewards has universally resulted in significant and sustained improvements in unit performance. My review included a comparison of individual unit targets with individual unit actual data for all four utilities over time. The actual EAF and HR performance for the individual units, for the most part, show mixed results. The data also indicate that the EAF and HR performance for many units was higher in past periods than in more recent periods. The data for individual units over time are presented in Exhibit_____ (JAR-2).

The example of FP&L helps make the point. FPL has the highest number of generating units in its GPIF calculation. Only a relatively small percentage of the total FPL units in the program show linear trend improvements in both the EAF and HR annualized performance. This phenomenon is illustrated in Schedule 7 of Exhibit______ (JAR-1). The analysis includes the linear trend for each unit's EAF and HR for annualized data during the 15–year period October 1989 through December 2004, and also the six-year most recent calendar year 1999 through 2004 period. The information in Schedule 7 shows that, of the 27 units evaluated, only 59.3% had EAF trending improvements over the 15-year period. Moreover, of the

16 units which showed trending improvements during the 15-year period, only 6 of those 16 (or about 38%) also showed trending improvements over the more recent six-year period.

The HR data exhibits even lower performance improvement trends. Of the 27 units evaluated, only 29.6% had HR trending improvements over the 15-year period. Moreover, of the 8 units which showed trending improvements during the 15-year period, only 2 of those 8 (or about 25%) also showed HR trending improvements over the six-year period. Finally, only 5 units (18.5% of the 27 units evaluated) showed both EAF and HR trending improvements over the 15-year period.

Q. HOW IS IT POSSIBLE FOR A UTILITY TO EARN A POSITIVE REWARD CONSISTENTLY, WHEN UNIT PERFORMANCE FLUCTUATES SO WIDELY OVER TIME?

A. This seemingly counterintuitive result is possible because the GPIF mechanism contemplates that a unit's "performance target" for a given projection period will be based largely on the unit's recent performance, even if the recent performance data reflect a deterioration in efficiency. Accordingly, a unit with a significant decline in recent performance can contribute toward a reward in the current period by merely returning to or forward a previously achieved performance level.

Q. WHAT CONCERNS DO YOU HAVE WITH THE PRESENT GPIF REWARD/PENALTY MECHANISM?

A. Fundamentally, a prudent utility having an objective to provide economical service should strive to maintain and operate generating units as efficiently as possible. This objective is particularly true for major baseload generating units. Accordingly, the Commission should expect sustained high equivalent availabilities and low (efficient) heat rates for baseload generating unit as the rule rather than the exception. To reward utilities for performance that fails to accomplish meaningful enhancements to availability and/or heat rate, or that even reflects deteriorating performance, is counterintuitive and at odds with the utility's obligations to customers. Contrary to regulators' logical expectations, the data demonstrate that, under the current GPIF mechanism, customers can be required to pay monetary rewards to utilities when performance does not improve—in fact, when efficiency actually declines over time.

Q. DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. The Commission should revise the GPIF process to treat ratepayers more equitably. The Commission should "raise the bar" with respect to ratepayer-funded GPIF rewards. Specifically, I recommend that the Commission should place a "dead band" on the GPIP, so as to require a meaningful degree of system improvement before granting a reward.

Q. PLEASE DESCRIBE THE "DEAD BAND" CONCEPT YOU HAVE IN MIND.

A. The utilities would continue to calculate the GPIF components as currently defined in the methodology including the GPIP. However, the current "Generating Performance Incentive Factor Reward/Penalty Table" would be modified such that unless the total system GPIP is in excess of a pre-determined level no reward would be due the utility. The GPIP dead band would simply be applied in the last step of the GPIF methodology; thus, all other aspects of the current GPIF would be unaffected. Schedule 8 of Exhibit __ (JAR-1) illustrates this modification. Ratepayers currently fund rewards for utility achievement over forecasted targets based upon a linear scale of 0 to 10, with 10 being the maximum achievable reward. Assuming, for purposes of illustration, that the adopted "GPIP dead band" ranges from a -3.0 to +7.0, the reward and penalty determination phase of the current GPIF methodology would be modified such that a GPIP total of +6.0 would result in no reward under the modified methodology (Column 3 at Line 5 of Schedule 8). In contrast, the current method would have required a reward payment of $6,644,554 (Column 2 at Line 5 of Schedule 8). On the other hand, a GPIP total of +8.0 would yield the utility the same $8,859,405 reward as the current methodology (Line 3). The penalty for poor performance would be similarly determined. For example, a GPIP total of -2.0 would result in no penalty under the modified methodology (Column 3 at Line 13 of Schedule 8). In contrast, the current method would have assessed a penalty of $2,214,851 (Column 2 at Line 13 of Schedule 8). On the other hand, a GPIP total of -.0 would assess the utility the same $4,429,702 penalty as the current methodology (Line 15). The upper limit on the dead-band should be no less than +5.0 and may be as high as +7.5 depending on further analysis of the GPIP that has resulted in rewards to the utilities. The lower limit on the GPIP dead-band could range between -3.5 and -2.5.

Q. HOW CAN THE COMMISSION ADDRESS THE PROBLEM OF RATEPAYER FUNDING OF REWARDS DURING A PERIOD OF SUSTAINED DETERIORATION IN UTILITY SYSTEM PERFORMANCE?

A. In addition to the "GPIP dead band" modification, the Commission can address the problem of a consistent decline in system performance over time (as in the case of TECO) by establishing absolute system weighted EAF and HR numbers for each utility that would preclude any reward payment for actual performance below these established minimum performance levels.

Q. WHAT WOULD BE INVOLVED IN ESTABLISHING EACH OF THESE MEASURES, AND HOW WOULD THE EFFORT NEEDED AFFECT THE TIMING OF IMPLEMENTATION?

A. Incorporating a "dead band" would not require the utilities to do anything differently. It could be implemented without delay. Because the establishment of minimum scores to serve as prerequisites to rewards would involve a review of each utility system's characteristics and capabilities, it would be necessary to gather and analyze system-specific information before developing these criteria. Accordingly, it would be implemented as a second phase of the applied remedy.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A
QUALIFICATIONS OF JAMES A. ROSS

Mr. Ross is a graduate of the University of Missouri, with the degrees of Bachelor of Science in Electrical Engineering and Master of Science in Engineering Management. After graduation in 1971, he was employed by Union Electric Company, a utility, which provides service to Metropolitan St. Louis, Missouri, and surrounding areas. While assigned to the Power Operation Function, Mr. Ross was responsible for system operation-related engineering evaluations, which included long-range and intermediate planning studies, various economic studies and computer simulation of system operations. In 1977 he was assigned to the Corporate Planning Function with responsibilities in capacity planning coordination activities and special studies.

Mr. Ross served on Edison Electric Institute committees and task forces, and participated in reliability, capacity planning, power plant siting and contract negotiation activities.

Subsequent to his approximate ten-year employment with Union Electric Company, Mr. Ross entered the field of utility rate and economic consulting. His experience includes evaluations related to various aspects of utility ratemaking, utility operation, utility planning, rate forecasting, contract negotiations and cogeneration activities. Mr. Ross is a member of Regulatory & Cogeneration

Services, Inc. ("RCS"), utility rate and economic consultants. Through its offices in Chesterfield, Missouri and Vancouver, Washington, RCS provides a wide range of utility rate and economic consulting services. The members of RCS have extensive utility operation, planning, and rate-related experience and have for several years been engaged in providing electric and gas utility-related consulting services to some of the largest corporations in the United States.

Mr. Ross has testified as an expert witness on utility rates, planning, contract negotiations and related matters before the regulatory commissions of Alabama, Arizona, California, Colorado, Florida, Idaho, Illinois, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Nevada, New York, Pennsylvania, South Carolina, Texas, Utah and Wyoming. Mr. Ross has also testified before the Federal Energy Regulatory Commission.

DOCKET NO. 060001-EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Direct Testimony has been furnished by U.S. Mail and electronic mail to the following parties on this 30th day of May, 2006.

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PREPARED EXHIBITS OF

JAMES A. ROSS

ON BEHALF OF THE

FLORIDA OFFICE OF PUBLIC COUNSEL

Generating Performance Incentive Factor
Calculation of Maximum Allowed
Incentive Dollars
Period of: January 2006 – December 2006

Line	Description	Amount
		(1)
1	Beginning of Period Balance of Common Equity	$2,803,101,493
	End of Month Balance of Common Equity:	
2	Month of JANUARY 2006	$2,826,898,987
3	Month of FEBRUARY 2006	$2,793,035,343
4	Month of MARCH 2006	$2,807,901,640
5	Month of APRIL 2006	$2,817,462,020
6	Month of MAY 2006	$2,795,385,247
7	Month of JUNE 2006	$2,828,501,259
8	Month of JULY 2006	$2,870,587,123
9	Month of AUGUST 2006	$2,868,201,600
10	Month of SEPTEMBER 2006	$2,902,460,231
11	Month of OCTOBER 2006	$2,925,904,045
12	Month of NOVEMBER 2006	$2,890,621,855
13	Month of DECEMBER 2006	$2,909,474,337
14	Average Common Equity for the Period (Summation of LINE 1 through LINE 13 divided by 13	$2,849,195,014
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum Allowed Incentive Dollars (LINE 14 times LINE 15 divided by LINE 16)	$11,604,586
18	Jurisdictional Sales (MWh)	$40,148,242
19	Total Sales (MWh)	$42,071,758
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	95.43%
21	Maximum Allowed Jurisdictional Incentive Dollars (LINE 17 times LINE 20)	$11,074,256

GPIF Target and Range Summary
Period of: January 2006 – December 2006

Line	Plant/Unit	Weighting Factor (%)	EAF Target (%)		Max. (%)	Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
		(1)	(2)		(3)	(4)	(5)	(6)
1	Unit 1	3.48	87.67		89.87	83.14	3,336	(3,897)
2	Unit 2	1.55	84.31		86.28	80.25	1,482	(662)
3	Unit 3	2.70	85.62		90.57	75.54	2,586	(201)
4	Unit 4	2.45	92.62		94.30	89.12	2,350	(1,763)
5	Unit 5	3.02	95.46		97.61	90.99	2,894	(565)
6	Unit 6	8.72	92.72		96.14	85.72	8,358	(2,667)
7	Unit 7	11.88	82.06		88.52	69.73	11,387	(3,160)
8	Unit 8	1.44	97.31		98.58	94.67	1,383	(2,622)
9	Unit 9	4.50	93.22		95.25	89.06	4,316	(4,216)
10	Unit 10	10.65	87.27		89.64	82.45	10,211	(2,497)
11	Unit 11	0.88	87.63		89.33	84.08	846	(2,211)
12	Unit 12	0.73	88.99		91.44	84.10	701	(1,497)
13	GPIF System	52.00					49,850	(25,958)

Line	Plant/Unit	Weighting Factor (%)	ANOHR Target (Btu/kWh)	NOF	ANOHR Range Min. (Btu/kWh)	Max. (Btu/kWh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
14	Unit 1	4.87	10483	39.6	10055	10911	4,665	(4,665)
15	Unit 2	2.71	10352	40.8	10096	10609	2,598	(2,598)
16	Unit 3	1.22	10942	50.2	10601	11284	1,166	(1,166)
17	Unit 4	1.71	10890	59.6	10438	11343	1,635	(1,635)
18	Unit 5	3.30	10216	57.2	9750	10683	3,163	(3,163)
19	Unit 6	2.74	10296	69.1	9983	10610	2,630	(2,630)
20	Unit 7	3.92	10116	69.6	9731	10501	3,753	(3,753)
21	Unit 8	3.79	10259	100.1	10109	10409	3,637	(3,637)
22	Unit 9	3.59	9511	82.6	9321	9702	3,443	(3,443)
23	Unit 10	4.32	9513	85.9	9277	9749	4,138	(4,138)
24	Unit 11	8.92	7450	73.3	7080	7820	8,548	(8,548)
25	Unit 12	6.93	8006	87.3	7275	8736	6,639	(6,639)
26	GPIF System	48.00					46,015	(46,015)

Generating Performance Incentive Factor
Reward/Penalty Table
Period of: January 2006 – December 2006

Line	Generating Performance Incentive Points (GPIP)	Generating Performance Incentive Factor ($)
	(1)	(2)
1	10	$11,074,256
2	9	$9,966,831
3	8	$8,859,405
4	7	$7,751,979
5	6	$6,644,554
6	5	$5,537,128
7	4	$4,429,702
8	3	$3,322,277
9	2	$2,214,851
10	1	$1,107,426
11	0	$0
12	-1	($1,107,426)
13	-2	($2,214,851)
14	-3	($3,322,277)
15	-4	($4,429,702)
16	-5	($5,537,128)
17	-6	($6,644,554)
18	-7	($7,751,979)
19	-8	($8,859,405)
20	-9	($9,966,831)
21	-10	($11,074,256)

Florida Power and Light Company
Reward/(Penalty)

Line	Period	Annual	Cumulative
		(1)	(2)
1	April 1983 - Mar. 1984	-$1,698,828	-$1,698,828
2	April 1984 - Mar. 1985	-$3,885,027	-$5,583,855
3	April 1985 - Mar. 1986	$2,844,485	-$2,739,370
4	April 1986 - Mar. 1987	$1,750,177	-$989,193
5	April 1987 - Mar. 1988	-$2,289,937	-$3,279,130
6	April 1988 - Mar. 1989	$827,355	-$2,451,775
7	April 1989 - Mar. 1990	-$1,077,213	-$3,528,988
8	April 1990 - Mar. 1991	$2,087,214	-$1,441,774
9	April 1991 - Mar. 1992	$7,929,821	$6,488,047
10	April 1992 - Mar. 1993	$2,706,587	$9,194,634
11	April 1993 - Mar. 1994	$3,979,812	$13,174,446
12	April 1994 - Mar. 1995	$6,155,318	$19,329,764
13	April 1995 - Mar. 1996	$4,106,191	$23,435,955
14	Oct. 1996 - Sept. 1997	$9,353,960	$32,789,915
15	Oct. 1997 - Sept. 1999	$9,669,694	$42,459,609
16	Oct. 1998 - Dec. 1998	$1,697,372	$44,156,981
17	Jan. 1999 - Dec. 1999	$6,973,751	$51,130,732
18	Jan. 2000 - Dec. 2000	$9,004,713	$60,135,445
19	Jan. 2001 - Dec. 2001	$7,049,431	$67,184,876
20	Jan. 2002 - Dec. 2002	$7,449,429	$74,634,305
21	Jan. 2003 - Dec. 2003	$6,615,282	$81,249,587
22	Jan. 2004 - Dec. 2004	$10,816,748	$92,066,335

Progress Energy Florida, Inc.
Reward/(Penalty)

Line	Period	Annual	Cumulative
		(1)	(2)
1	April 1983 - Mar. 1984	$834,729	$834,729
2	April 1984 - Mar. 1985	$2,093,785	$2,928,514
3	April 1985 - Mar. 1986	-$1,155,445	$1,773,069
4	April 1986 - Mar. 1987	-$1,426,899	$346,170
5	April 1987 - Mar. 1988	$1,316,588	$1,662,758
6	April 1988 - Mar. 1989	$705,197	$2,367,955
7	April 1989 - Mar. 1990	$26,720	$2,394,675
8	April 1990 - Mar. 1991	$2,814,563	$5,209,238
9	April 1991 - Mar. 1992	$2,632,881	$7,842,119
10	April 1992 - Mar. 1993	$2,430,176	$10,272,295
11	April 1993 - Mar. 1994	$2,110,084	$12,382,379
12	April 1994 - Mar. 1995	$1,170,075	$13,552,454
13	April 1995 - Mar. 1996	$2,983,727	$16,536,181
14	April 1996 - Mar. 1997	$176,152	$16,712,333
15	April 1997 - Mar. 1998	$735,508	$17,447,841
16	April 1998 - Dec. 1998	$1,047,140	$18,494,981
17	Jan. 1999 - Dec. 1999	$2,183,063	$20,678,044
18	Jan. 2000 - Dec. 2000	$266,919	$20,944,963
19	Jan. 2001 - Dec. 2001	$608,057	$21,553,020
20	Jan. 2002 - Dec. 2002	$2,781,223	$24,334,243
21	Jan. 2003 - Dec. 2003	$2,139,695	$26,473,938
22	Jan. 2004 - Dec. 2004	$532,353	$27,006,291

Gulf Power Company
Reward/(Penalty)

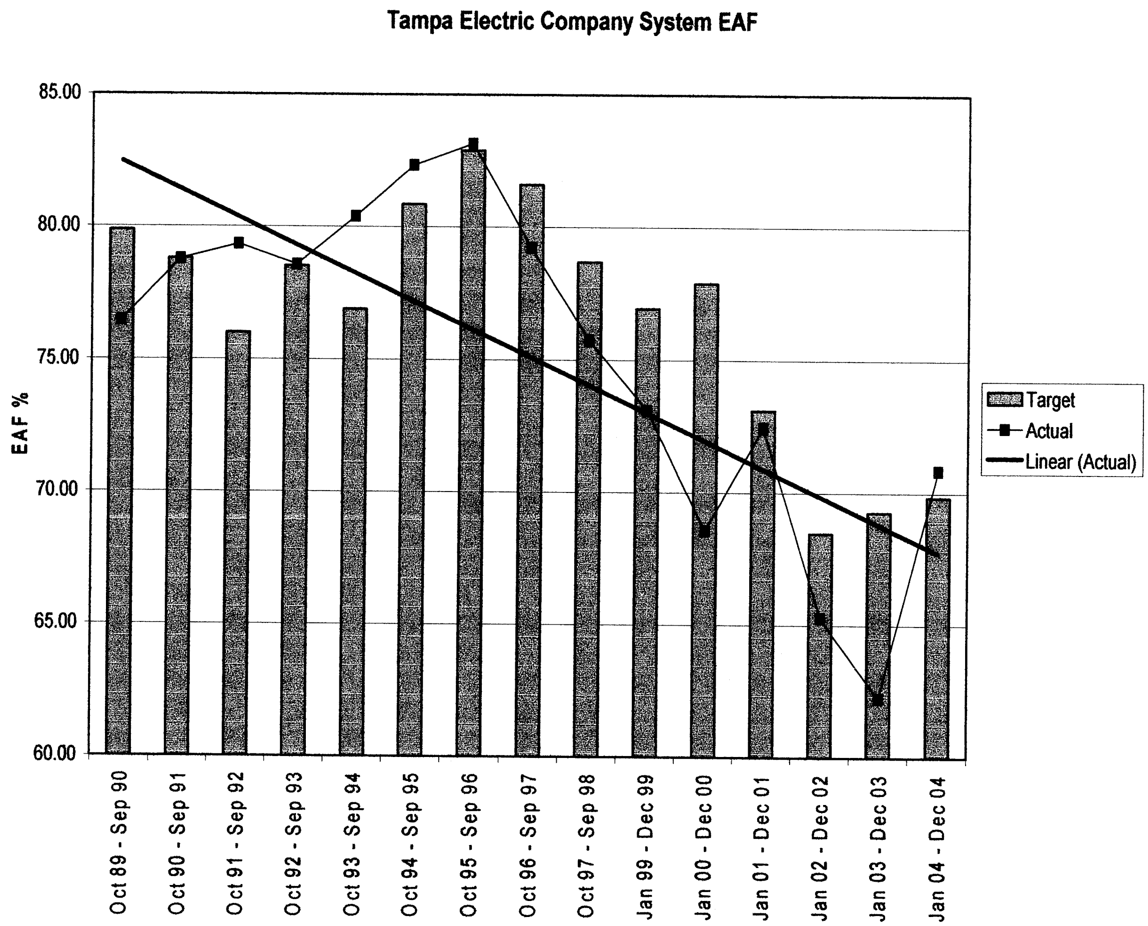
Line	Period	Annual	Cumulative
		(1)	(2)
1	April 1983 - Mar. 1984	$494,999	$494,999
2	April 1984 - Mar. 1985	$705,314	$1,200,313
3	April 1985 - Mar. 1986	$169,921	$1,370,234
4	April 1986 - Mar. 1987	$30,432	$1,400,666
5	April 1987 - Mar. 1988	-$252,378	$1,148,288
6	April 1988 - Mar. 1989	$178,576	$1,326,864
7	April 1989 - Mar. 1990	$29,028	$1,355,892
8	April 1990 - Mar. 1991	-$21,382	$1,334,510
9	April 1991 - Mar. 1992	-$126,447	$1,208,063
10	April 1992 - Mar. 1993	$695,369	$1,903,432
11	April 1993 - Mar. 1994	$43,611	$1,947,043
12	April 1994 - Mar. 1995	$22,931	$1,969,974
13	April 1995 - Mar. 1996	-$527,311	$1,442,663
14	April 1996 - Mar. 1997	$93,547	$1,536,210
15	April 1997 - Mar. 1998	-$238,113	$1,298,097
16	April 1998 - Dec. 1998	-$36,679	$1,261,418
17	Jan. 1999 - Dec. 1999	$183,842	$1,445,260
18	Jan. 2000 - Dec. 2000	$379,732	$1,824,992
19	Jan. 2001 - Dec. 2001	-$369,498	$1,455,494
20	Jan. 2002 - Dec. 2002	$431,920	$1,887,414
21	Jan. 2003 - Dec. 2003	$625,280	$2,512,694
22	Jan. 2004 - Dec. 2004	$441,988	$2,954,682

Docket No. 06001-EI
OPC witness Ross
Exhibit ______(JAR – 1)
Schedule 2
Page 4 of 4

Tampa Electric Company
Reward/(Penalty)

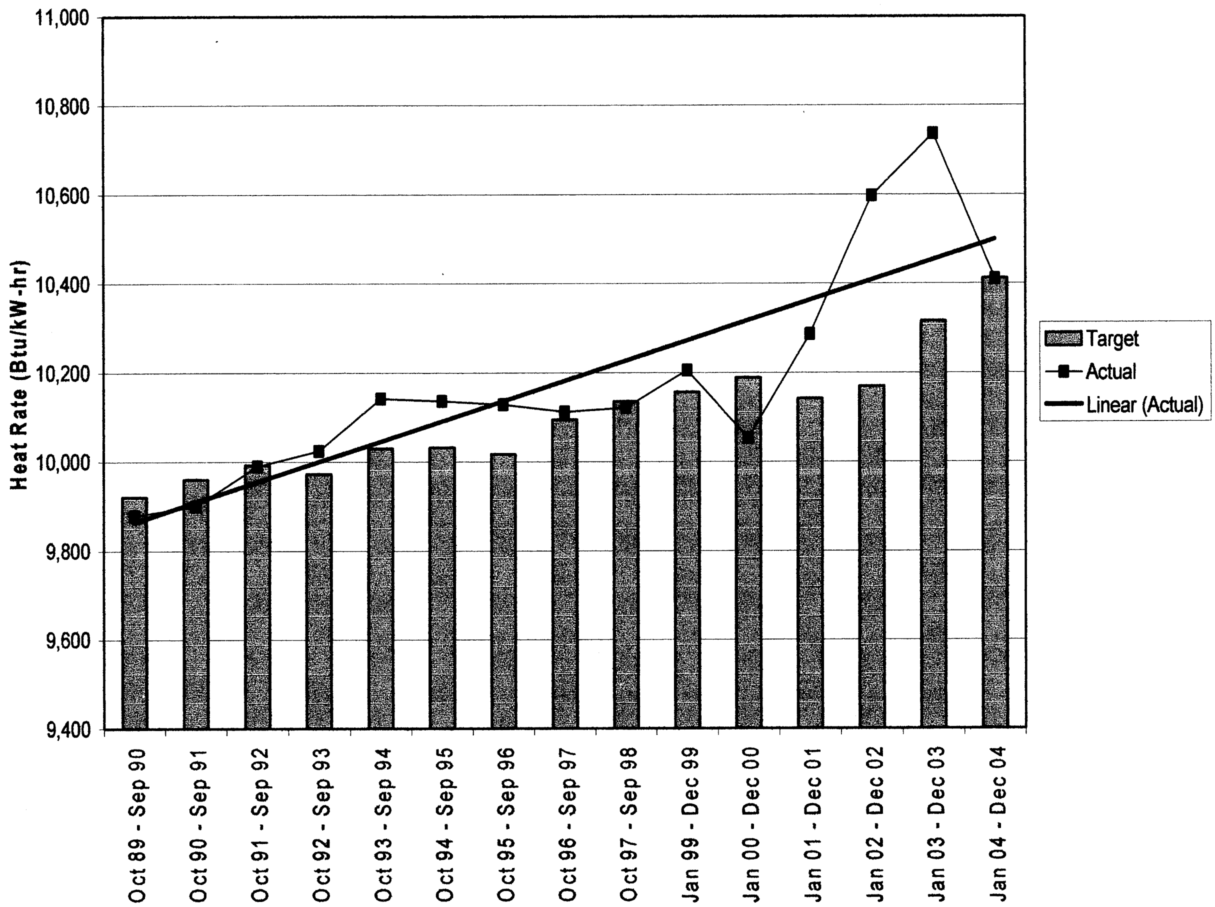
Line	Year	Annual	Cumulative
		(1)	(2)
1	April 1983 - Mar. 1984	$359,976	$359,976
2	April 1984 - Mar. 1985	$1,031,411	$1,391,387
3	April 1985 - Mar. 1986	$1,396,432	$2,787,819
4	April 1986 - Mar. 1987	$812,784	$3,600,603
5	April 1987 - Mar. 1988	$447,916	$4,048,519
6	April 1988 - Mar. 1989	-$132,313	$3,916,206
7	April 1989 - Mar. 1990	-$741,134	$3,175,072
8	April 1990 - Mar. 1991	$535,695	$3,710,767
9	April 1991 - Mar. 1992	$800,474	$4,511,241
10	April 1992 - Mar. 1993	$449,861	$4,961,102
11	April 1993 - Mar. 1994	$192,167	$5,153,269
12	April 1994 - Mar. 1995	-$324,888	$4,828,381
13	April 1995 - Mar. 1996	$272,216	$5,100,597
14	April 1996 - Mar. 1997	-$201,709	$4,898,888
15	April 1997 - Mar. 1998	-$552,131	$4,346,757
16	April 1998 - Dec. 1998	-$276,901	$4,069,856
17	Jan. 1999 - Dec. 1999	-$1,151,236	$2,918,620
18	Jan. 2000 - Dec. 2000	$1,095,745	$4,014,365
19	Jan. 2001 - Dec. 2001	-$831,029	$3,183,336
20	Jan. 2002 - Dec. 2002	-$2,496,021	$687,315
21	Jan. 2003 - Dec. 2003	-$3,678,414	-$2,991,099
22	Jan. 2004 - Dec. 2004	$729,534	-$2,261,565

Docket No. 06001-EI
OPC witness Ross
Exhibit______(JAR – 1)
Schedule 3
Figure 1
Page 1 of 1



Docket No. 06001-EI
OPC witness Ross
Exhibit______(JAR – 1)
Schedule 3
Figure 2
Page 1 of 1

Tampa Electric Company System Heat Rate



Tampa Electric Company

Line	Description	Target		Actual Adjusted	
		EAF	Heat Rate	EAF	Heat Rate
		(1)	(2)	(3)	(4)
1	Calendar Year 2001 System Wtd. Numbers	73.11	10,143	72.46	10,287
2	Calendar Year 2002 System Wtd. Numbers	68.47	10,170	65.27	10,597
3	Calendar Year 2003 System Wtd. Numbers	69.26	10,316	62.24	10,737
4	Calendar Year 2004 System Wtd. Numbers	69.83	10,413	70.86	10,411
5	Percent Decline in Performance	4.49%	2.66%	2.21%	1.21%

Progress Energy Florida, Inc.

Line	Description	Actual Adjusted EAF	Actual Adjusted Heat Rate	Reward or (Penalty)
		(1)	(2)	(3)
1	Calendar Year 2001 System Wtd. Numbers	86.68	9,494	$608,057
2	Calendar Year 2002 System Wtd. Numbers	84.78	9,772	$2,781,223
3	Change in Calendar Year 2002 From 2001	-1.90	278	na
4	Percent Decline in Performance	2.19%	2.93%	na

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OPC witness Ross
Exhibit ______(JAR – 1)
Schedule 6

Gulf Power Company

Line	Description	Actual Adjusted EAF	Actual Adjusted Heat Rate	Reward or Penalty
		(1)	(2)	(3)
1	Calendar Year 2001 System Wtd. Numbers	83.55	10,135	$625,280
2	Calendar Year 2002 System Wtd. Numbers	77.07	10,164	$441,988
3	Change in Calendar Year 2002 From 2001	-6.48	30	na
4	Percent Decline in Performance	7.76%	0.30%	na

Florida Power and Light Company					
Line	Plant/Unit	15-Year EAF Trend	6-Year EAF Trend	15-Year Heat Rate Trend	6-Year Heat Rate Trend
		(1)	(2)	(3)	(4)
1	Cape Canaveral 1	Improve	Improve	Decline	Improve
2	Cape Canaveral 2	Decline	Improve	Decline	Improve
3	Fort Lauderdale 4	Decline	Decline	Decline	Decline
4	Fort Lauderdale 5	Decline	Decline	Decline	Decline
5	Fort Myers 2	Improve	Improve	Improve	Decline
6	Manatee 1	Improve	Improve	Decline	Decline
7	Manatee 2	Improve	Decline	Decline	Improve
8	Martin 1	Improve	Improve	Decline	Decline
9	Martin 2	Improve	Decline	Improve	Decline
10	Martin 3	Decline	Decline	Improve	Decline
11	Martin 4	Decline	Improve	Improve	Improve
12	Port Everglades 2	Decline	na	Improve	na
13	Port Everglades 3	Improve	Improve	Decline	Decline
14	Port Everglades 4	Improve	Decline	Decline	Improve
15	Putnam 1	Decline	Decline	Decline	Improve
16	Putnam 2	Decline	na	Decline	na
17	Riviera 3	Improve	Improve	Decline	Improve
18	Riviera 4	Improve	na	Improve	na
19	Sanford 4	Decline	Decline	Decline	Decline
20	Sanford 5	Decline	Decline	Decline	Improve
21	Scherer 4	Decline	Decline	Decline	Improve
22	St. Lucie 1	Improve	Improve	Decline	Decline
23	St. Lucie 2	Improve	Decline	Decline	Decline
24	Turkey Point 1	Improve	Decline	Improve	Improve
25	Turkey Point 2	Improve	Decline	Improve	Decline
26	Turkey Point 3	Improve	Decline	Decline	Decline
27	Turkey Point 4	Improve	Improve	Decline	Improve

Generating Performance Incentive Factor
Reward/Penalty Table
Period of: January 2006 – December 2006

Line	Generating Performance Incentive Points (GPIP)	Current Generating Performance Incentive Factor ($)	Modified Generating Performance Incentive Factor ($)
	(1)	(2)	(3)
1	10	$11,074,256	$11,074,256
2	9	$9,966,831	$9,966,831
3	8	$8,859,405	$8,859,405
4	7	$7,751,979	$0
5	6	$6,644,554	$0
6	5	$5,537,128	$0
7	4	$4,429,702	$0
8	3	$3,322,277	$0
9	2	$2,214,851	$0
10	1	$1,107,426	$0
11	0	$0	$0
12	-1	($1,107,426)	$0
13	-2	($2,214,851)	$0
14	-3	($3,322,277)	$0
15	-4	($4,429,702)	($4,429,702)
16	-5	($5,537,128)	($5,537,128)
17	-6	($6,644,554)	($6,644,554)
18	-7	($7,751,979)	($7,751,979)
19	-8	($8,859,405)	($8,859,405)
20	-9	($9,966,831)	($9,966,831)
21	-10	($11,074,256)	($11,074,256)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	Docket No. 060001-EI

PREPARED EXHIBIT __ (JAR-2) OF

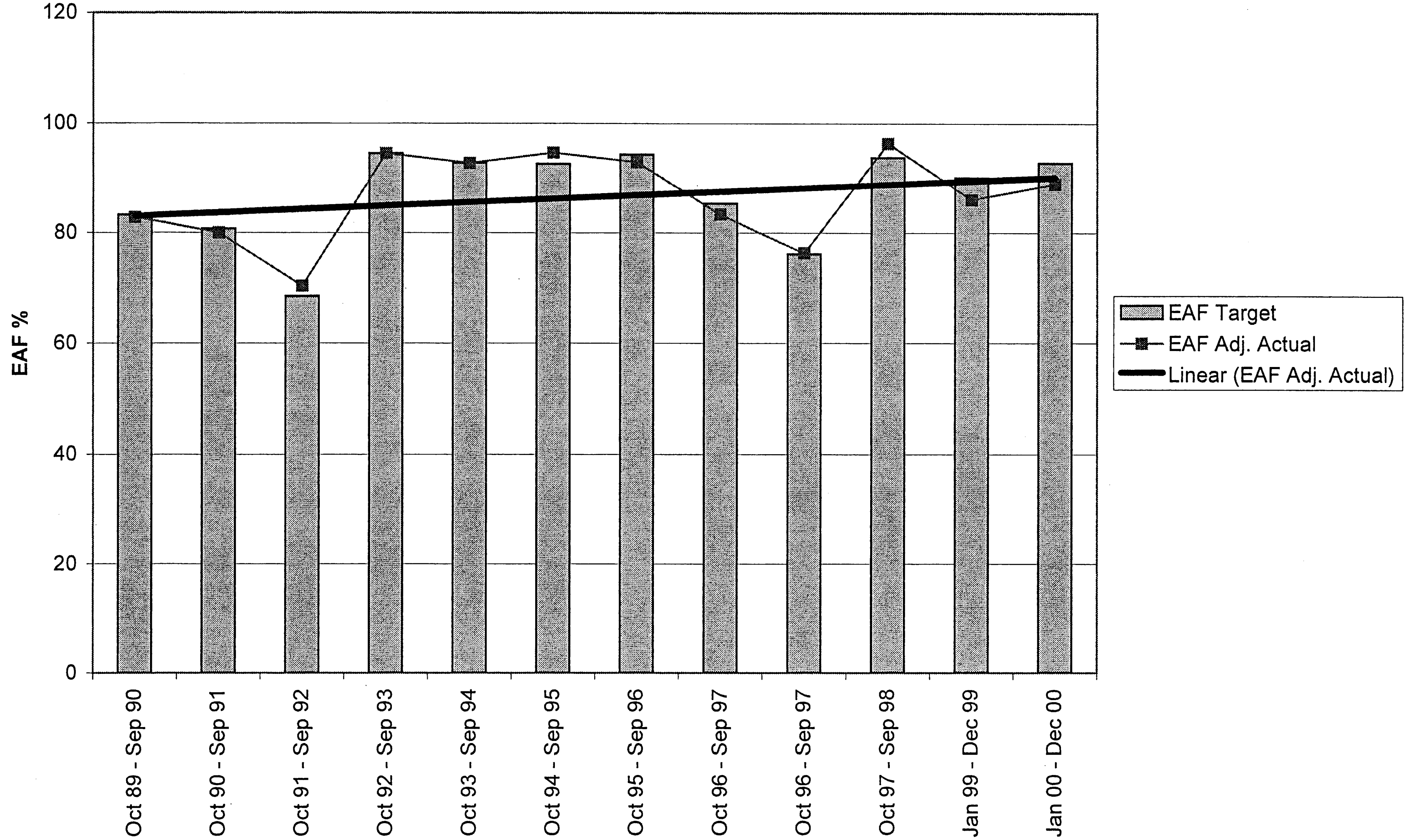
JAMES A. ROSS

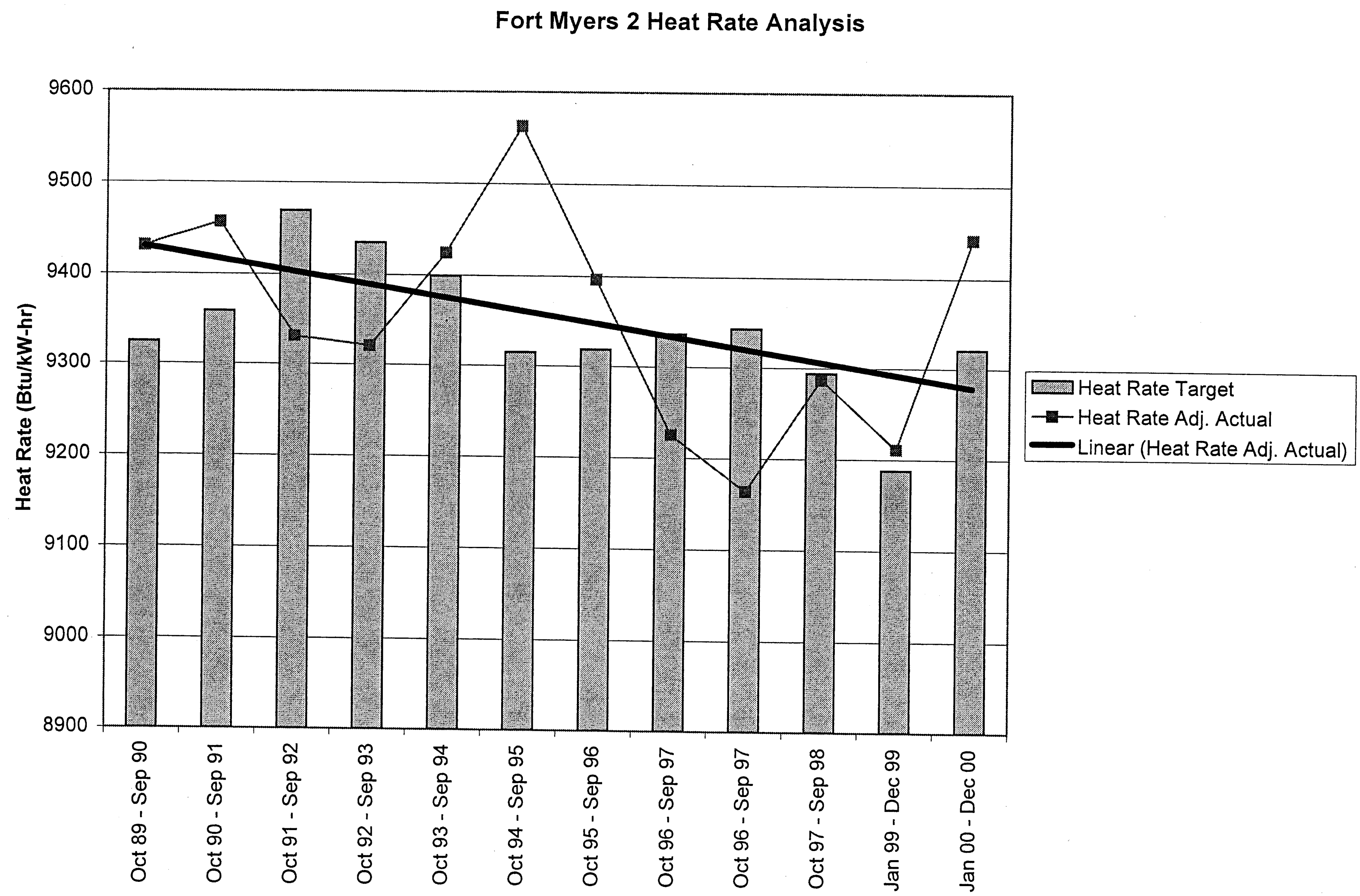
ON BEHALF OF THE

FLORIDA OFFICE OF PUBLIC COUNSEL

May, 2006

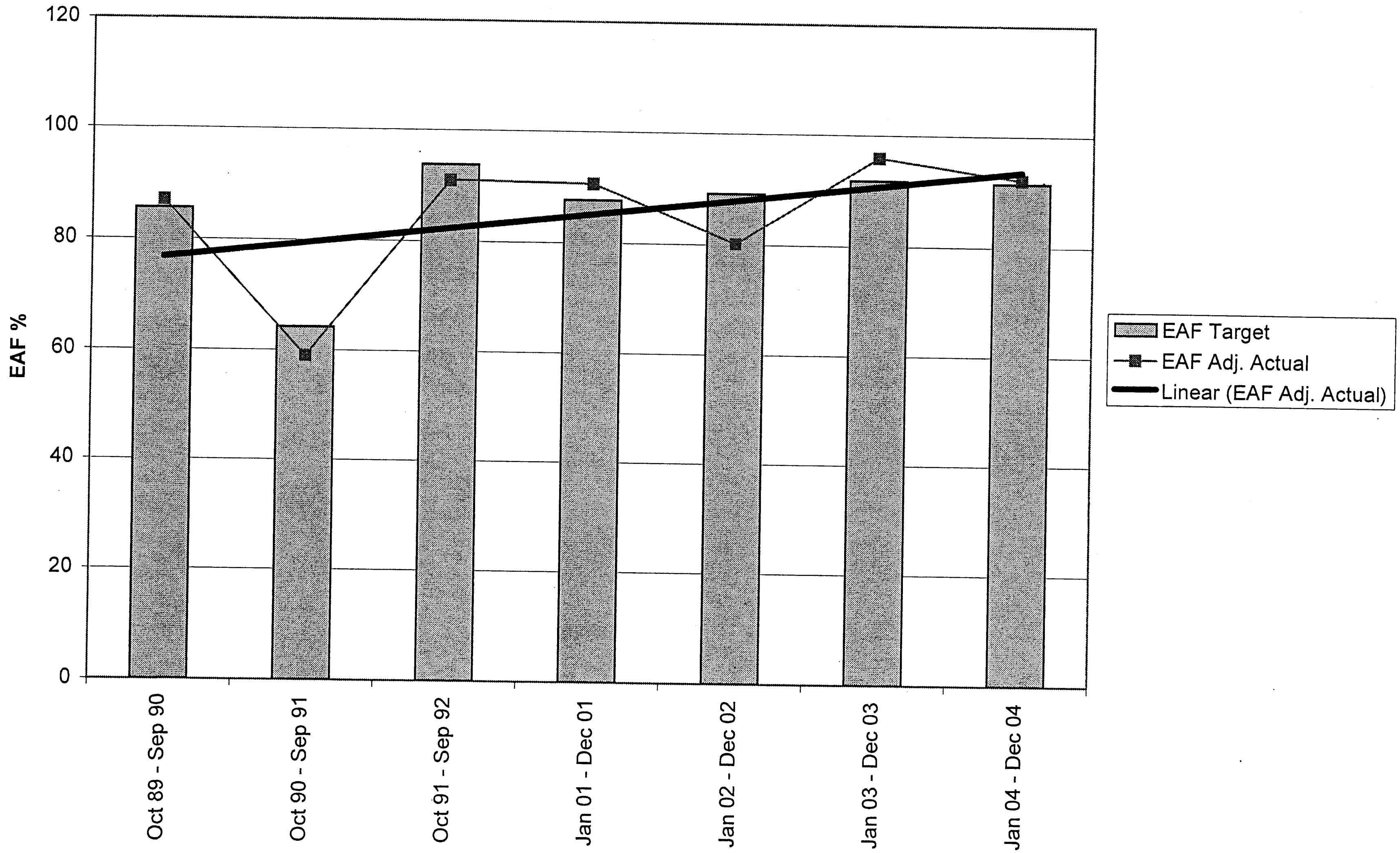
Fort Myers 2 EAF Analysis



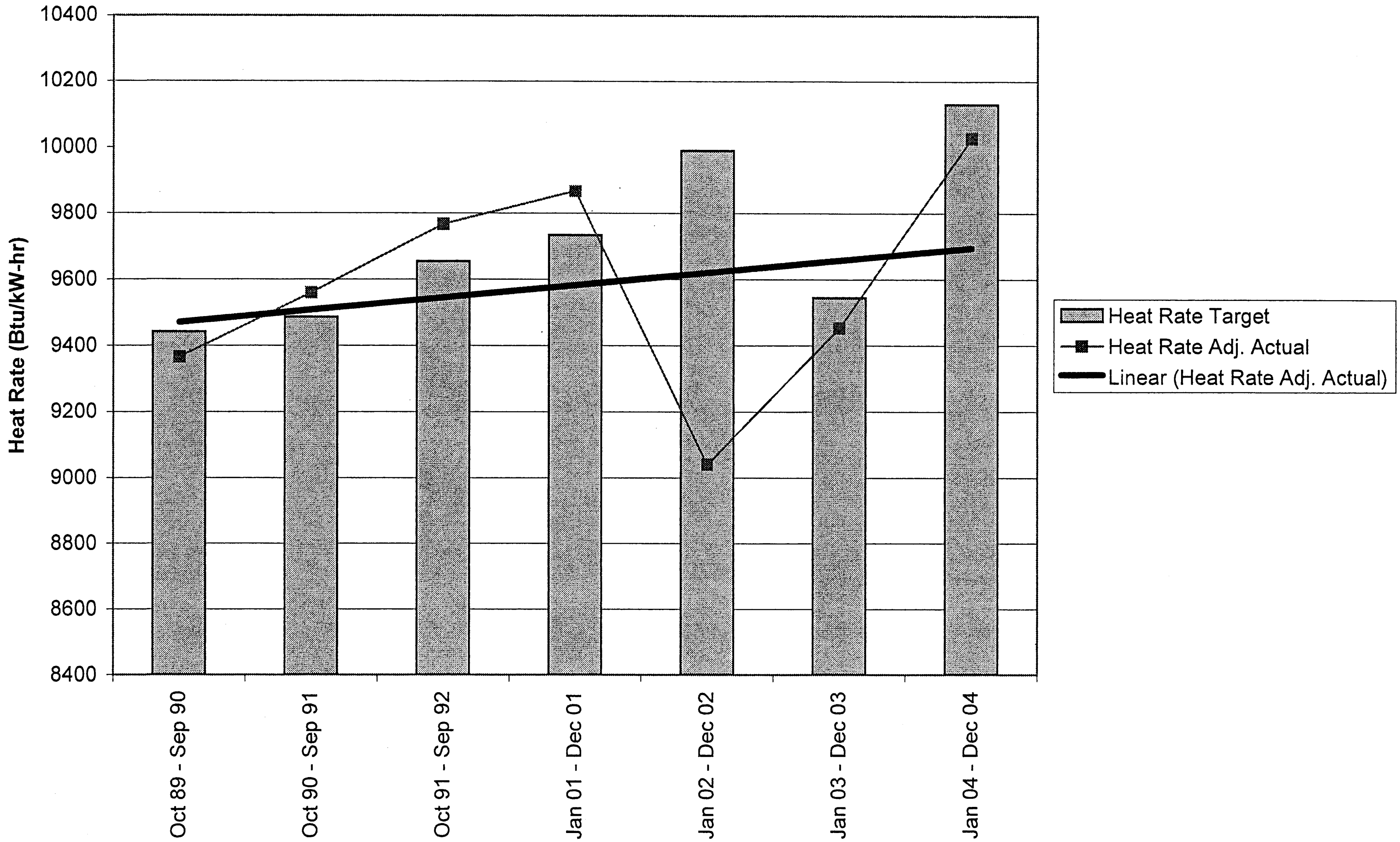


Fort Myers 2 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9600
9500
9400
9300
9200
9100
9000
8900
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

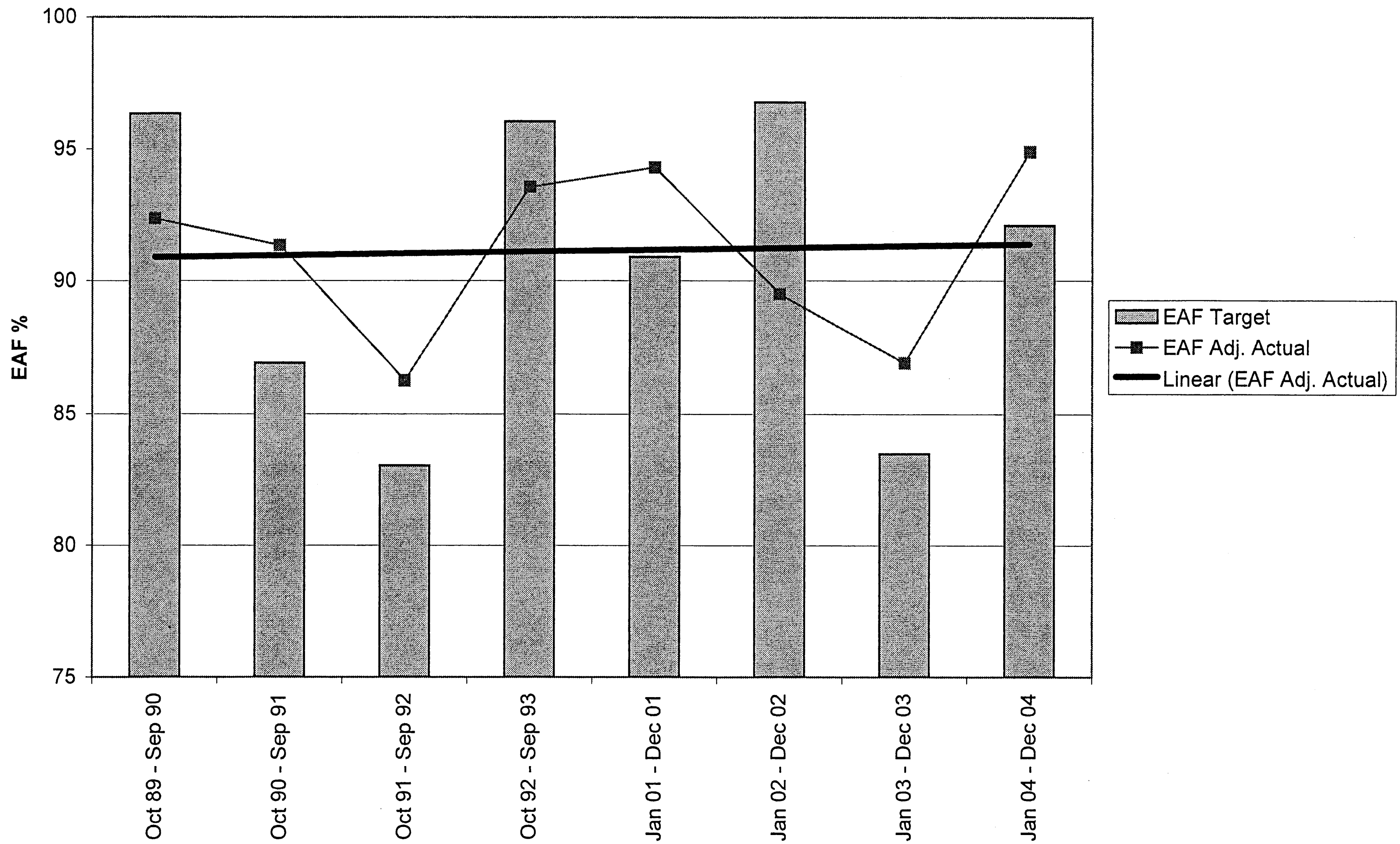
Martin 1 EAF Analysis



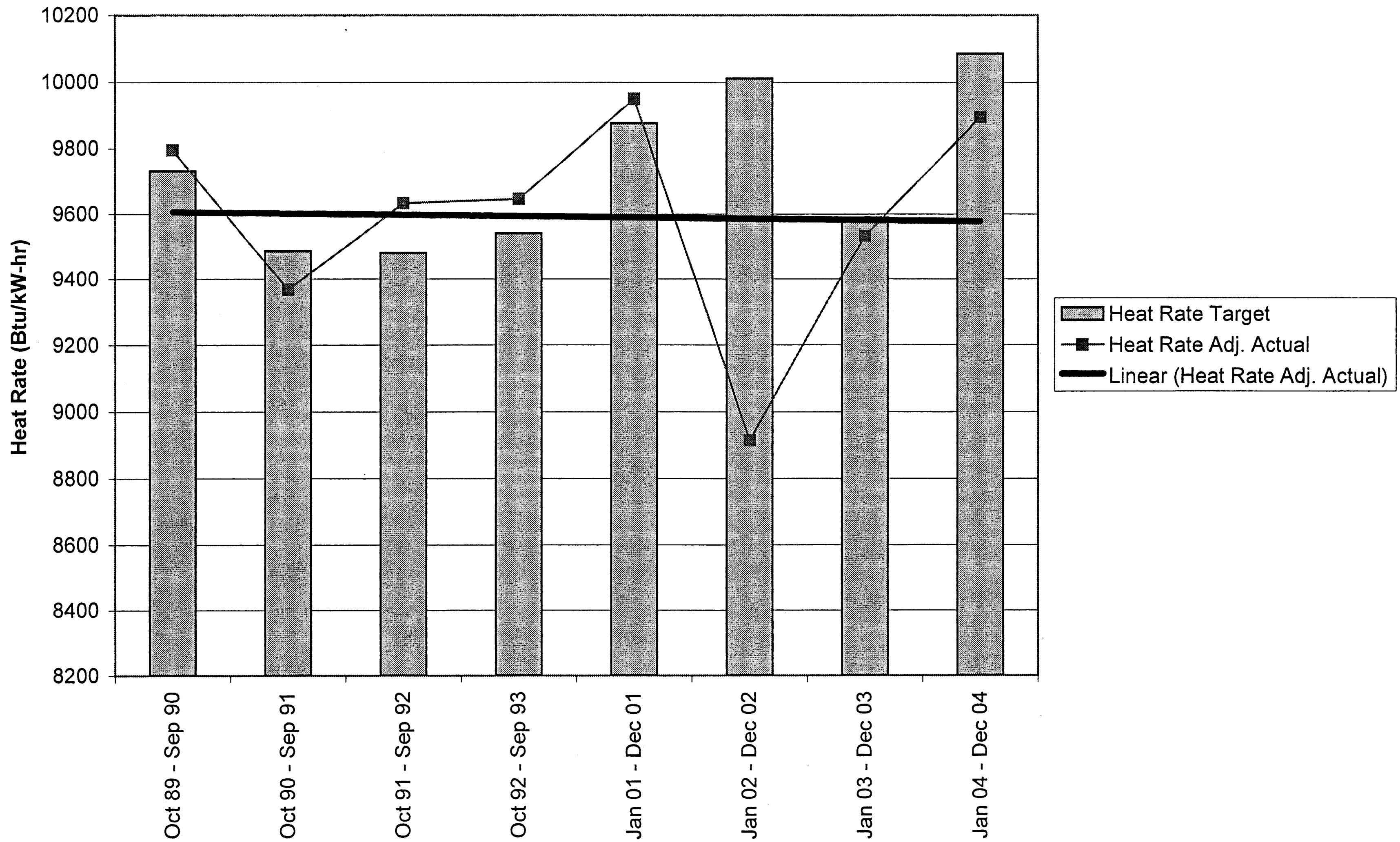
Martin 1 Heat Rate Analysis



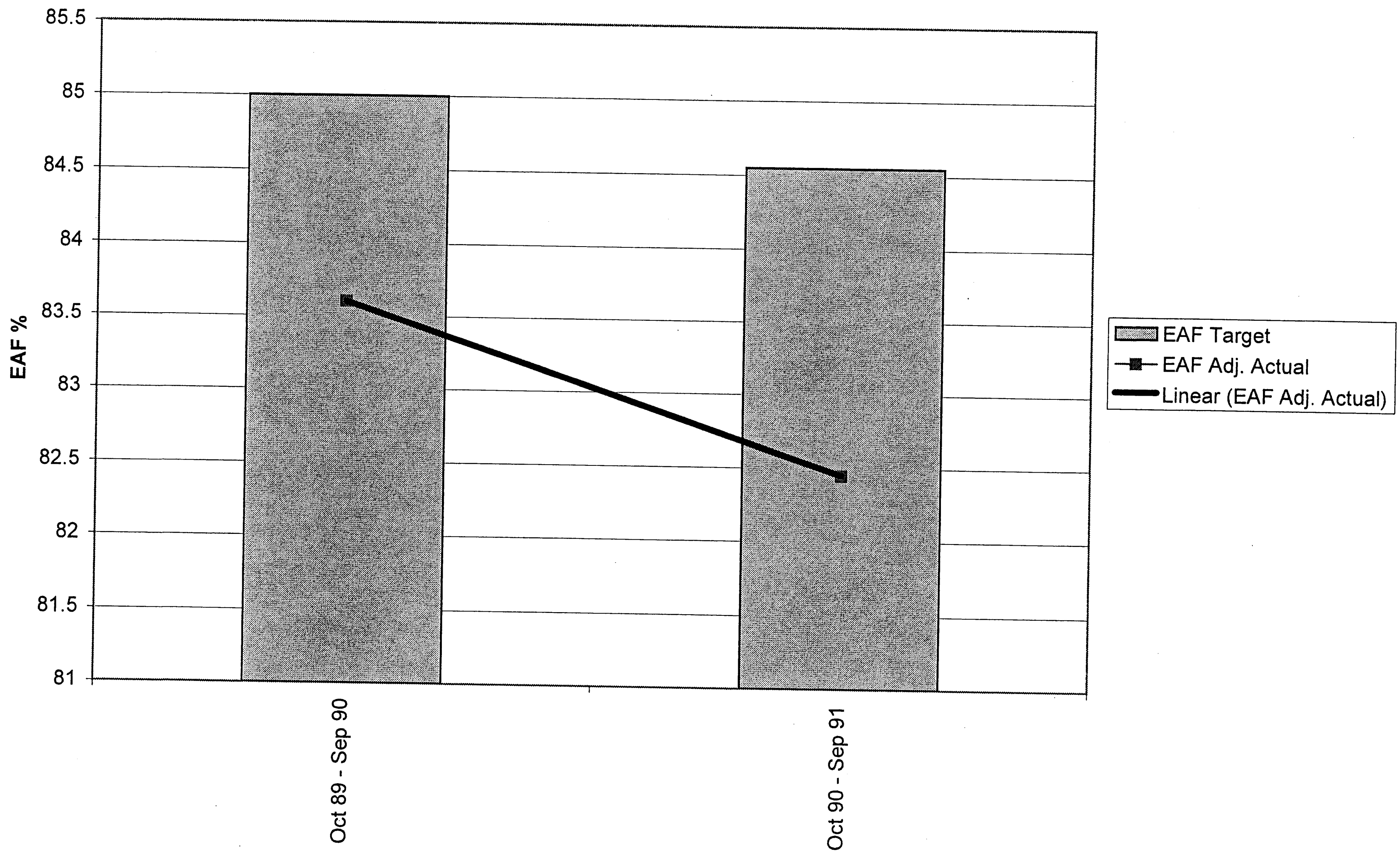
Martin 2 EAF Analysis

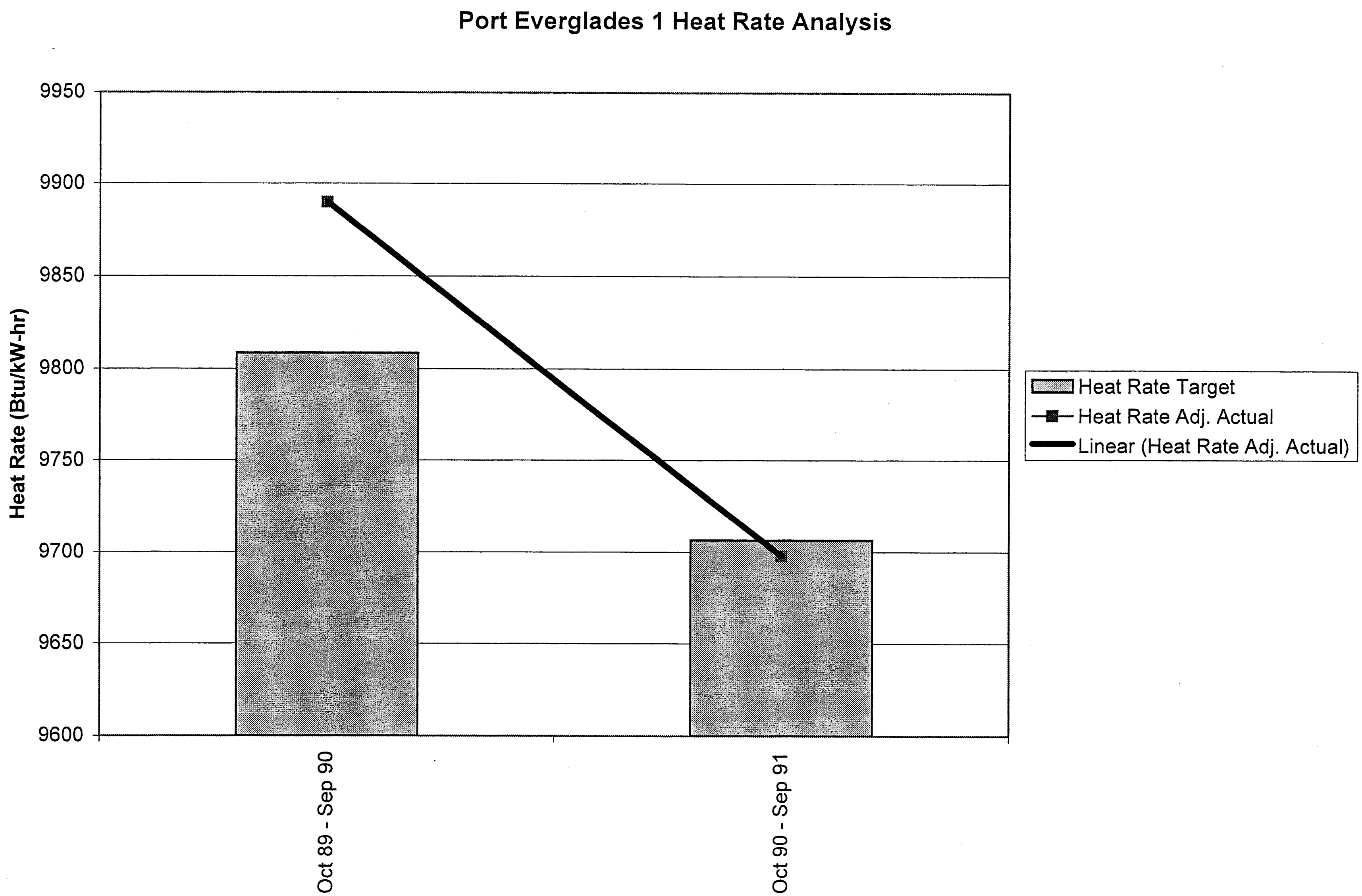


Martin 2 Heat Rate Analysis

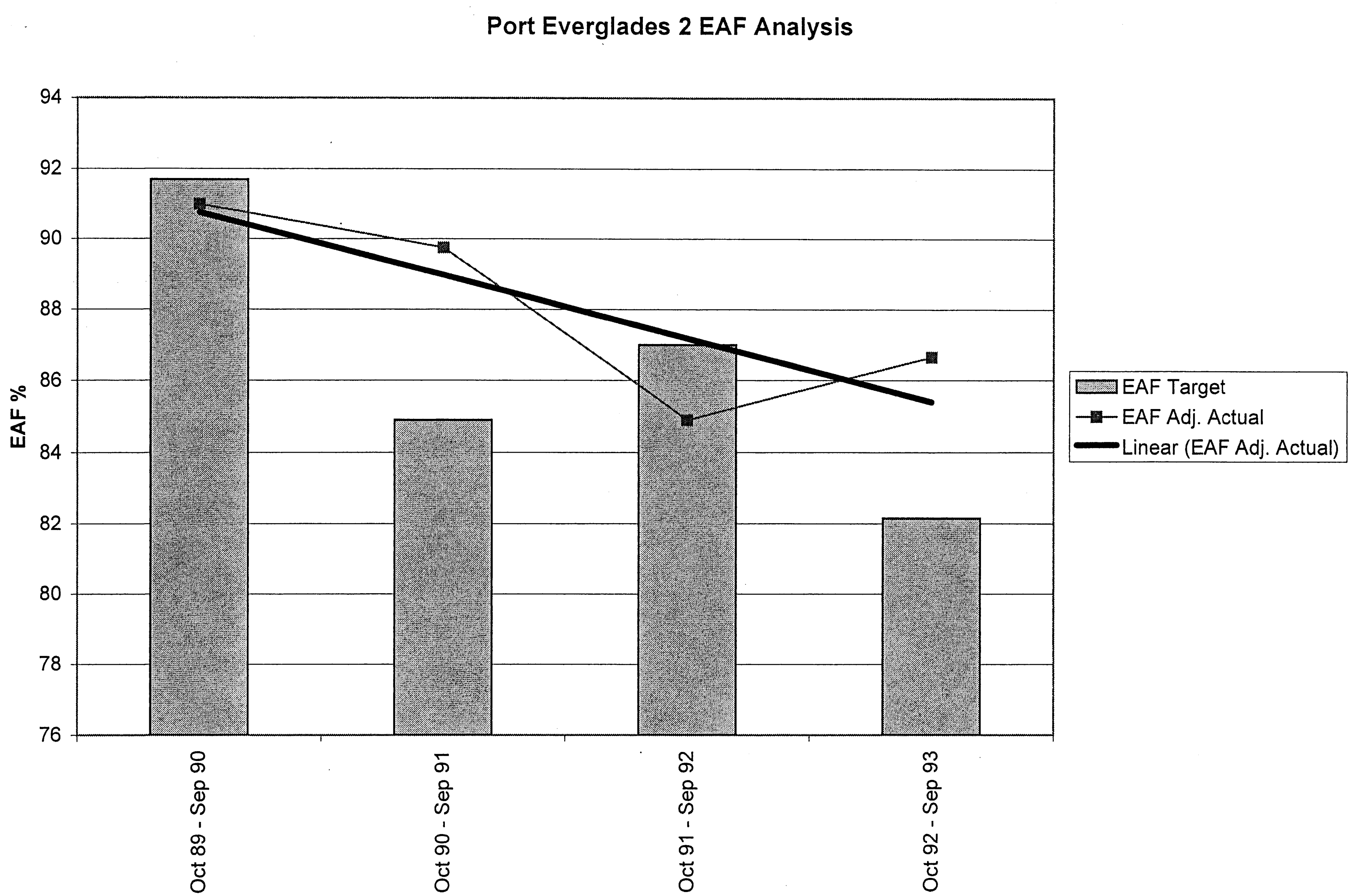


Port Everglades 1 EAF Analysis



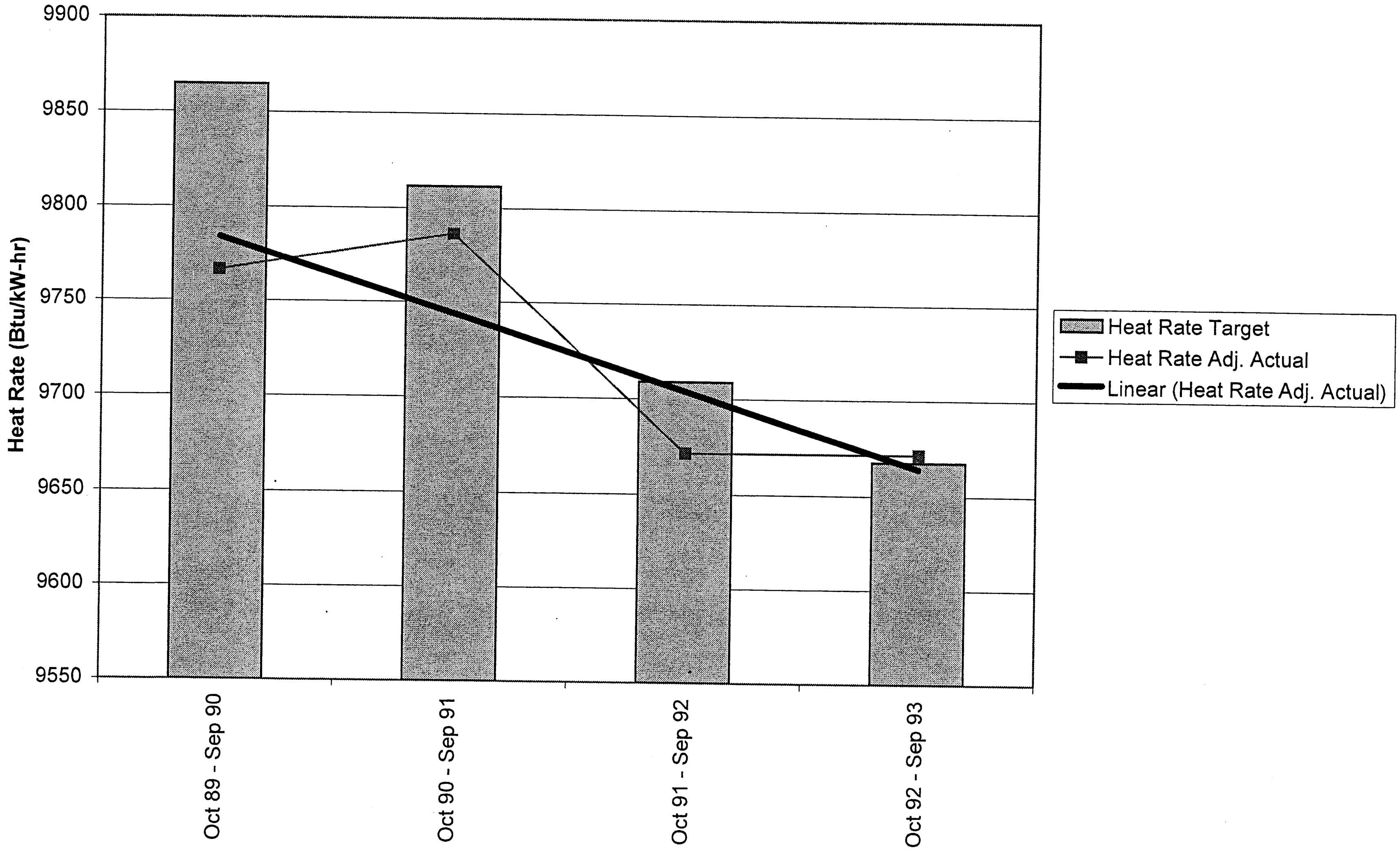


Port Everglades 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9950
9900
9850
9800
9750
9700
9650
9600
Oct 89 - Sep 90
Oct 90 - Sep 91
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

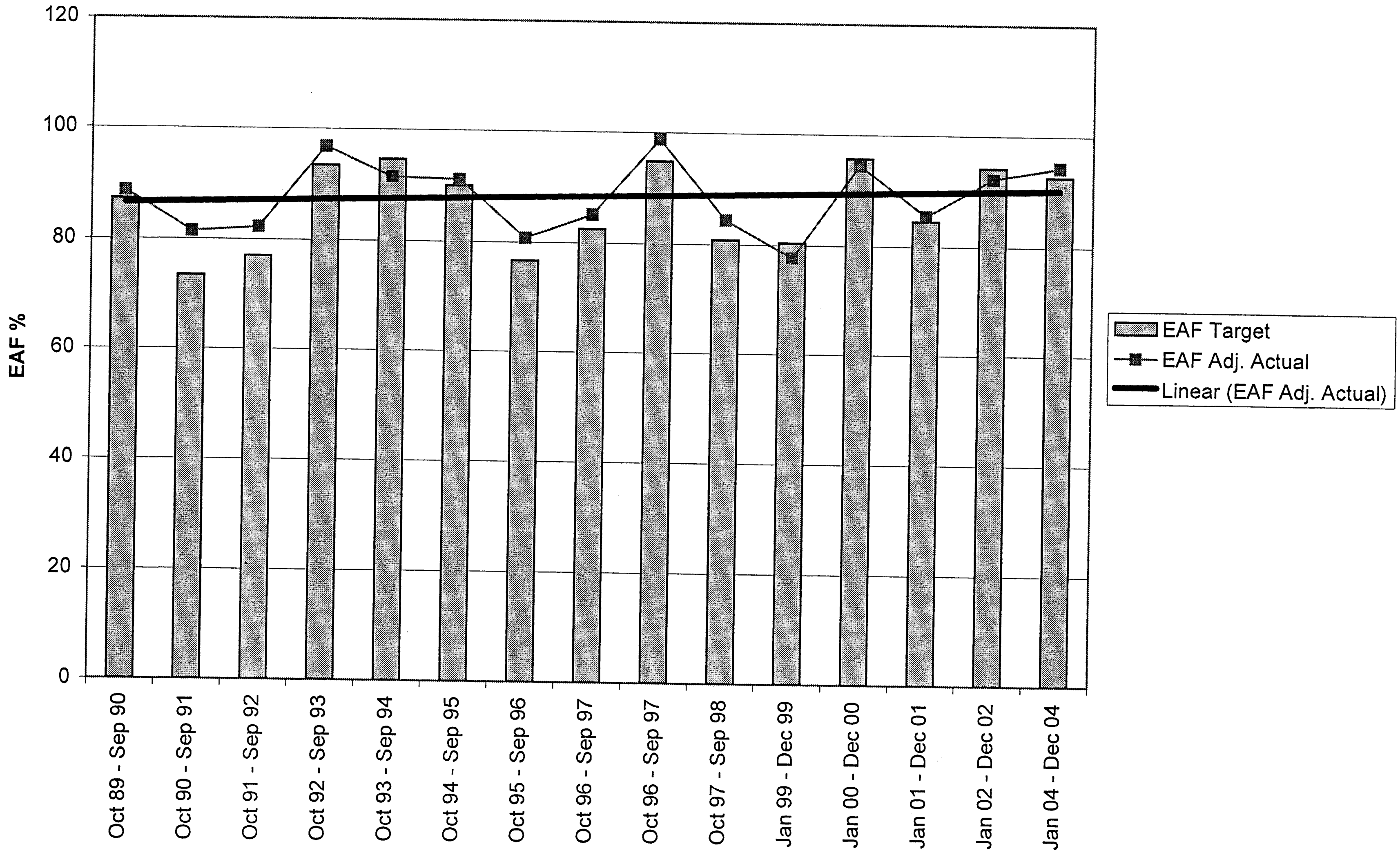


Port Everglades 2 EAF Analysis
EAF %
94
92
90
88
86
84
82
80
78
76
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

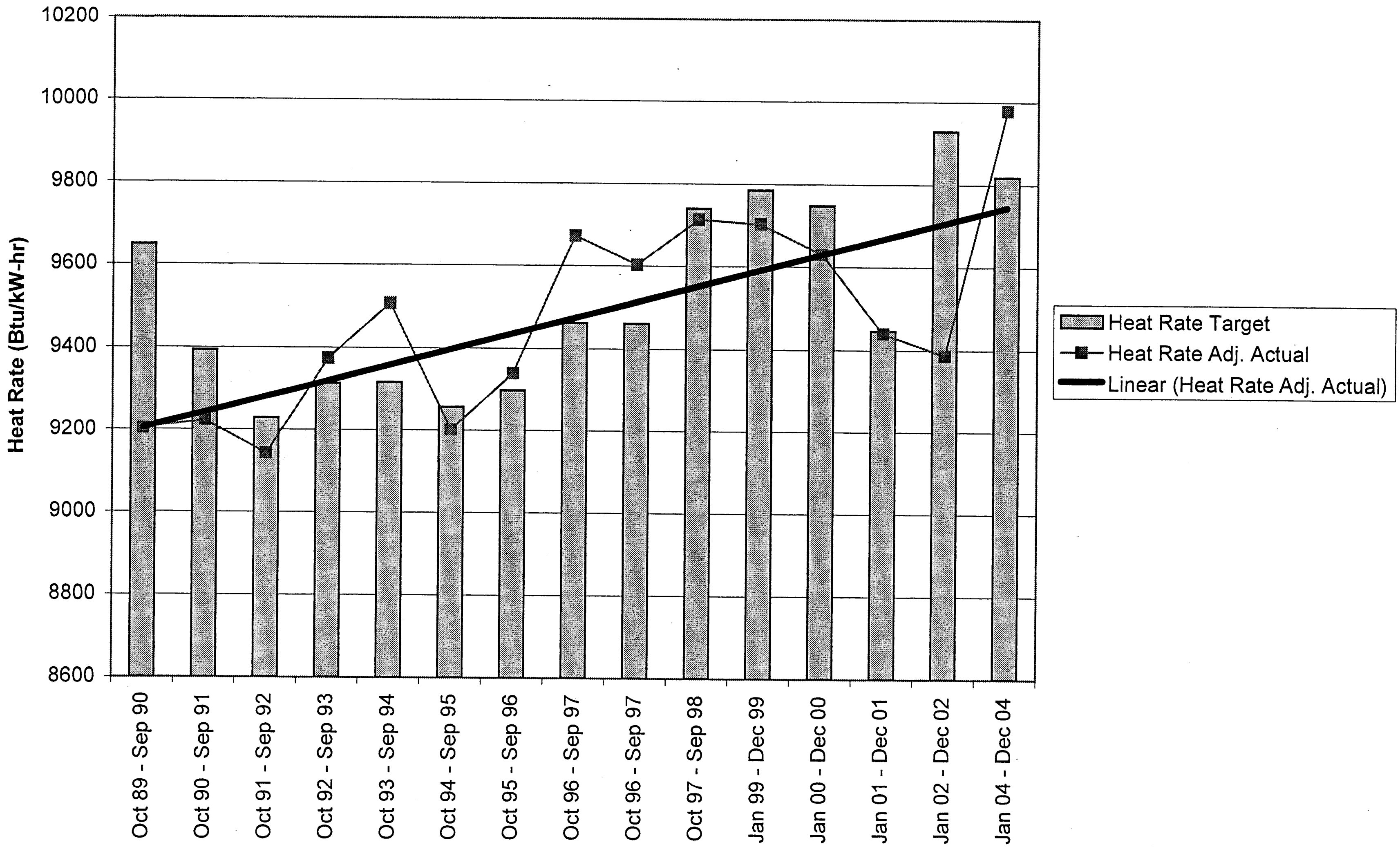
Port Everglades 2 Heat Rate Analysis



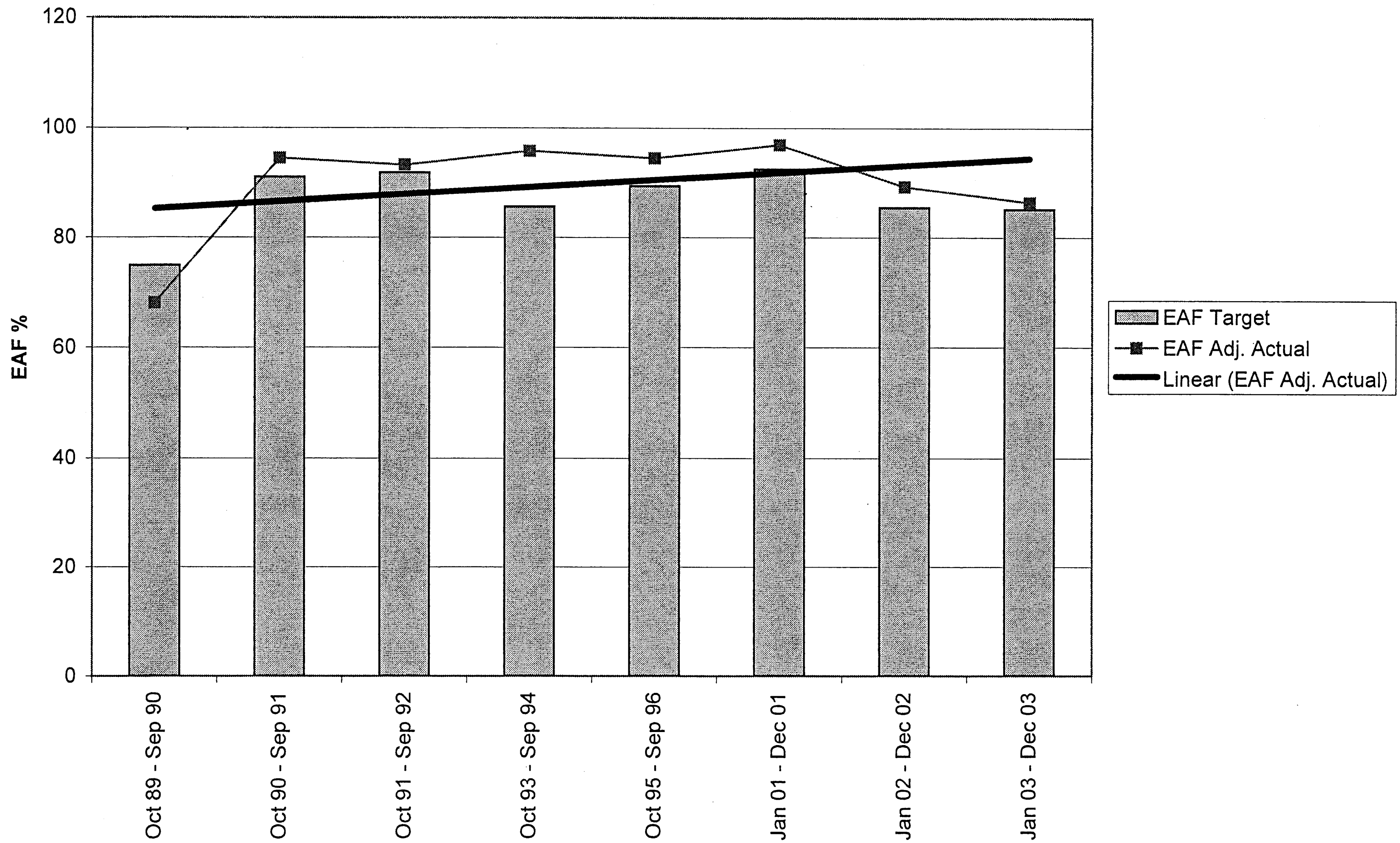
Port Everglades 3 EAF Analysis



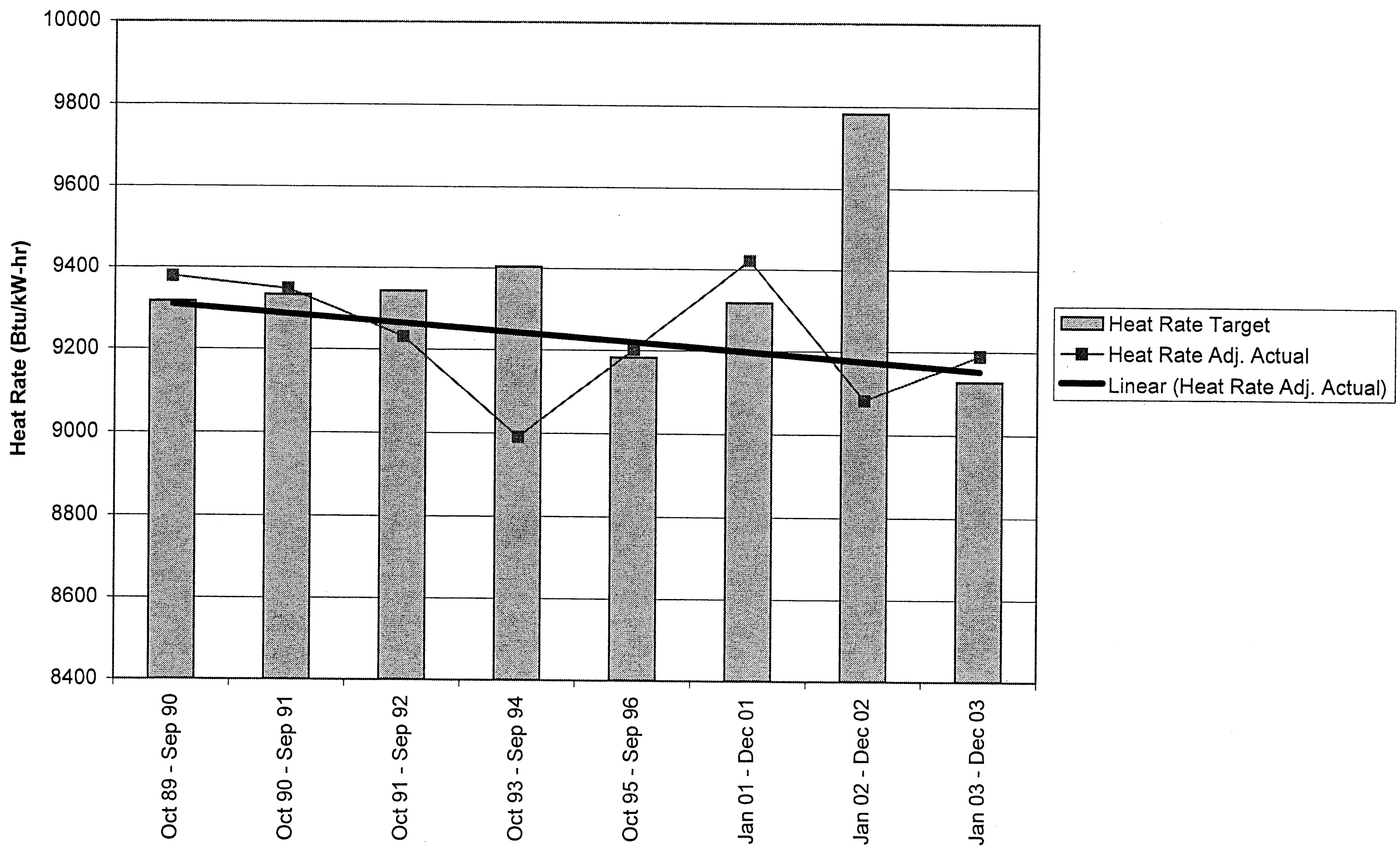
Port Everglades 3 Heat Rate Analysis



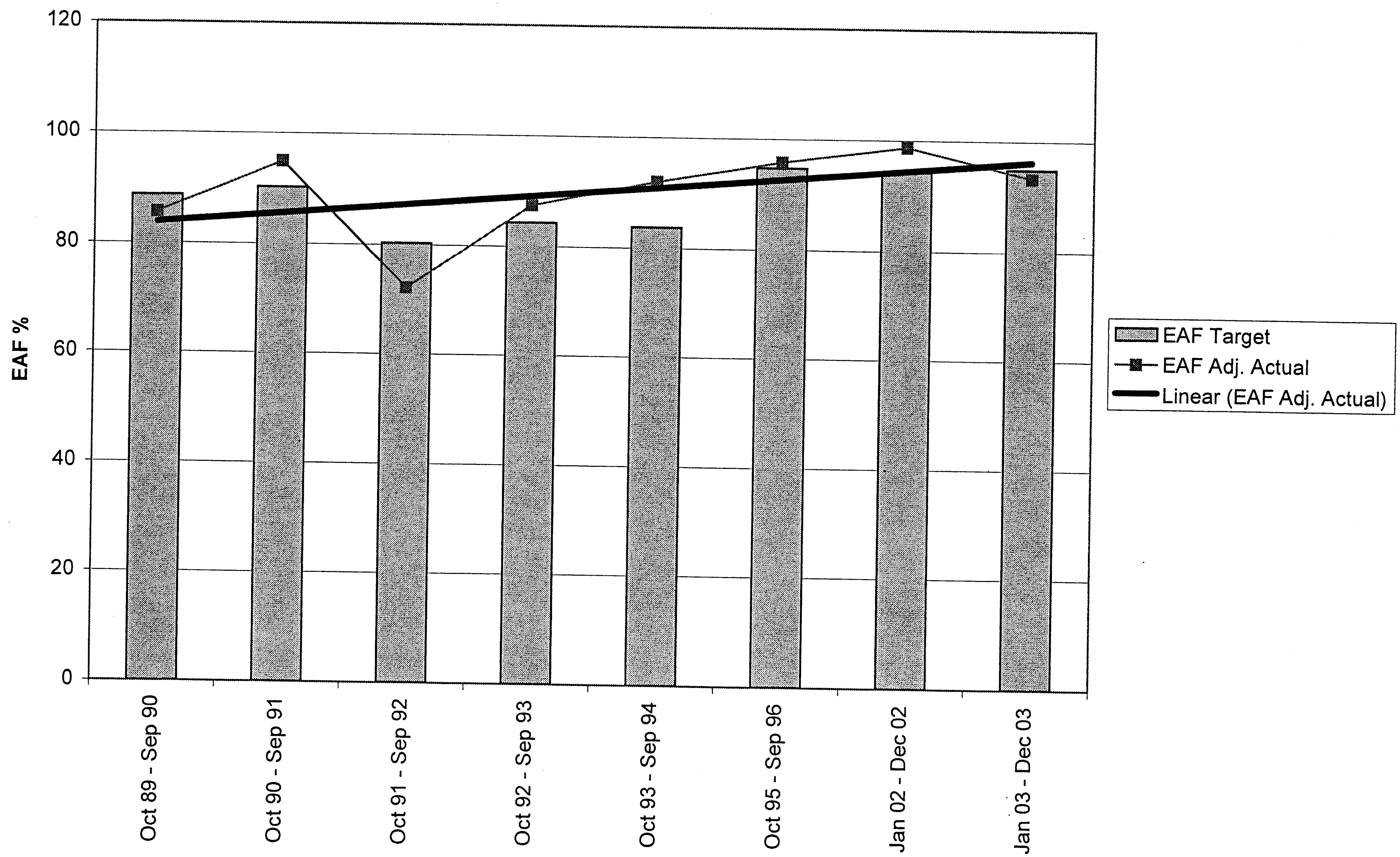
Turkey Point 1 EAF Analysis



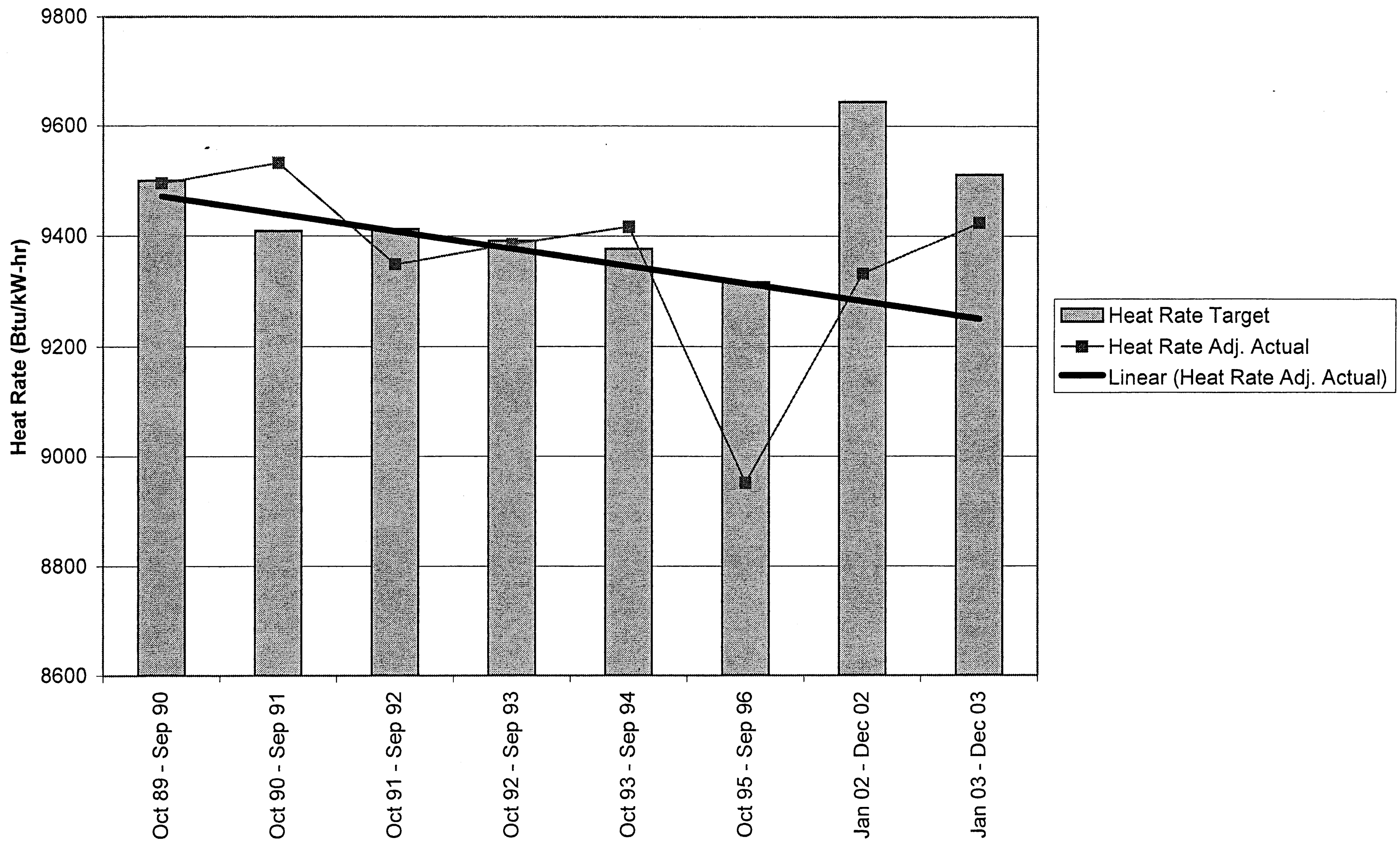
Turkey Point 1 Heat Rate Analysis



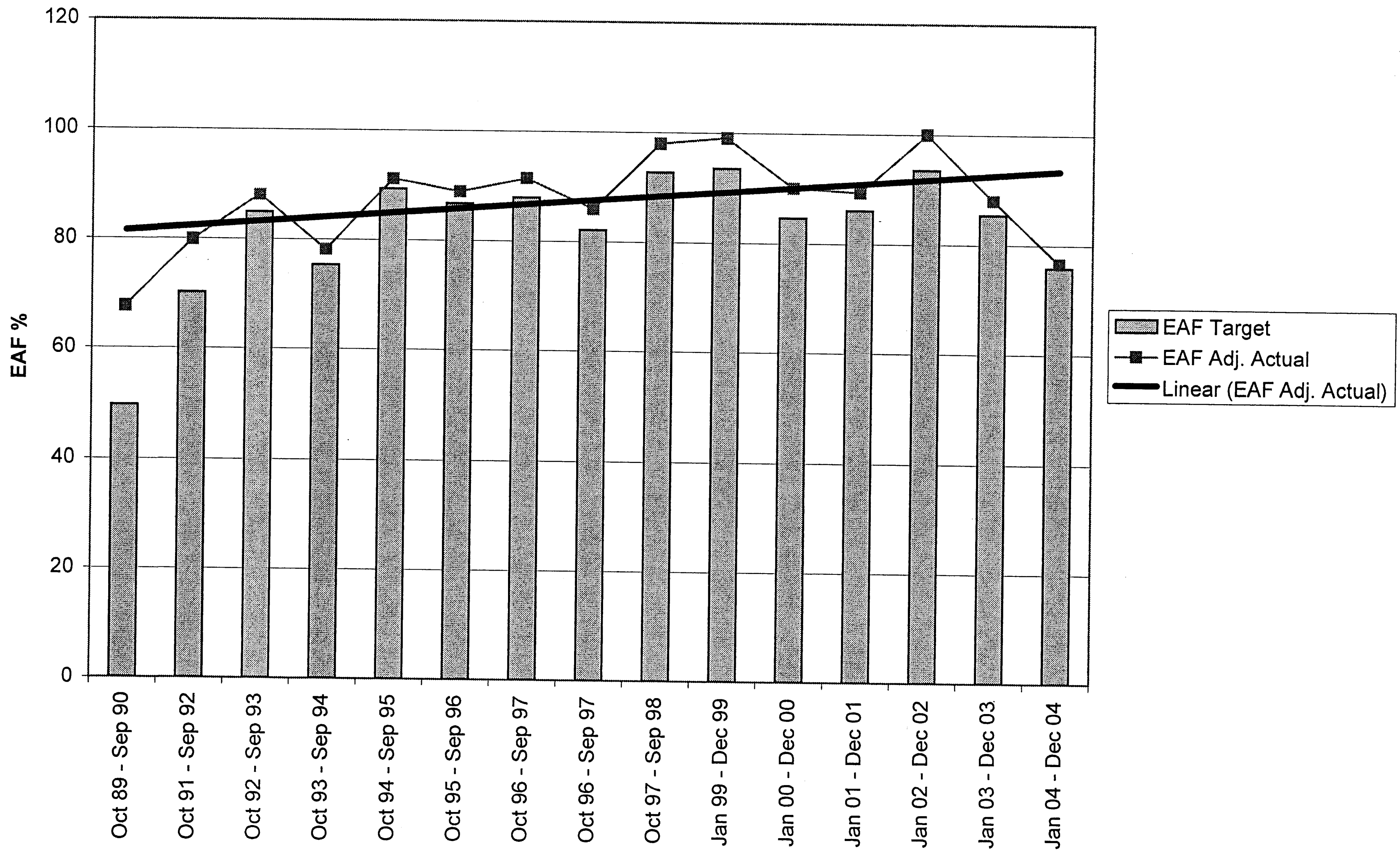
Turkey Point 2 EAF Analysis



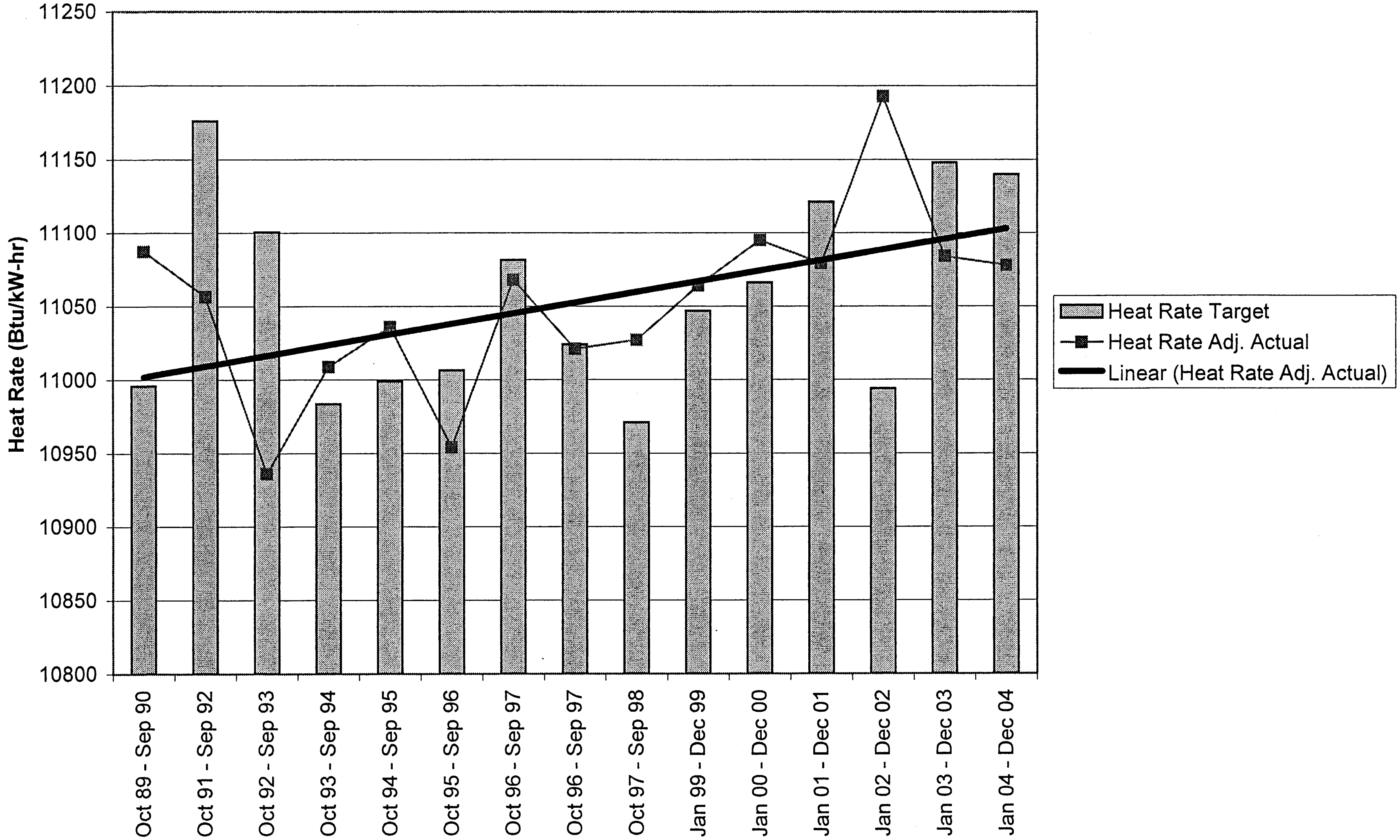
Turkey Point 2 Heat Rate Analysis

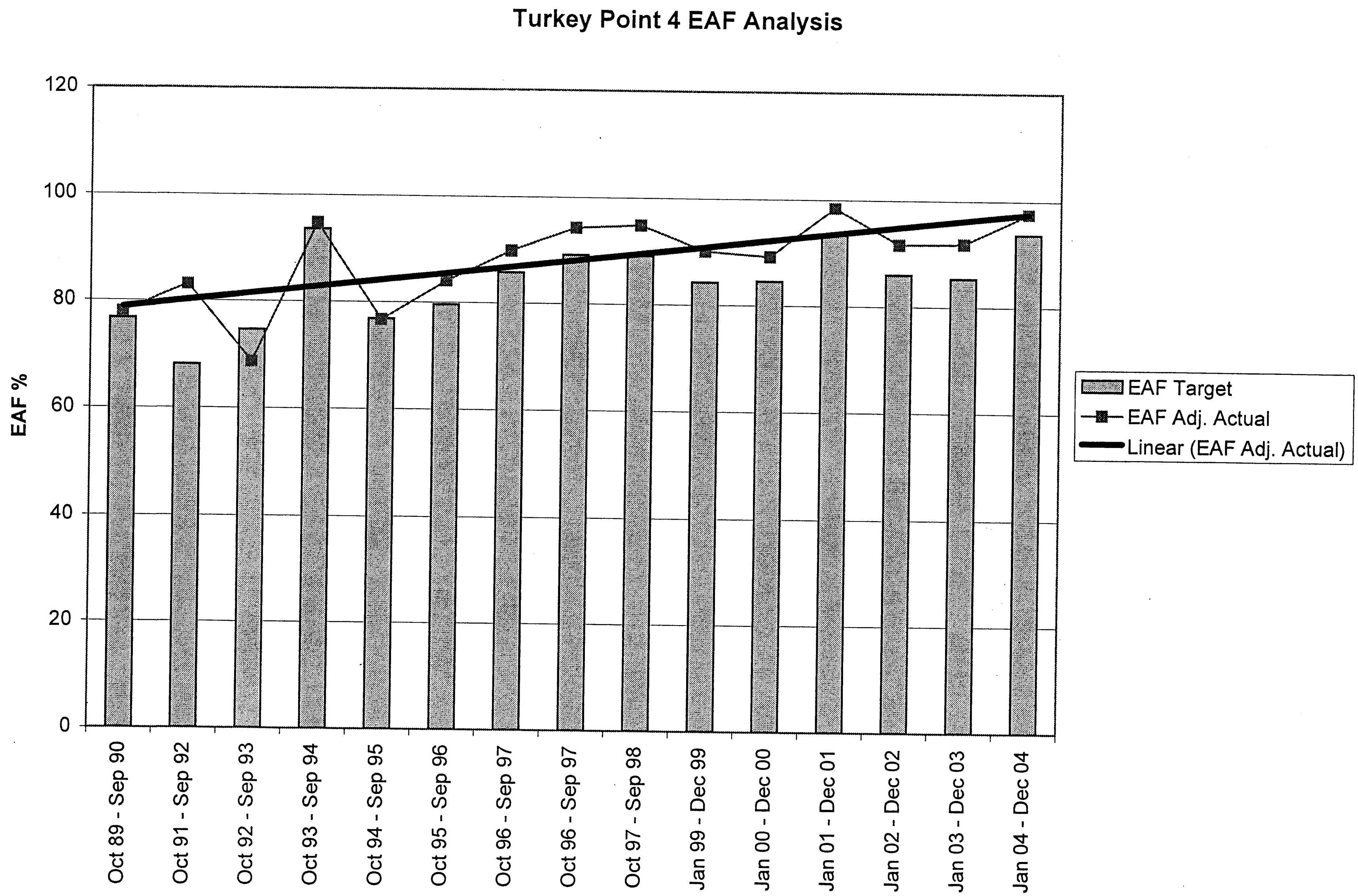


Turkey Point 3 EAF Analysis

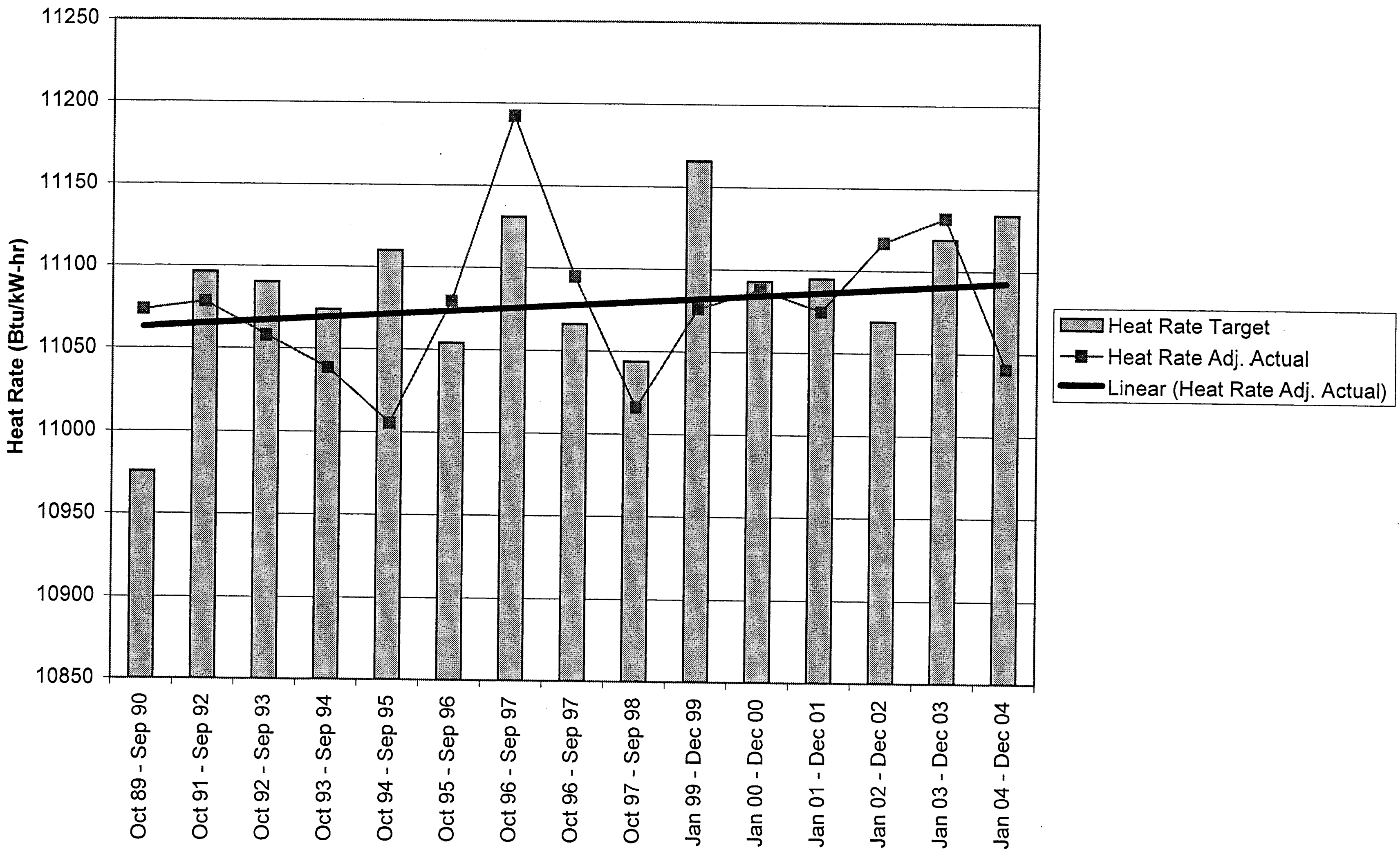


Turkey Point 3 Heat Rate Analysis

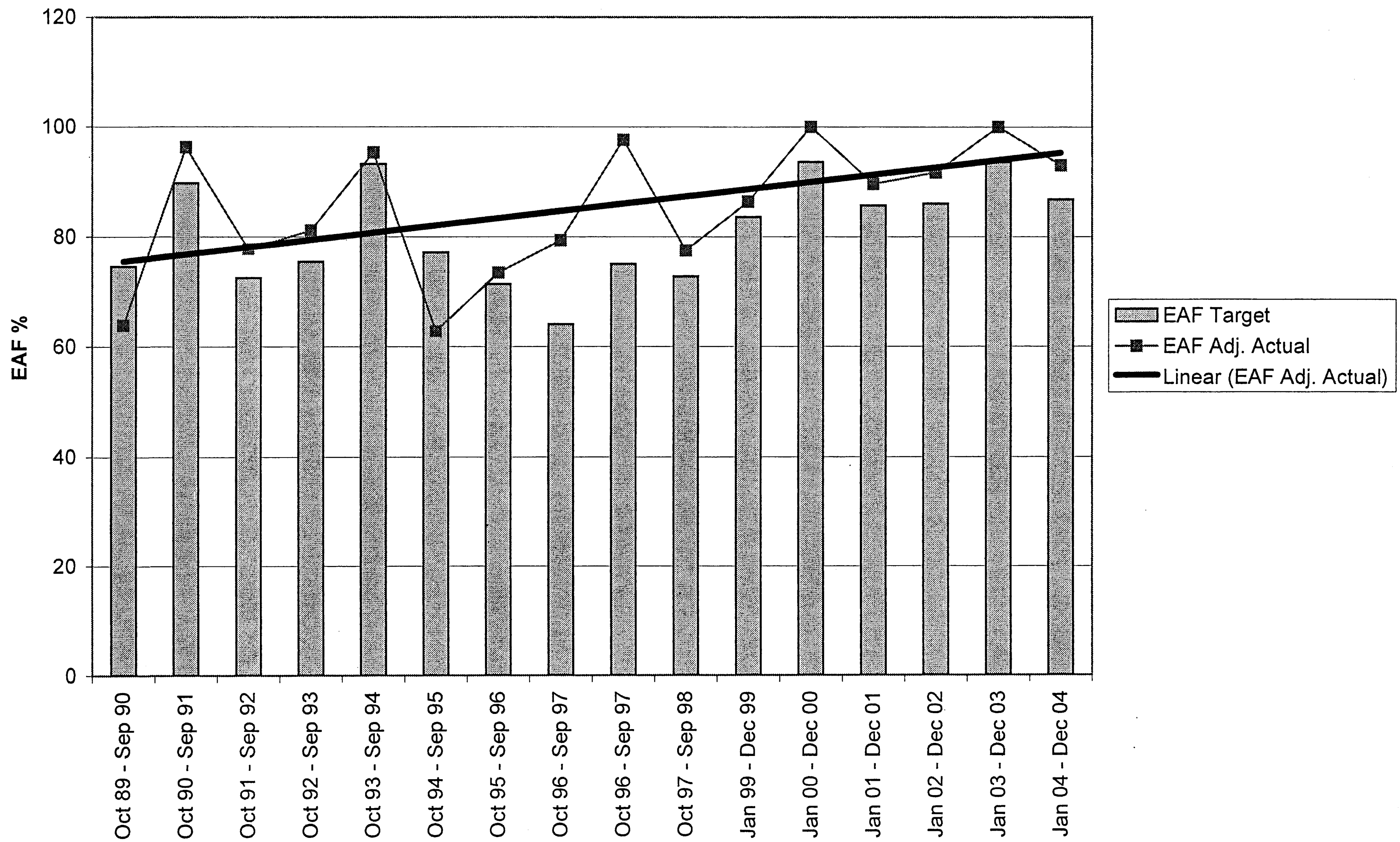



Turkey Point 4 EAF Analysis
EAF %
120
100
80
60
40
20
0
Oct 89 - Sep 90
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

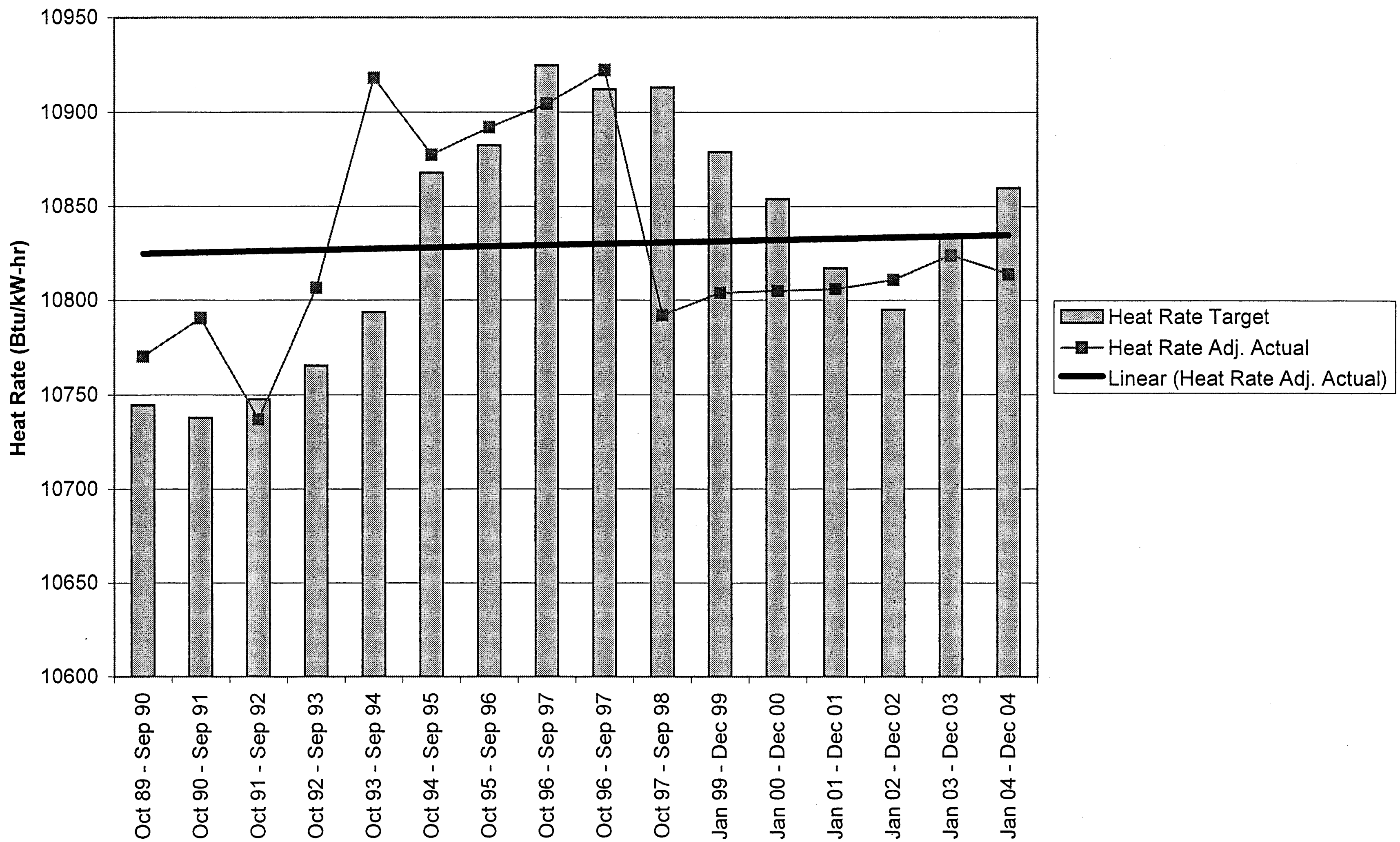
Turkey Point 4 Heat Rate Analysis



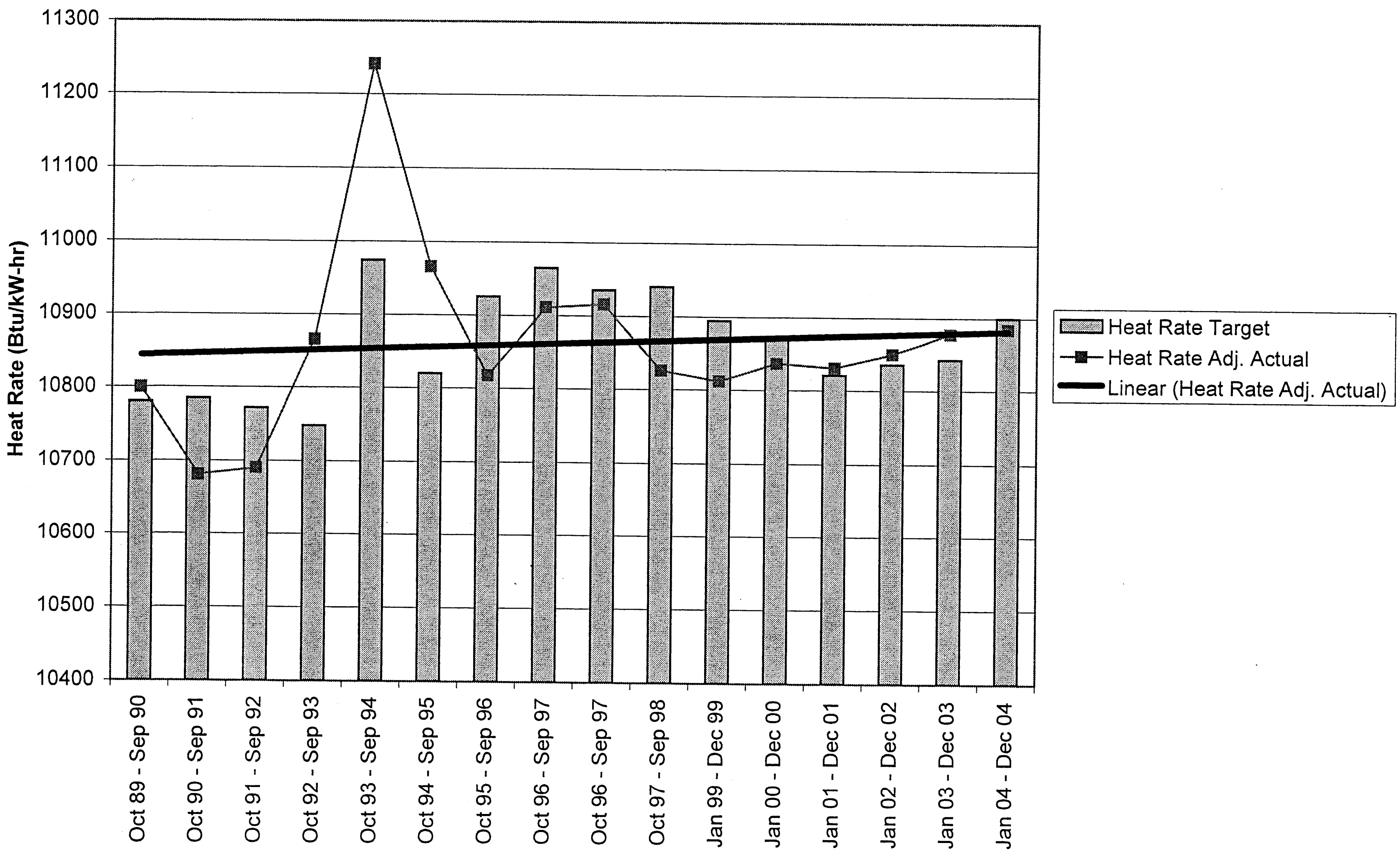
St. Lucie 1 EAF Analysis



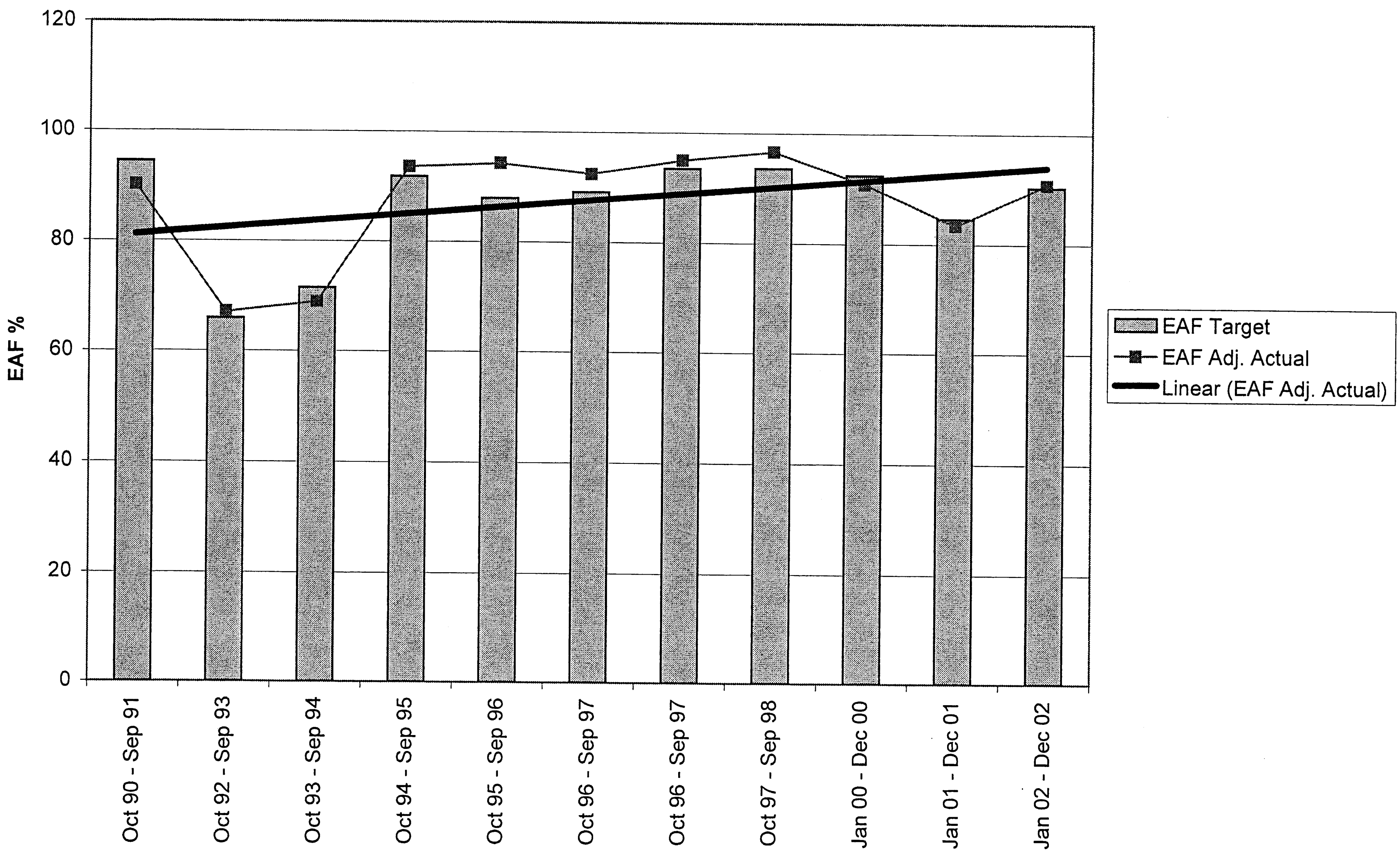
St. Lucie 1 Heat Rate Analysis

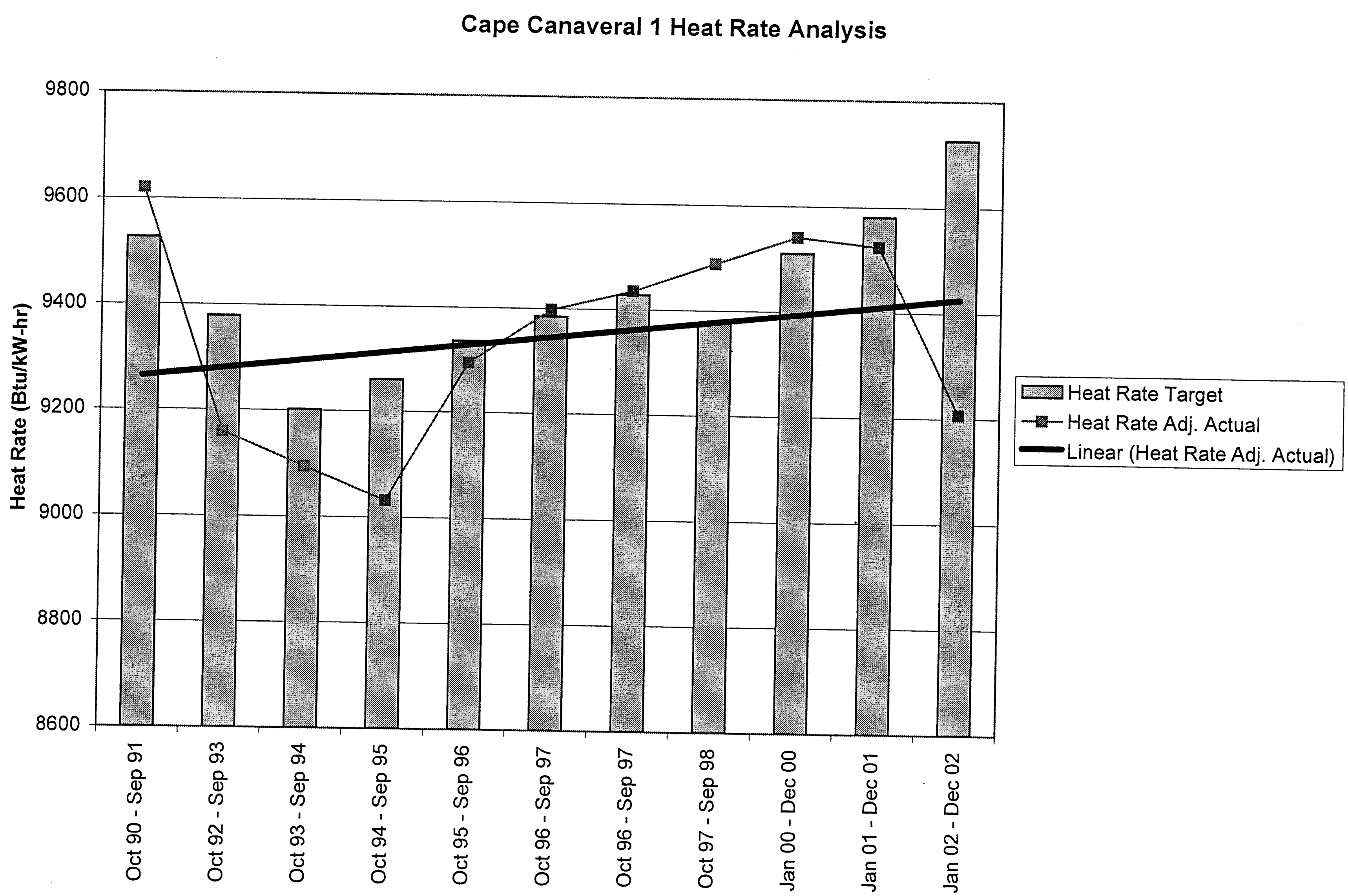


St. Lucie 2 Heat Rate Analysis

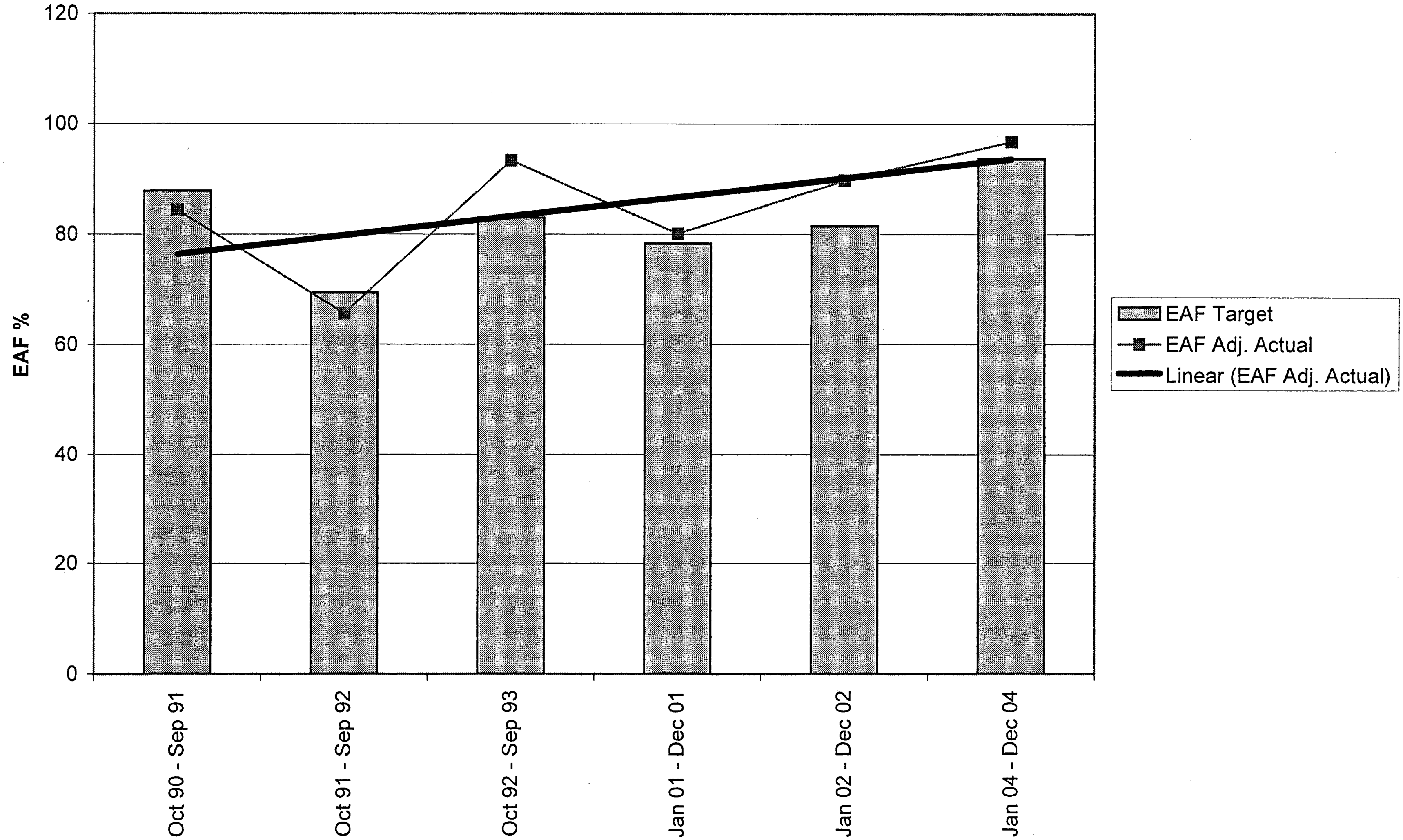


Cape Canaveral 1 EAF Analysis

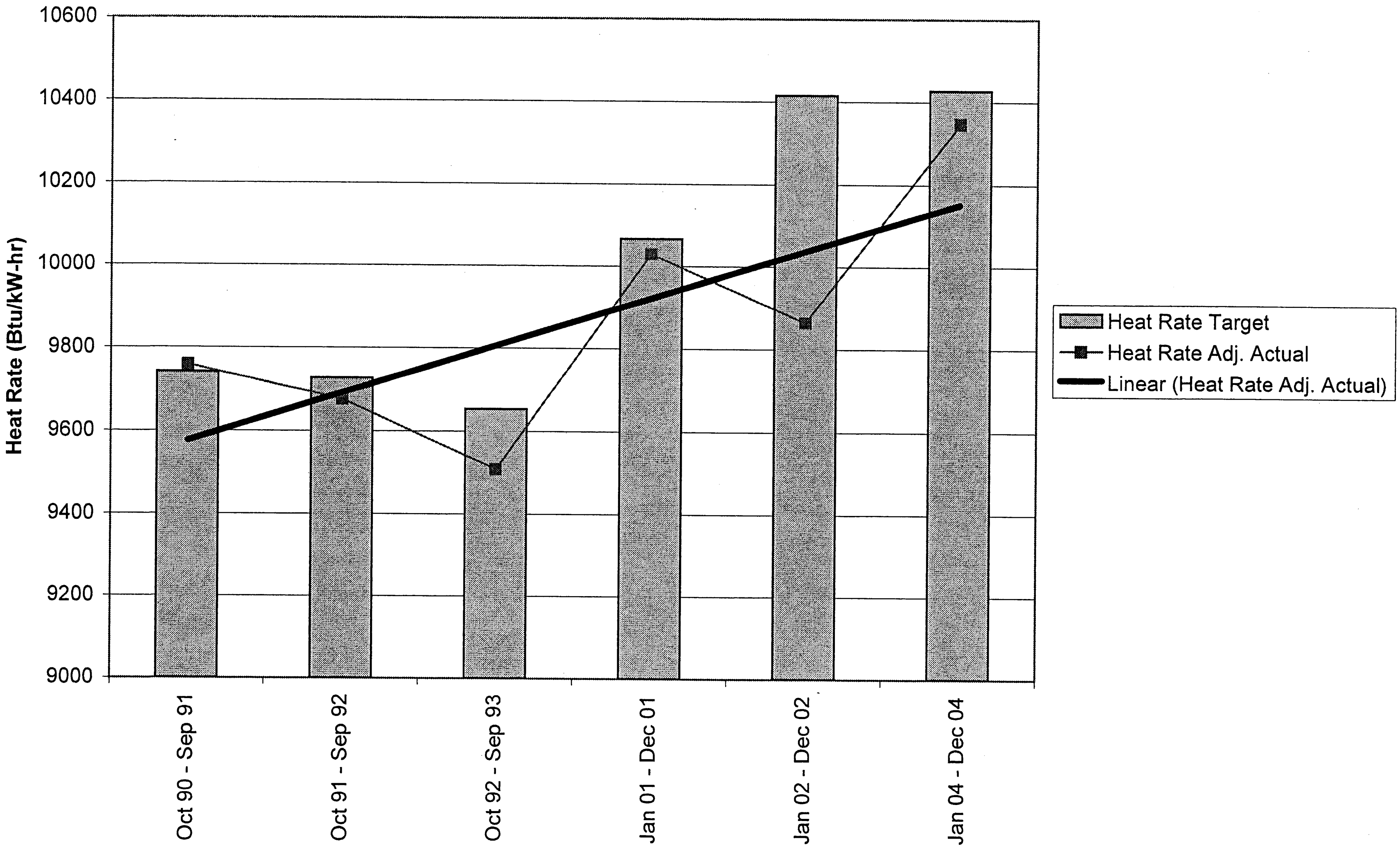



Cape Canaveral 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9800
9600
9400
9200
9000
8800
8600
Oct 90 - Sep 91
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

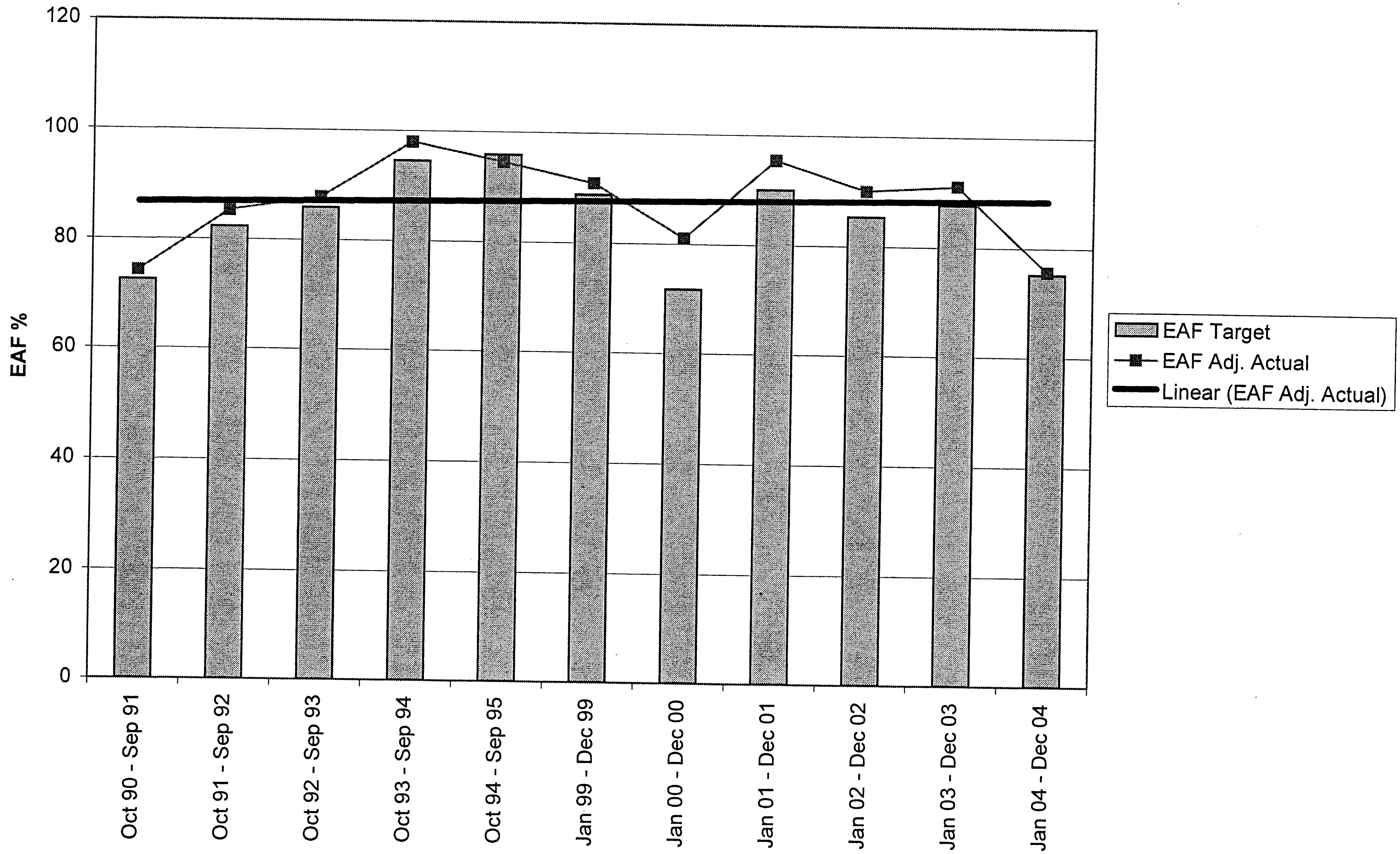
Manatee 1 EAF Analysis



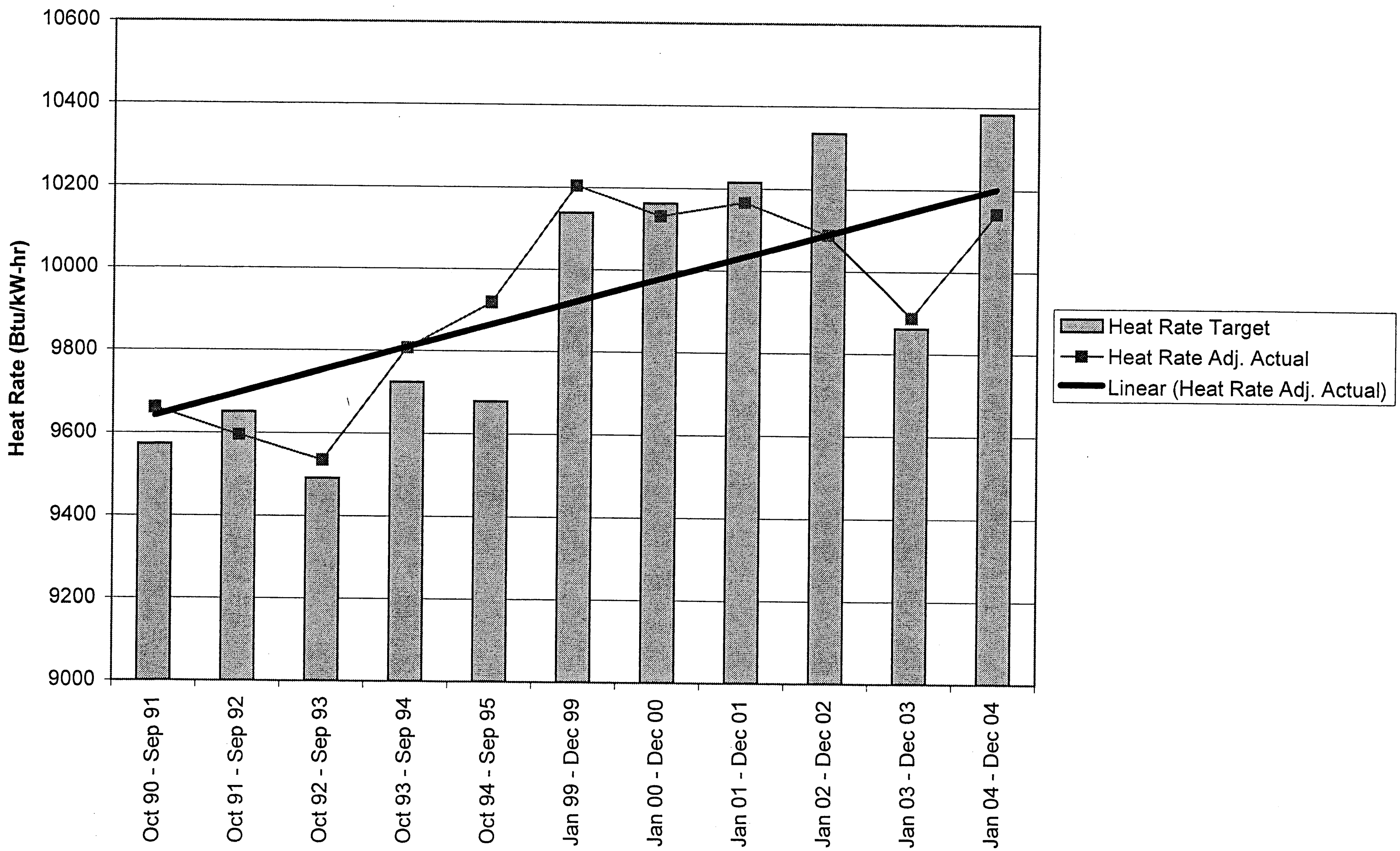
Manatee 1 Heat Rate Analysis



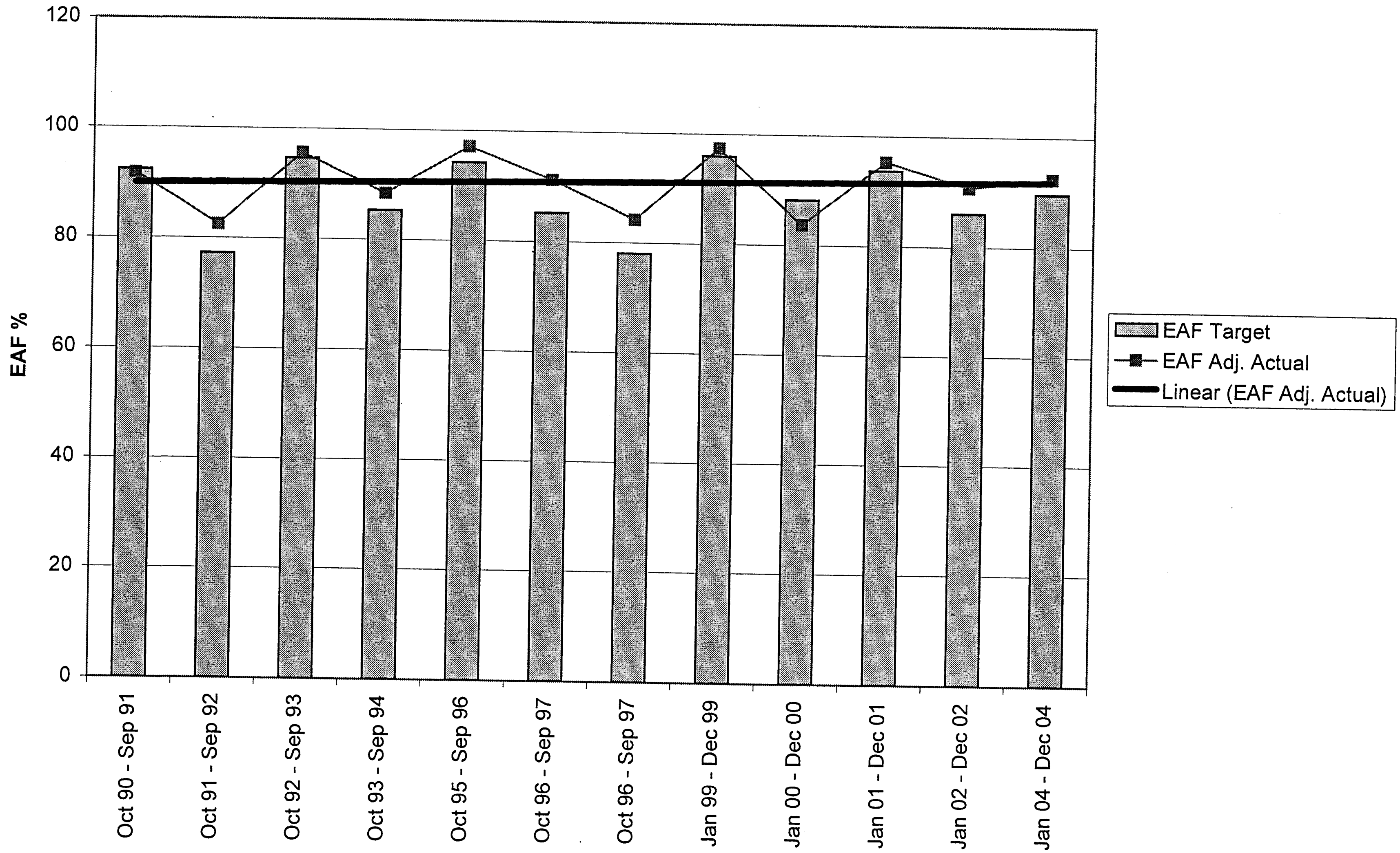
Manatee 2 EAF Analysis

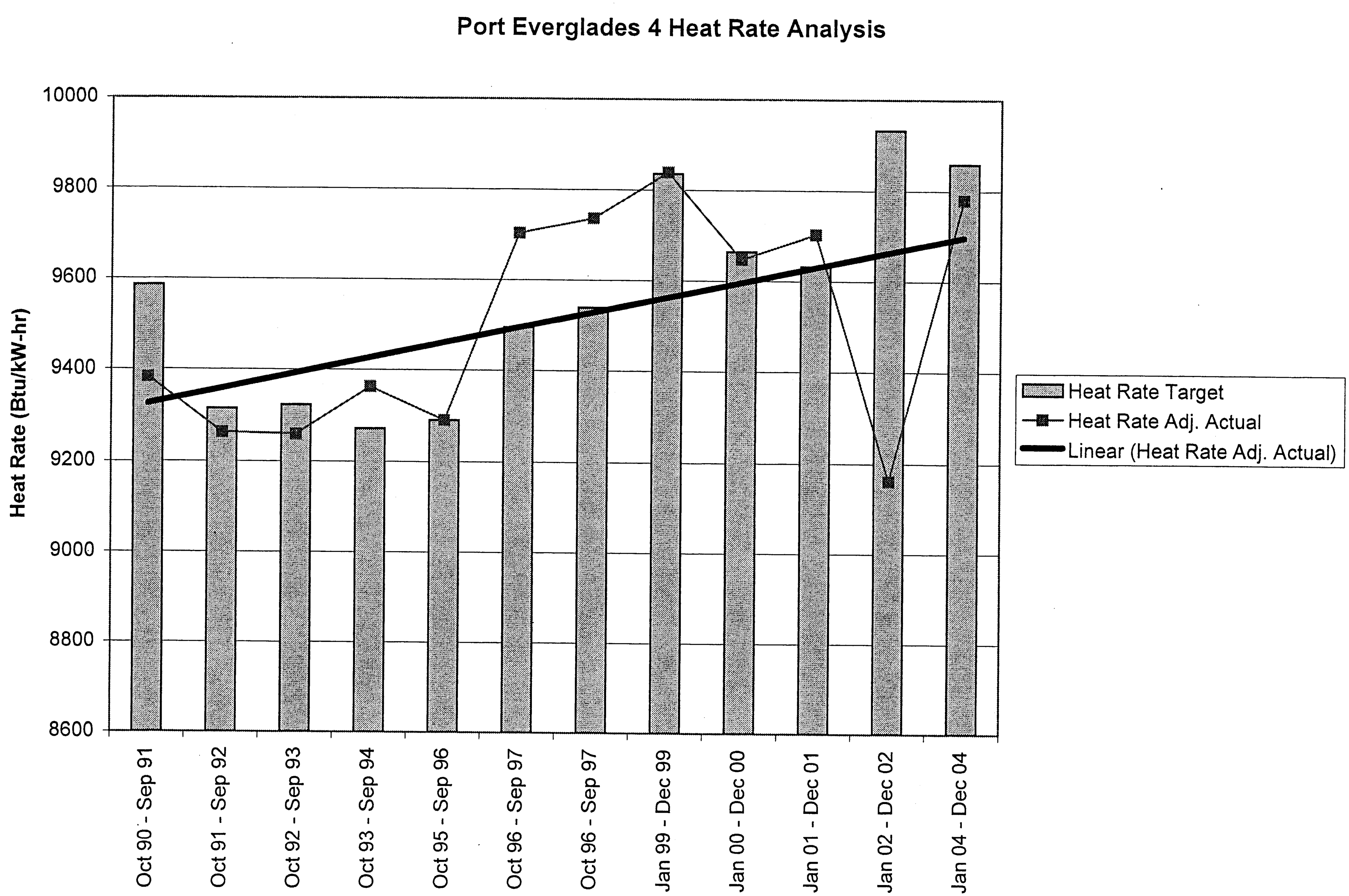


Manatee 2 Heat Rate Analysis



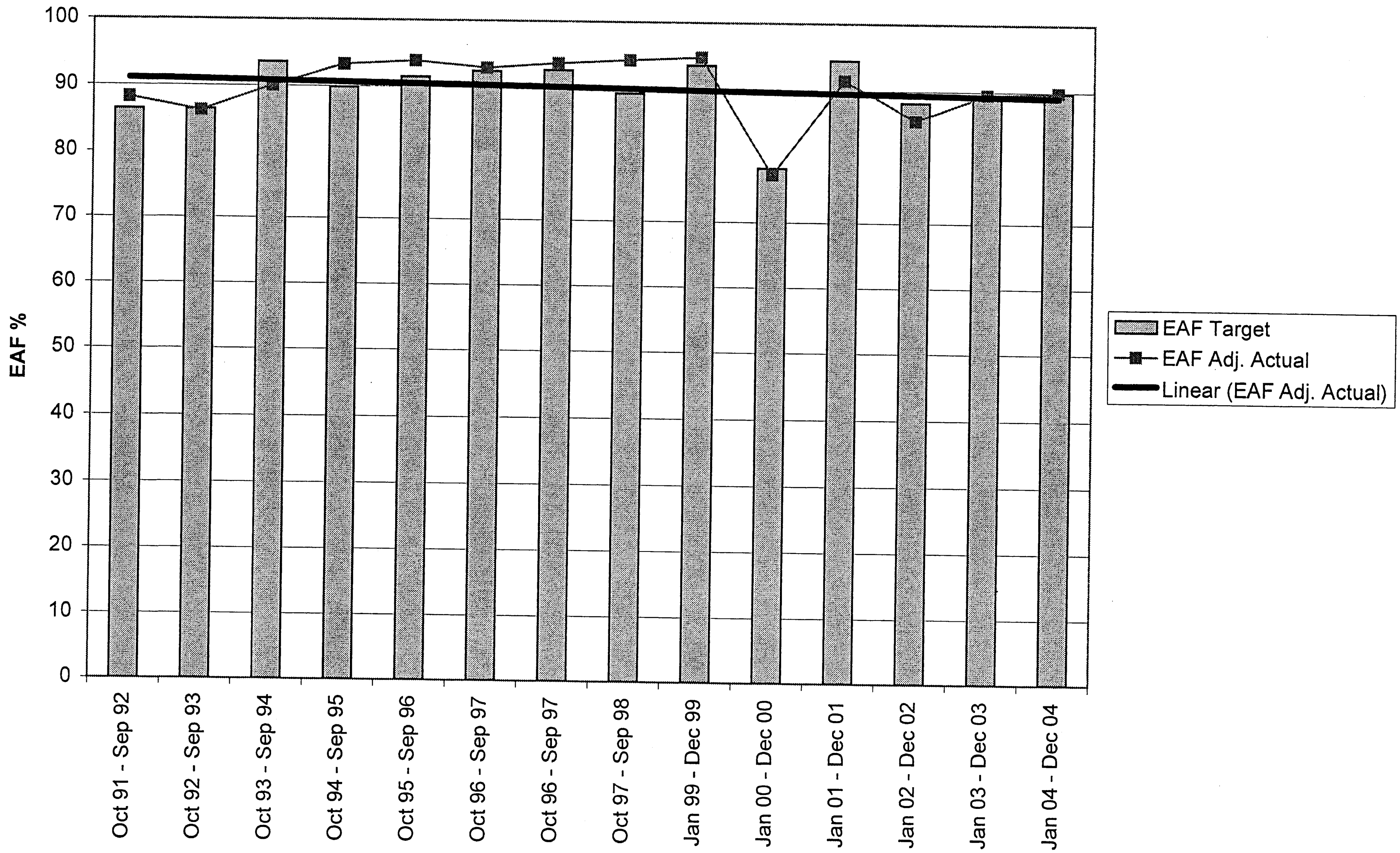
Port Everglades 4 EAF Analysis



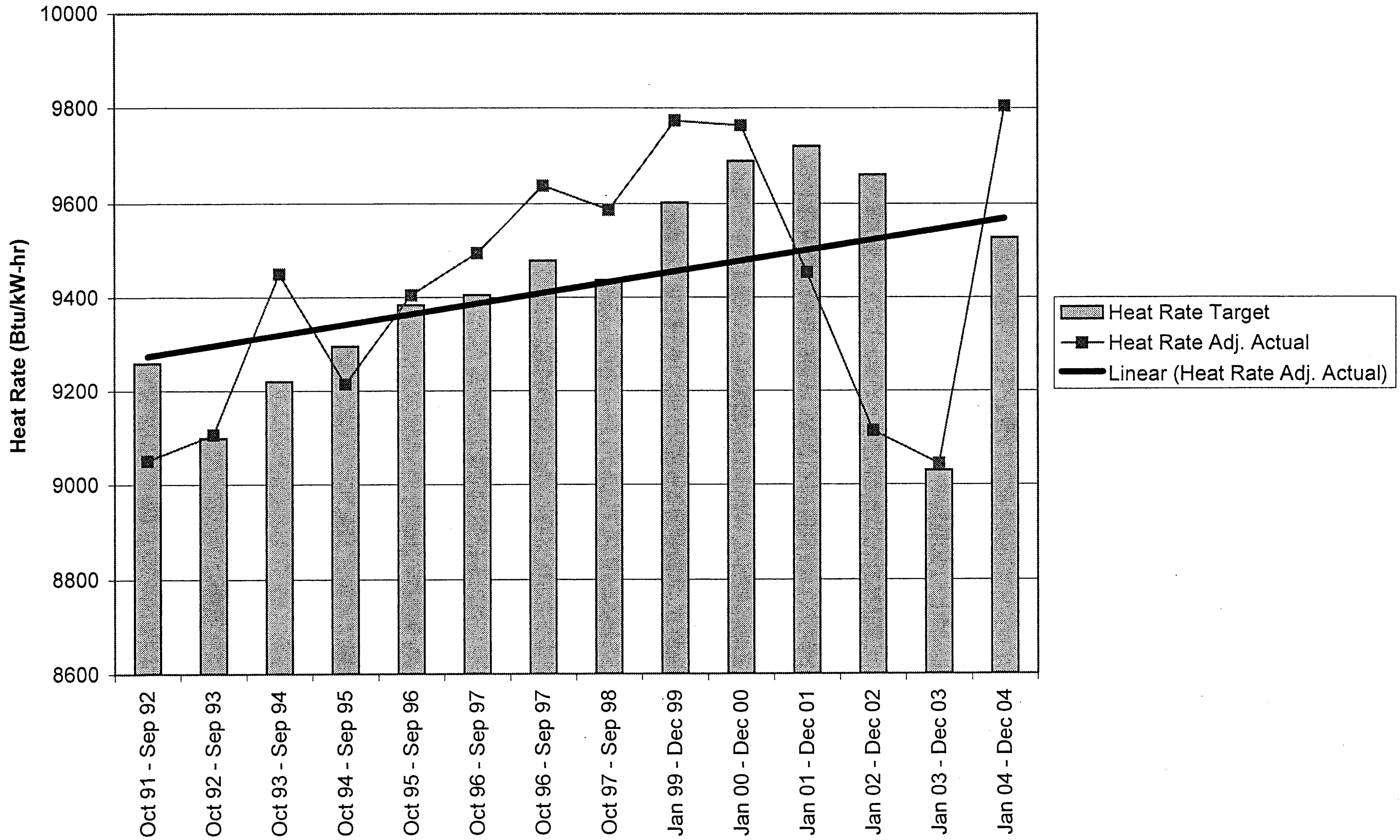


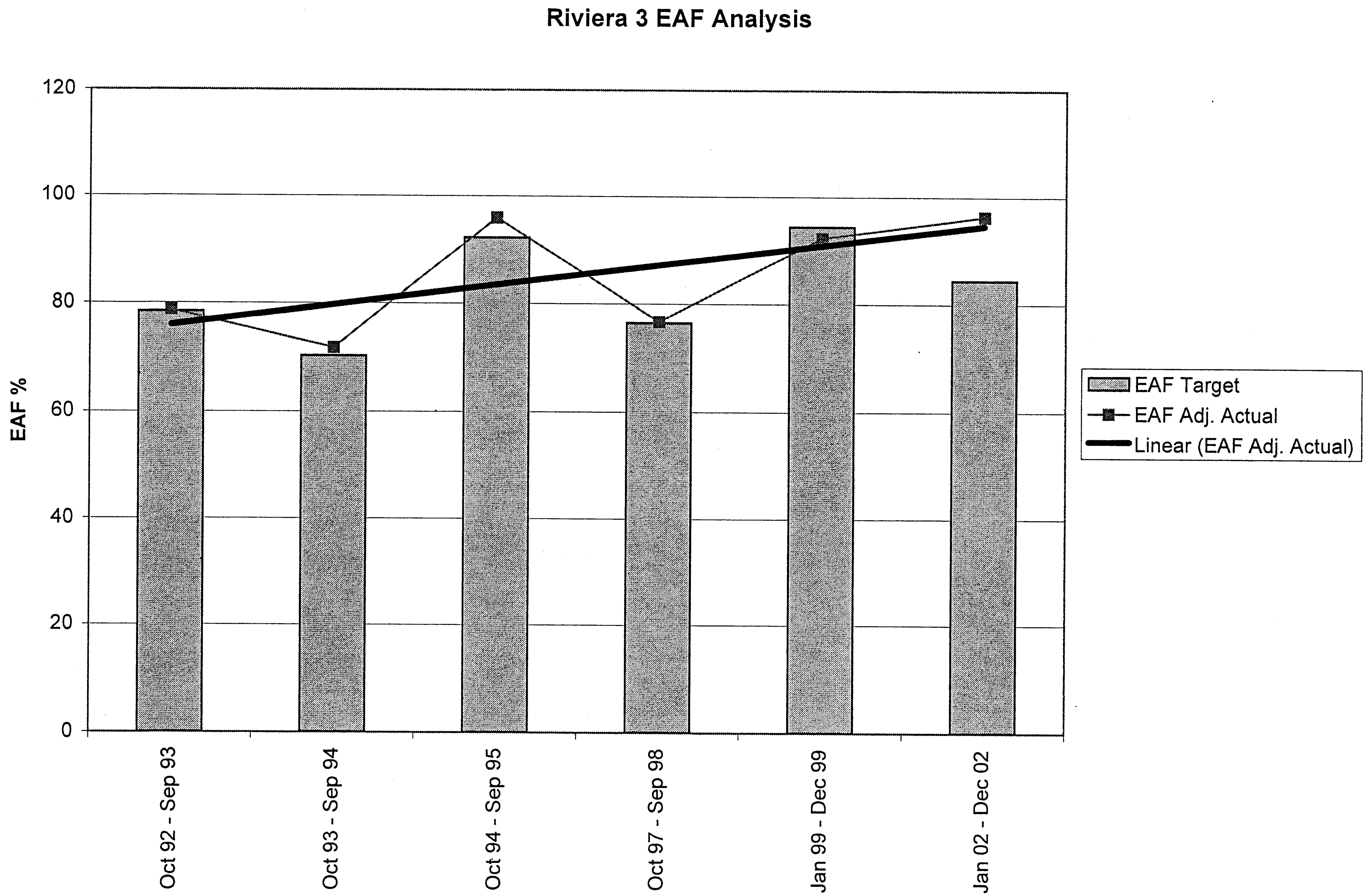
Port Everglades 4 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10000
9800
9600
9400
9200
9000
8800
8600
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 96 - Sep 97
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

Cape Canaveral 2 EAF Analysis



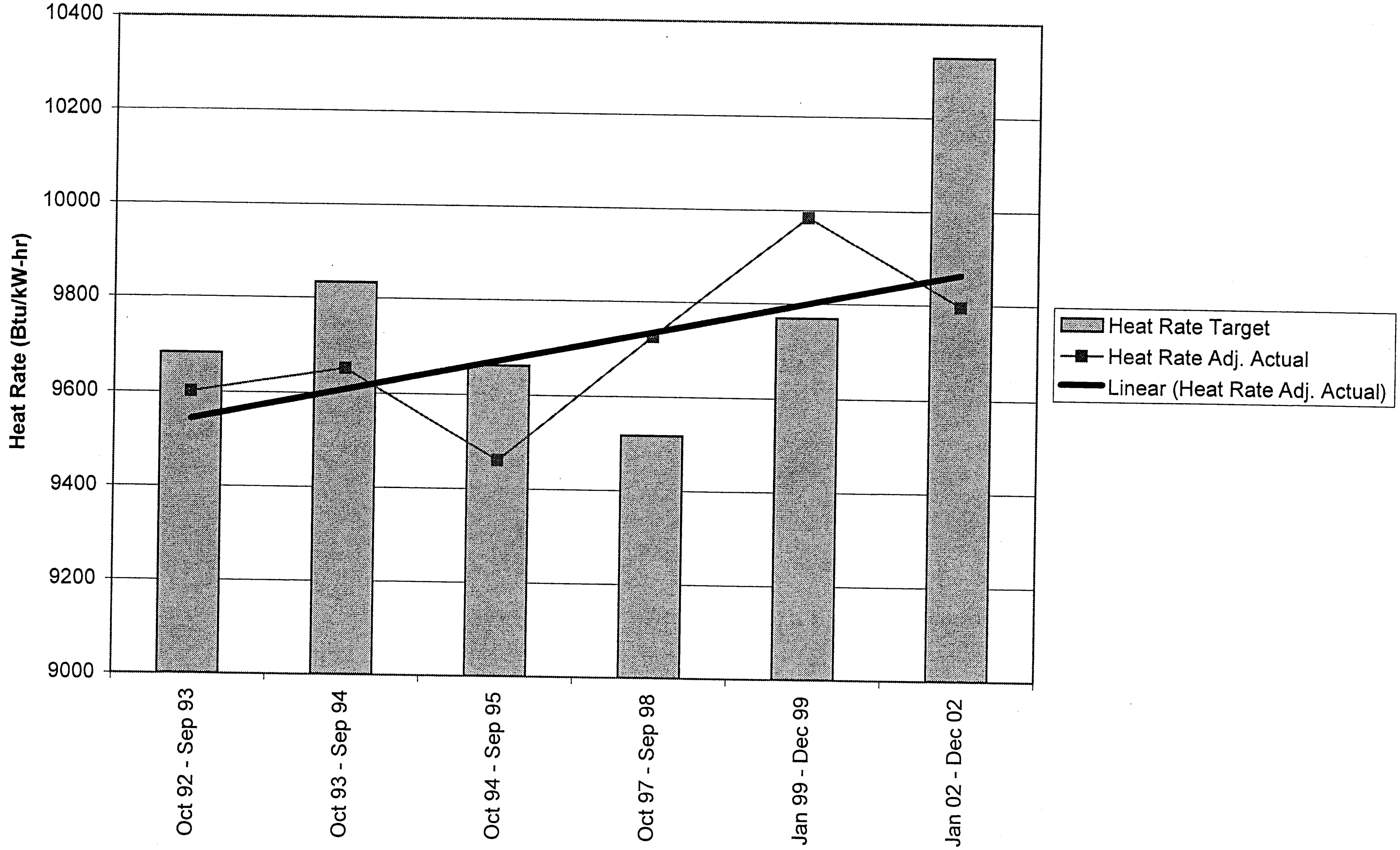
Cape Canaveral 2 Heat Rate Analysis



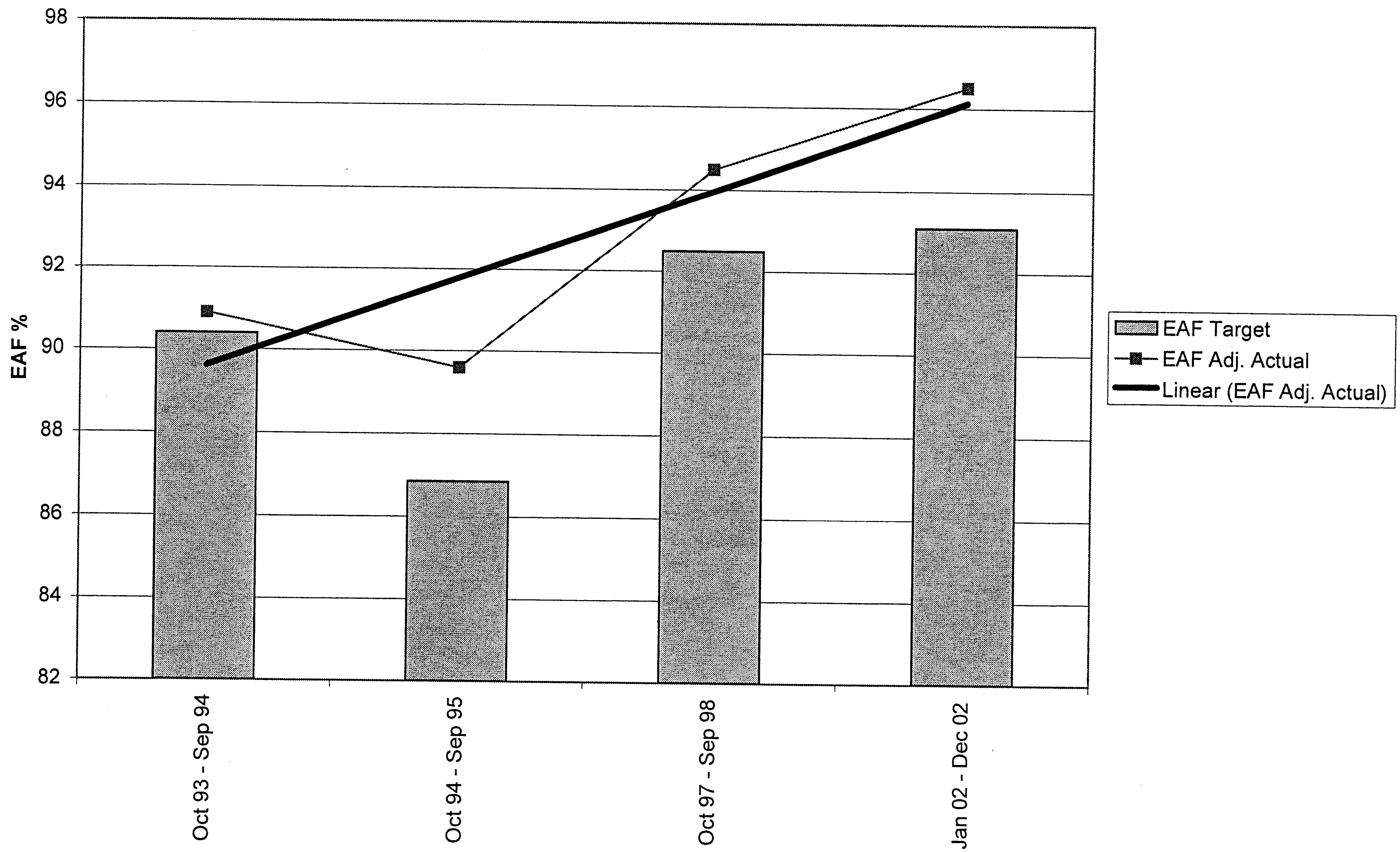


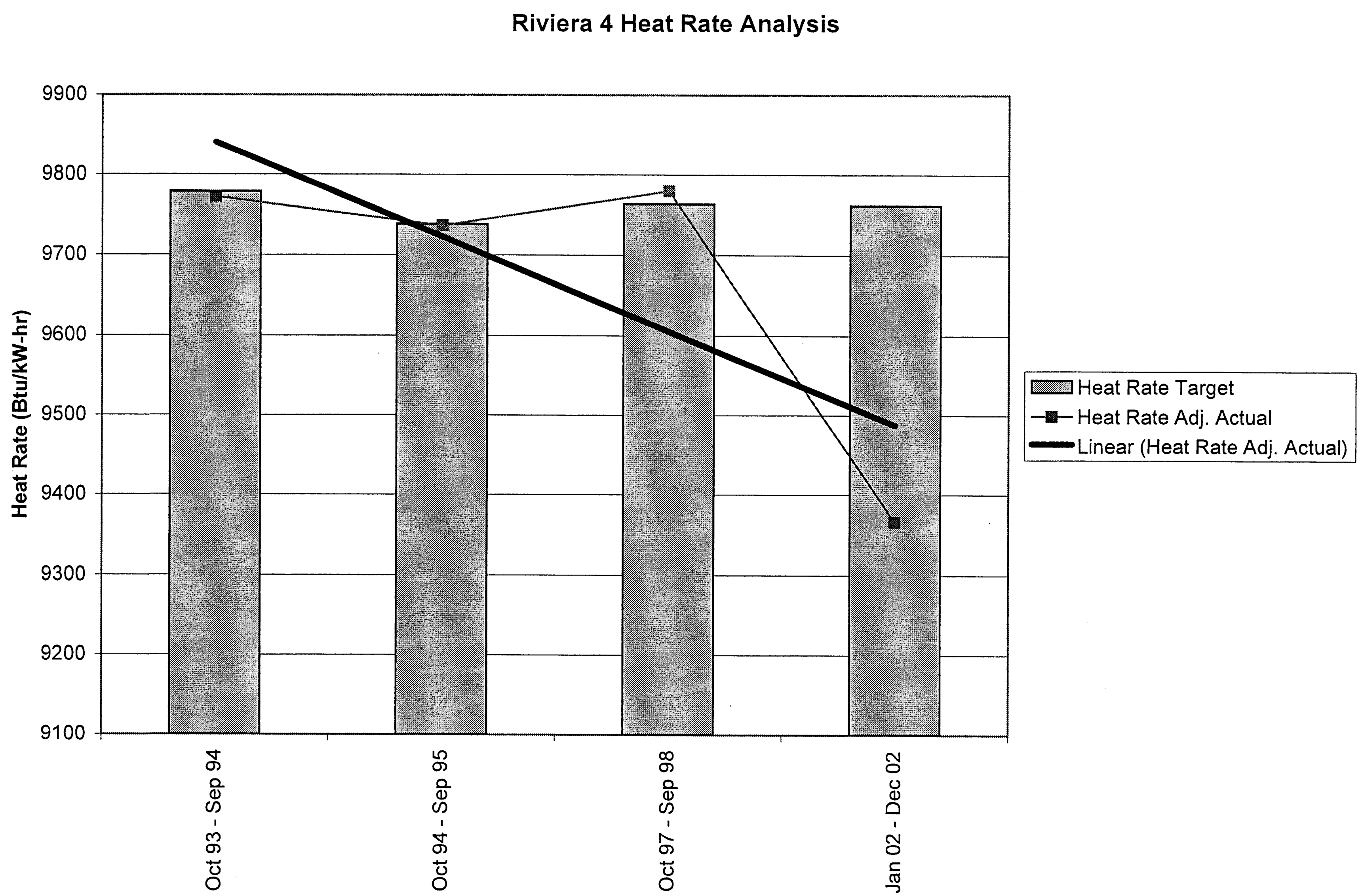
Riviera 3 EAF Analysis
EAF %
120
100
80
60
40
20
0
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 02 - Dec 02
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

Riviera 3 Heat Rate Analysis

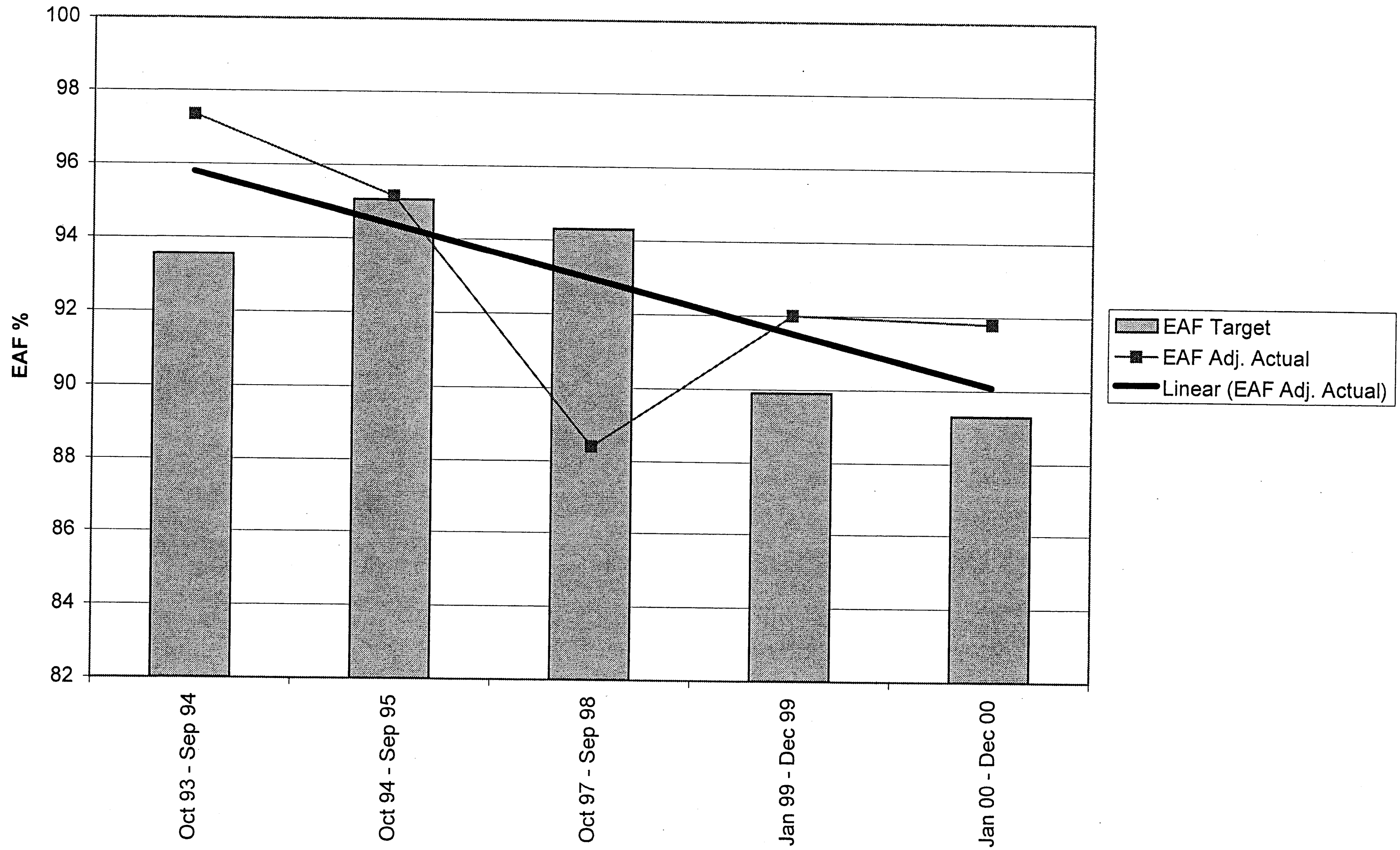


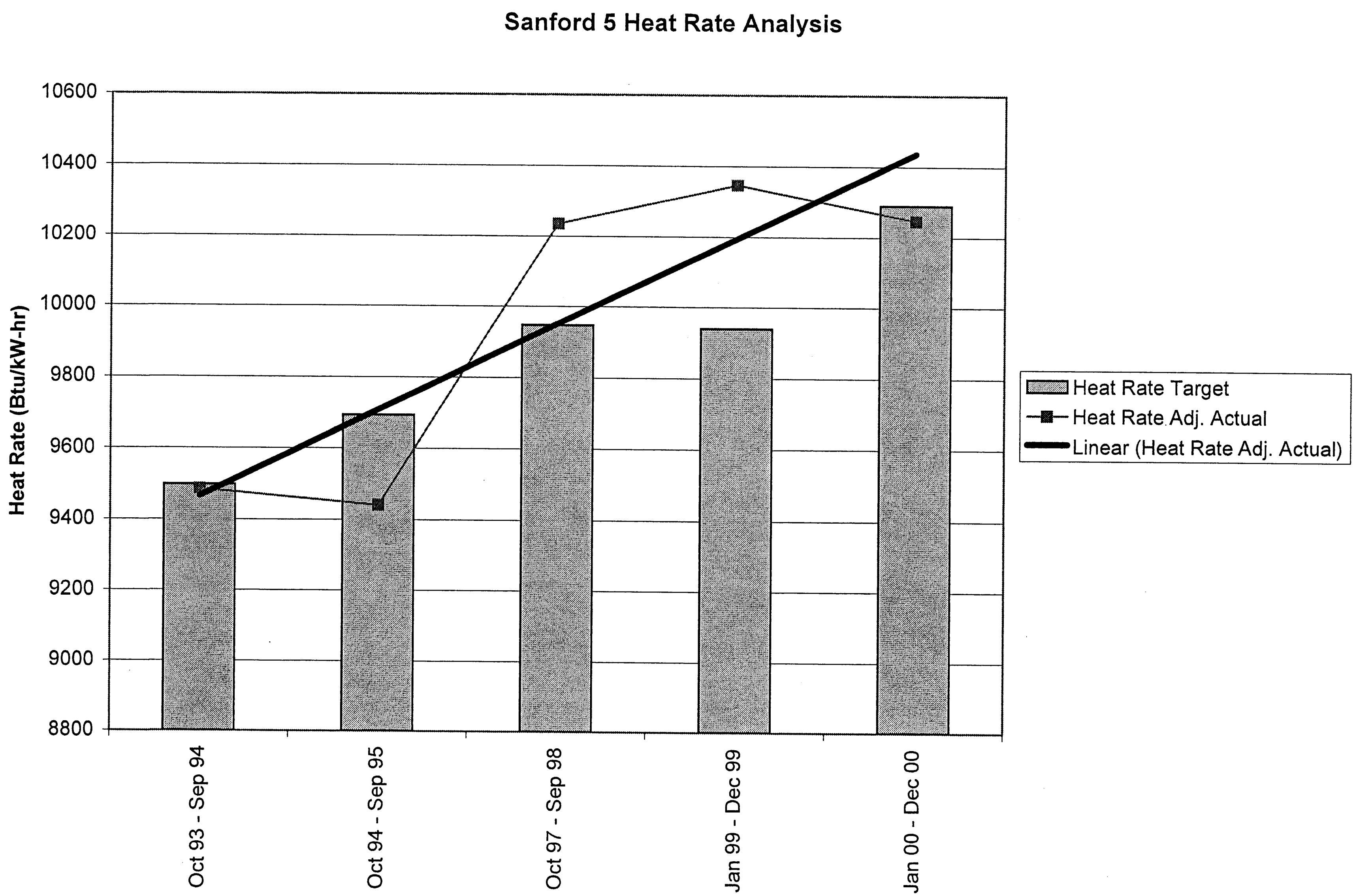
Riviera 4 EAF Analysis




Riviera 4 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9900
9800
9700
9600
9500
9400
9300
9200
9100
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 97 - Sep 98
Jan 02 - Dec 02
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

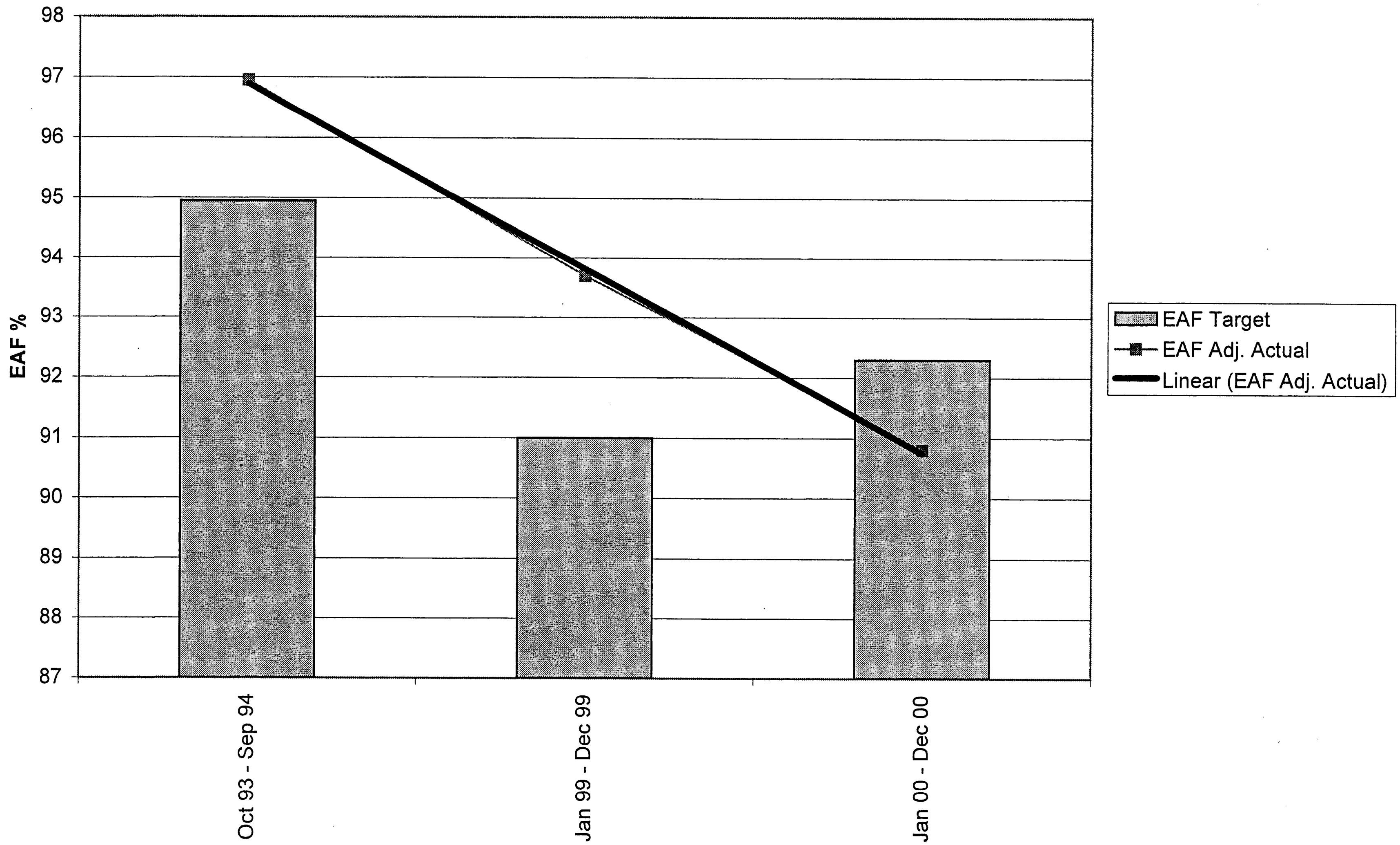
Sanford 5 EAF Analysis



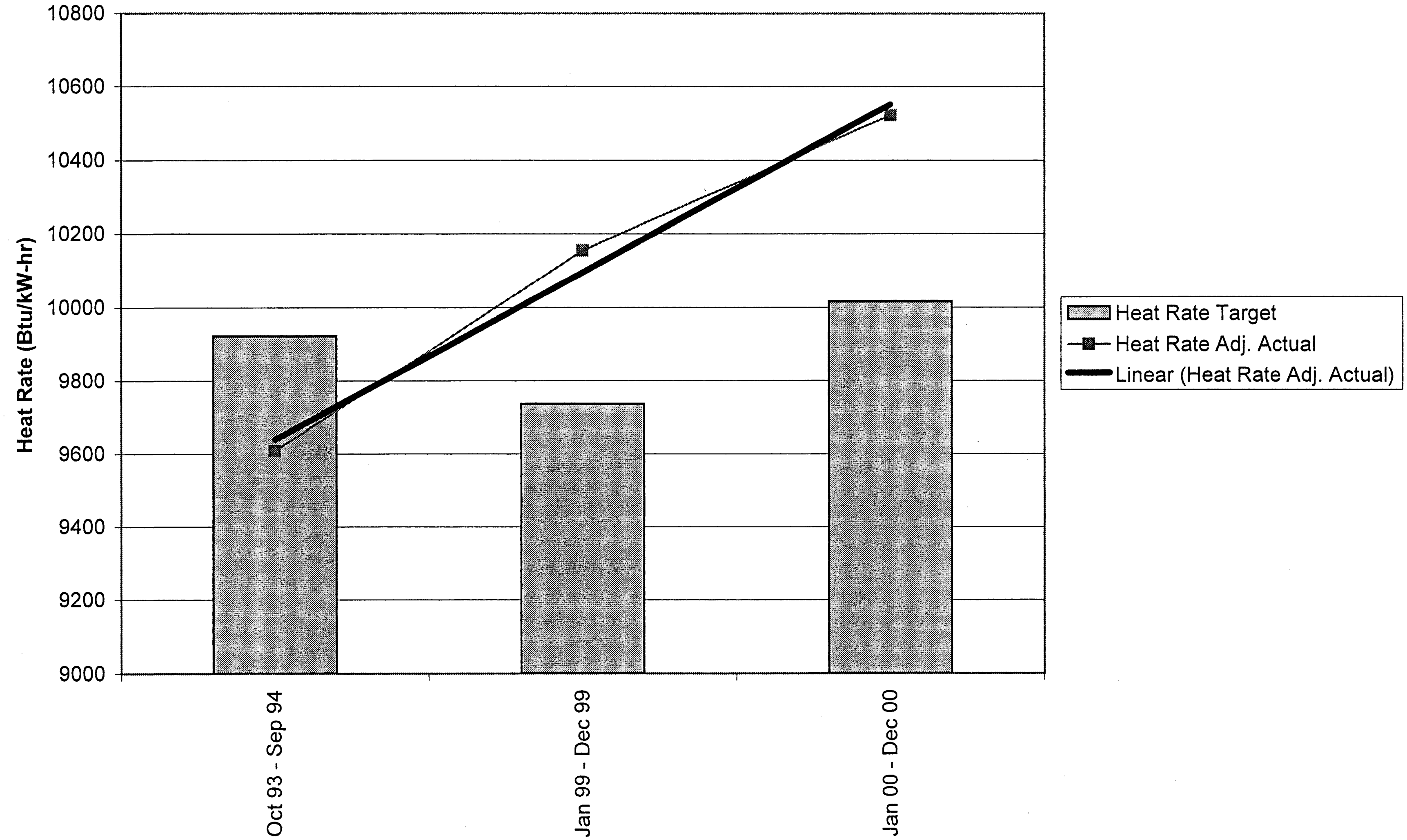


Sanford 5 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10600
10400
10200
10000
9800
9600
9400
9200
9000
8800
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

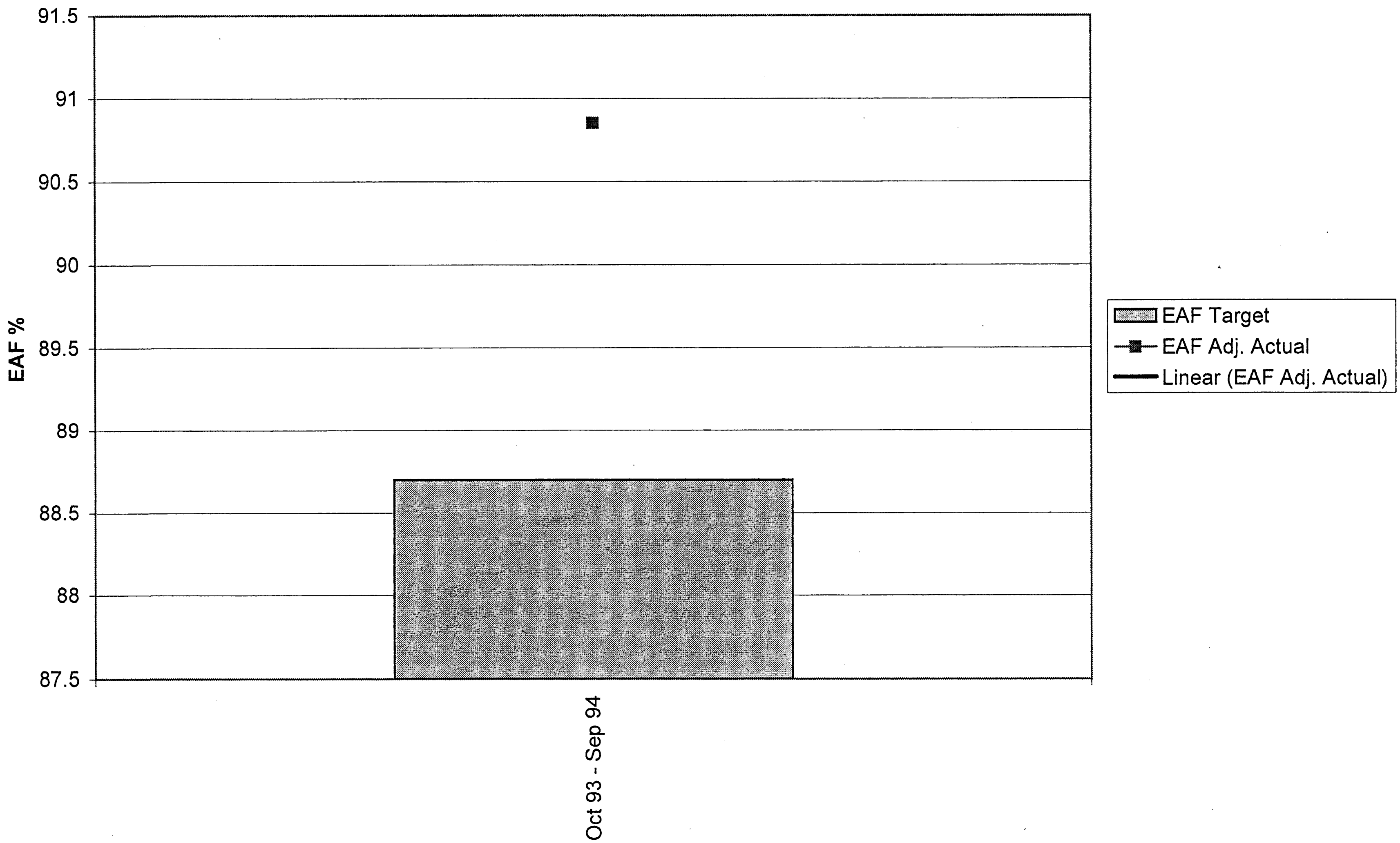
Sanford 4 EAF Analysis



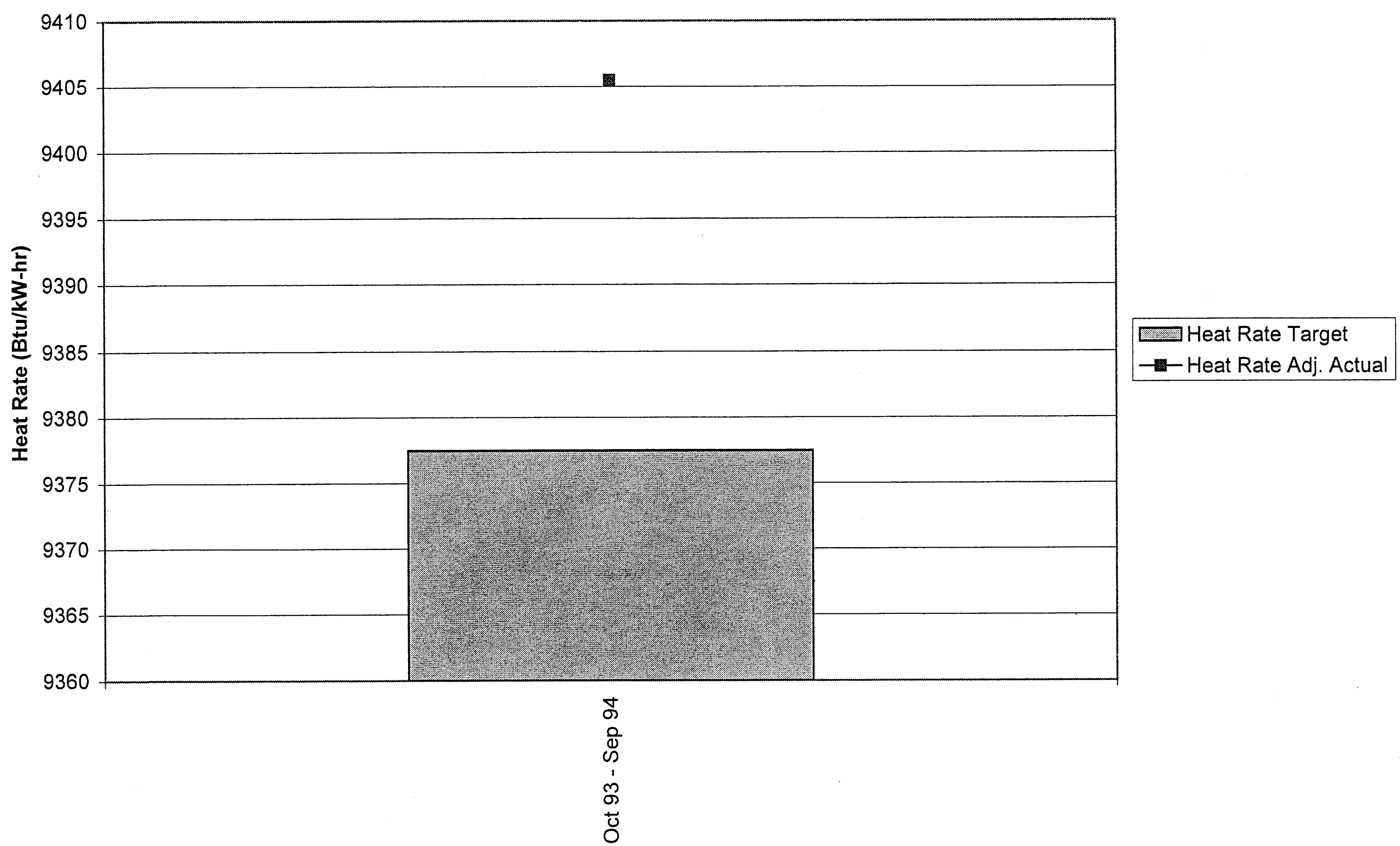
Sanford 4 Heat Rate Analysis



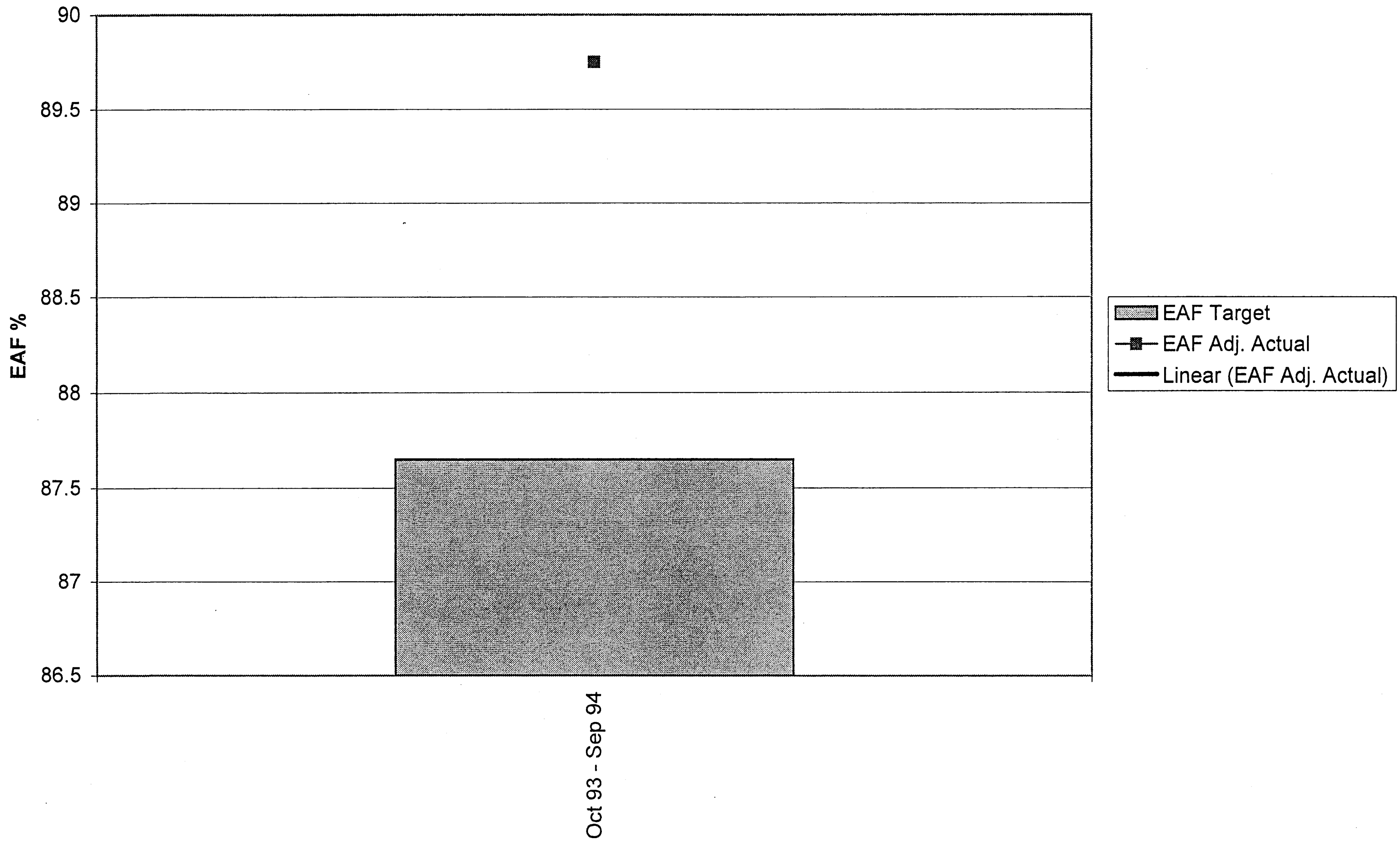
St. Johns River 1 EAF Analysis

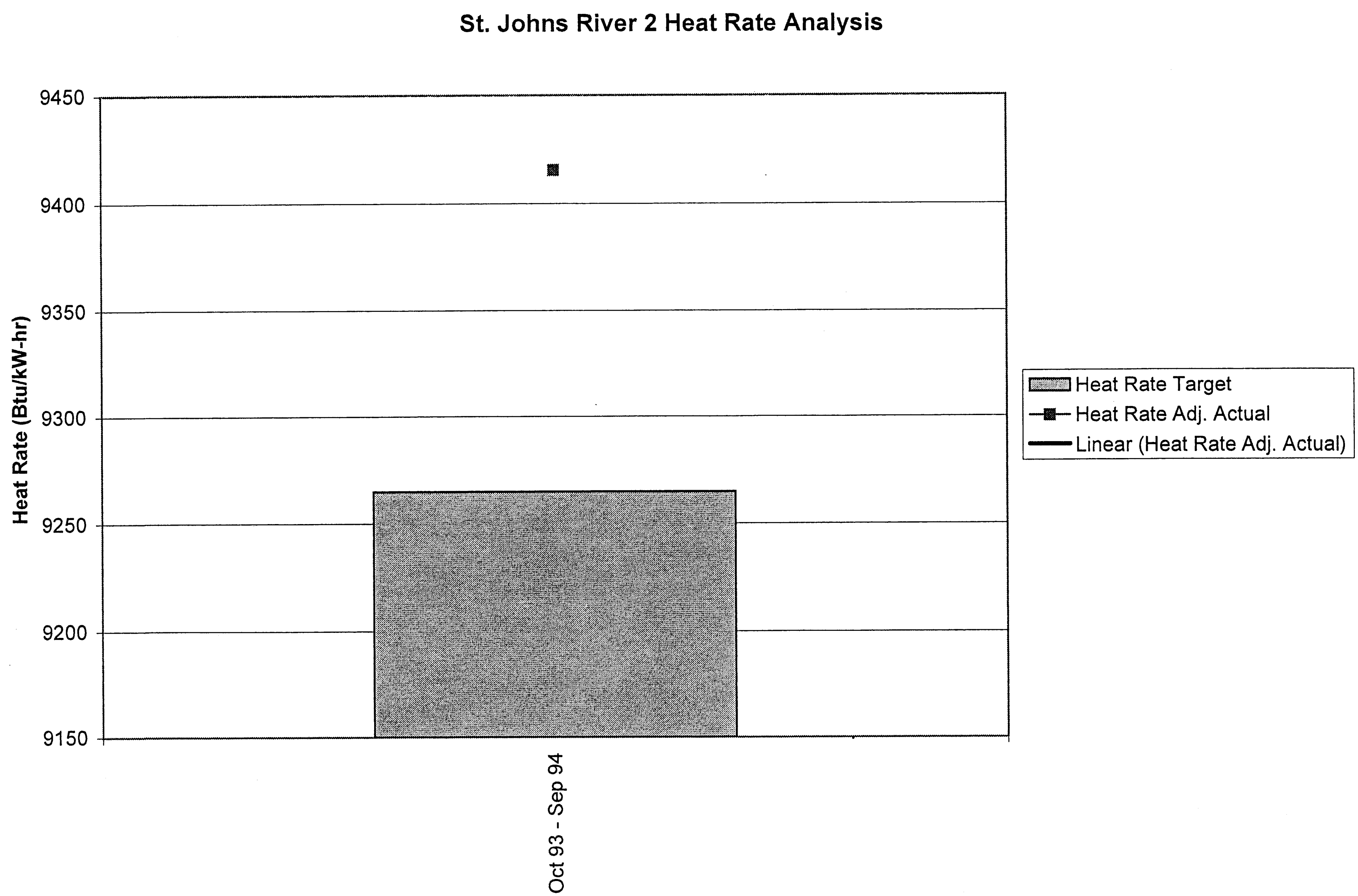


St. Johns River 1 Heat Rate Analysis



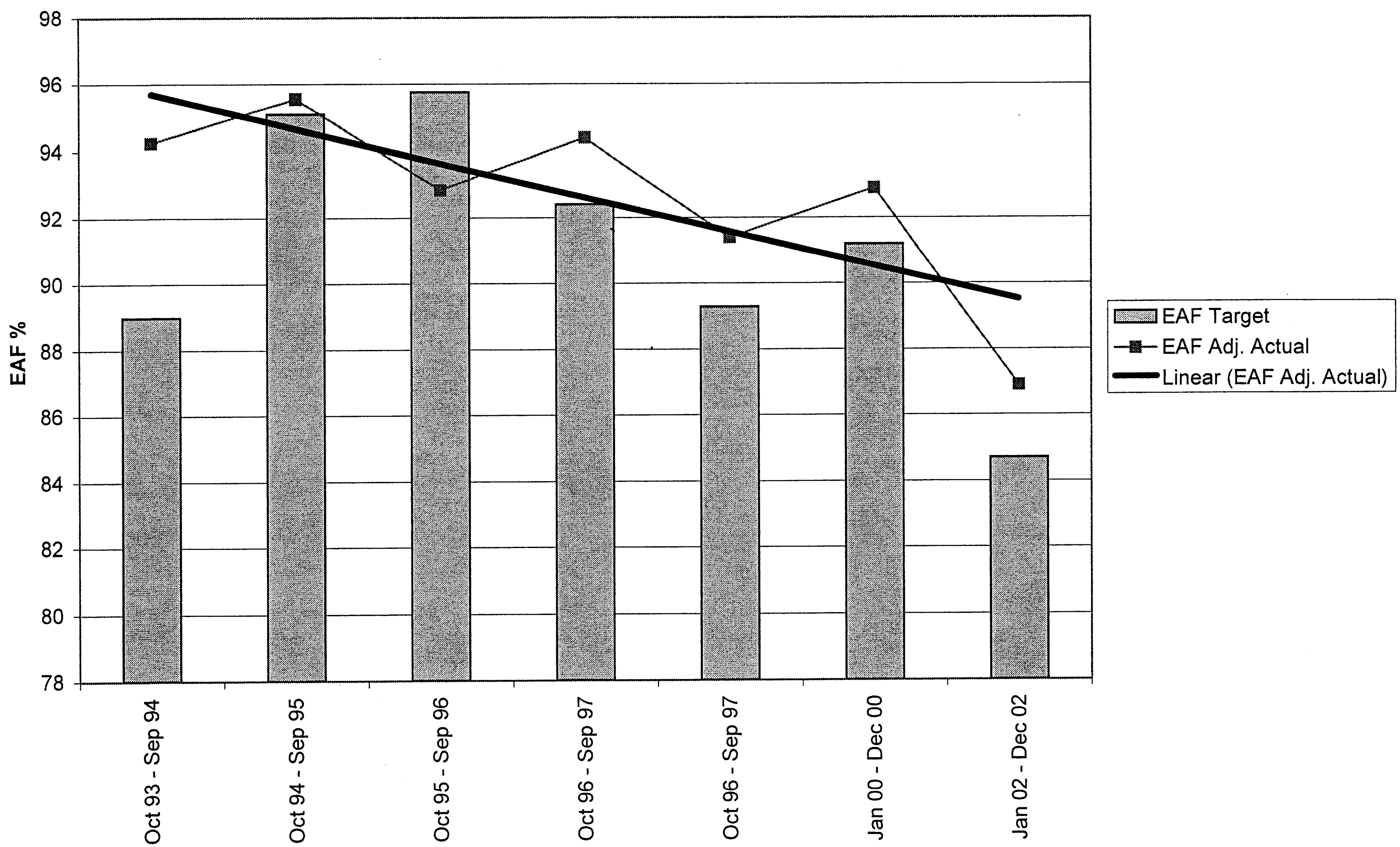
St. Johns River 2 EAF Analysis



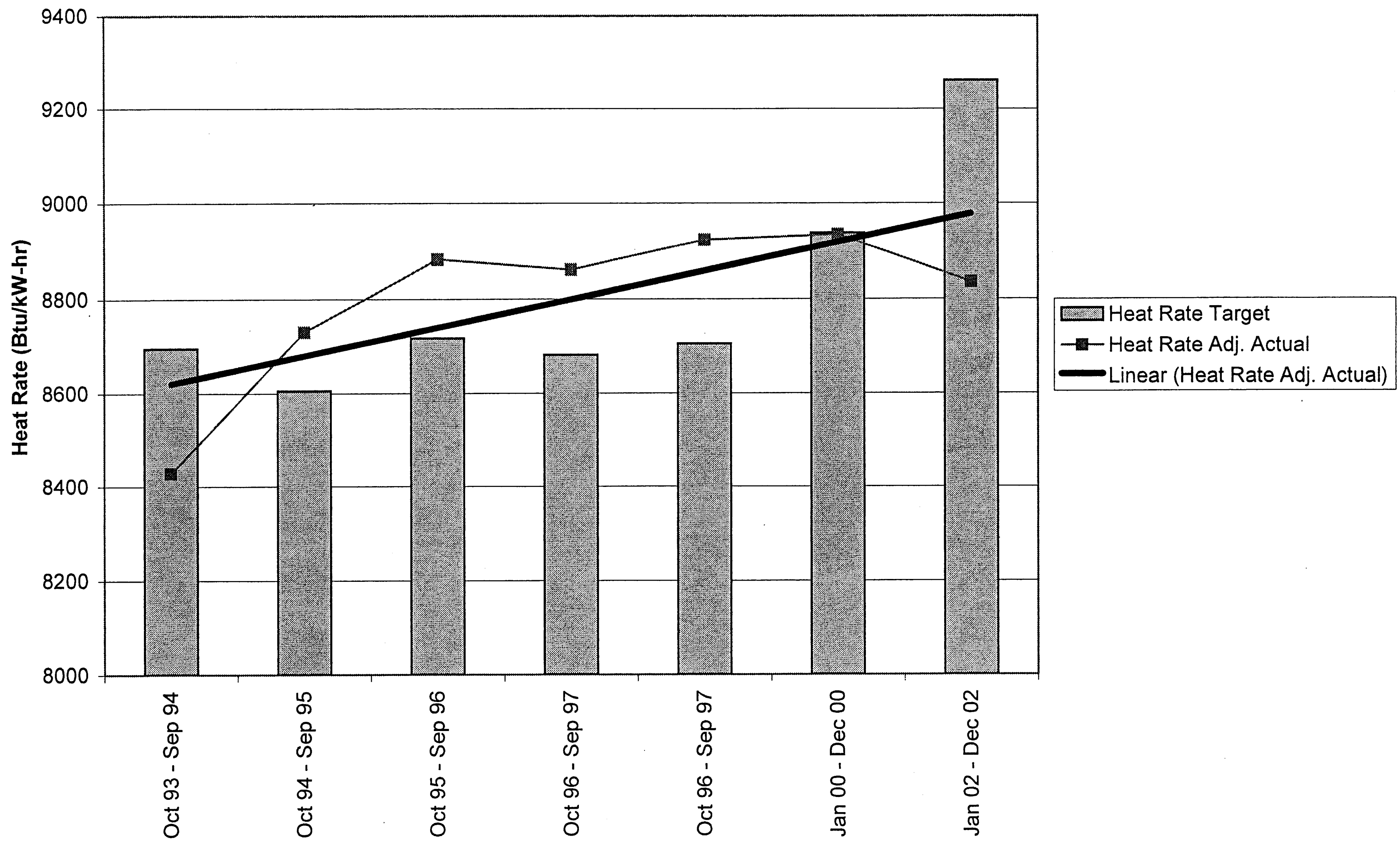


St. Johns River 2 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9450
9400
9350
9300
9250
9200
9150
Oct 93 - Sep 94
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

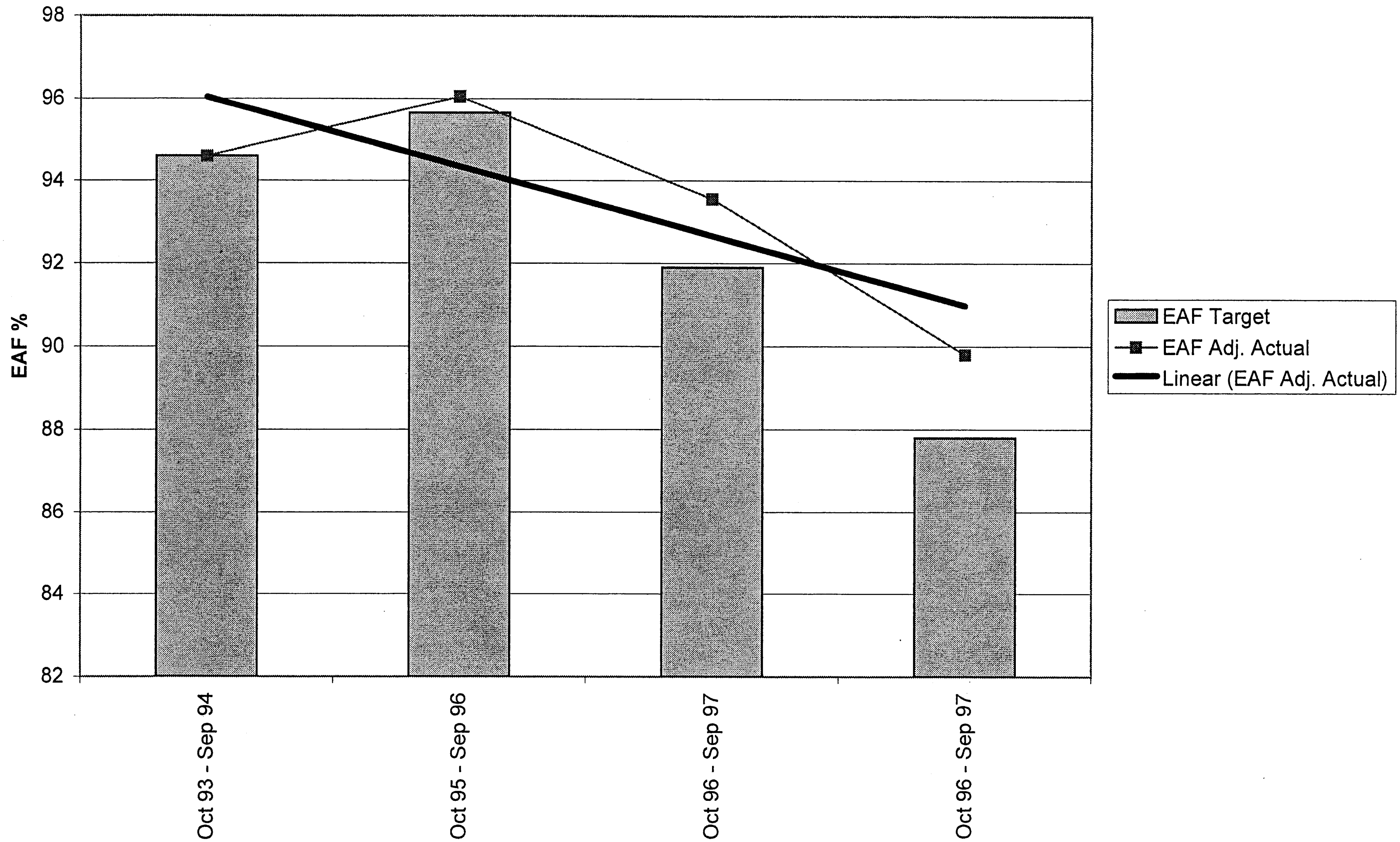
Putnam 1 EAF Analysis



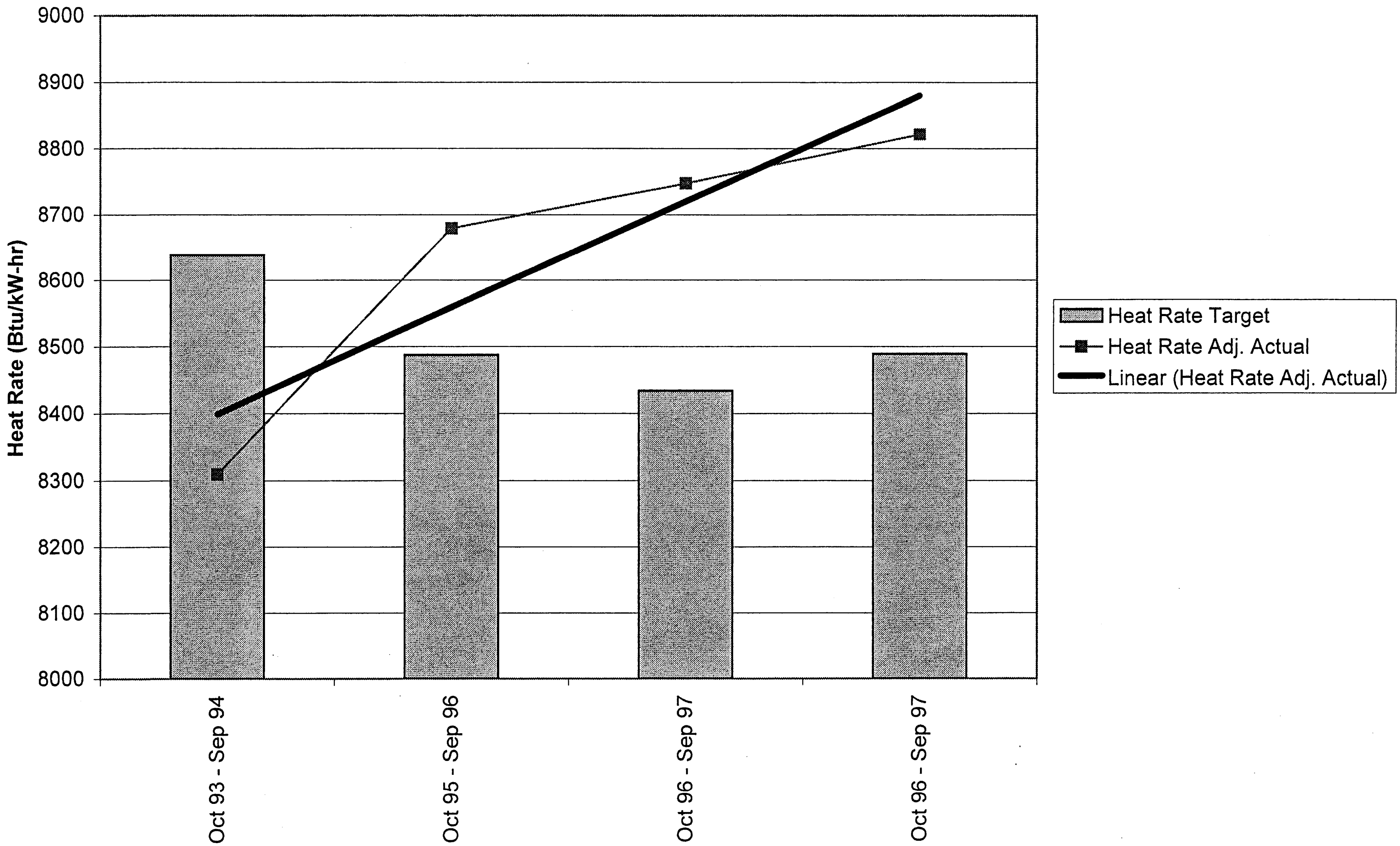
Putnam 1 Heat Rate Analysis



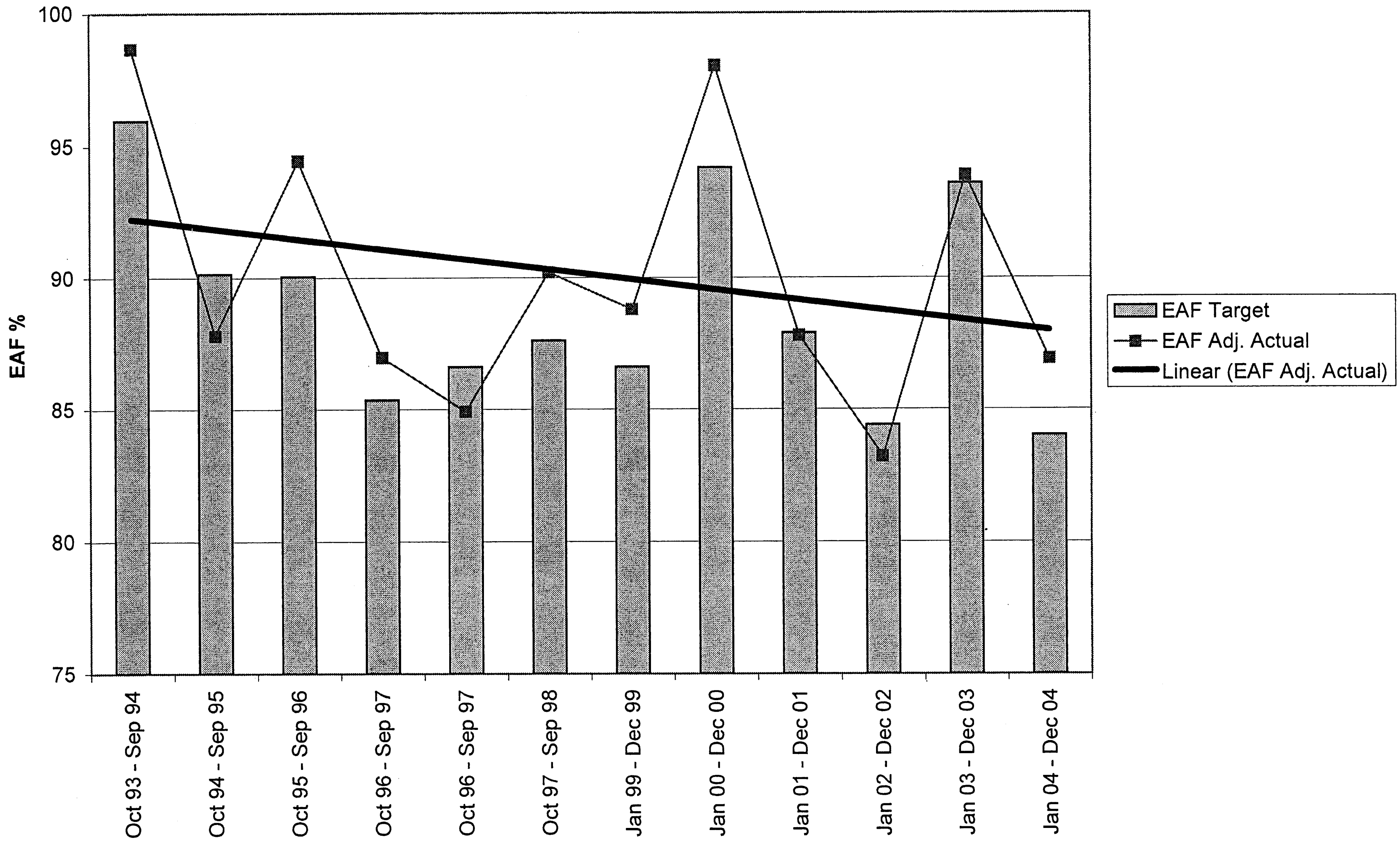
Putnam 2 EAF Analysis

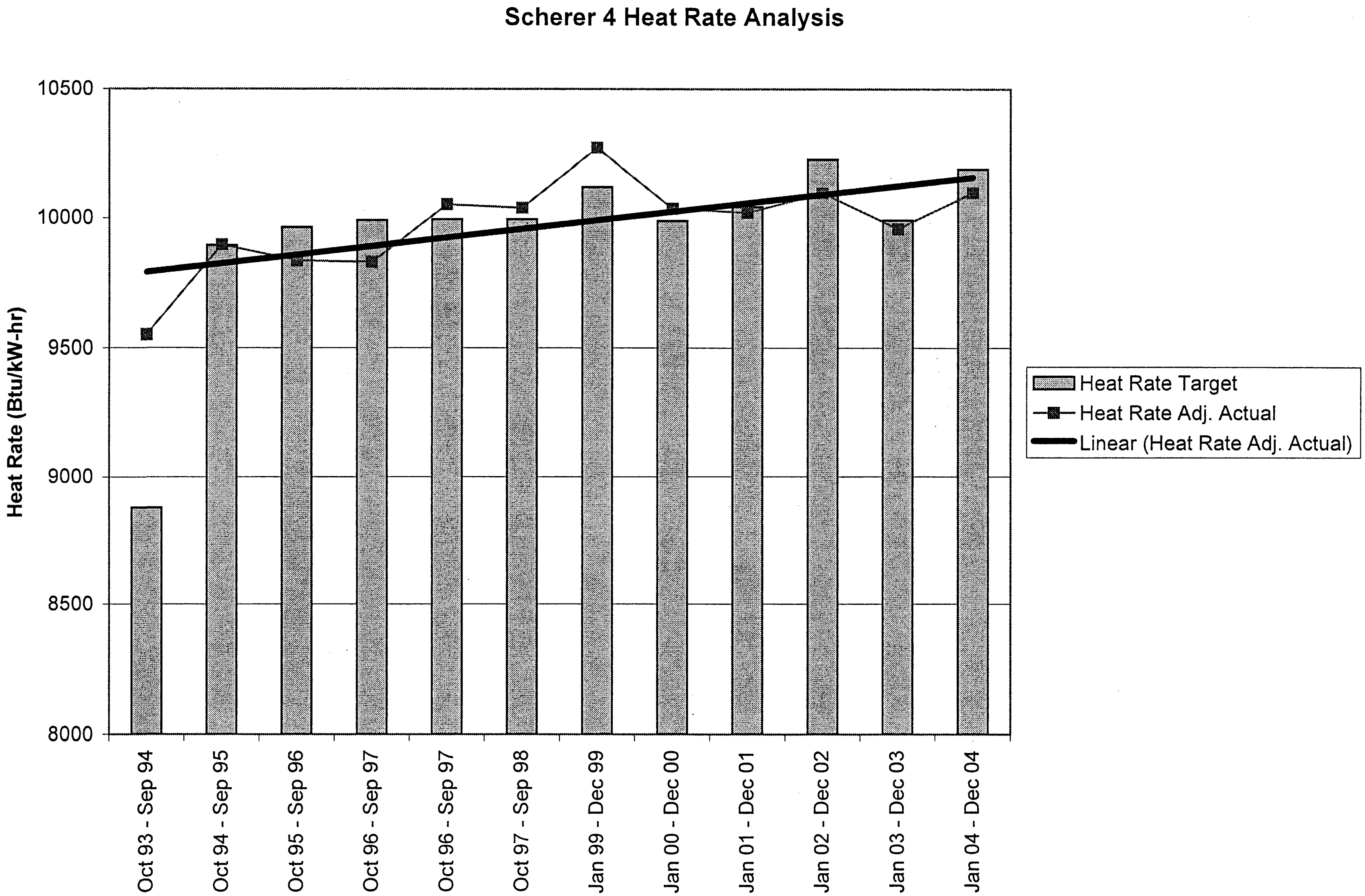


Putnam 2 Heat Rate Analysis



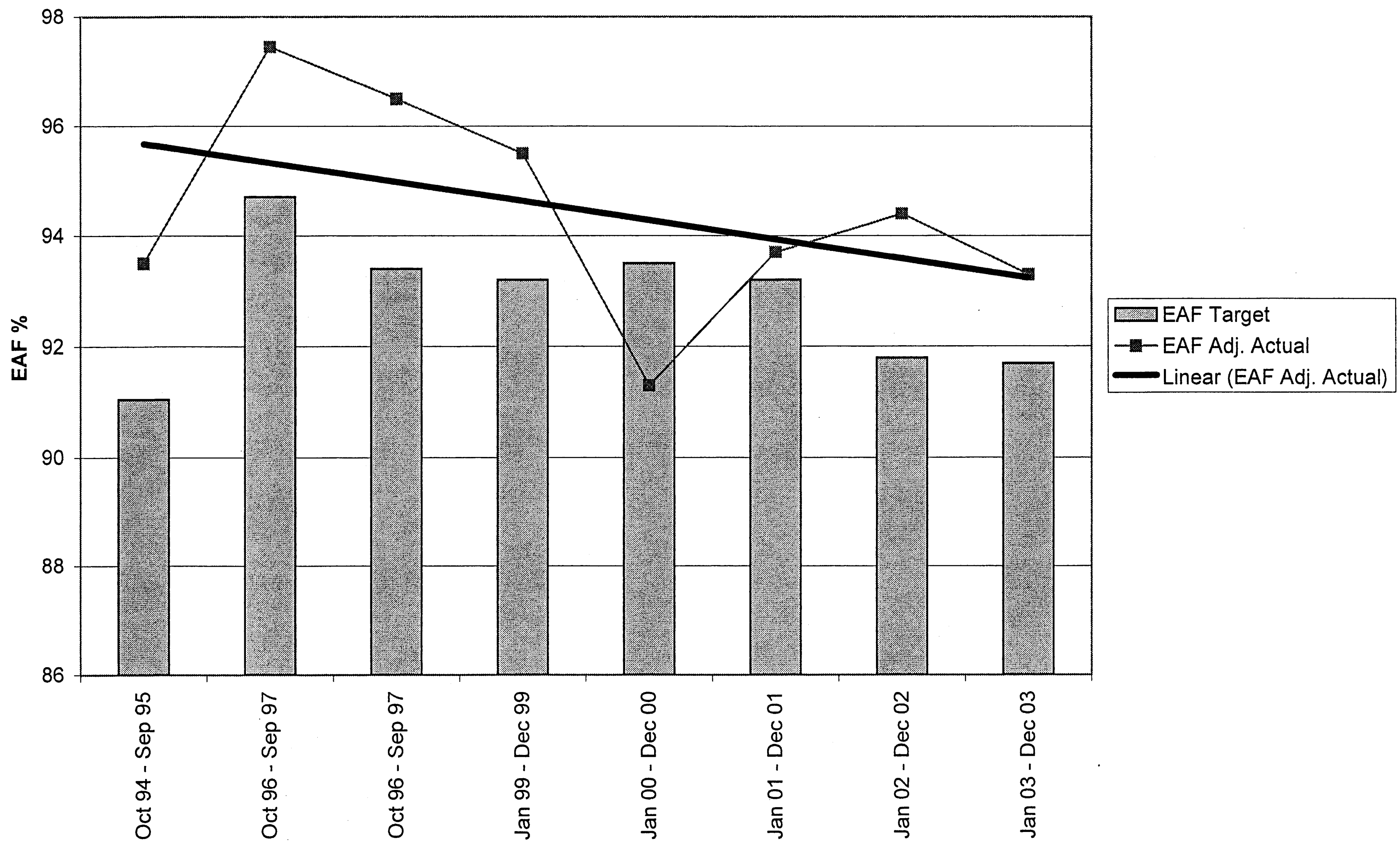
Scherer 4 EAF Analysis



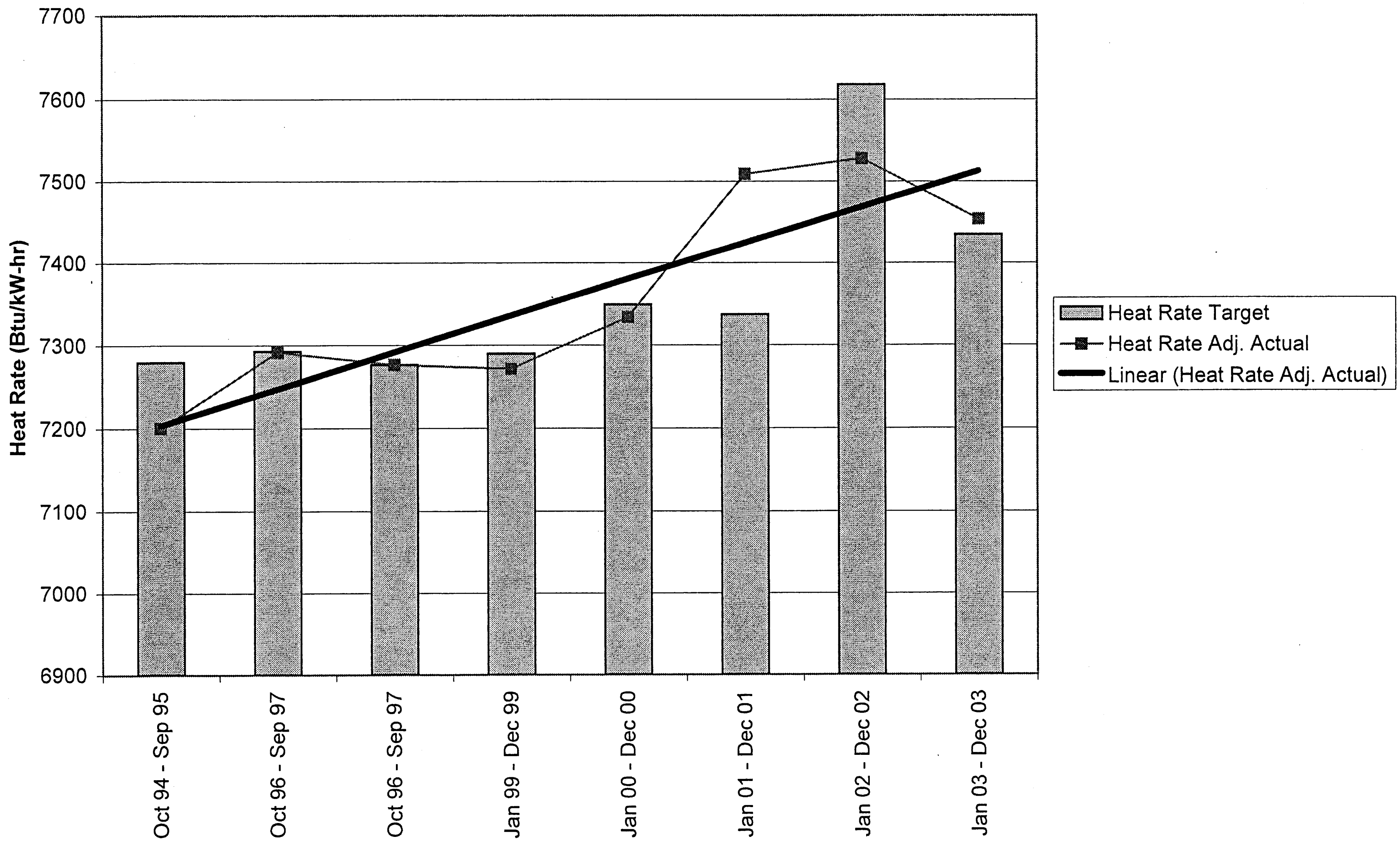


Scherer 4 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10500
10000
9500
9000
8500
8000
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

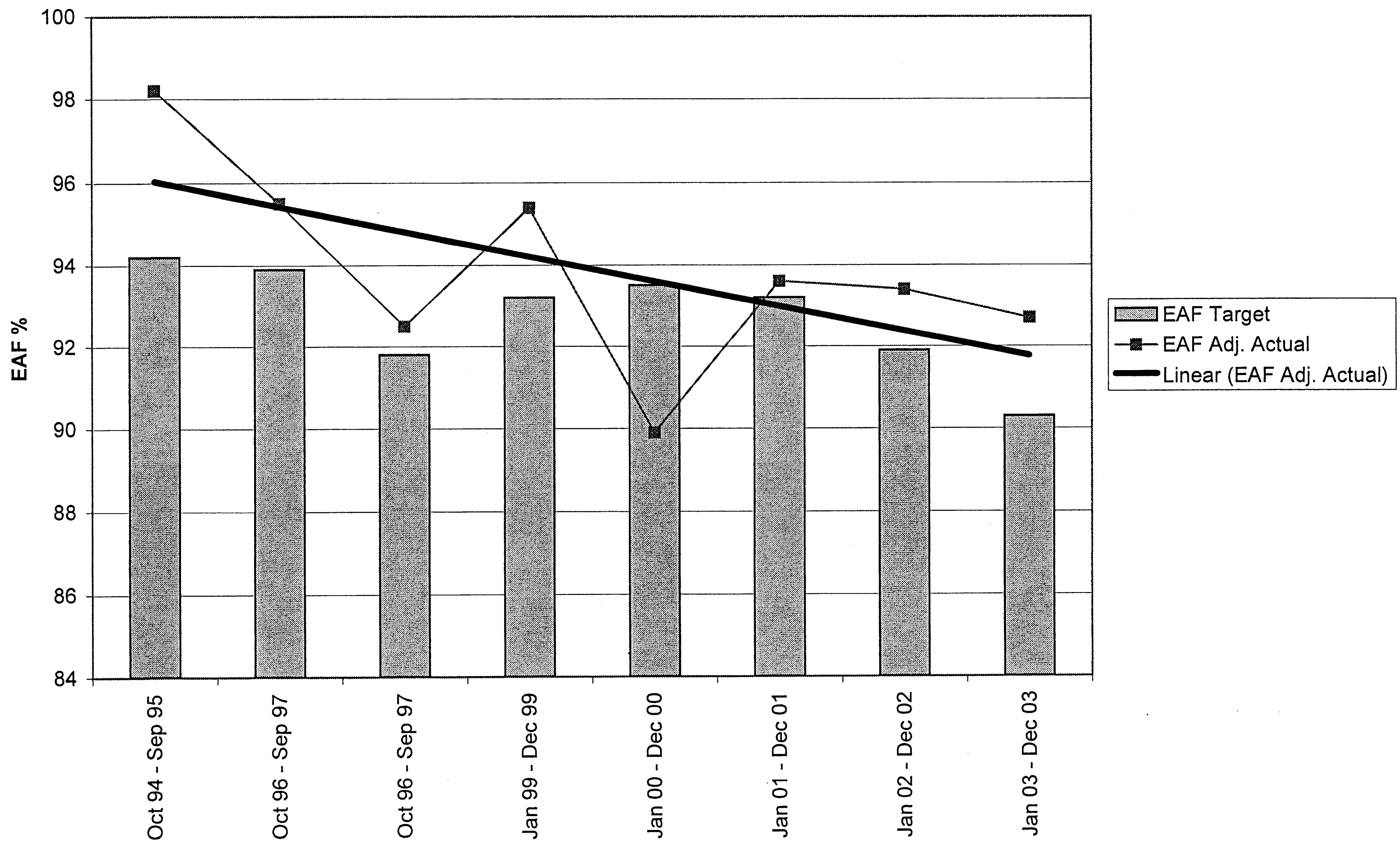
Fort Lauderdale 4 EAF Analysis

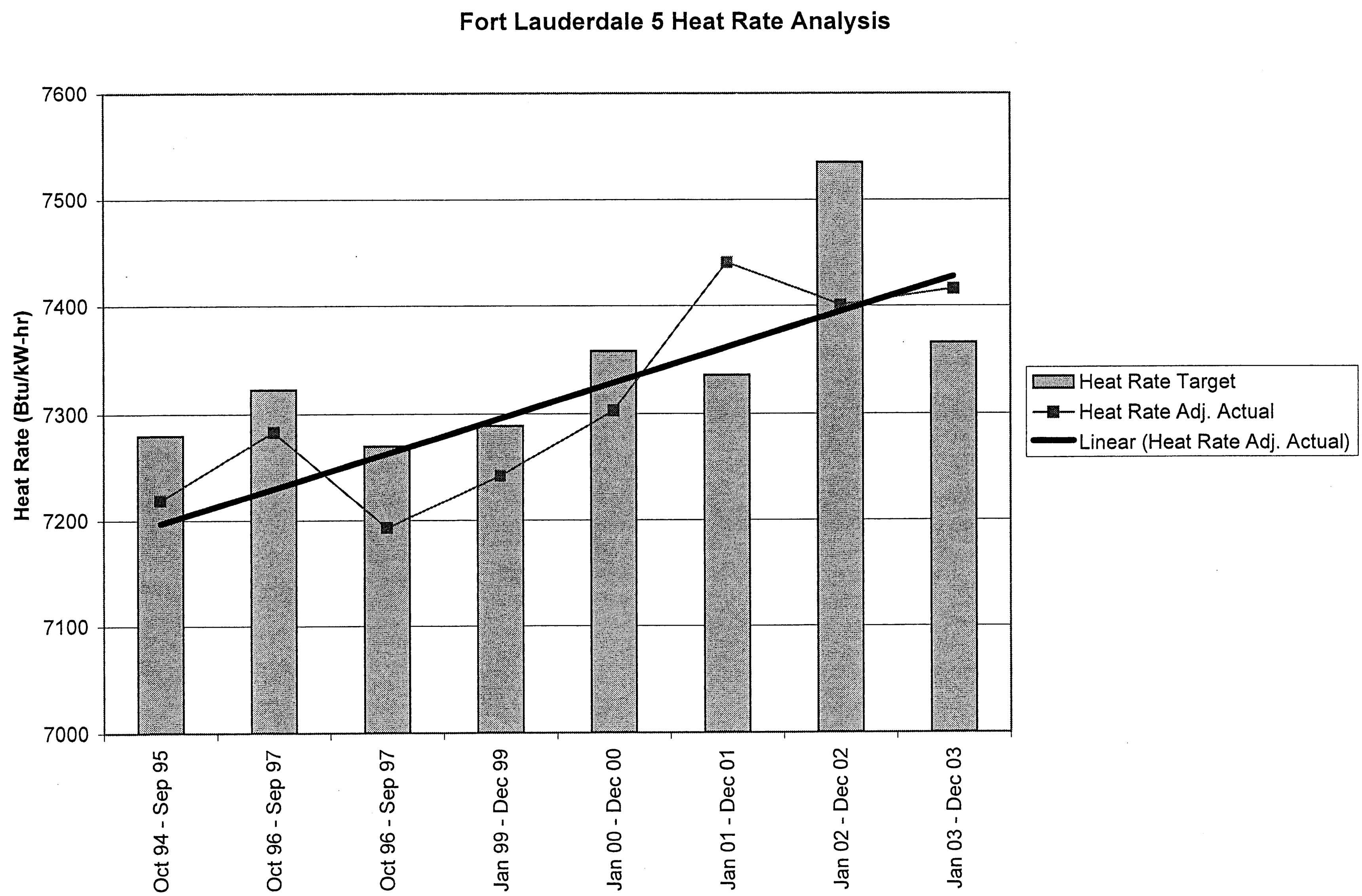


Fort Lauderdale 4 Heat Rate Analysis

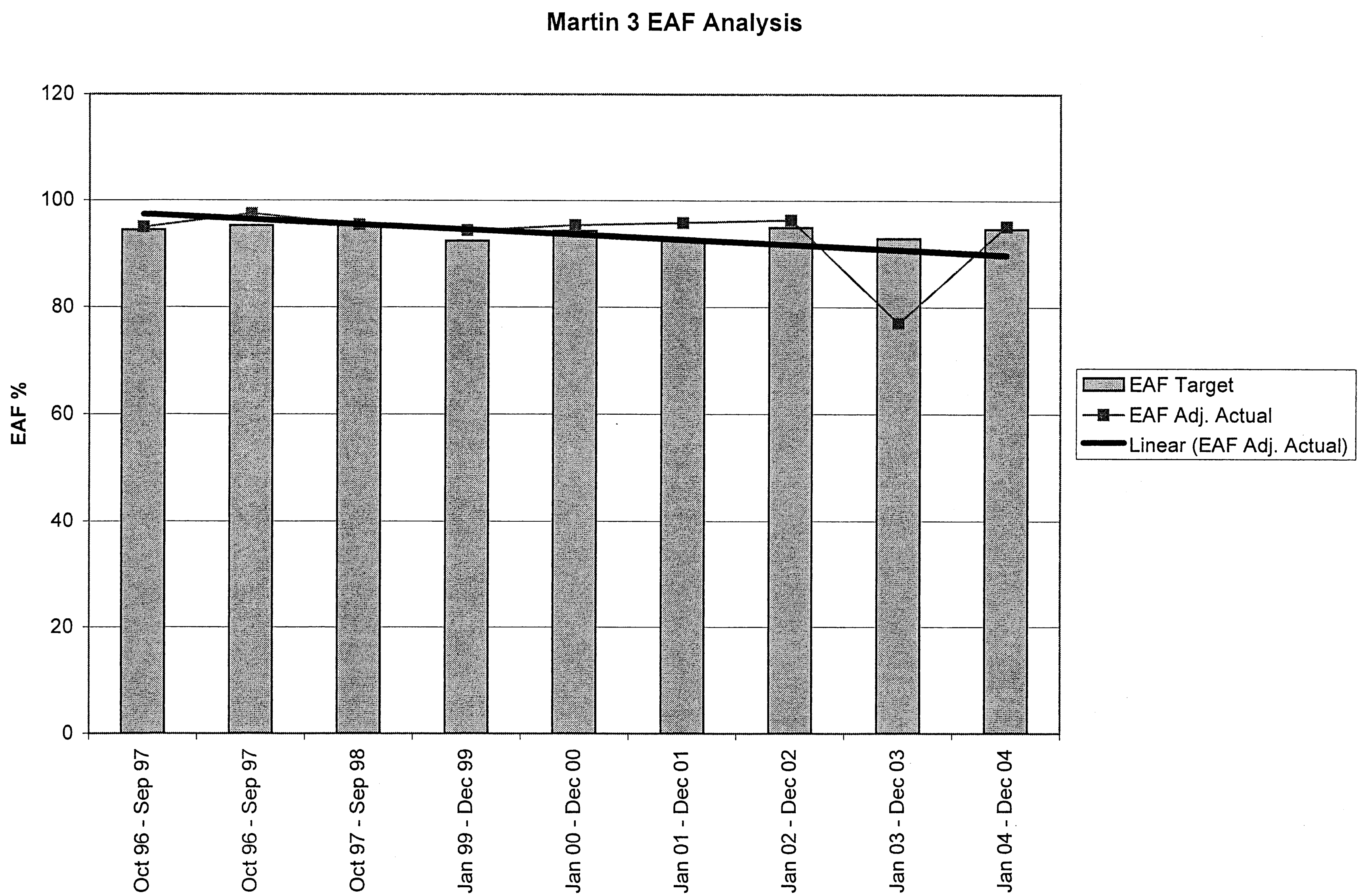


Fort Lauderdale 5 EAF Analysis



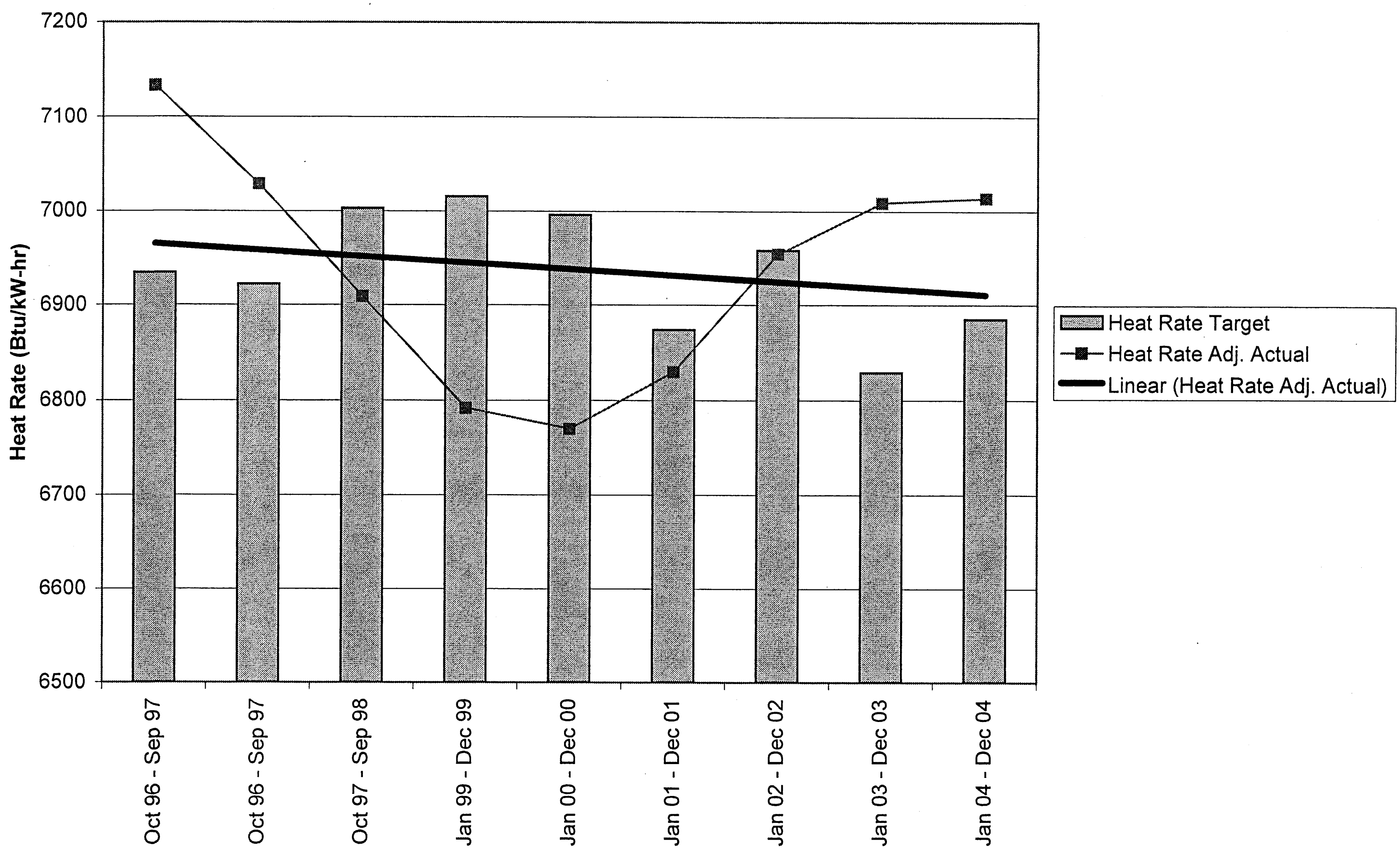


Fort Lauderdale 5 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
7600
7500
7400
7300
7200
7100
7000
Oct 94 - Sep 95
Oct 96 - Sep 97
Oct 96 - Sep 97
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

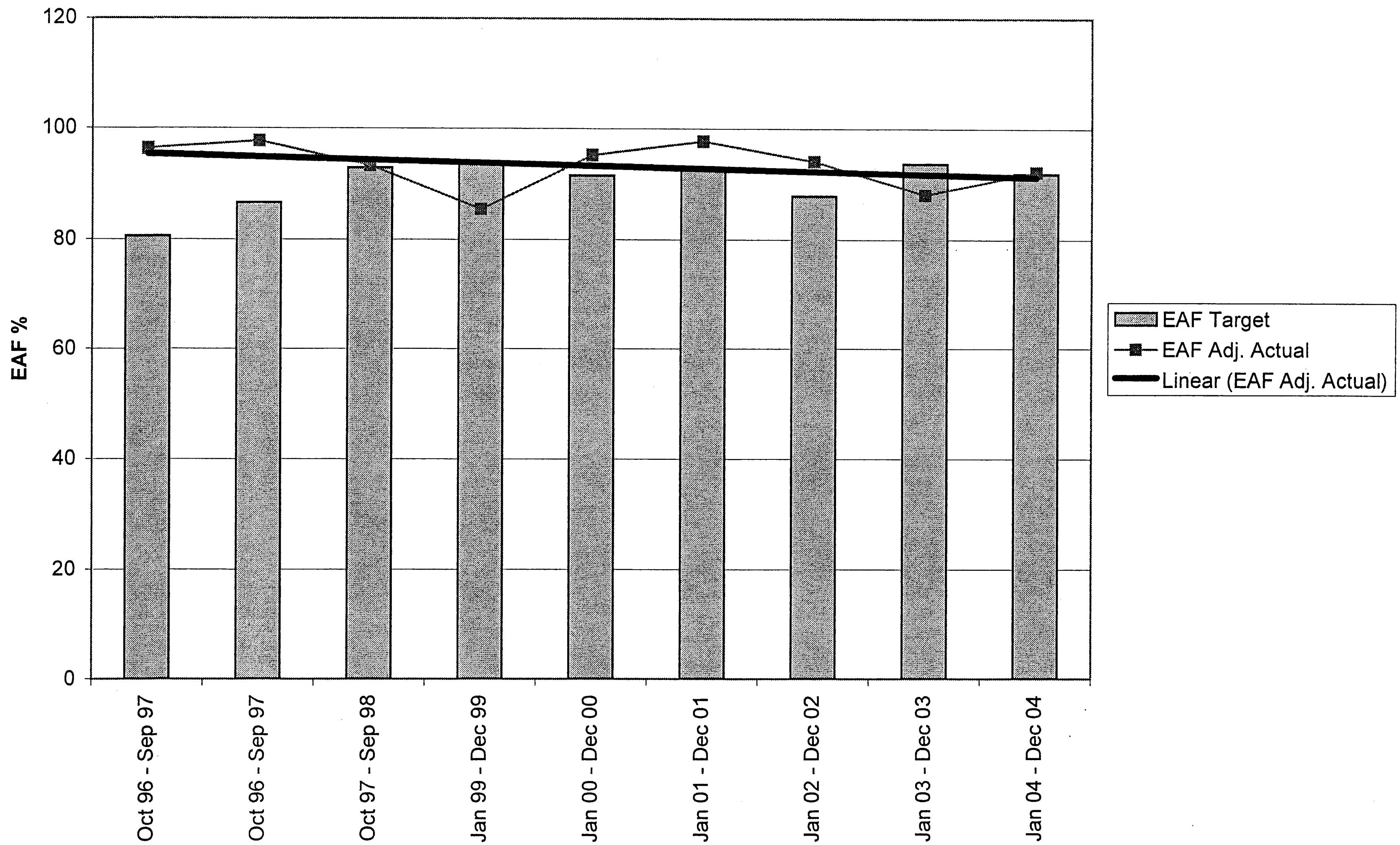


Martin 3 EAF Analysis
EAF %
120
100
80
60
40
20
0
Oct 96 - Sep 97
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

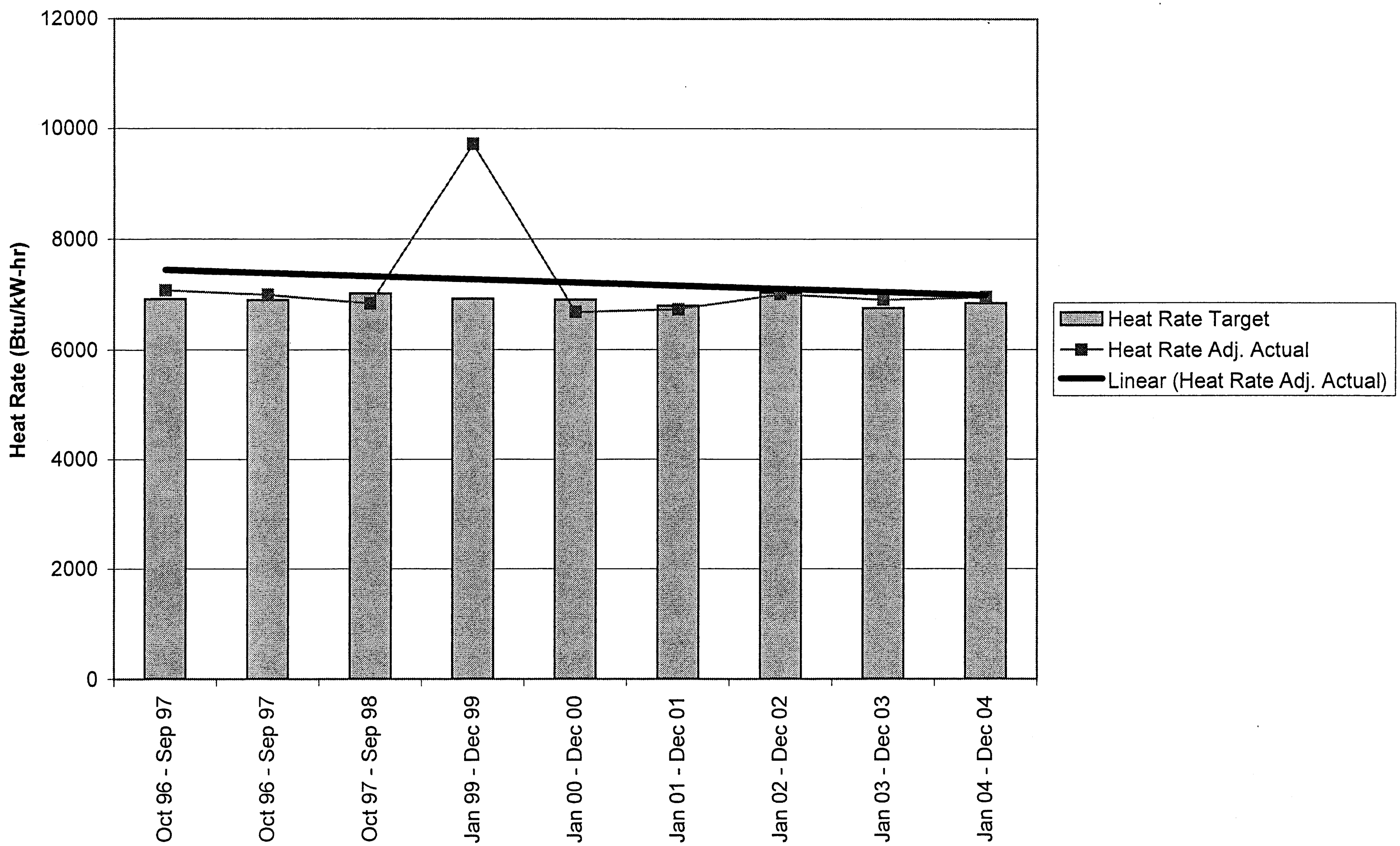
Martin 3 Heat Rate Analysis

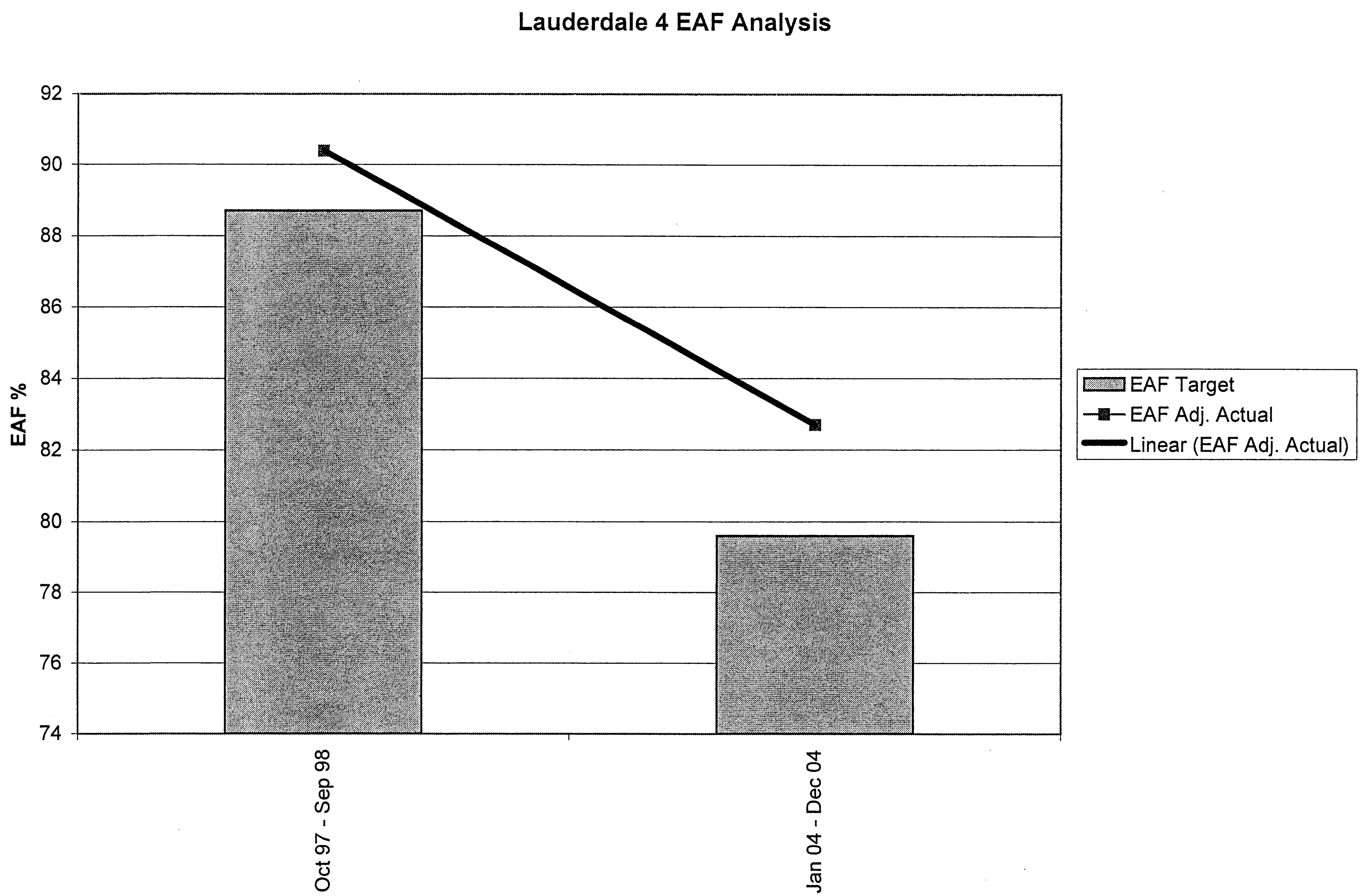


Martin 4 EAF Analysis

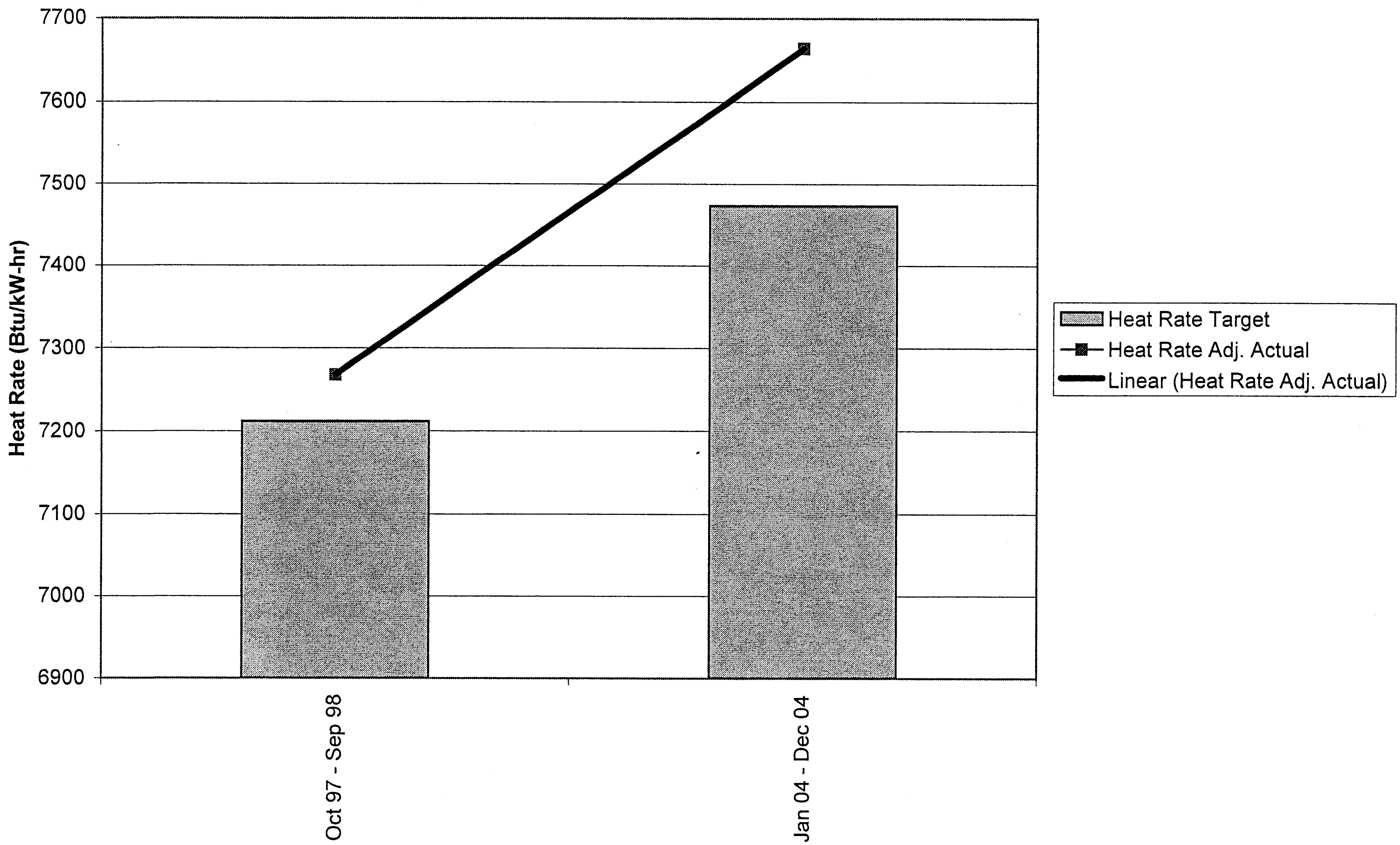


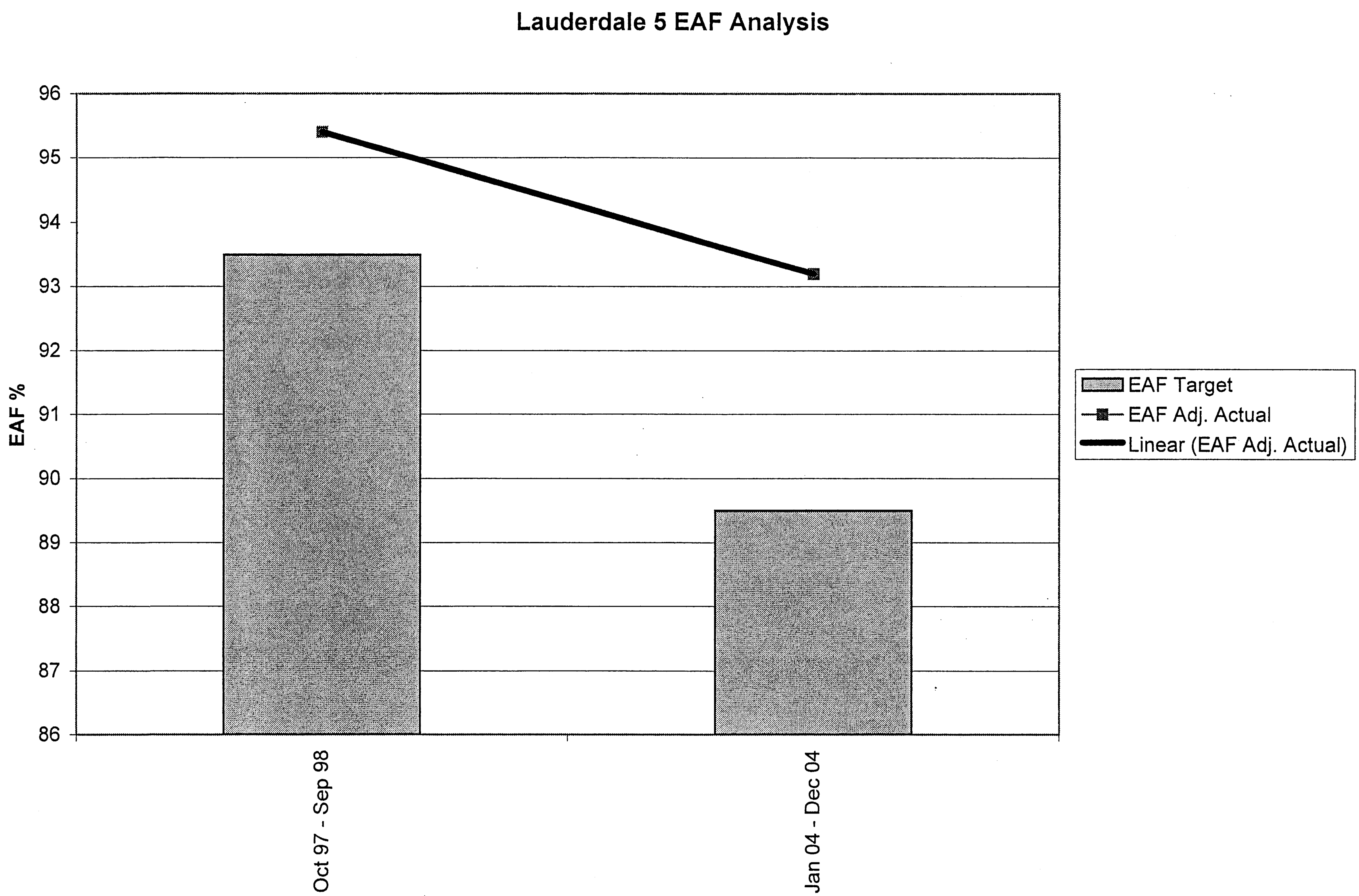
Martin 4 Heat Rate Analysis

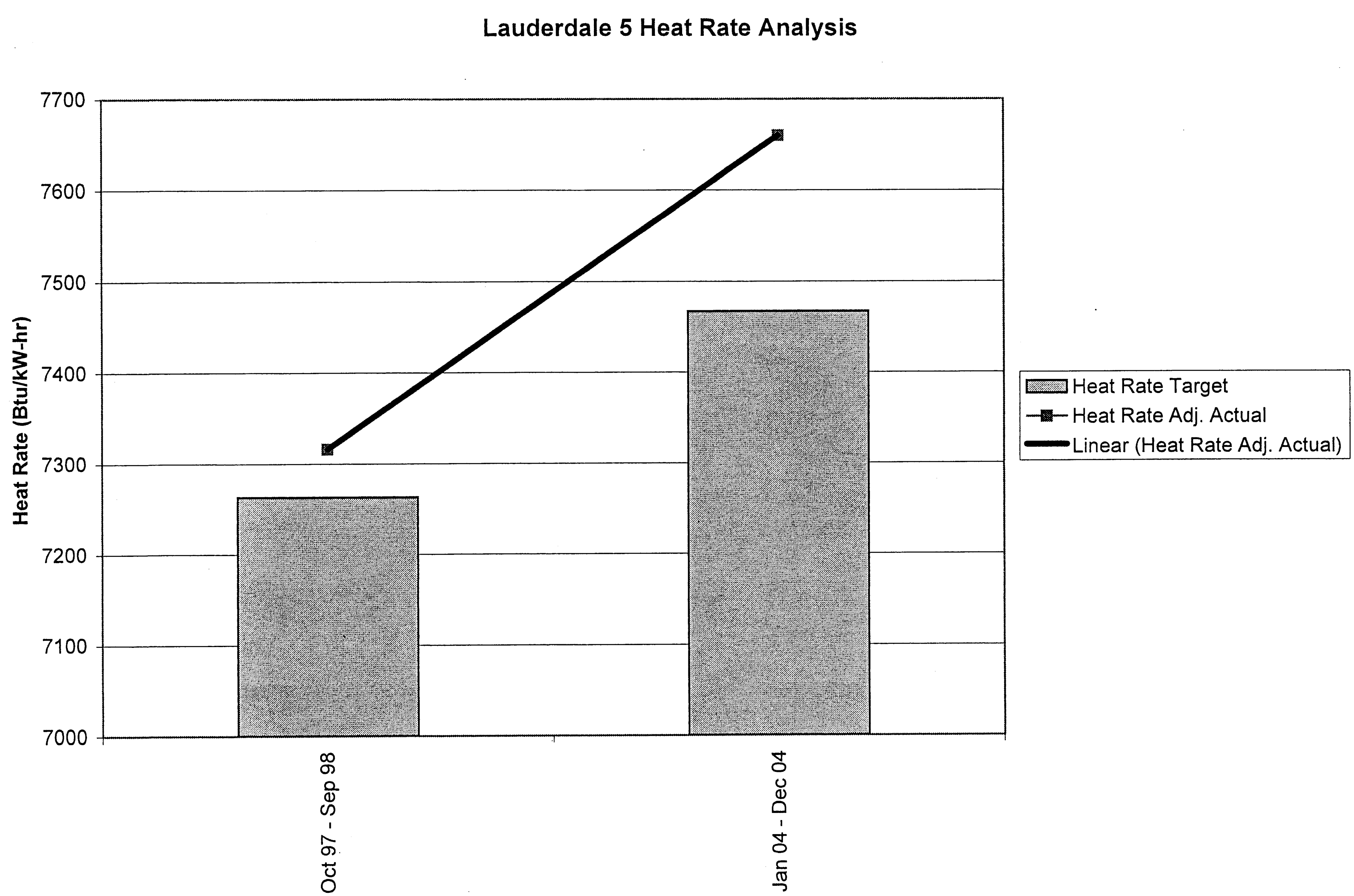



Lauderdale 4 EAF Analysis
EAF %
92
90
88
86
84
82
80
78
76
74
Oct 97 - Sep 98
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

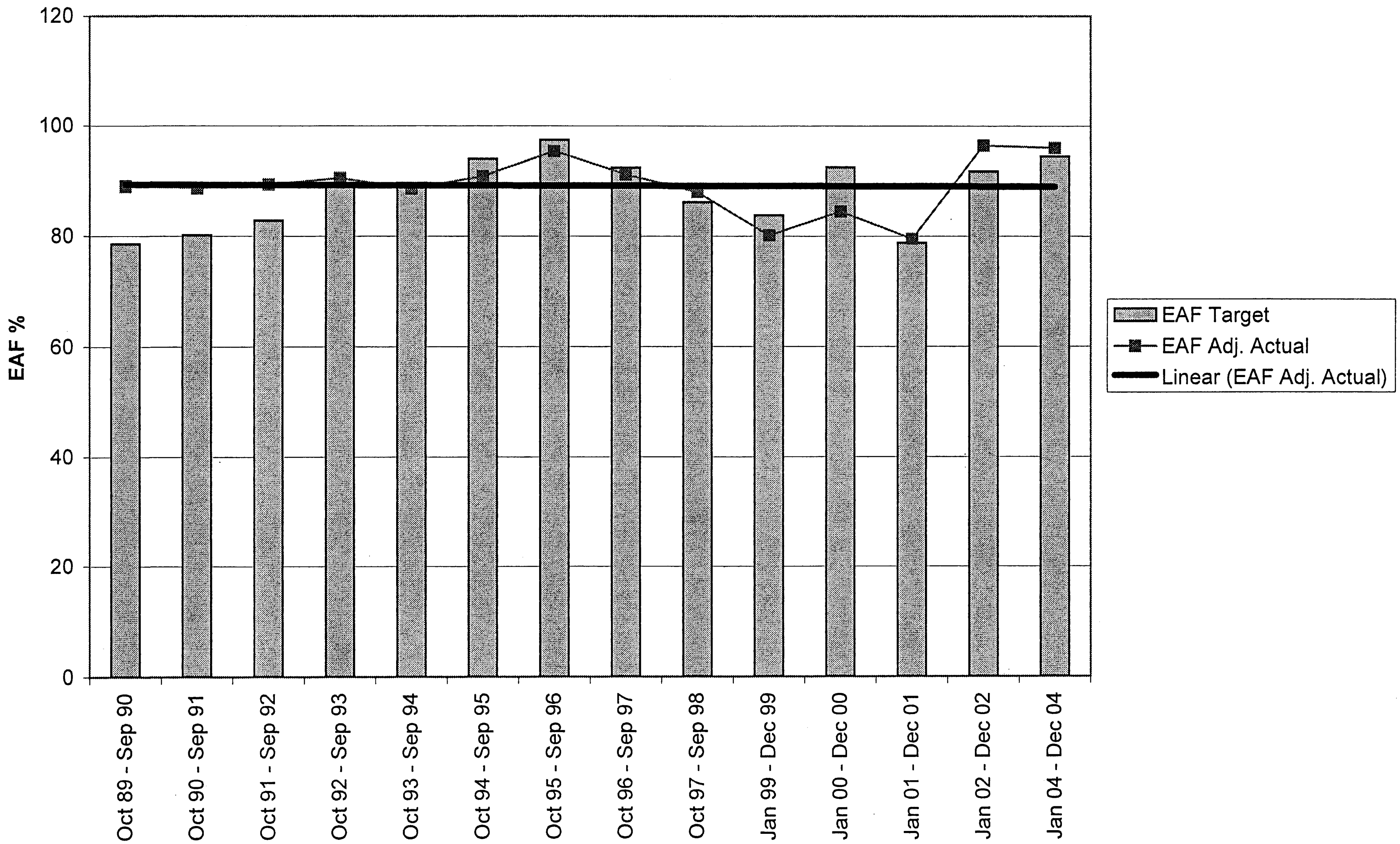
Lauderdale 4 Heat Rate Analysis

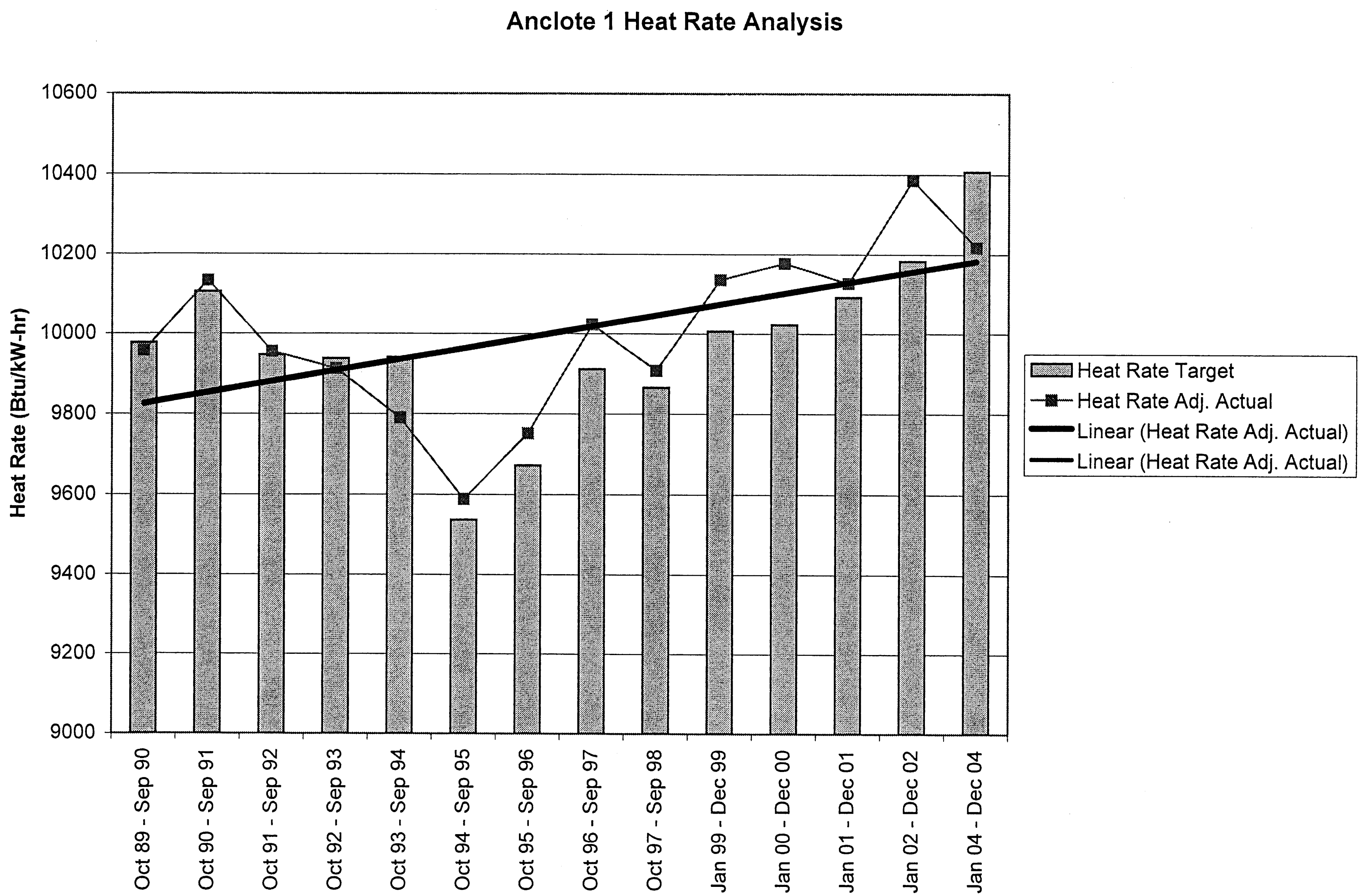



Lauderdale 5 EAF Analysis
EAF %
96
95
94
93
92
91
90
89
88
87
86
Oct 97 - Sep 98
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)


Lauderdale 5 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
7700
7600
7500
7400
7300
7200
7100
7000
Oct 97 - Sep 98
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

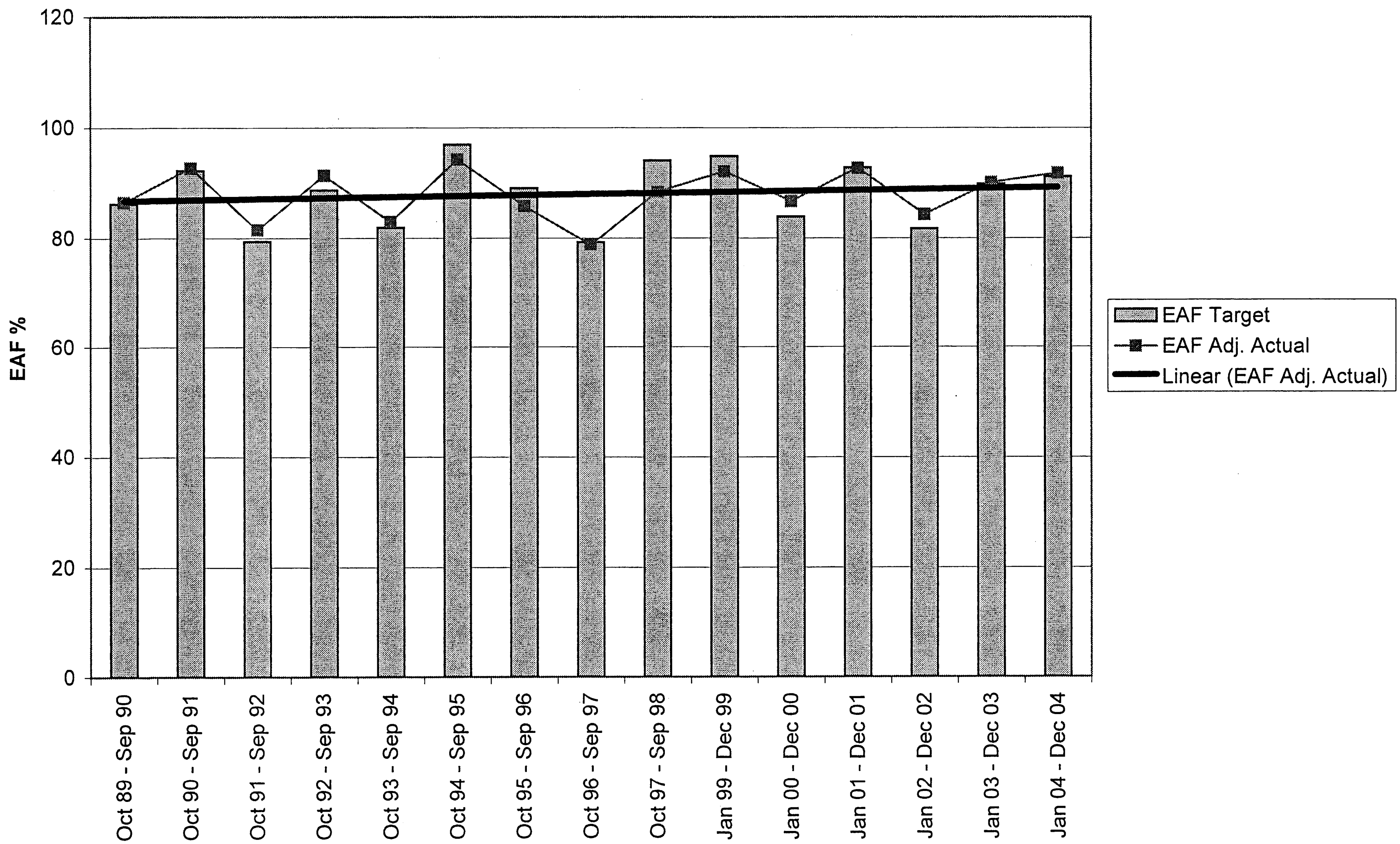
Anclote 1 EAF Analysis



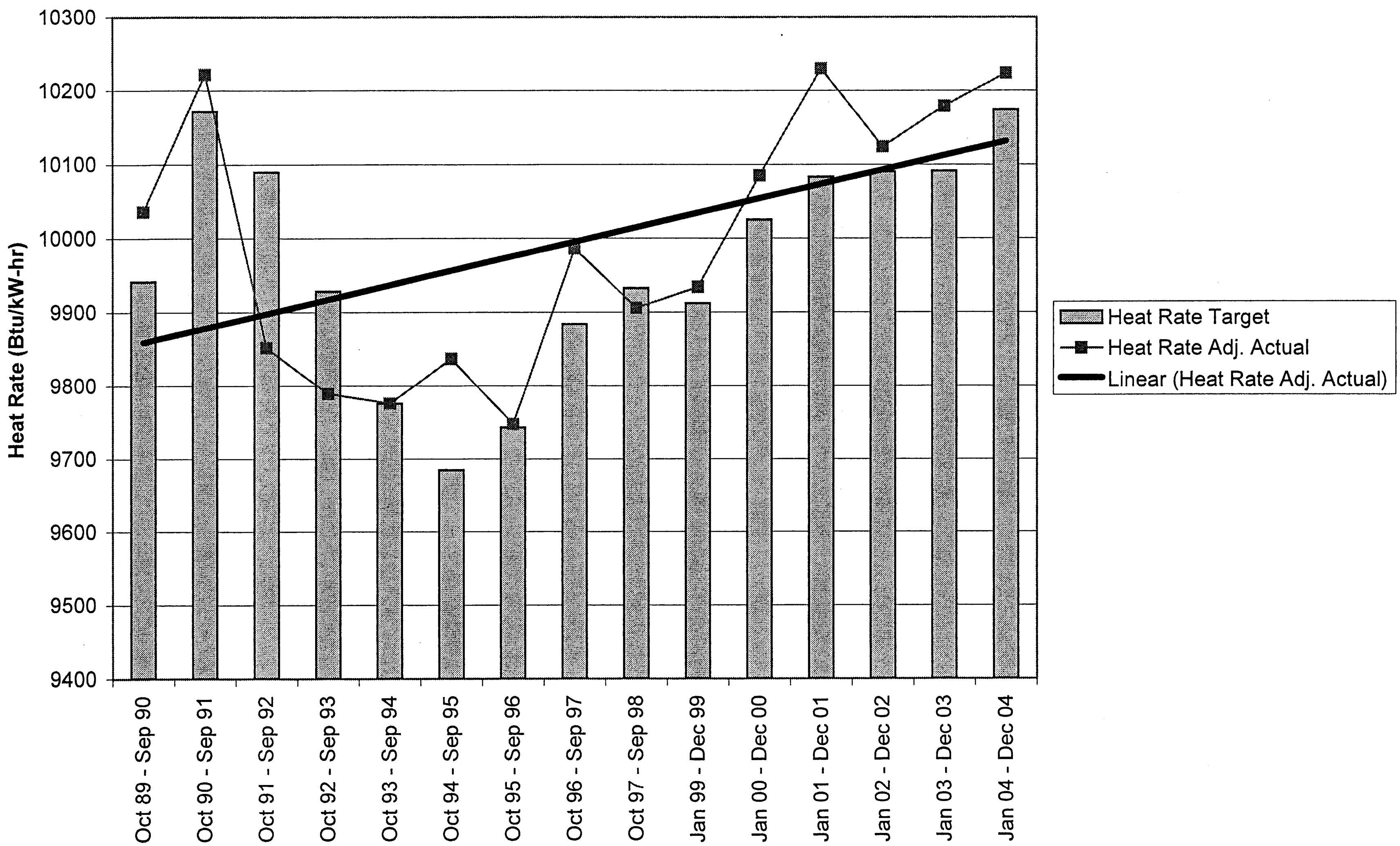


Anclote 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10600
10400
10200
10000
9800
9600
9400
9200
9000
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)
Linear (Heat Rate Adj. Actual)

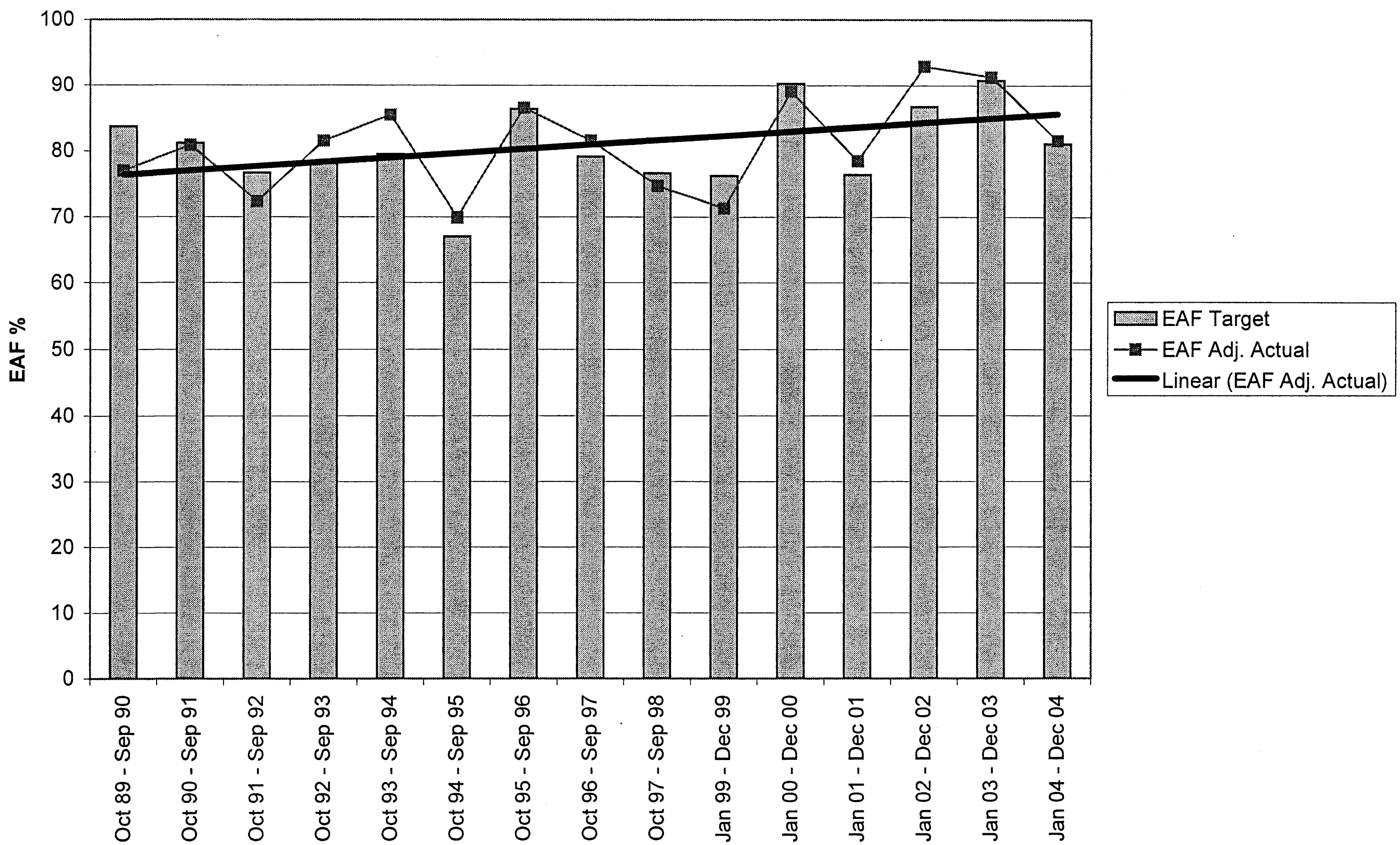
Anclote 2 EAF Analysis

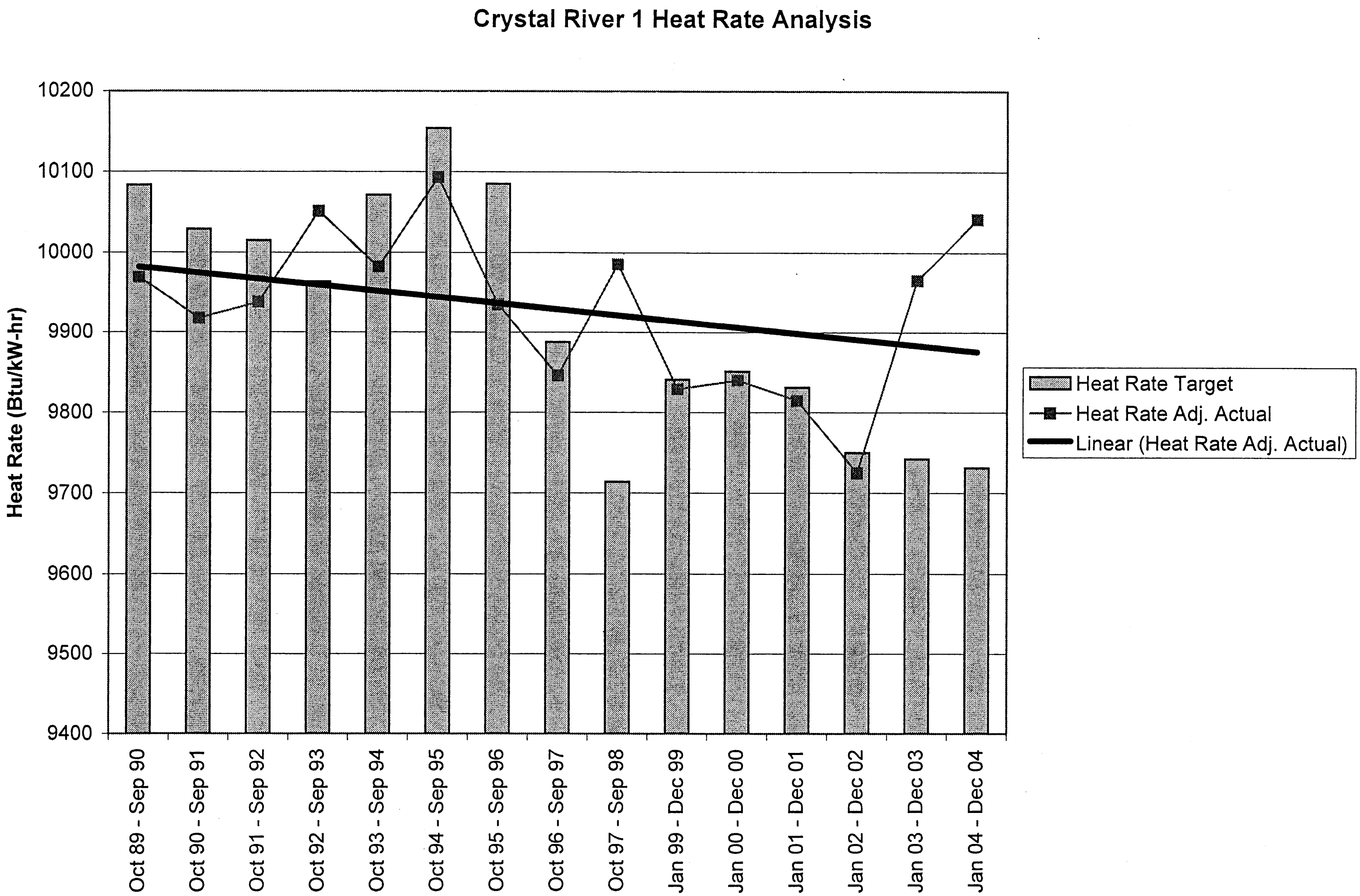


Anclote 2 Heat Rate Analysis

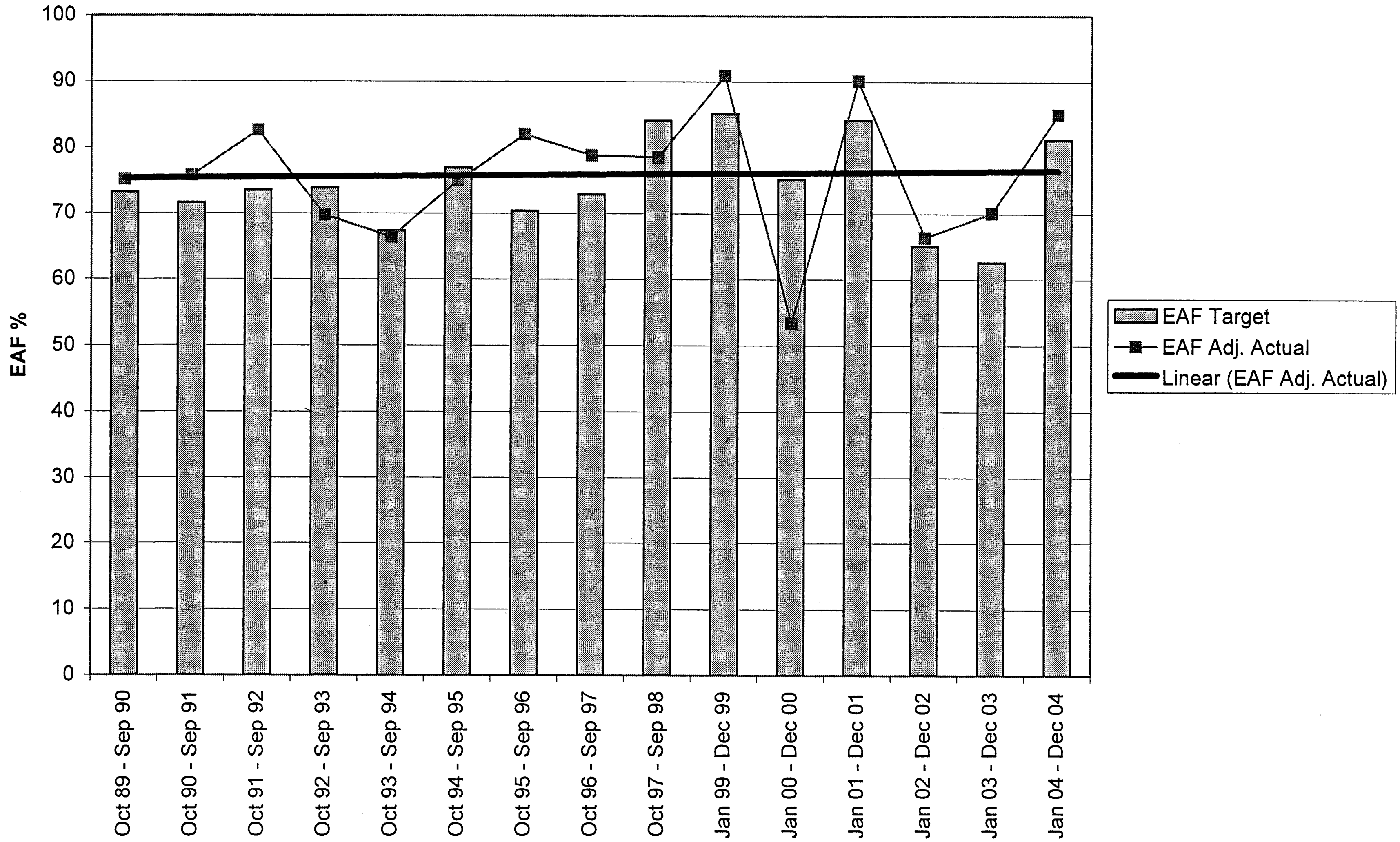


Crystal River 1 EAF Analysis

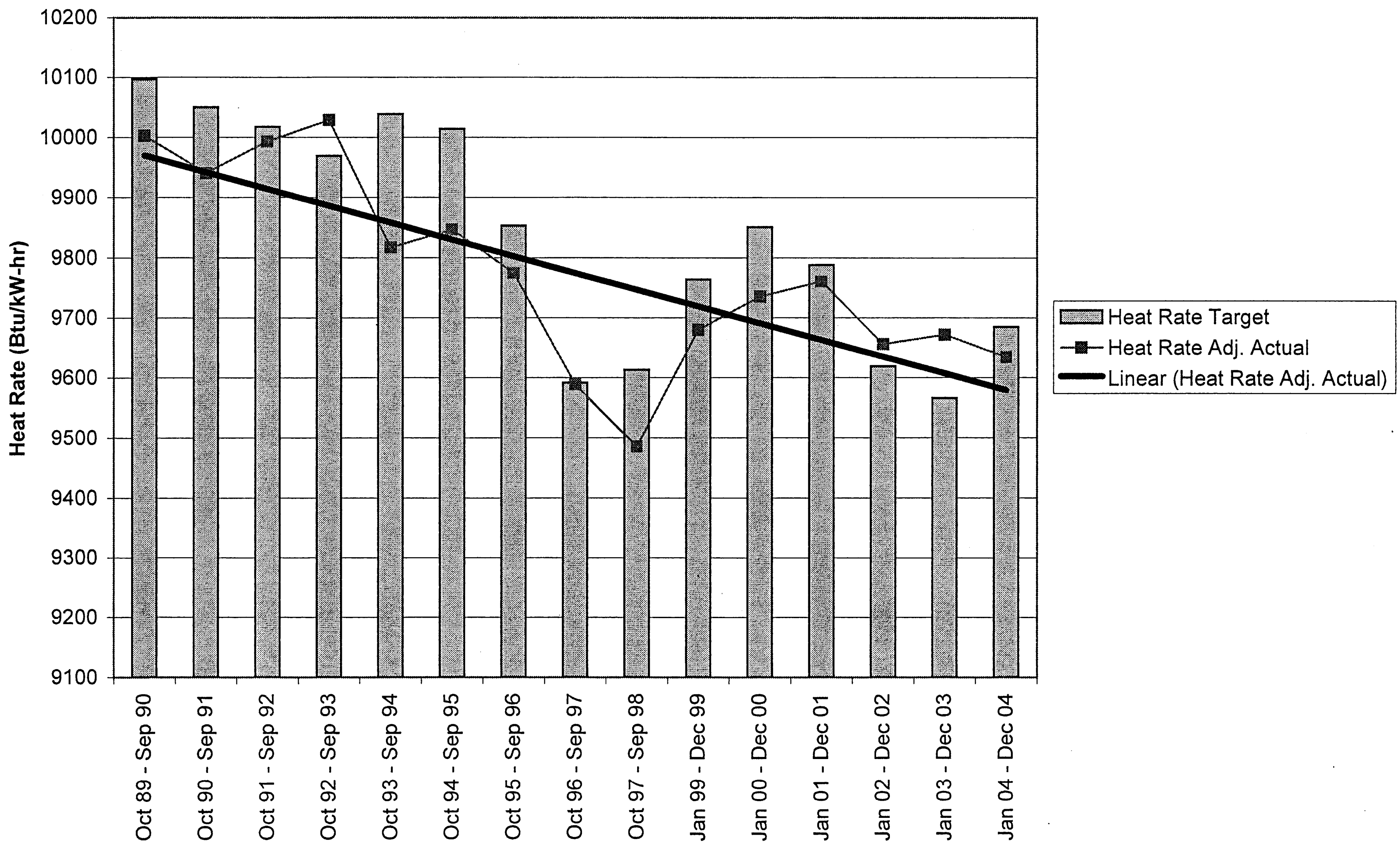



Crystal River 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10200
10100
10000
9900
9800
9700
9600
9500
9400
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

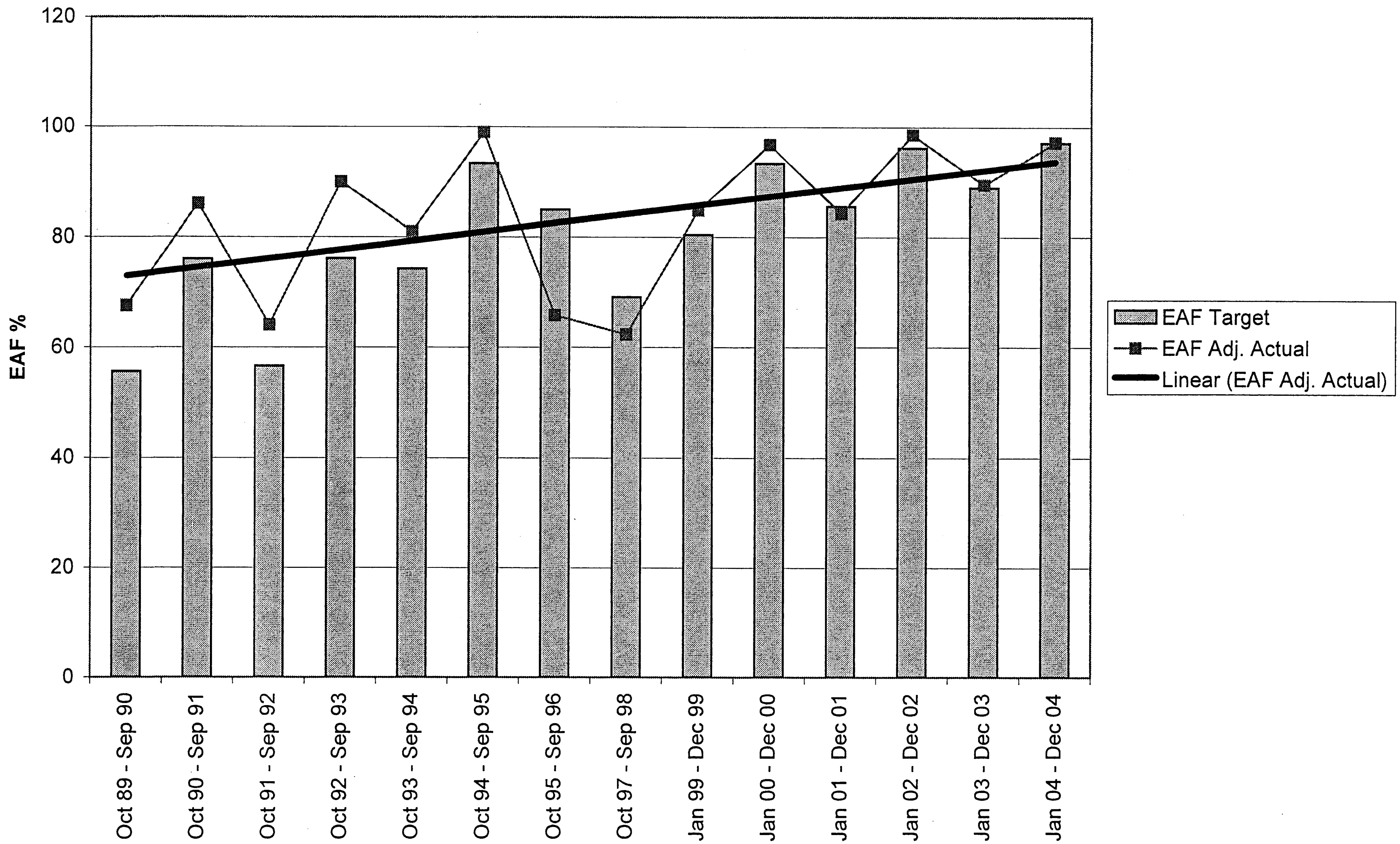
Crystal River 2 EAF Analysis

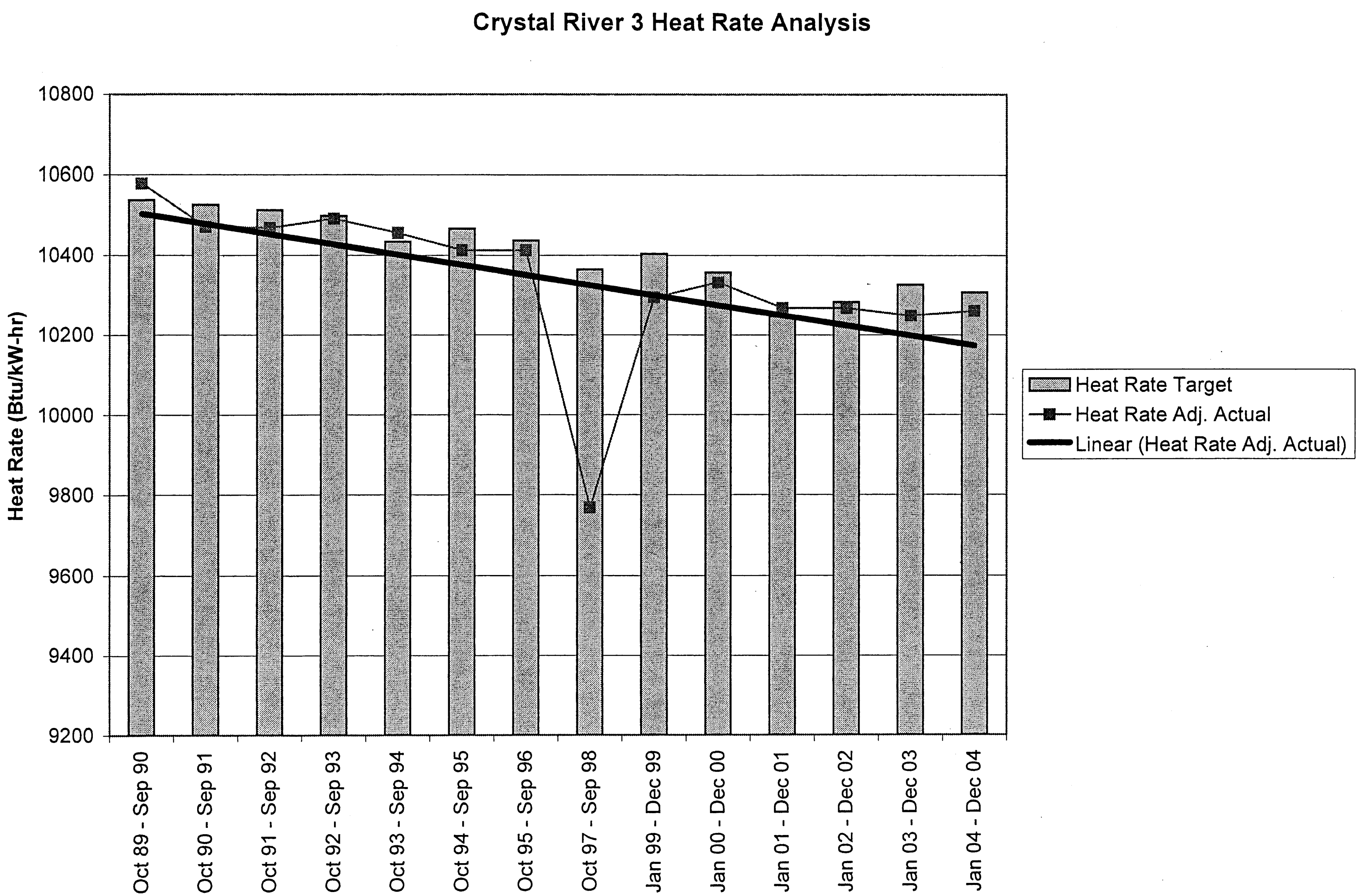


Crystal River 2 Heat Rate Analysis

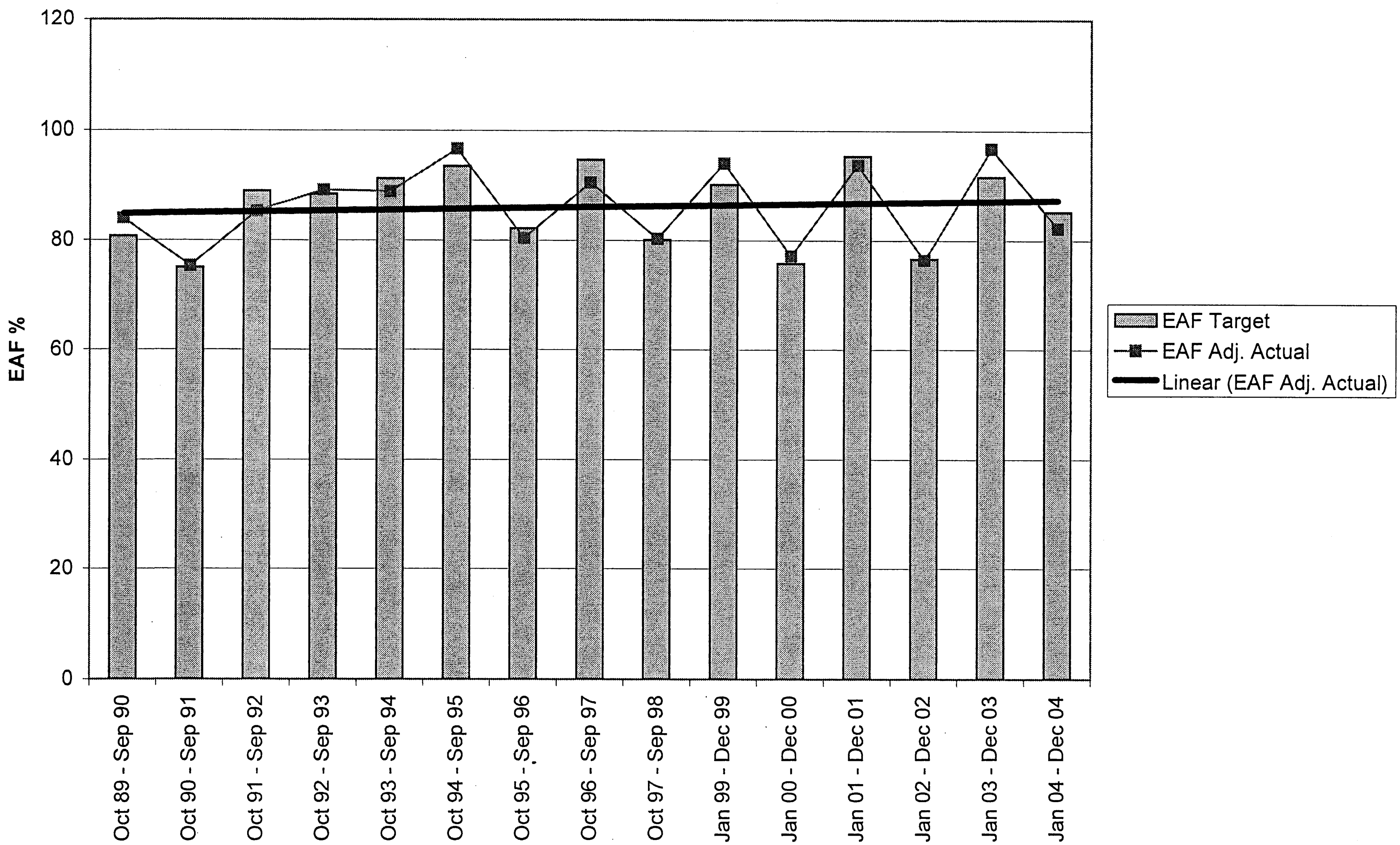


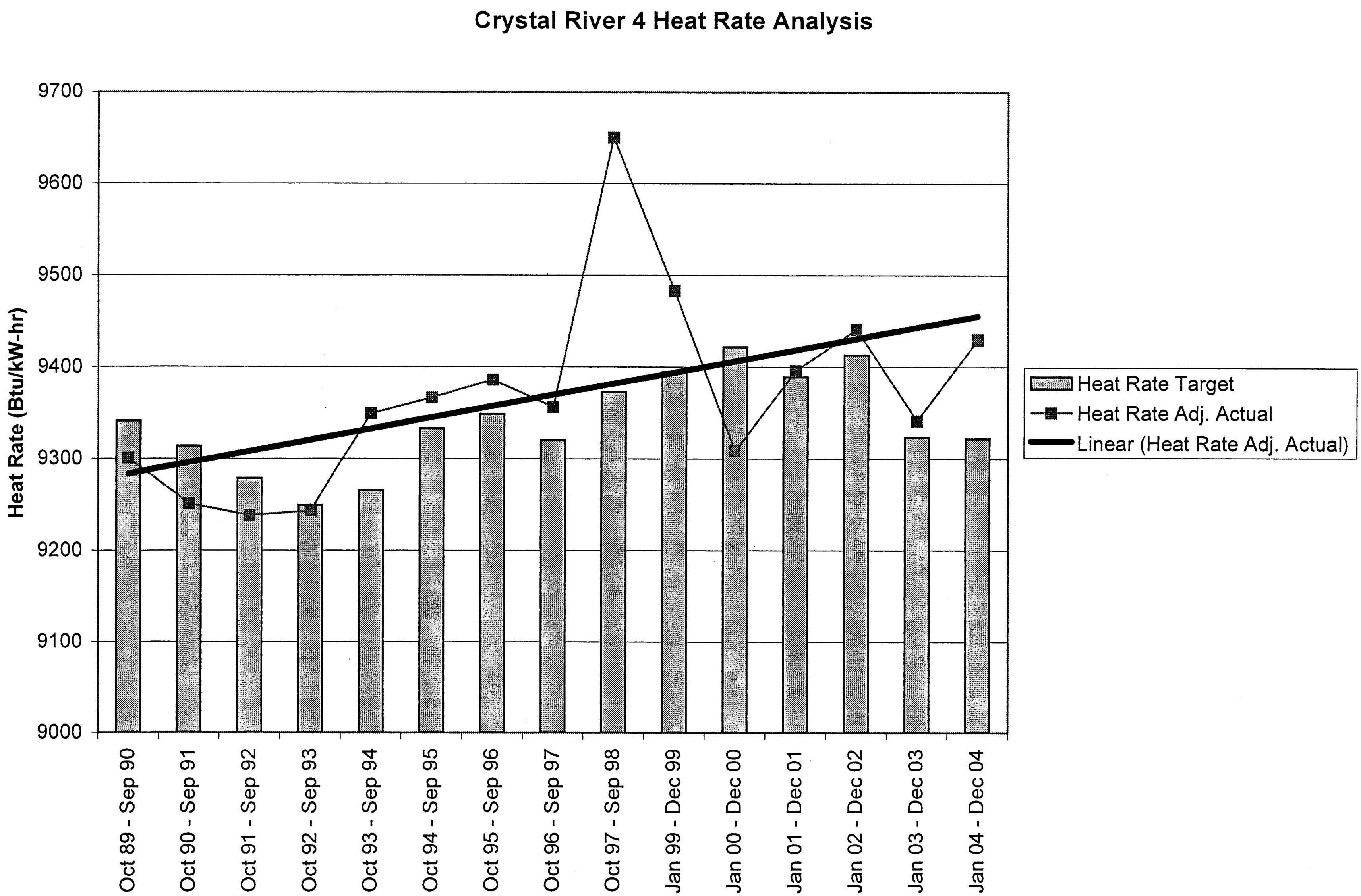
Crystal River 3 EAF Analysis



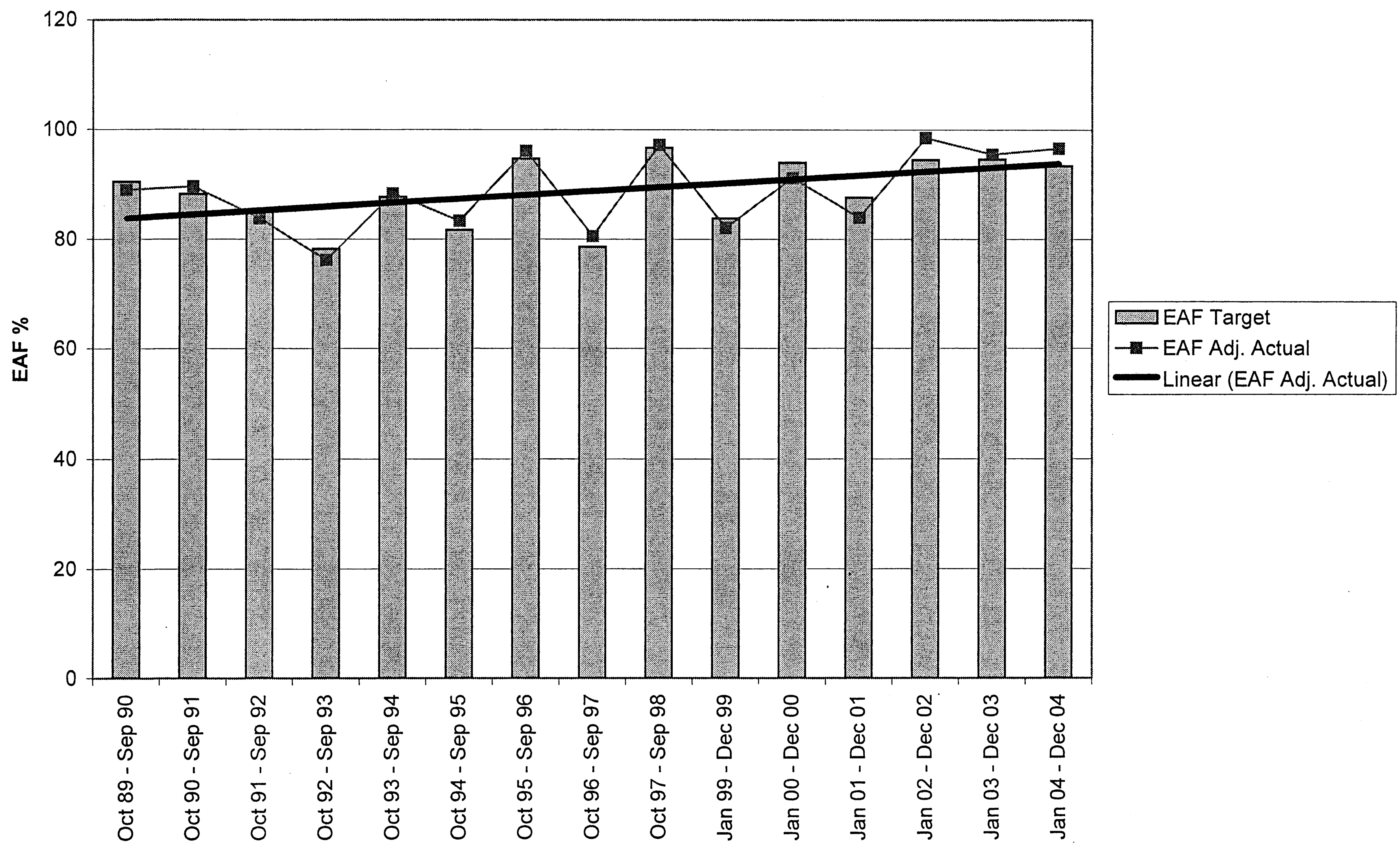

Crystal River 3 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10800
10600
10400
10200
10000
9800
9600
9400
9200
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

Crystal River 4 EAF Analysis

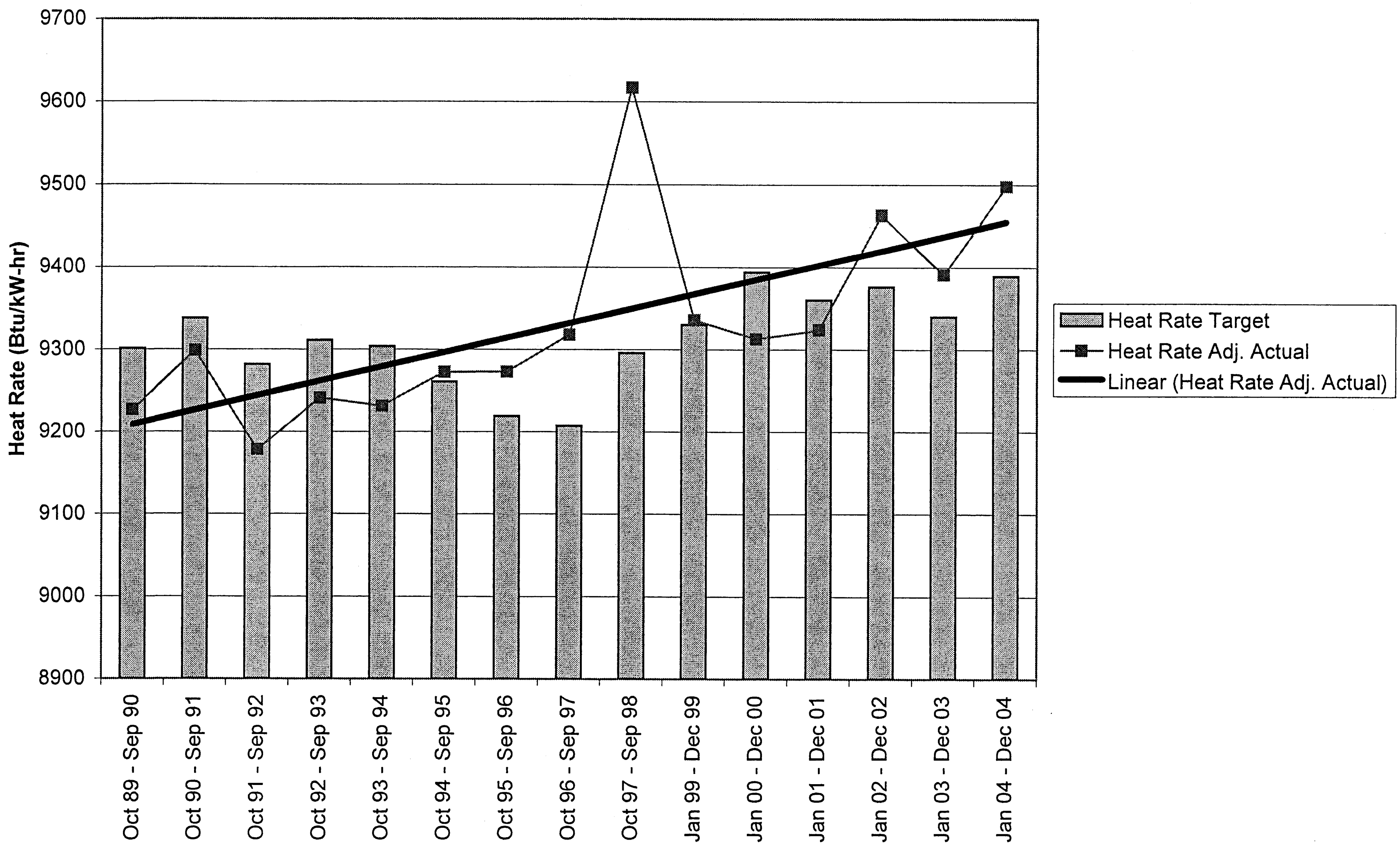



Crystal River 4 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
9700
9600
9500
9400
9300
9200
9100
9000
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

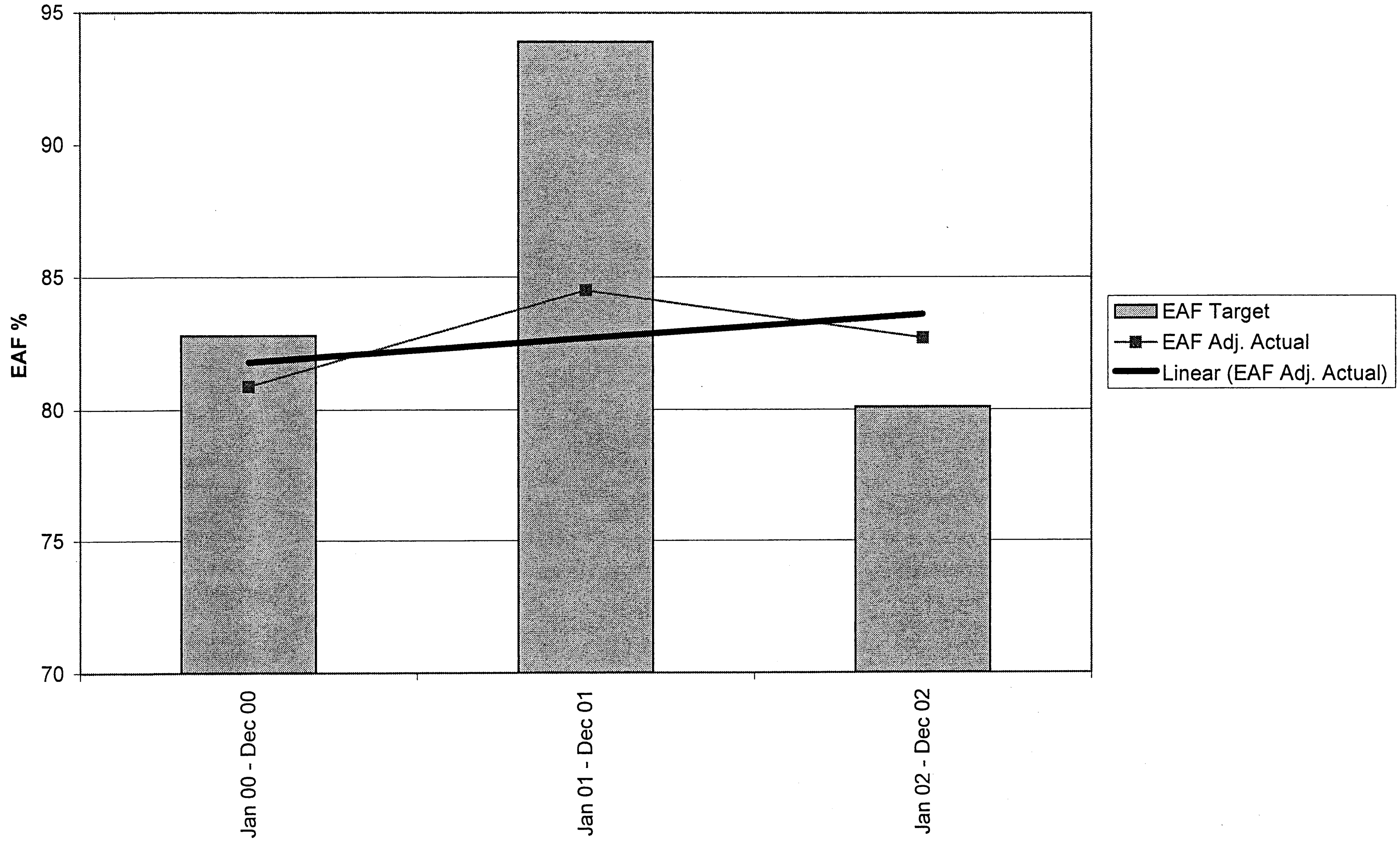
Crystal River 5 EAF Analysis

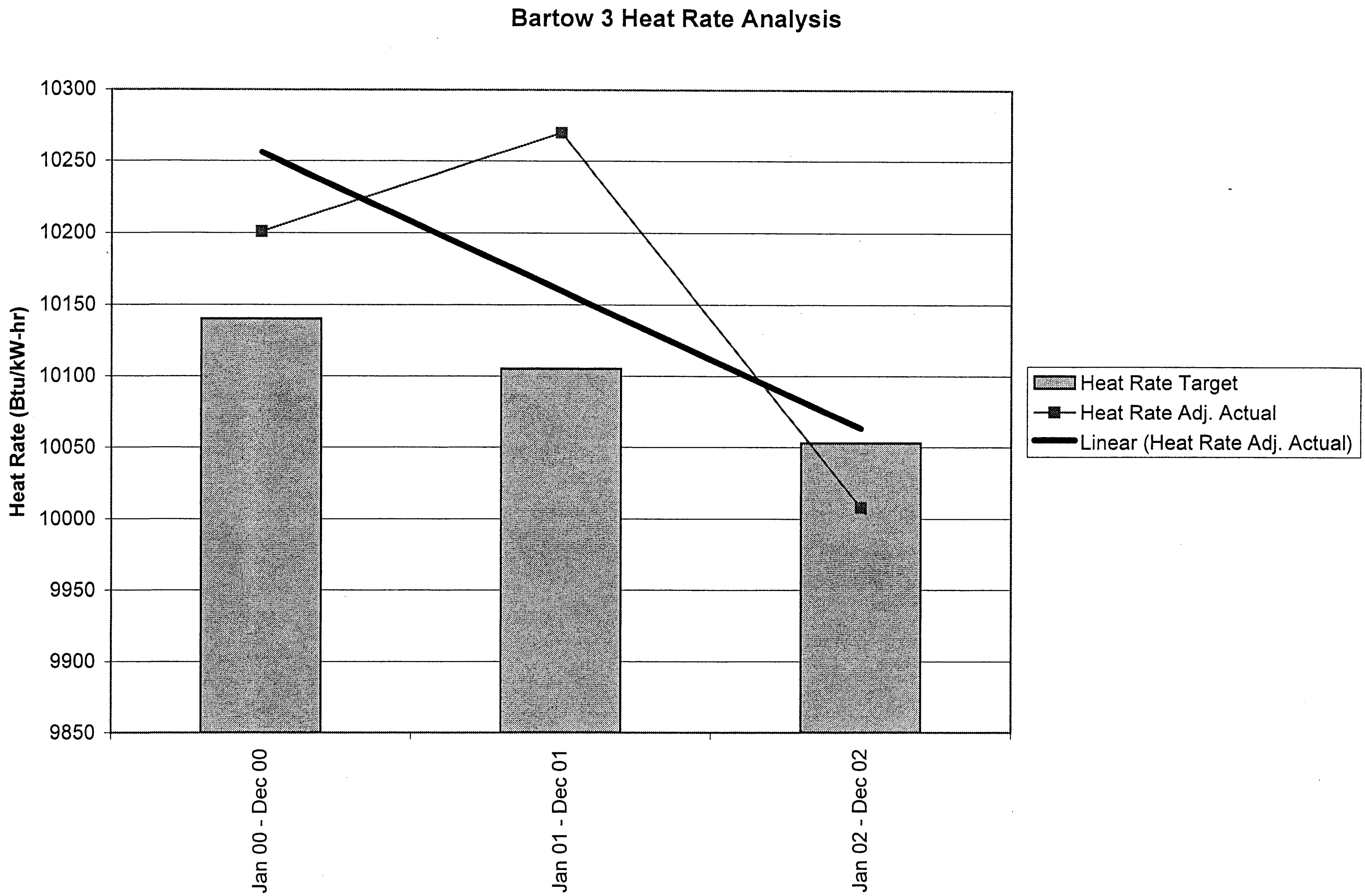


Crystal River 5 Heat Rate Analysis



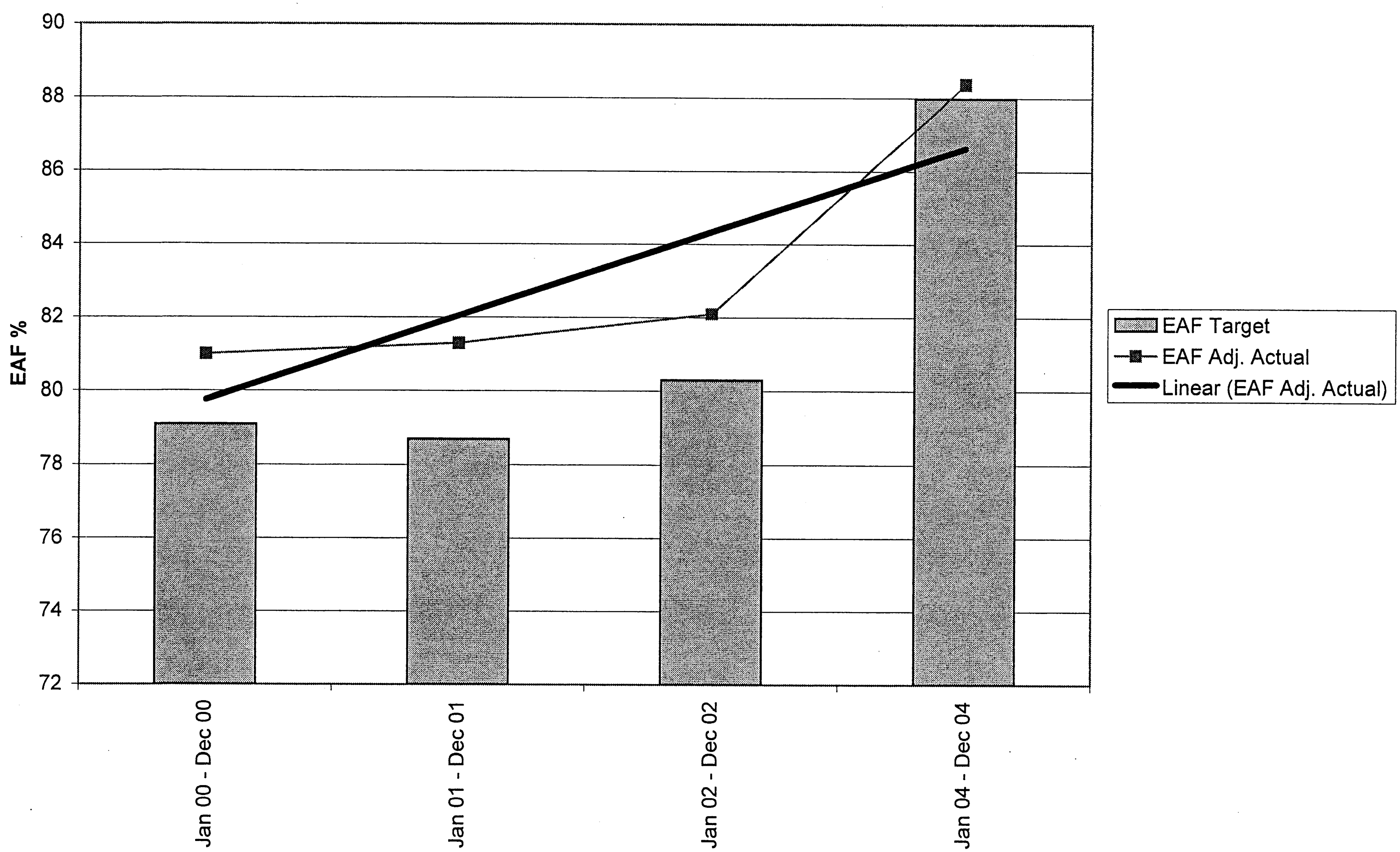
Bartow 3 EAF Analysis



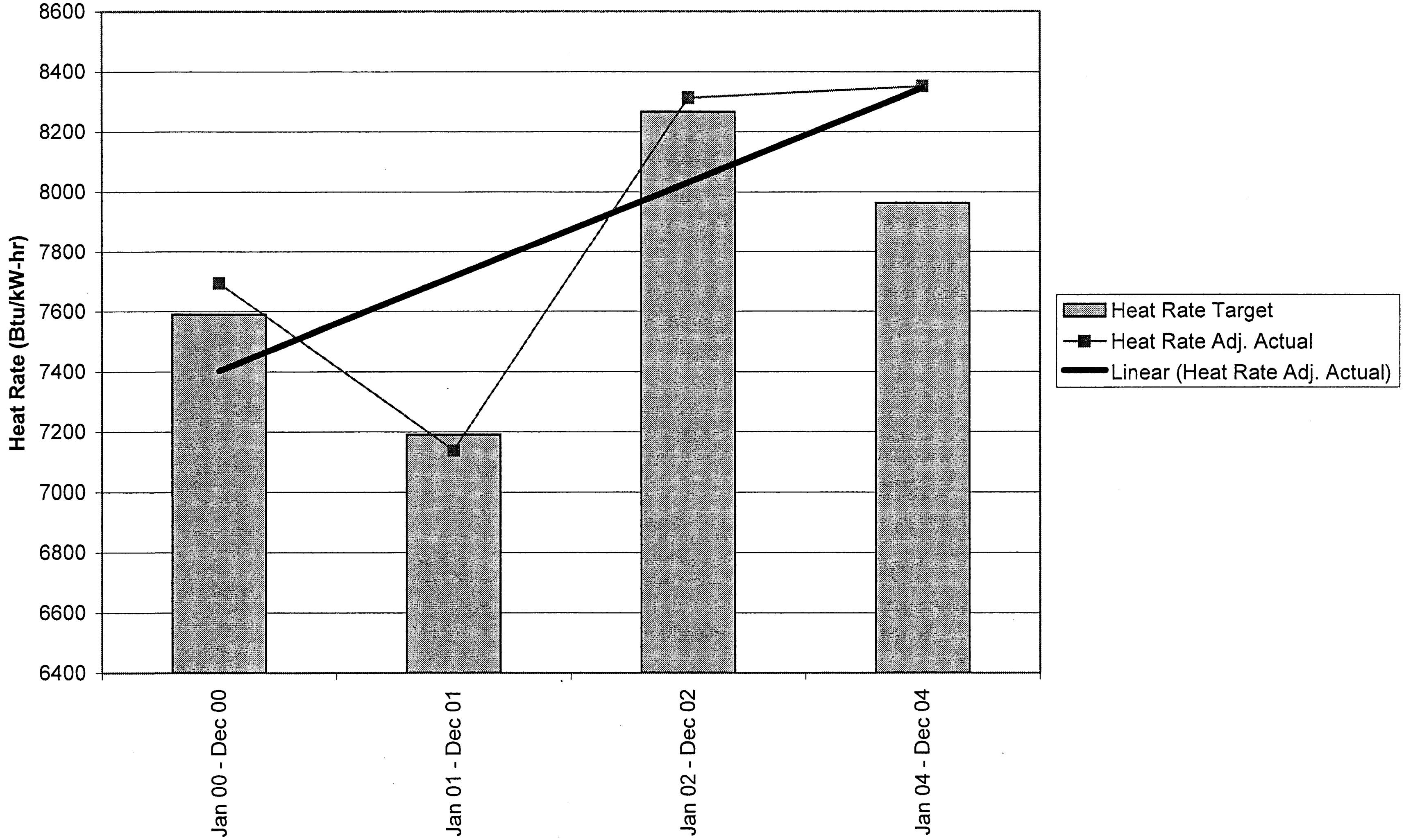


Bartow 3 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10300
10250
10200
10150
10100
10050
10000
9950
9900
9850
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

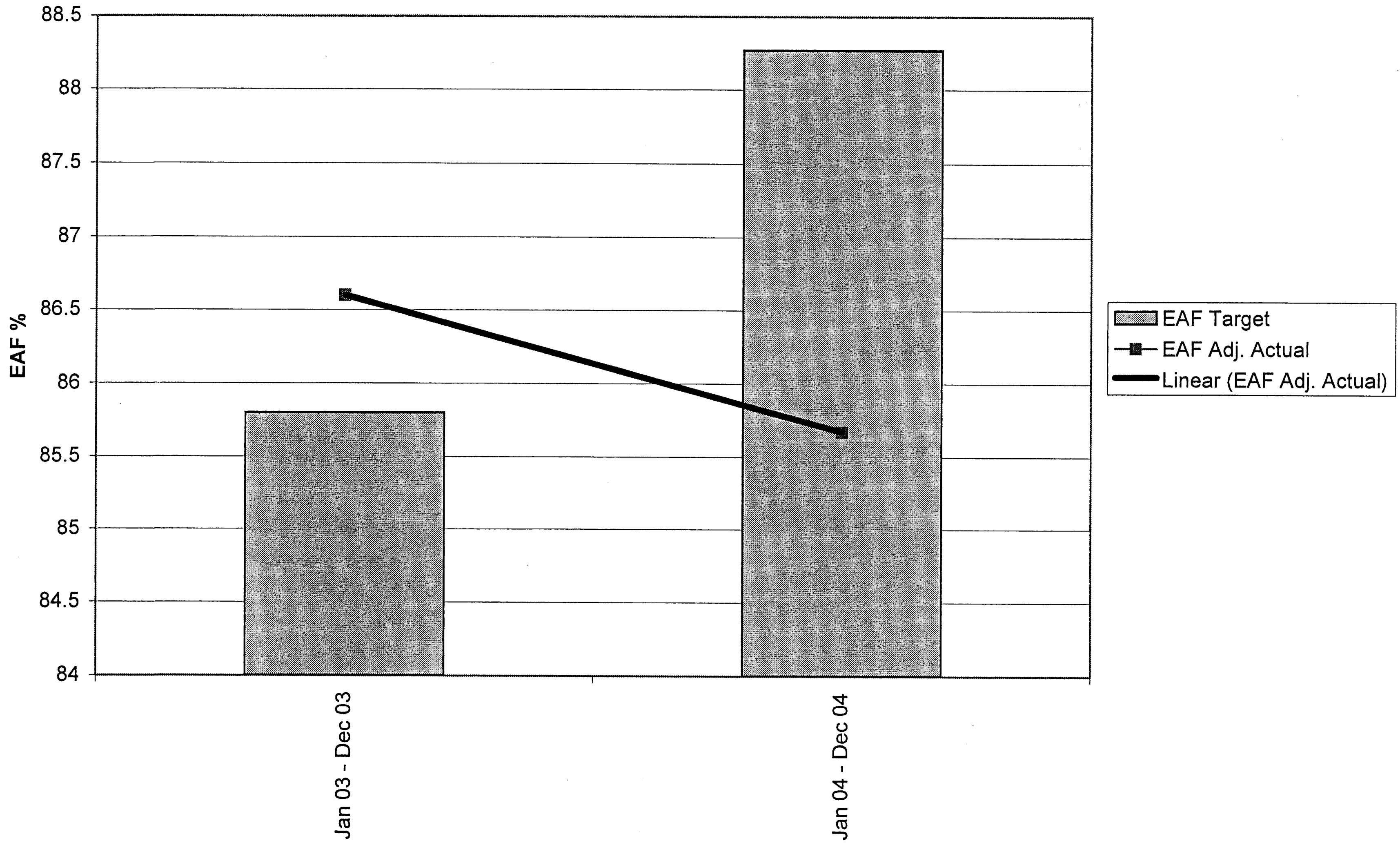
Tiger Bay EAF Analysis



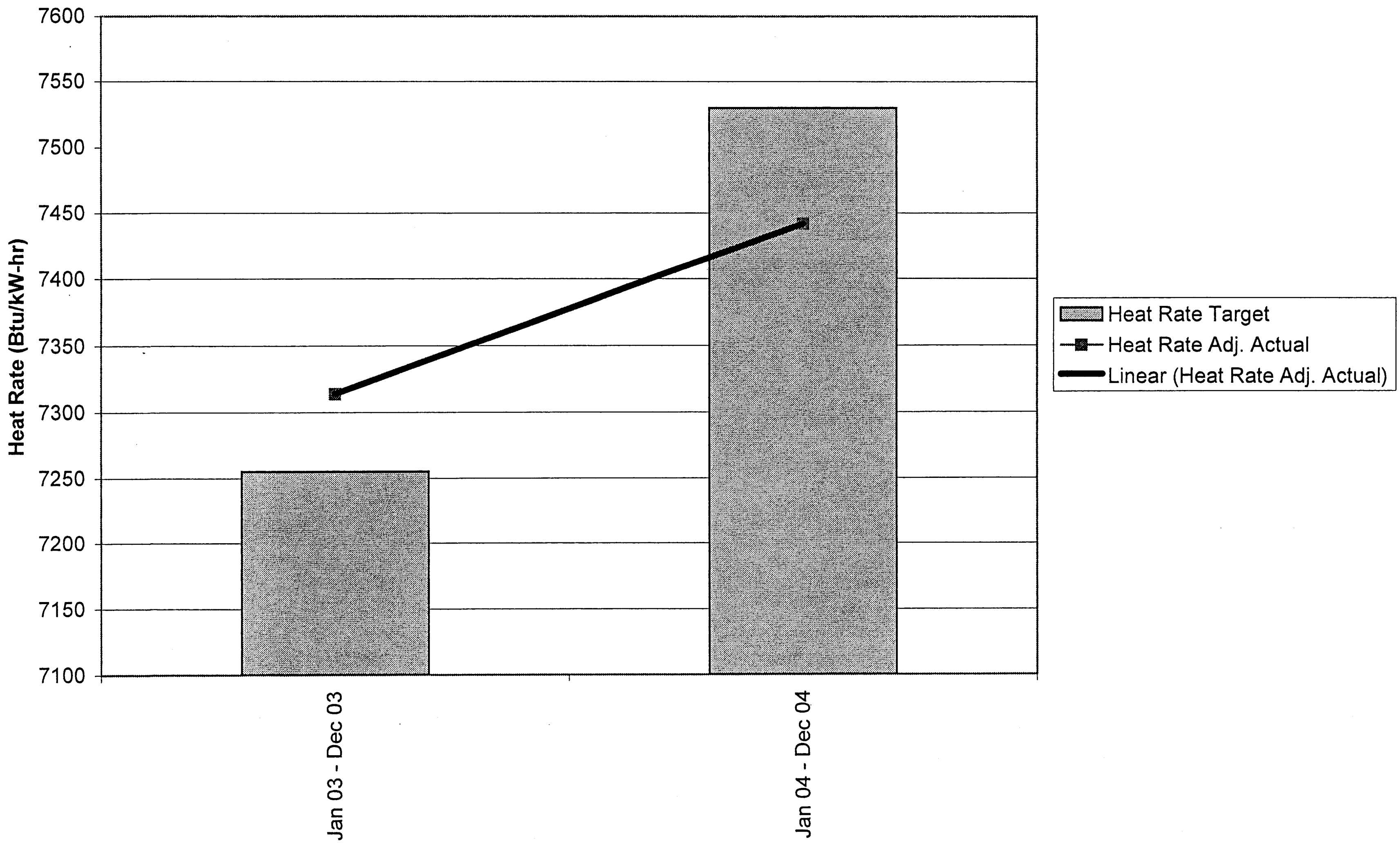
Tiger Bay Heat Rate Analysis



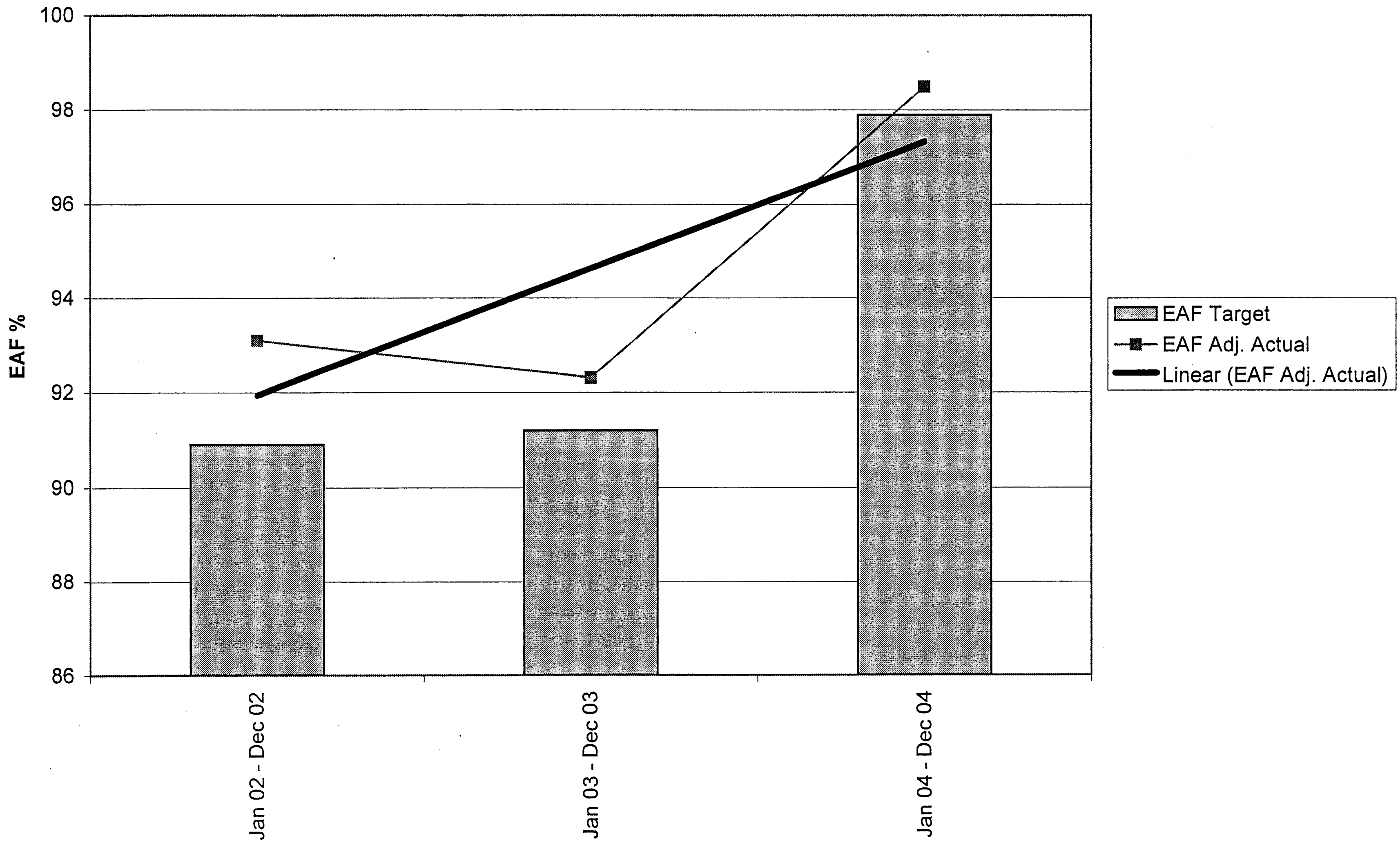
Hines 1 EAF Analysis



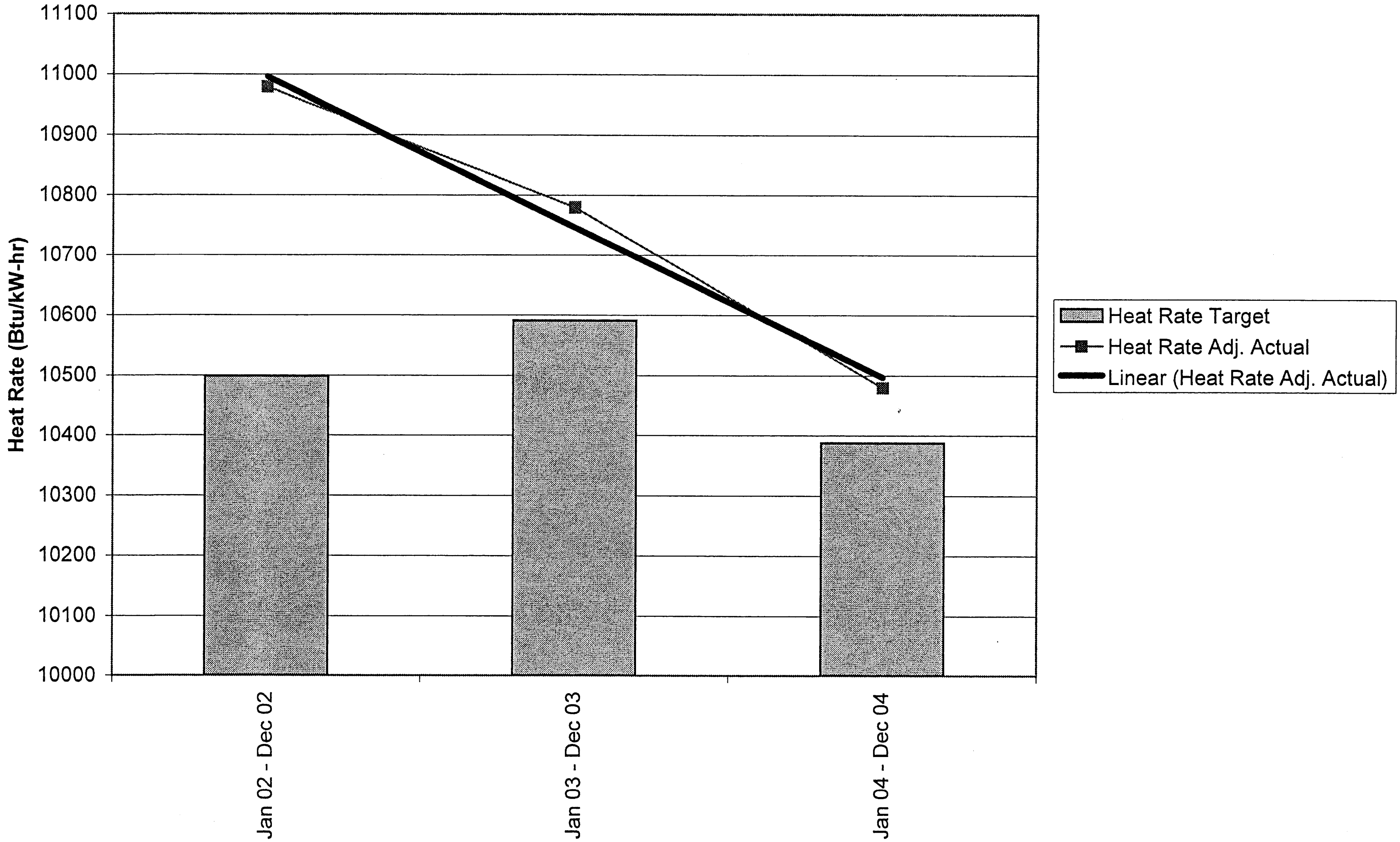
Hines 1 Heat Rate Analysis



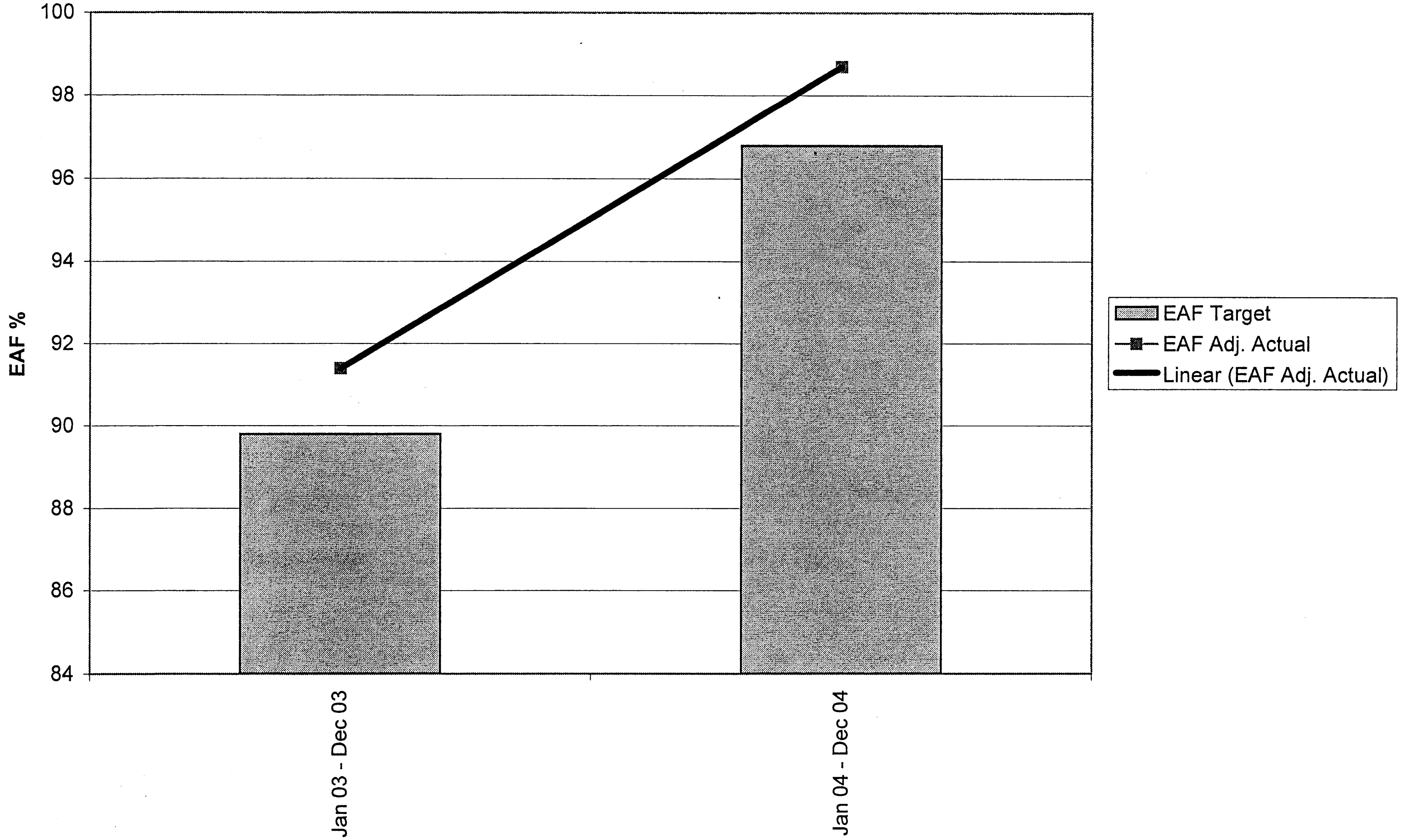
Crist 4 EAF Analysis



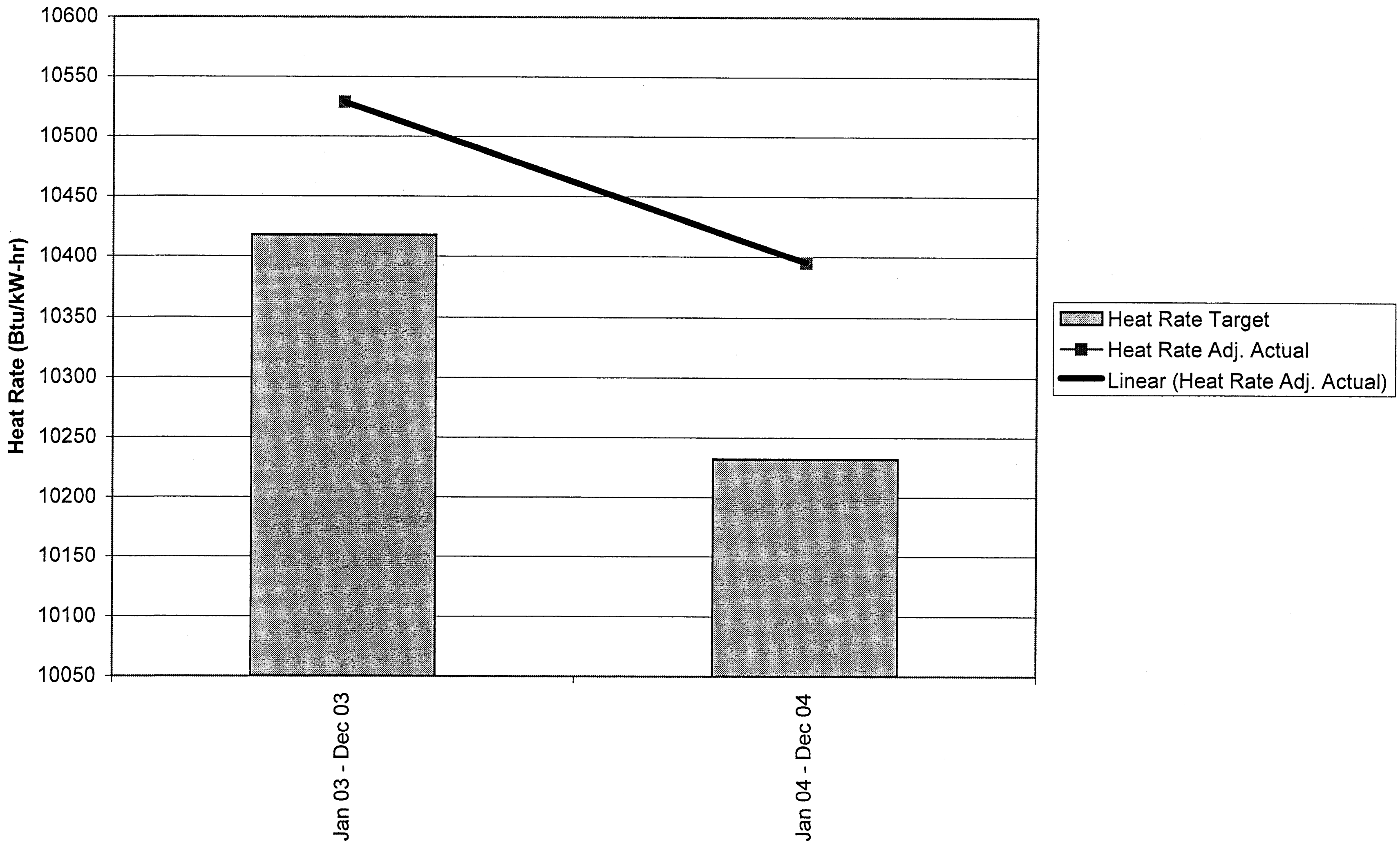
Crist 4 Heat Rate Analysis



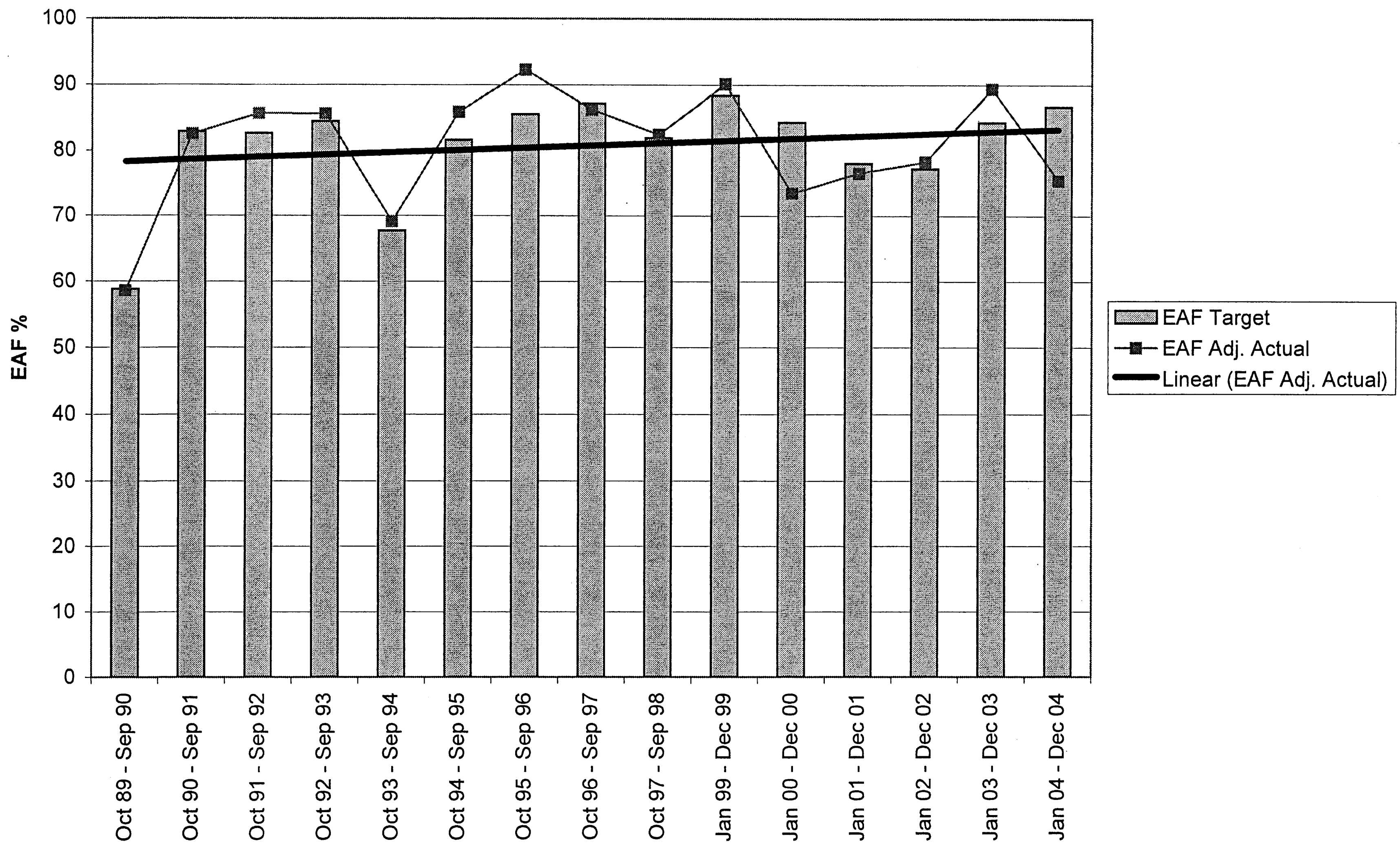
Crist 5 EAF Analysis

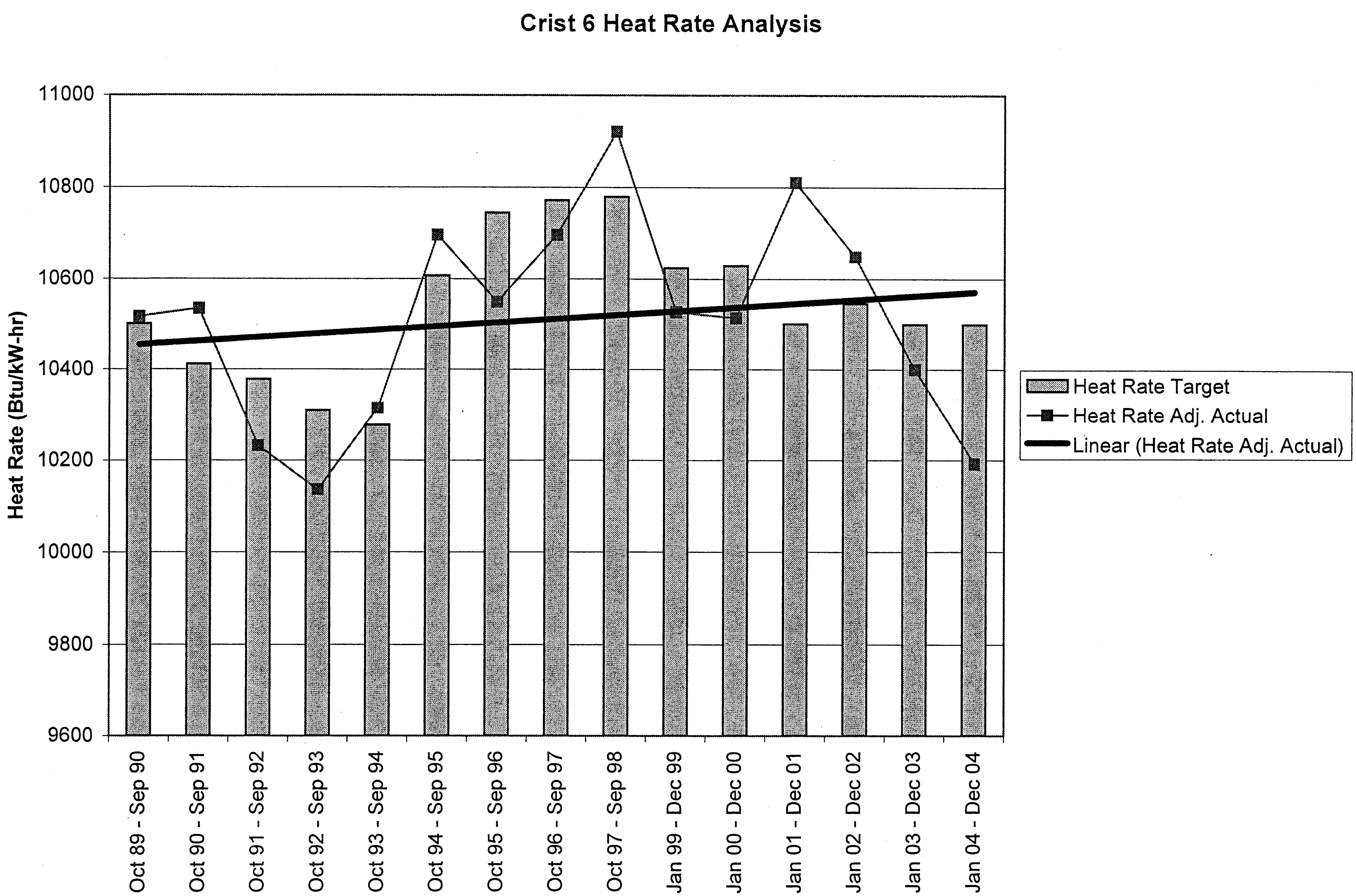


Crist 5 Heat Rate Analysis



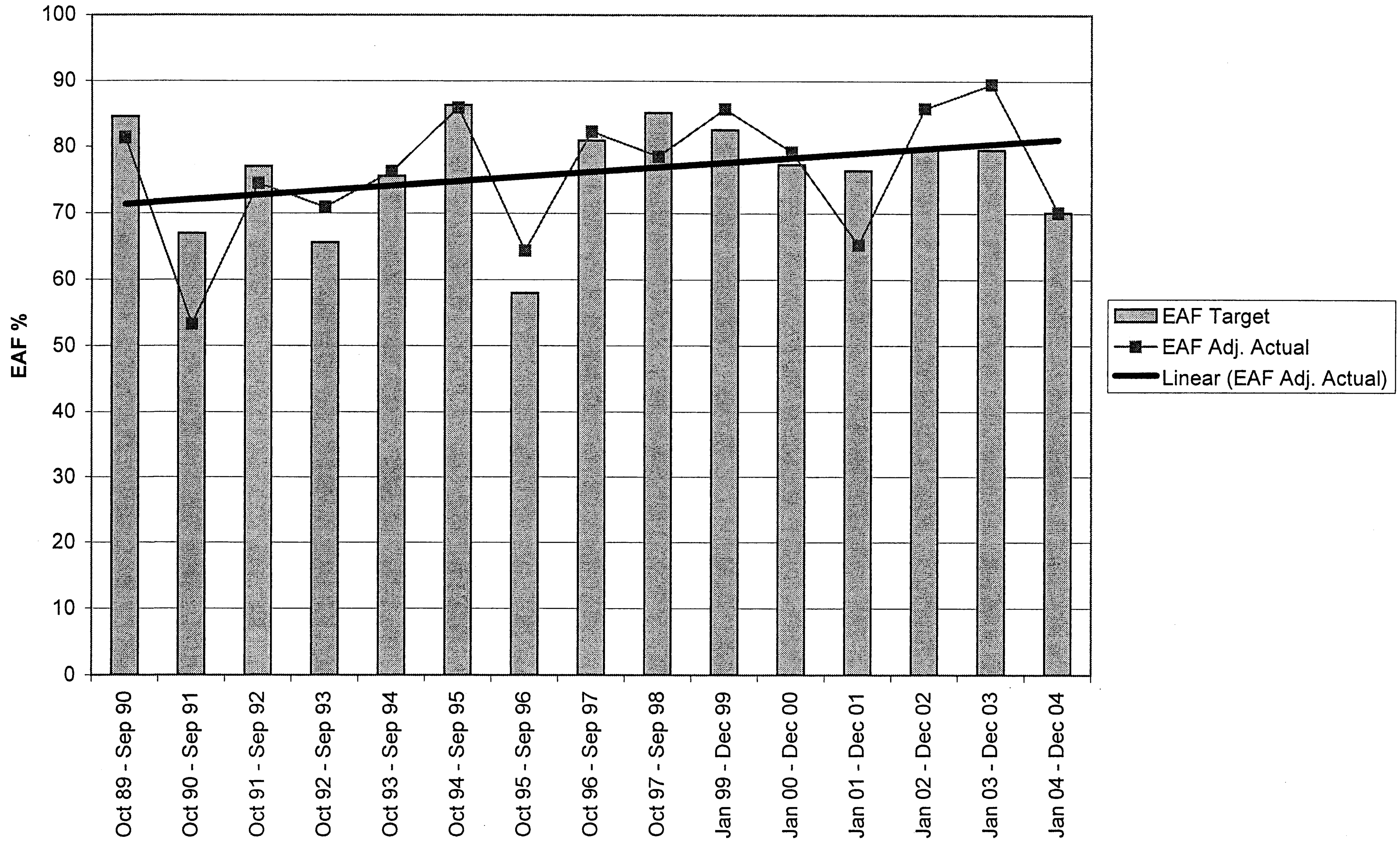
Crist 6 EAF Analysis



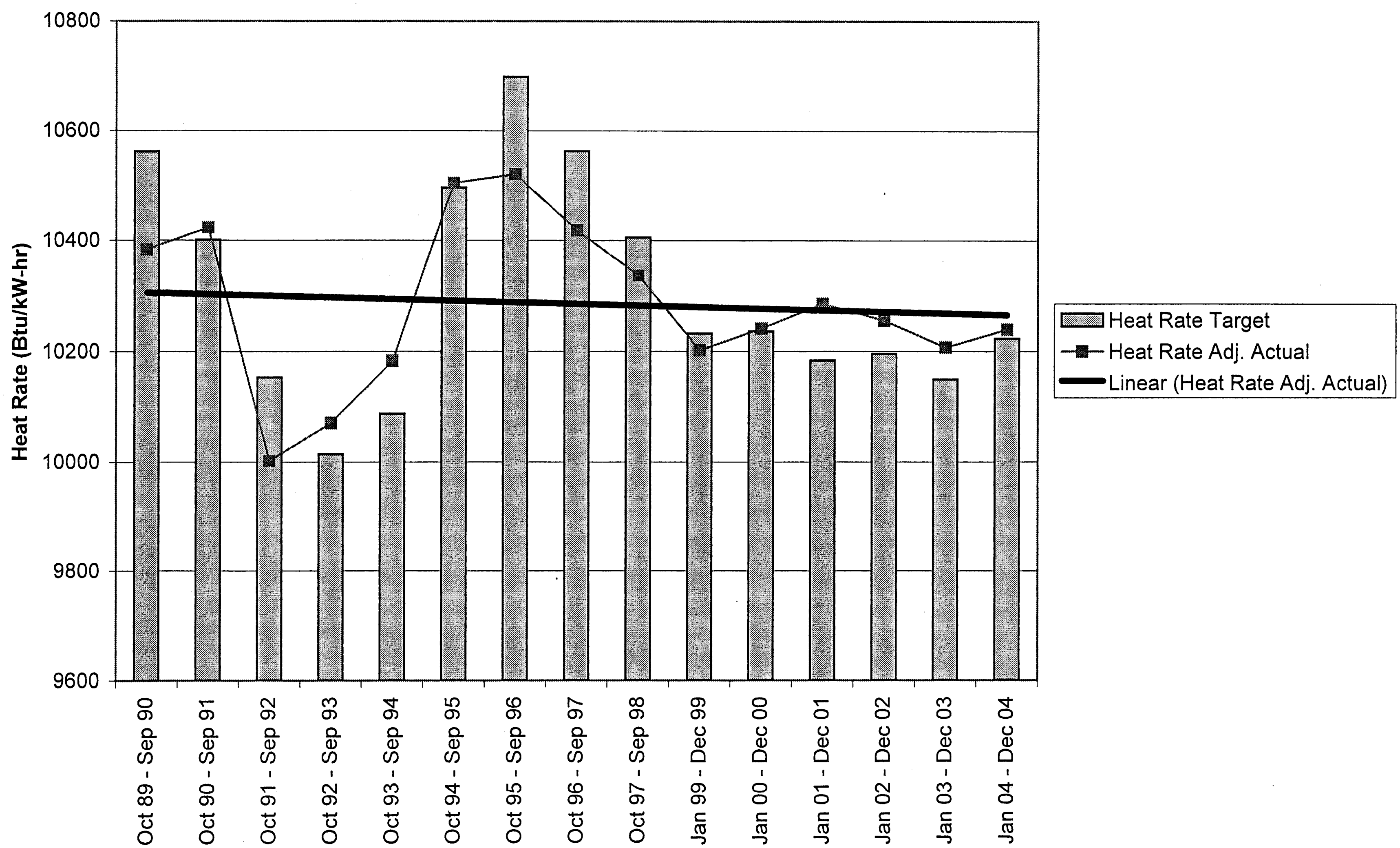


Crist 6 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
11000
10800
10600
10400
10200
10000
9800
9600
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

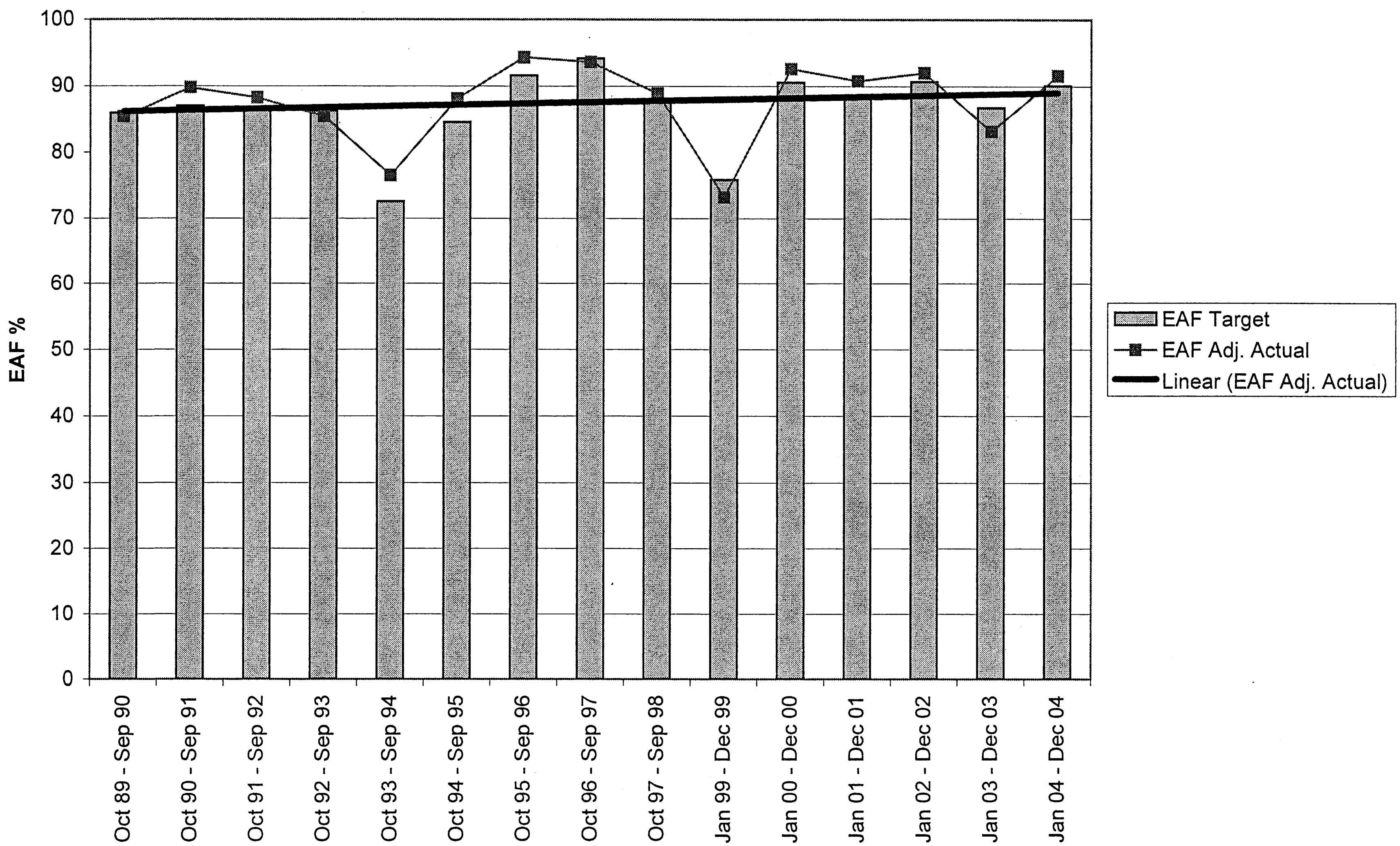
Crist 7 EAF Analysis

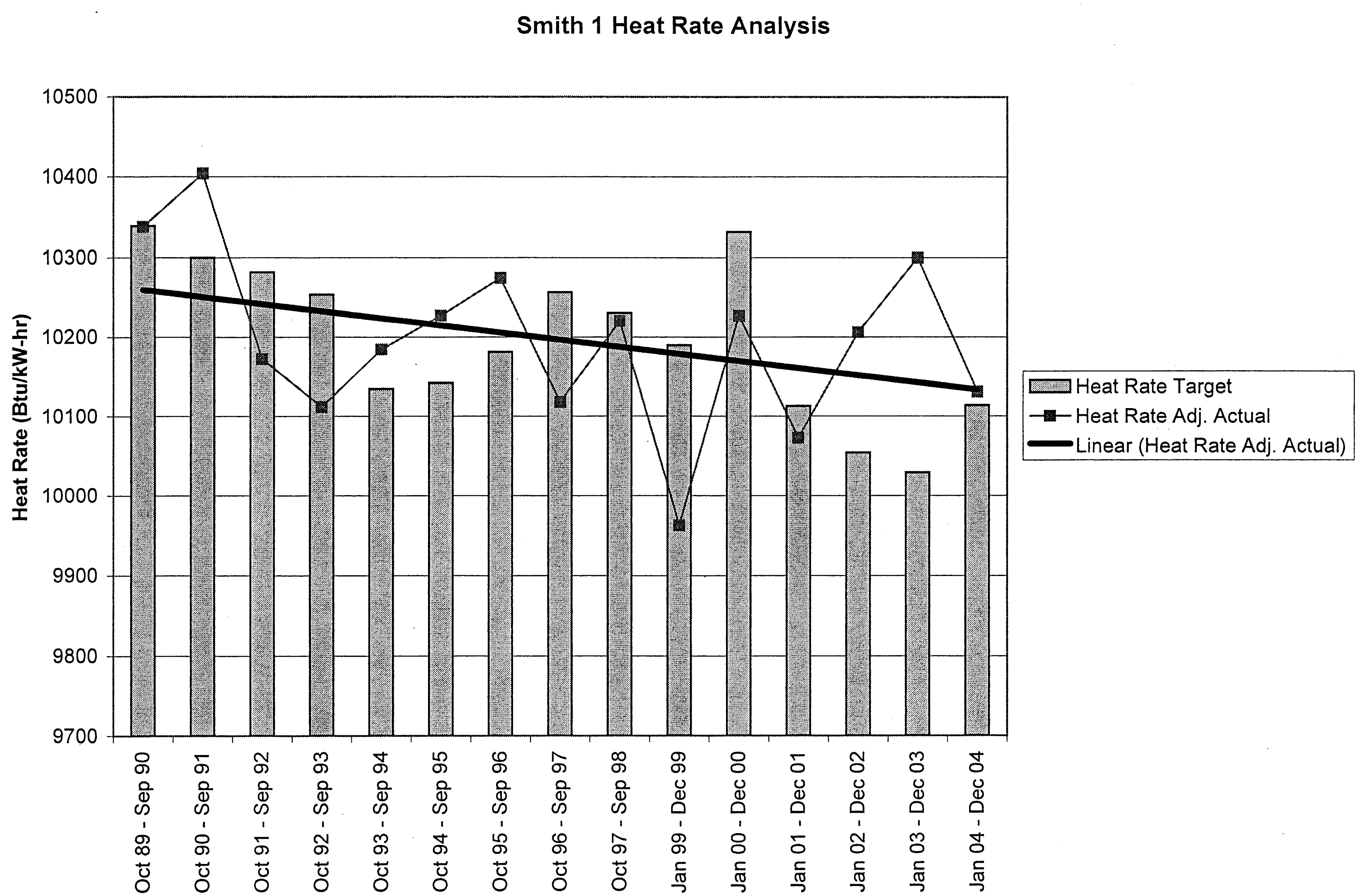


Crist 7 Heat Rate Analysis



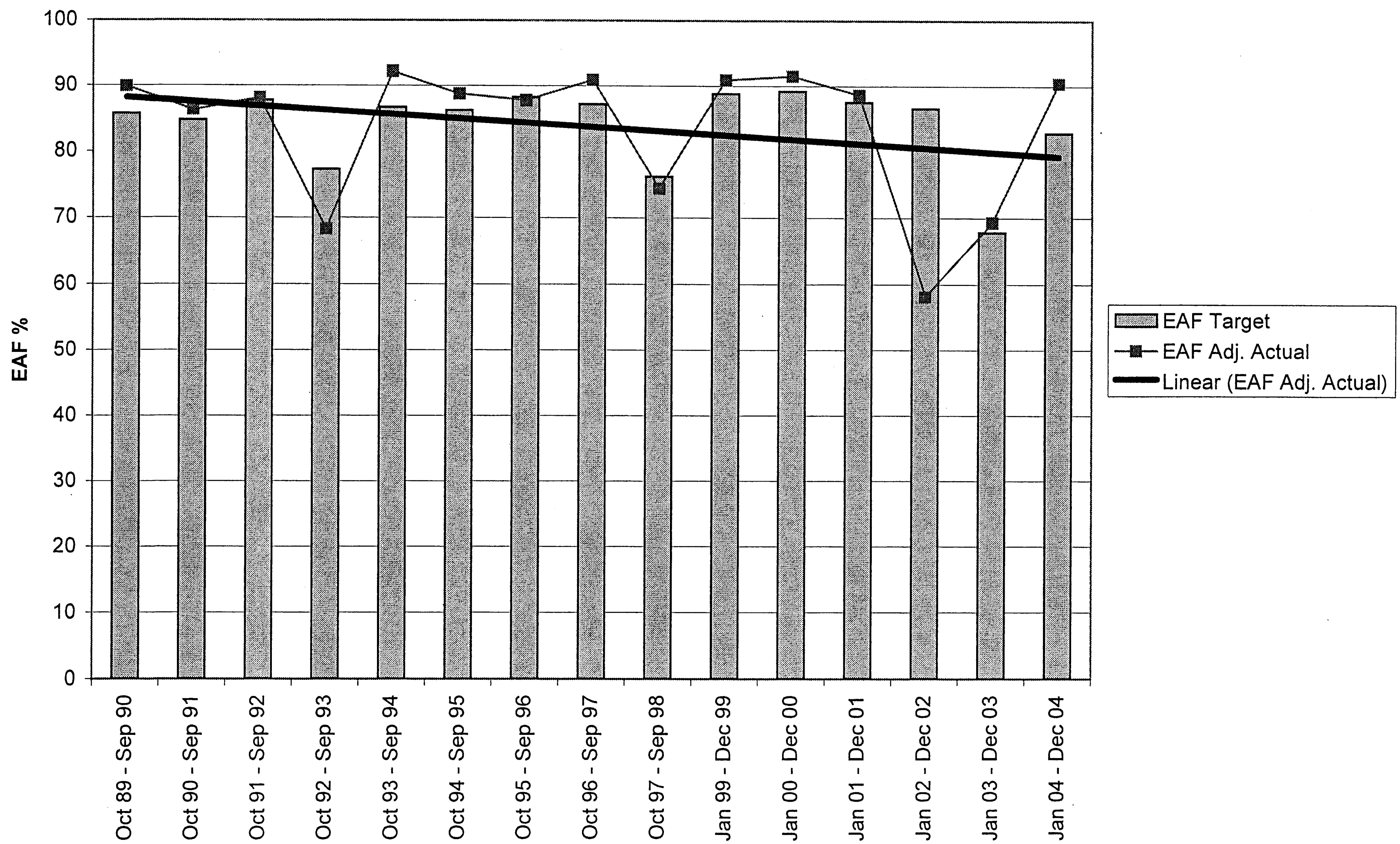
Smith 1 EAF Analysis



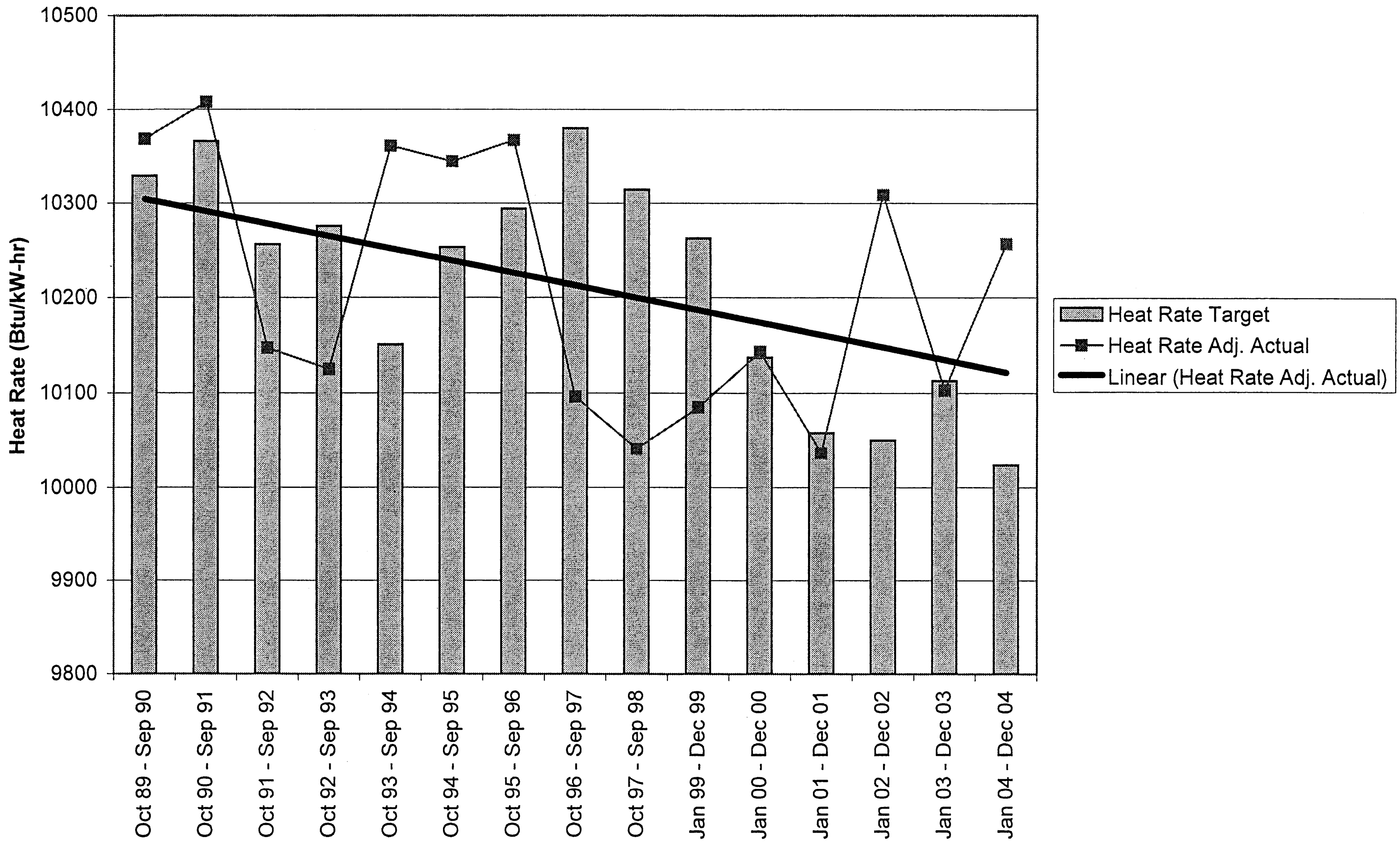


Smith 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10500
10400
10300
10200
10100
10000
9900
9800
9700
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

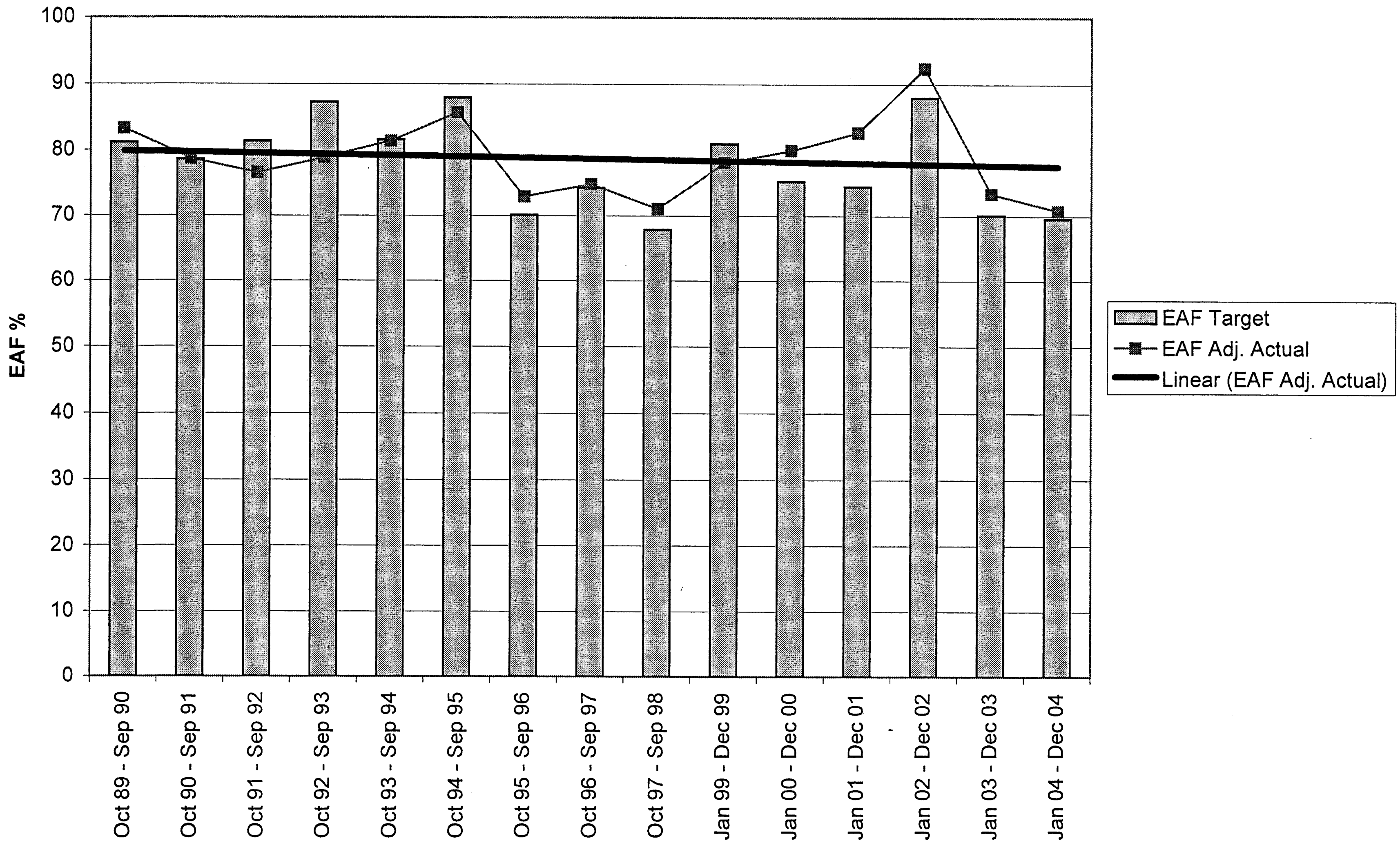
Smith 2 EAF Analysis

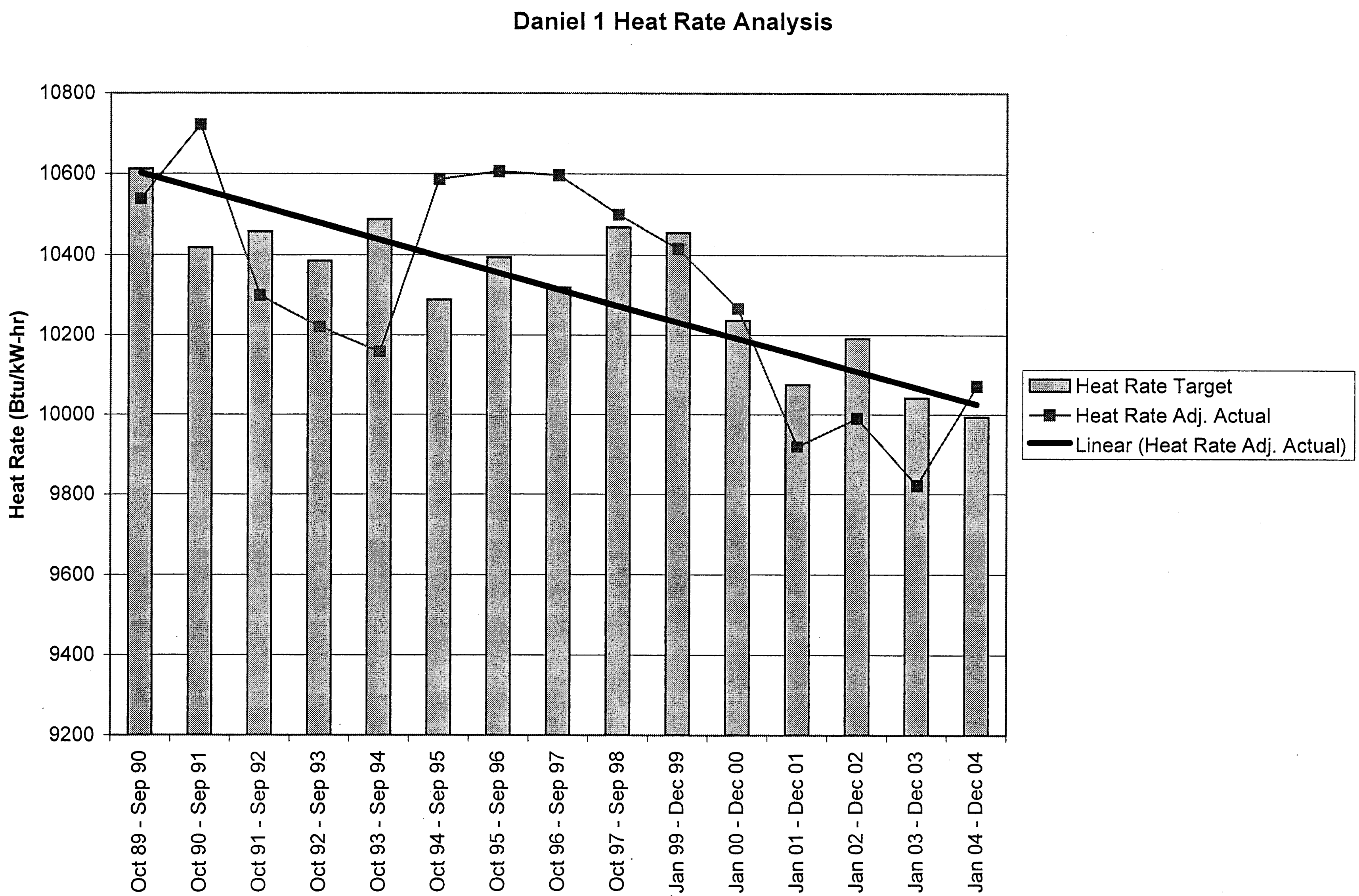


Smith 2 Heat Rate Analysis



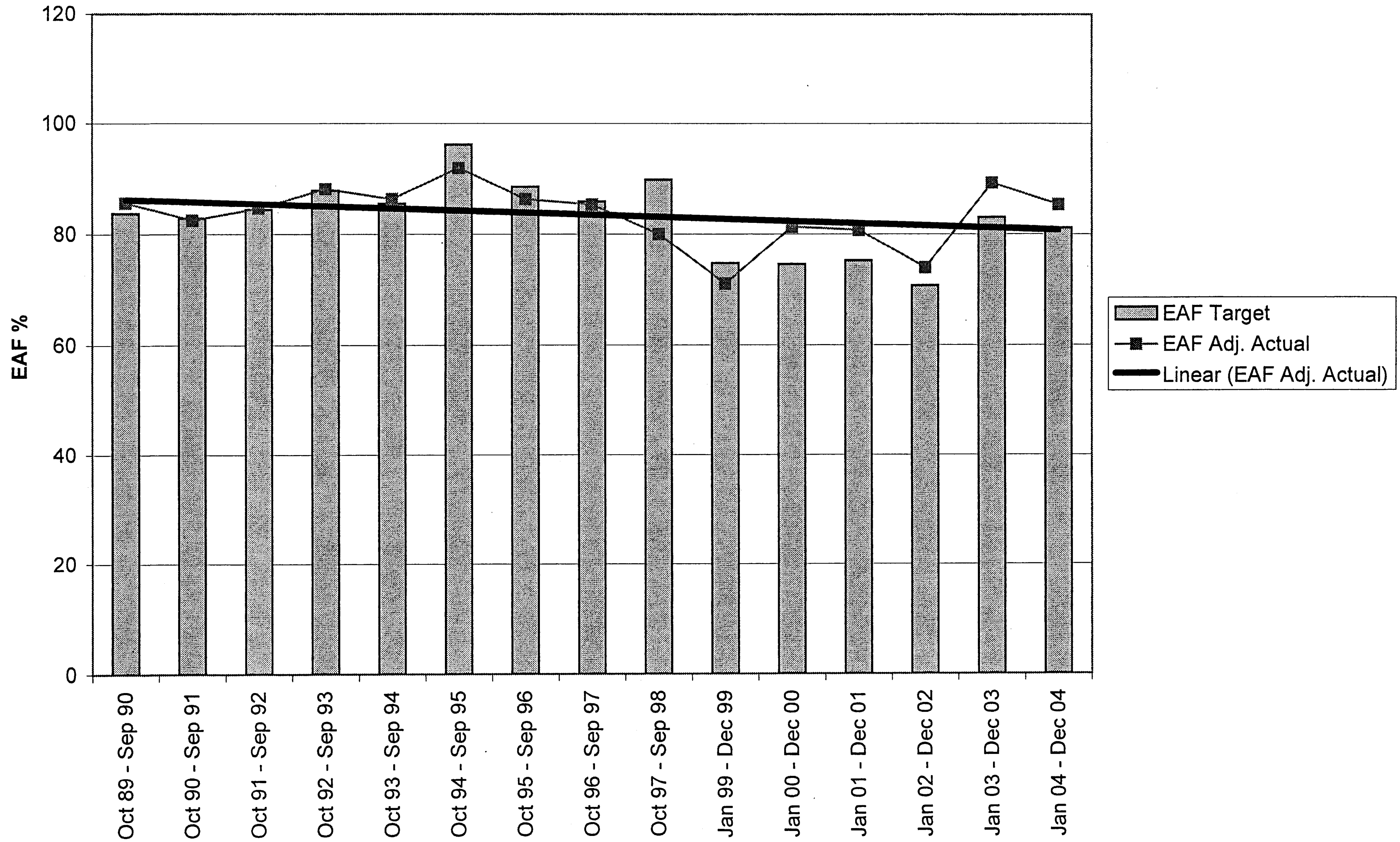
Daniel 1 EAF Analysis

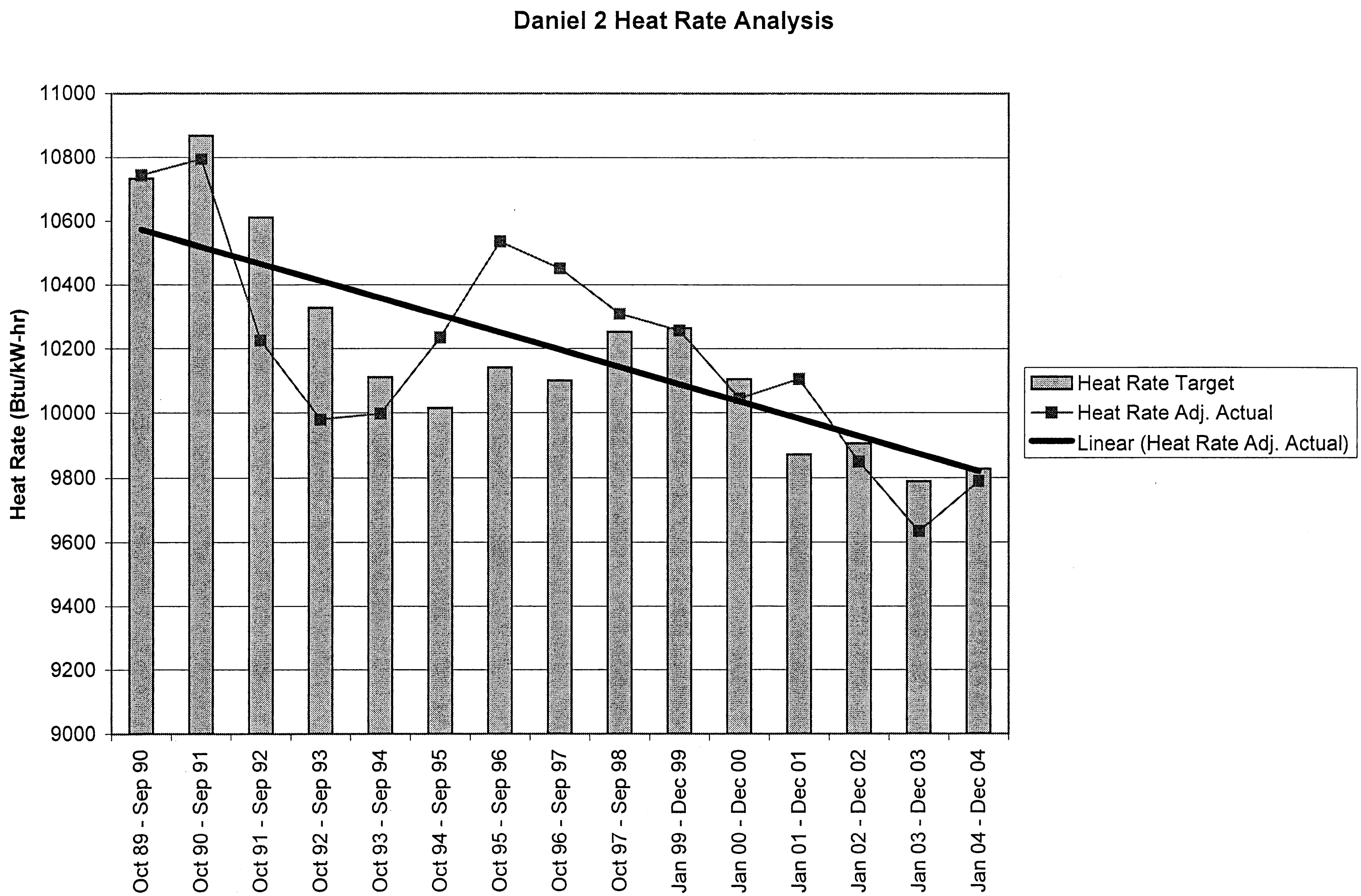


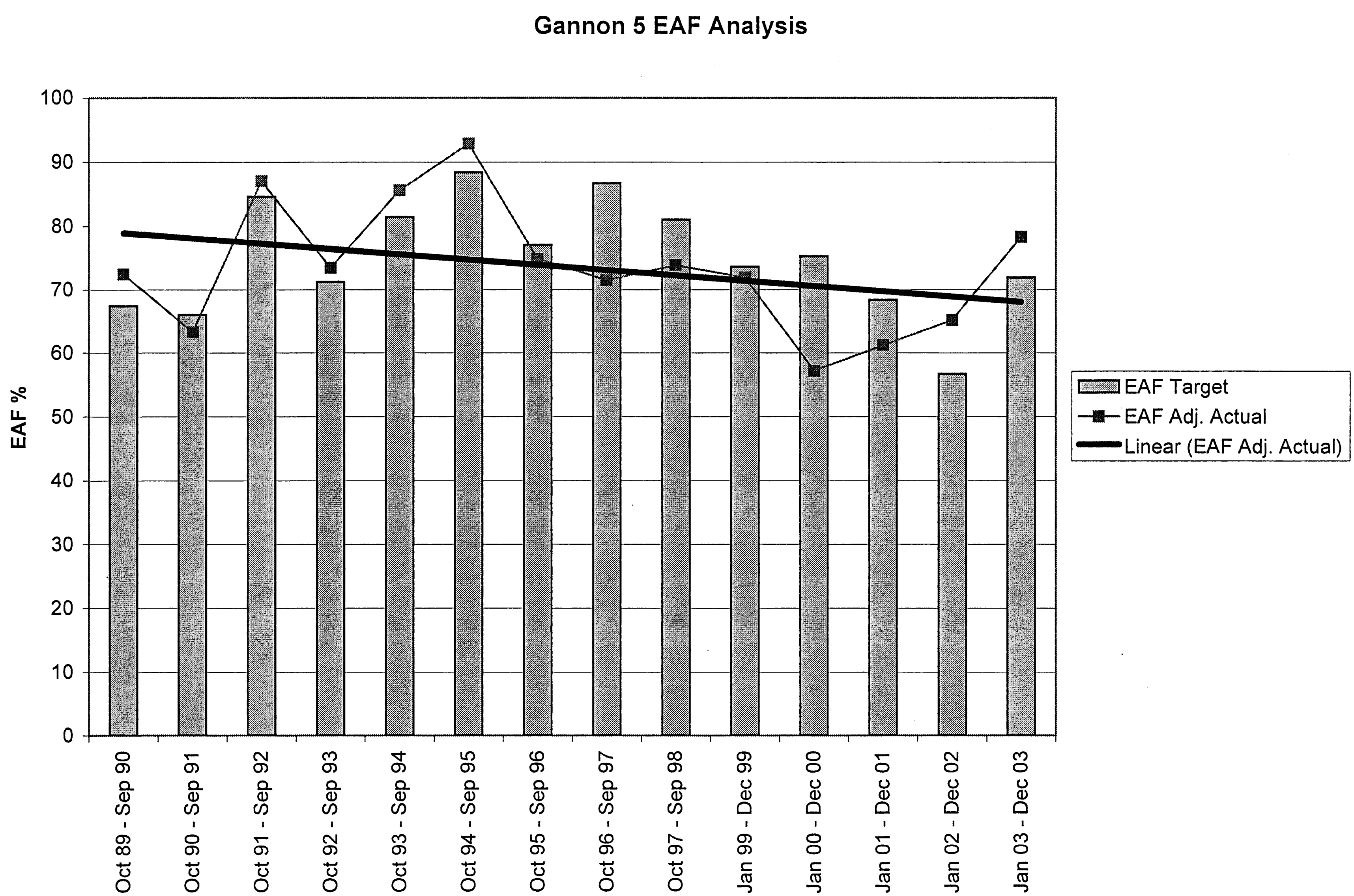


Daniel 1 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
10800
10600
10400
10200
10000
9800
9600
9400
9200
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)

Daniel 2 EAF Analysis

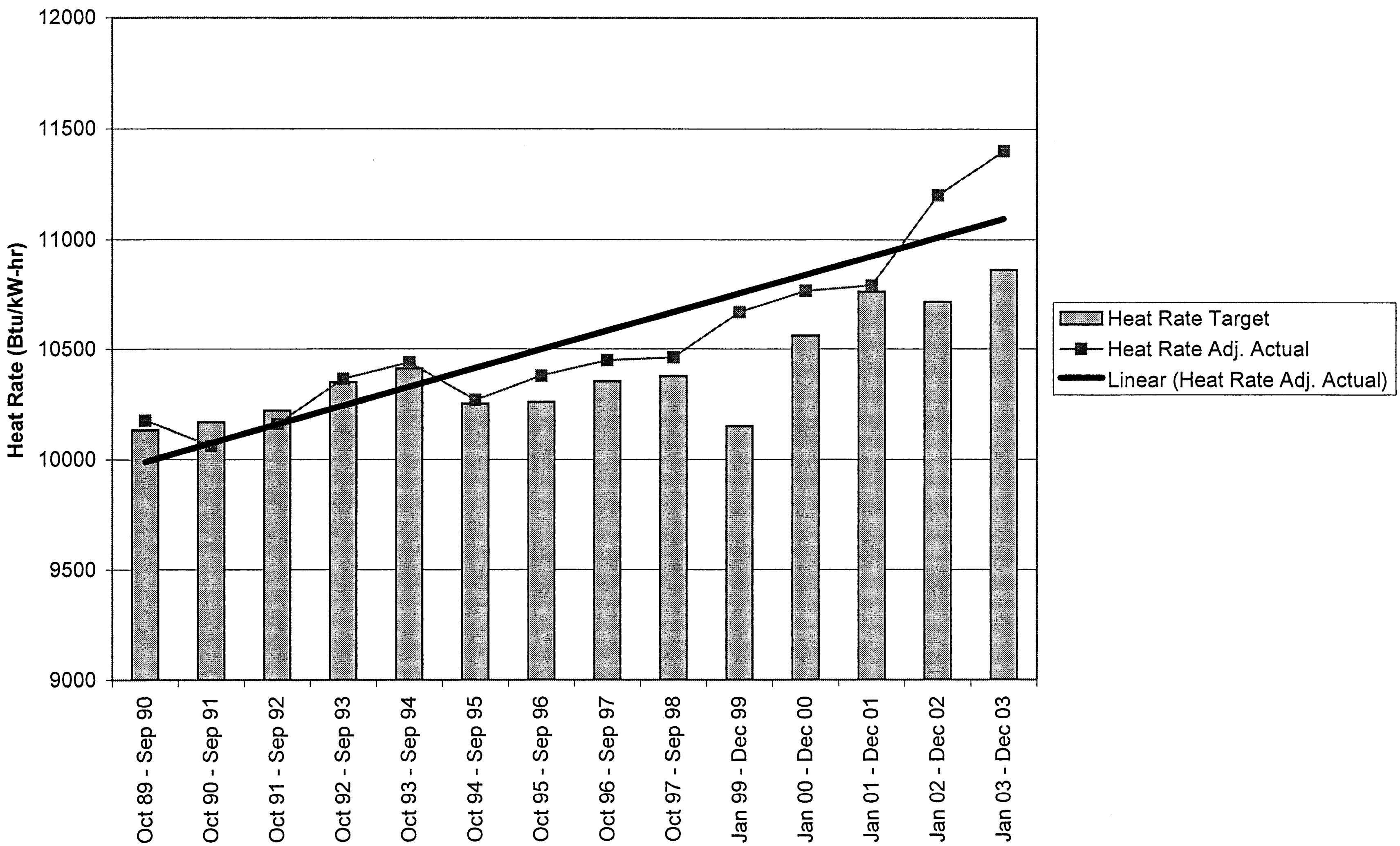


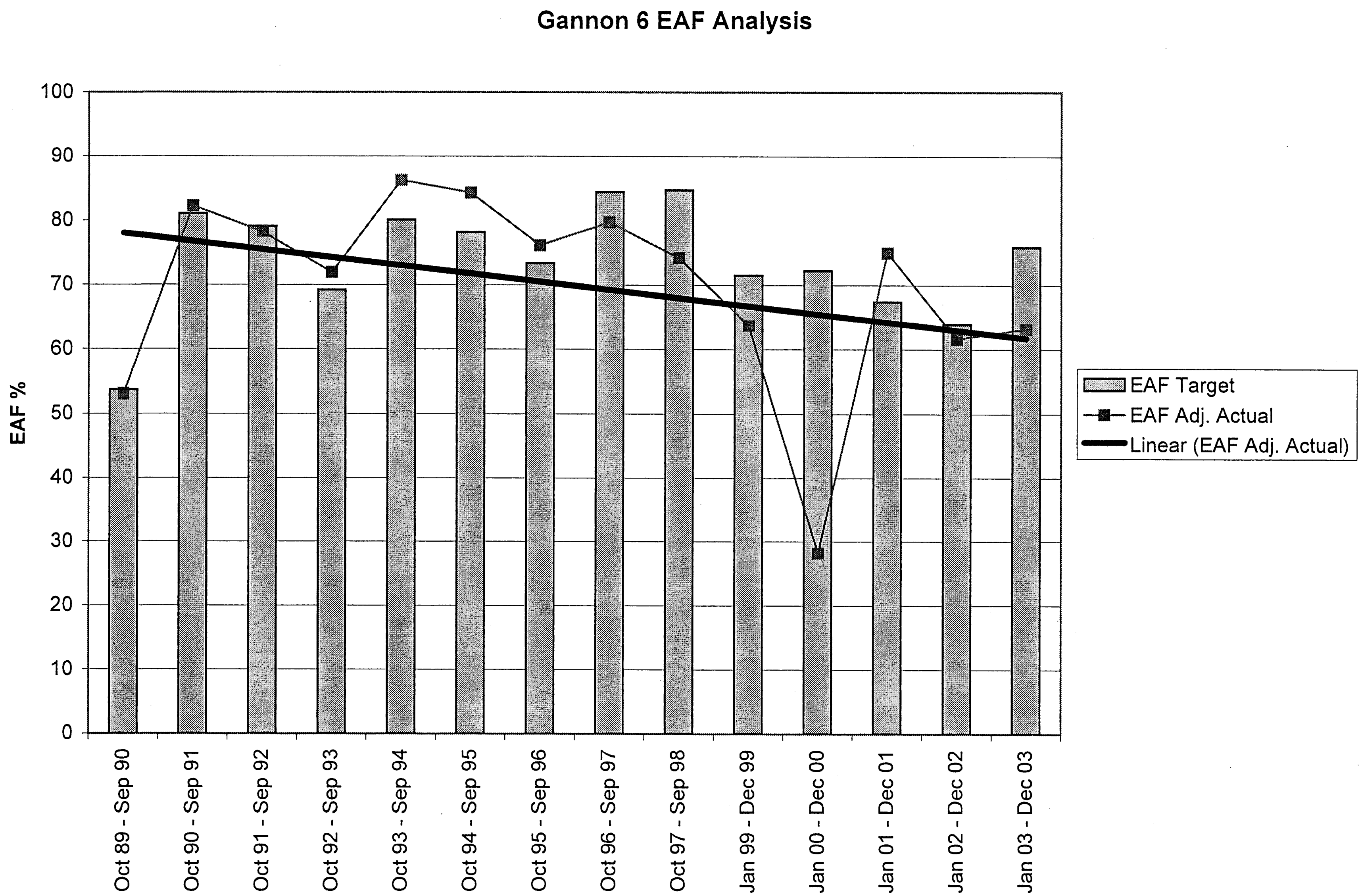

Daniel 2 Heat Rate Analysis
Heat Rate (Btu/kW-hr)
11000
10800
10600
10400
10200
10000
9800
9600
9400
9200
9000
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
Heat Rate Target
Heat Rate Adj. Actual
Linear (Heat Rate Adj. Actual)



Gannon 5 EAF Analysis
EAF %
100
90
80
70
60
50
40
30
20
10
0
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

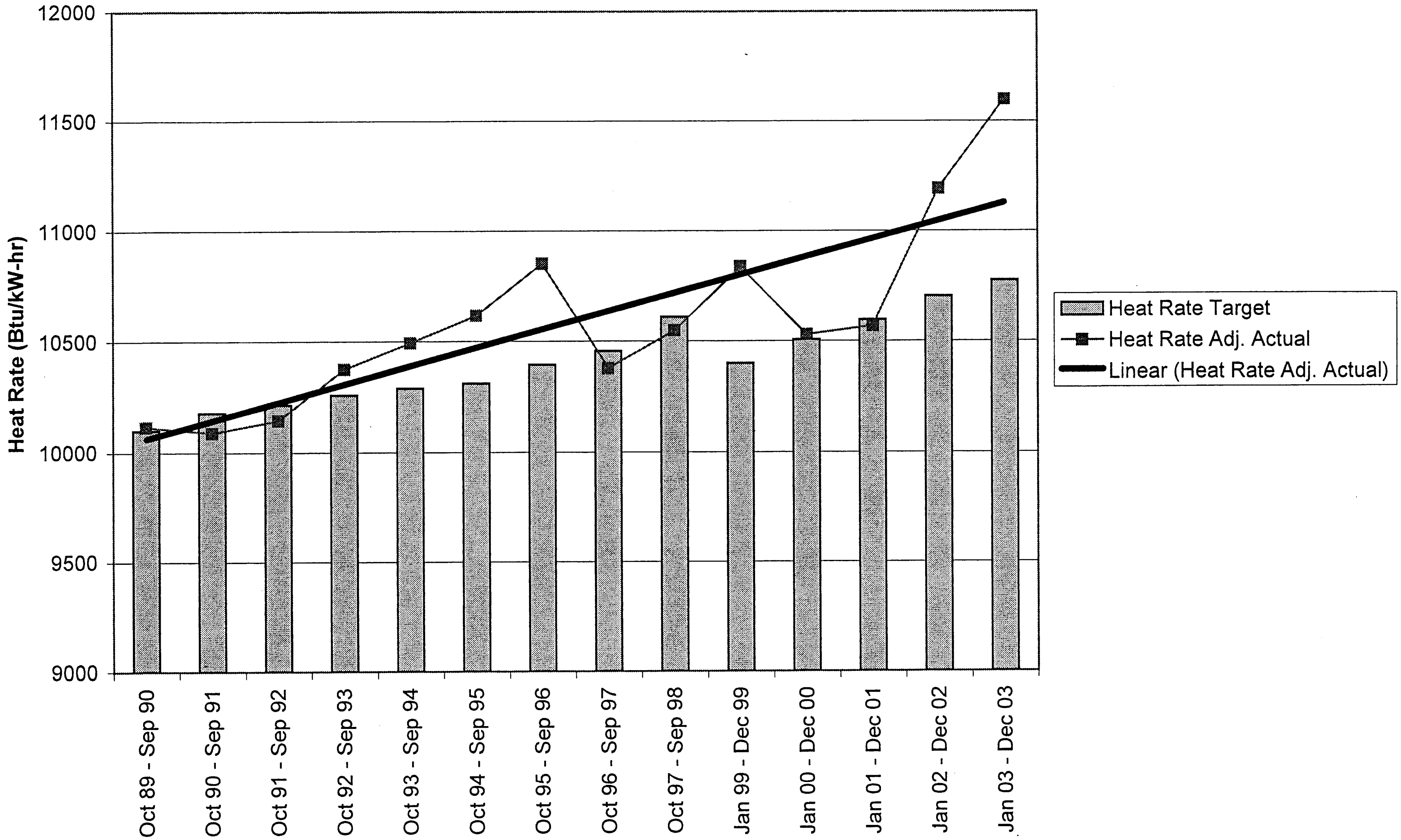
Gannon 5 Heat Rate Analysis



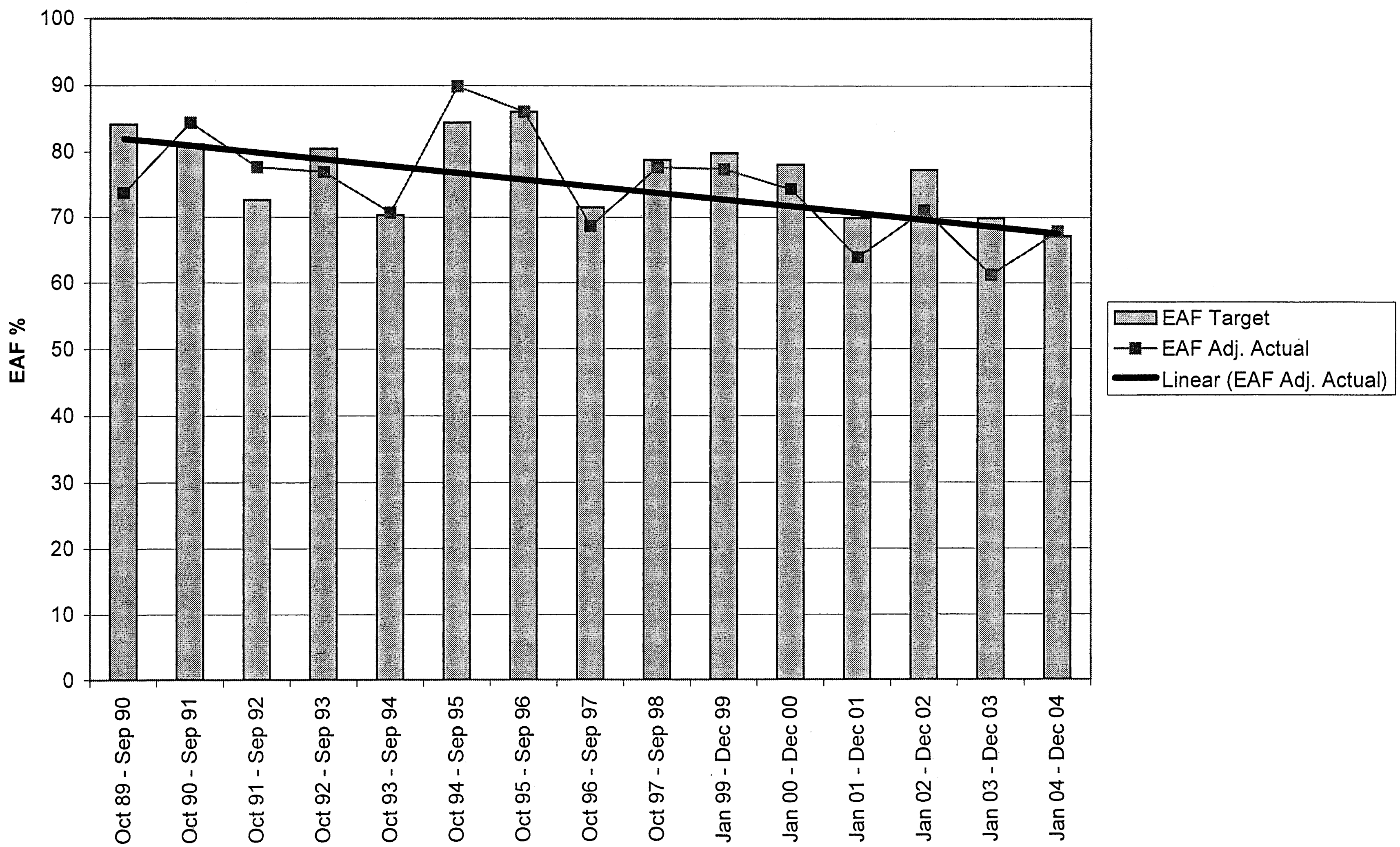


Gannon 6 EAF Analysis
EAF %
0
10
20
30
40
50
60
70
80
90
100
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

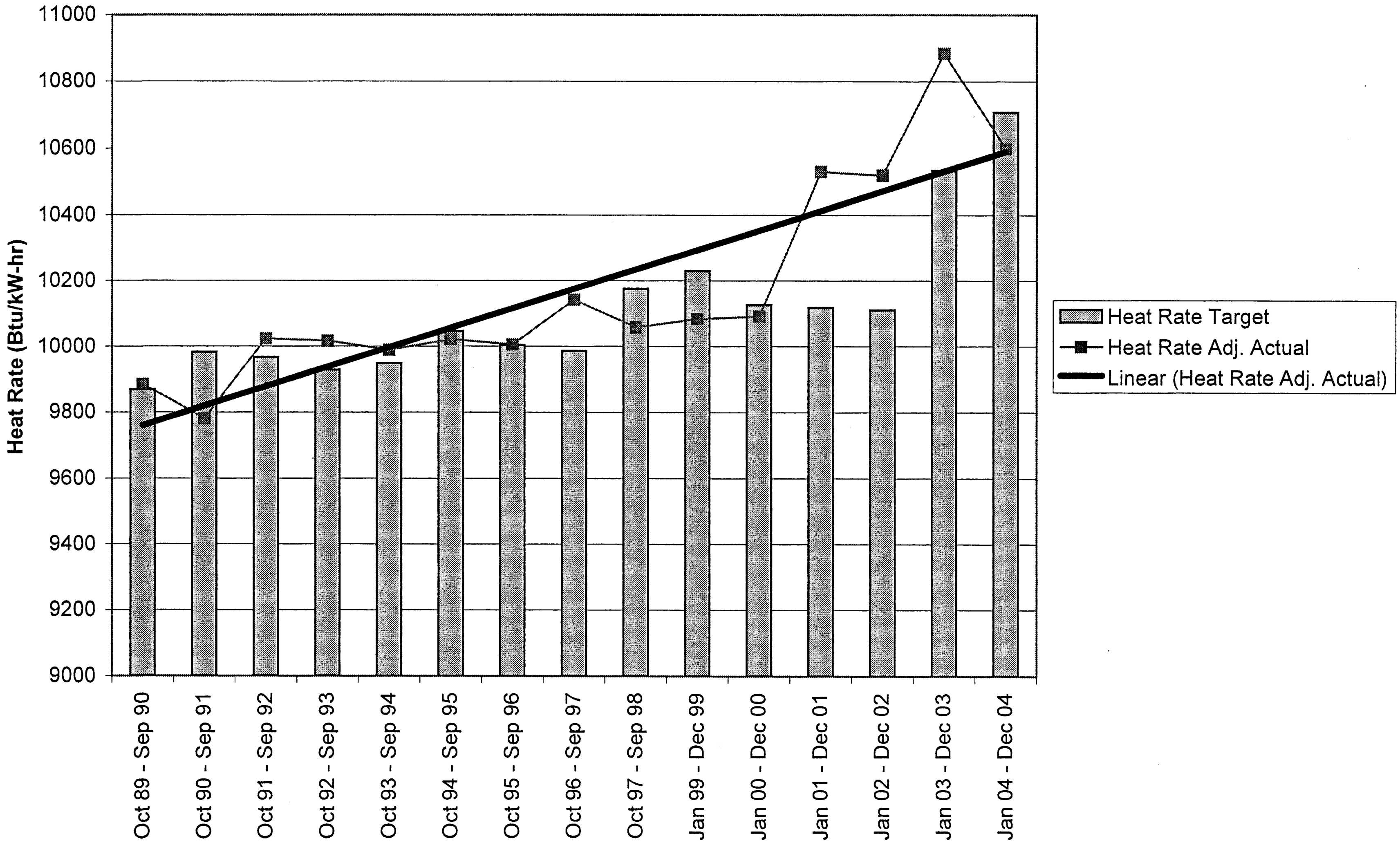
Gannon 6 Heat Rate Analysis

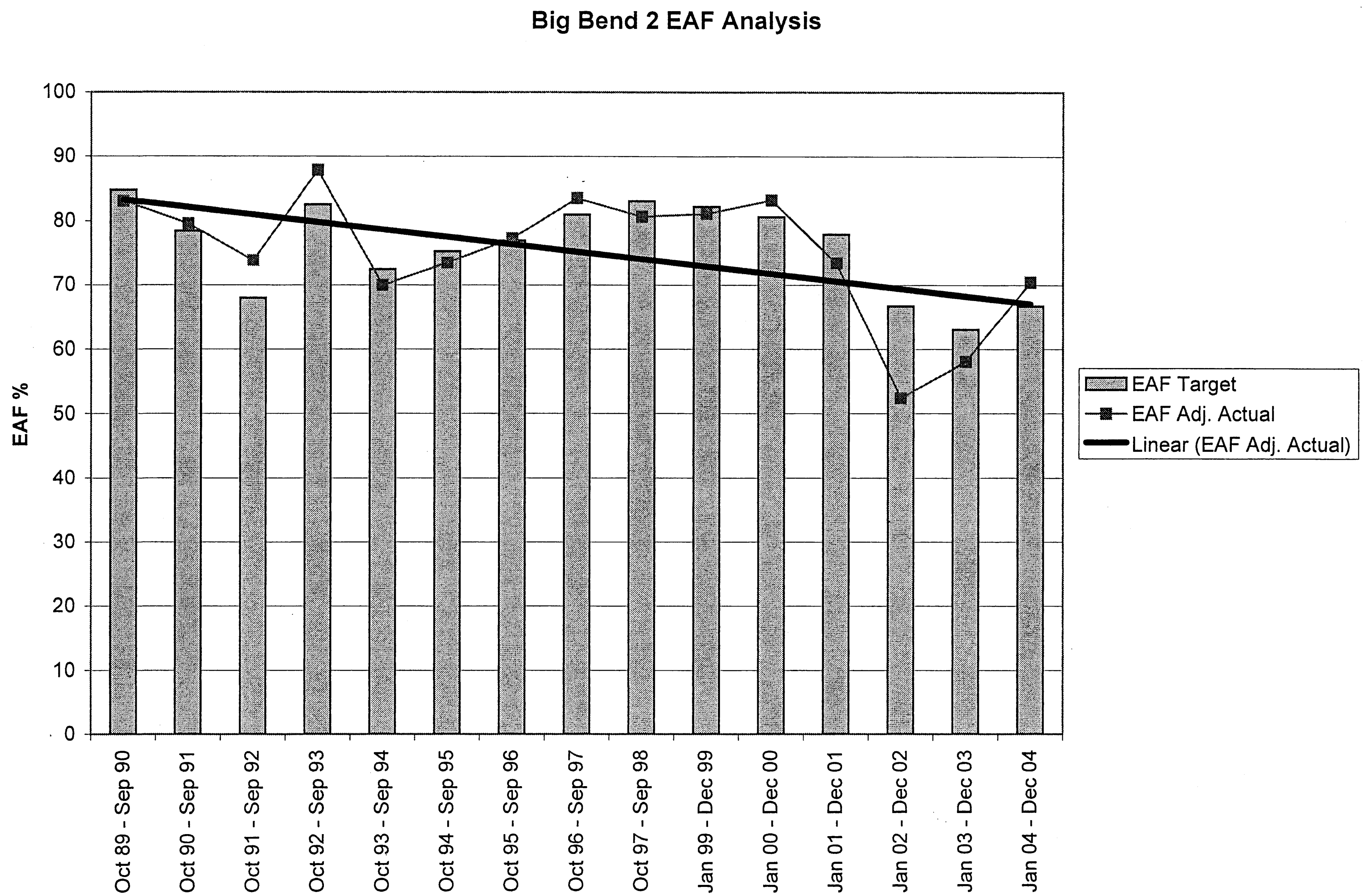


Big Bend 1 EAF Analysis



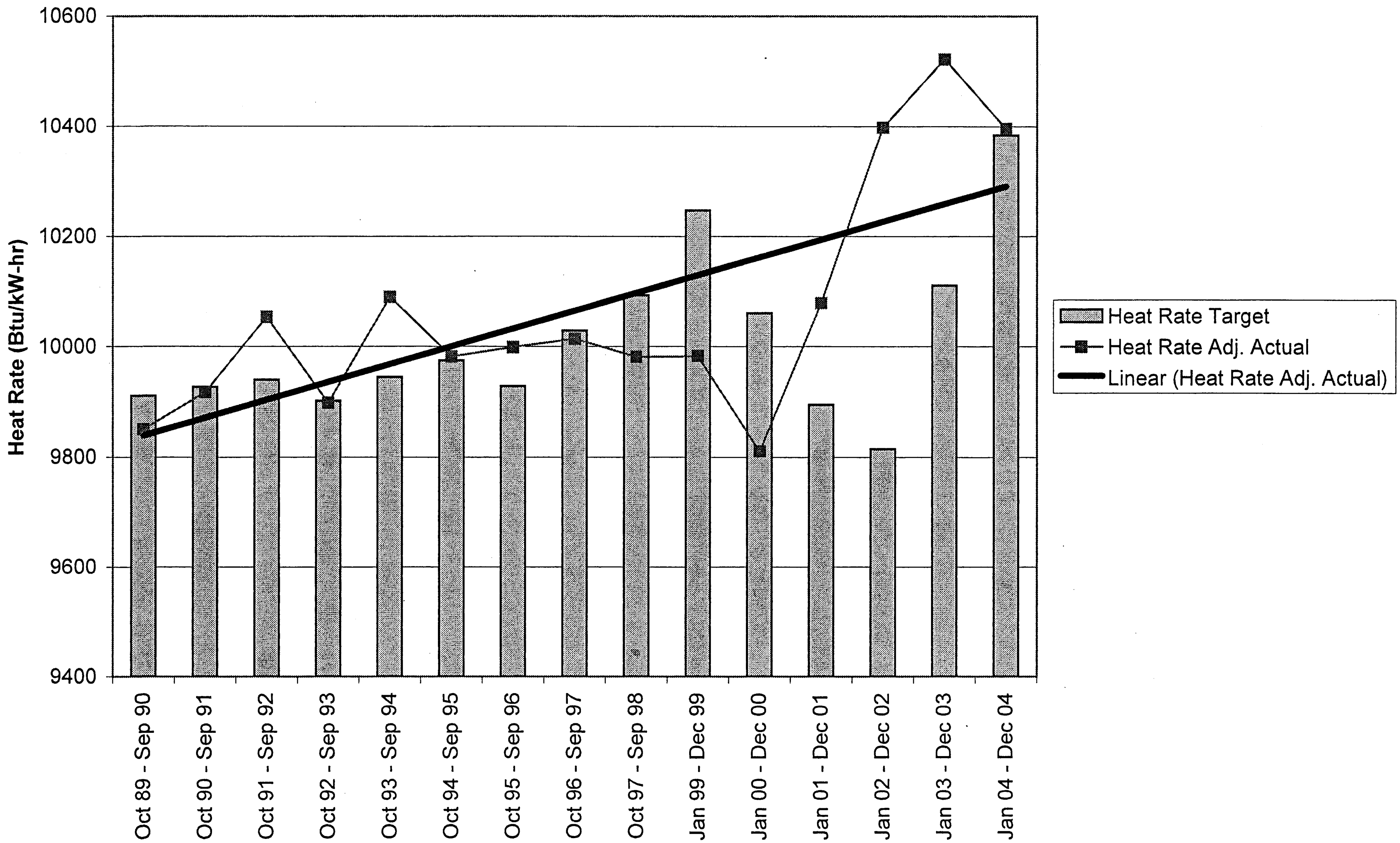
Big Bend 1 Heat Rate Analysis



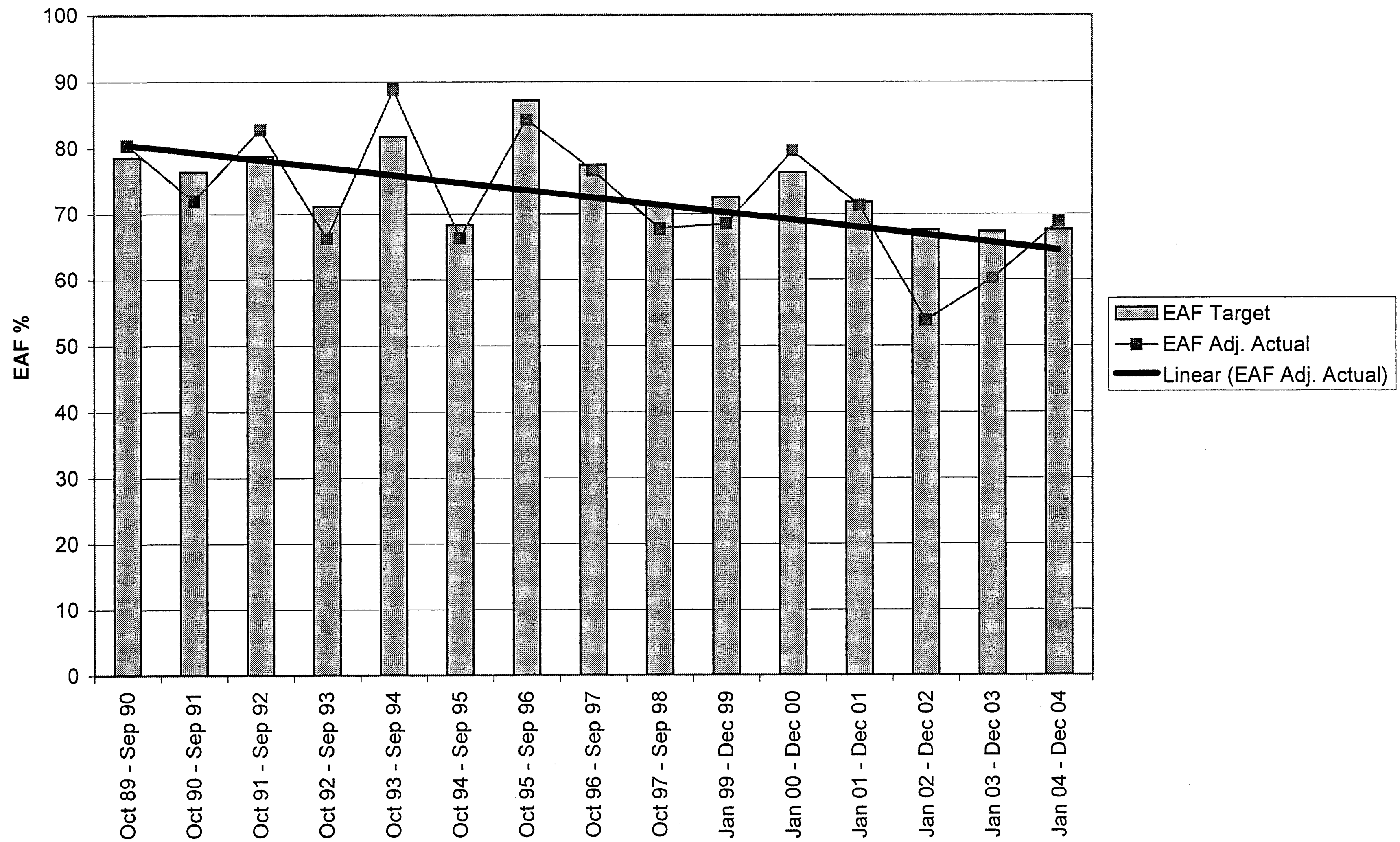


Big Bend 2 EAF Analysis
EAF %
100
90
80
70
60
50
40
30
20
10
0
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

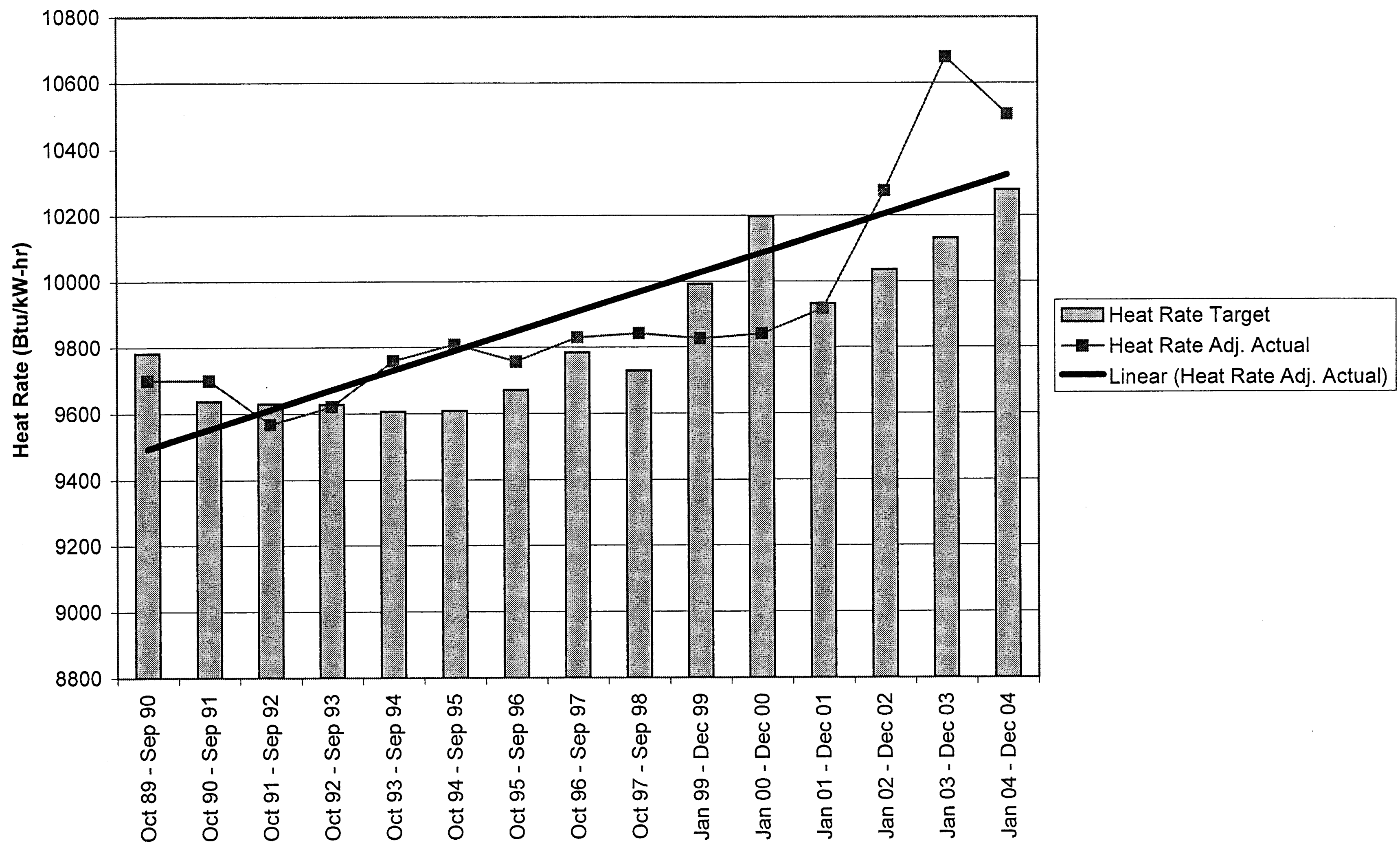
Big Bend 2 Heat Rate Analysis

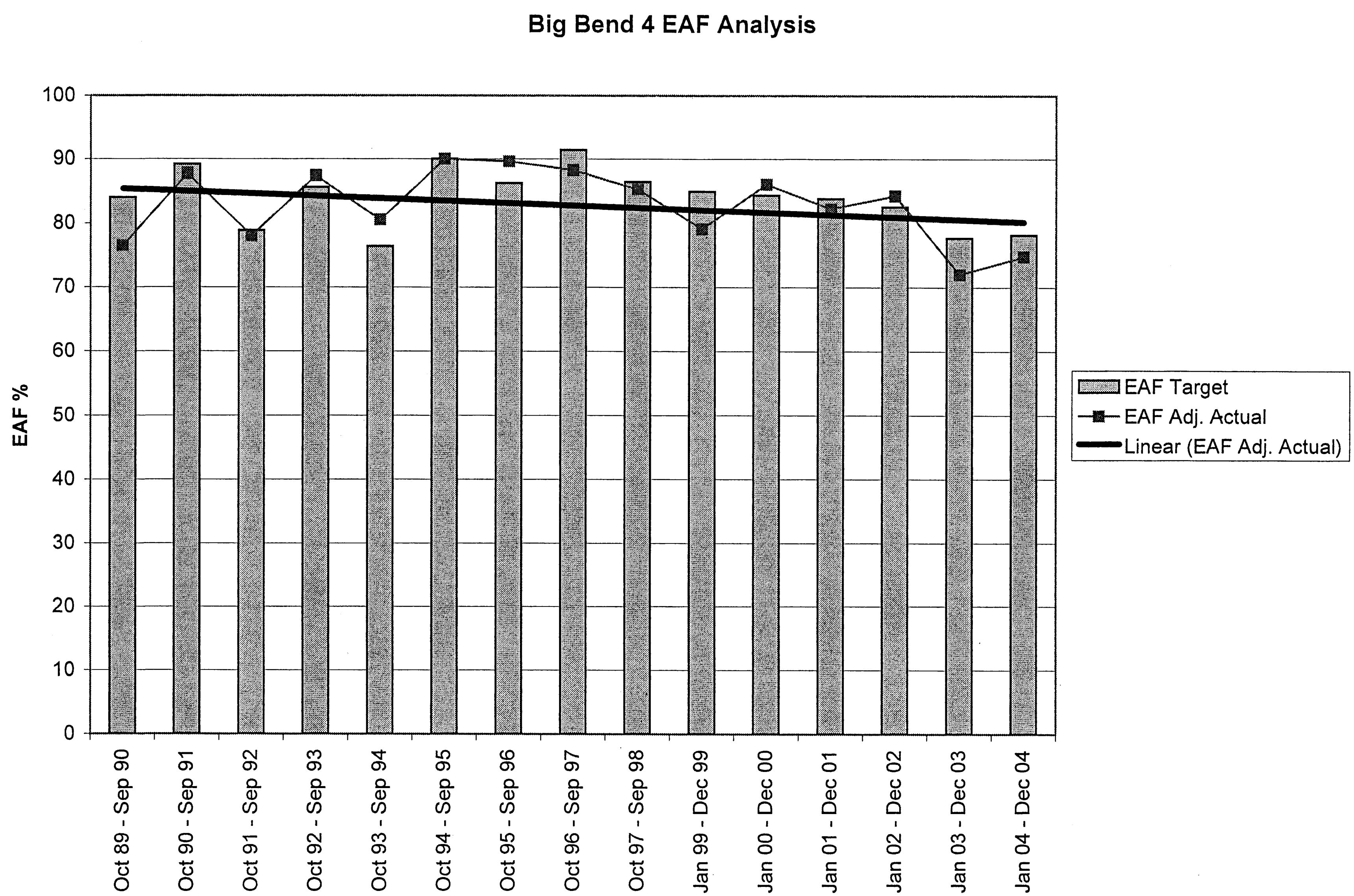


Big Bend 3 EAF Analysis



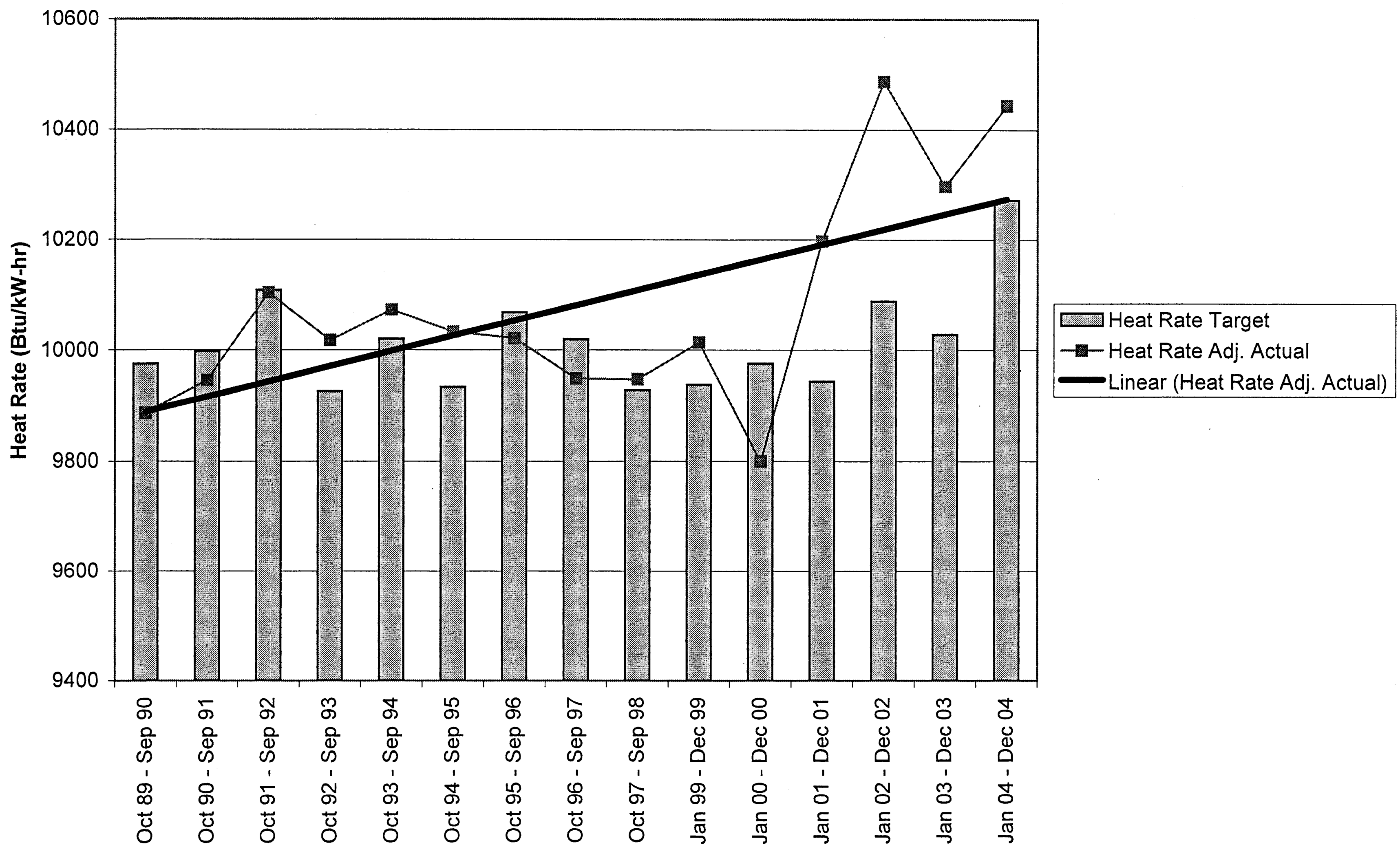
Big Bend 3 Heat Rate Analysis



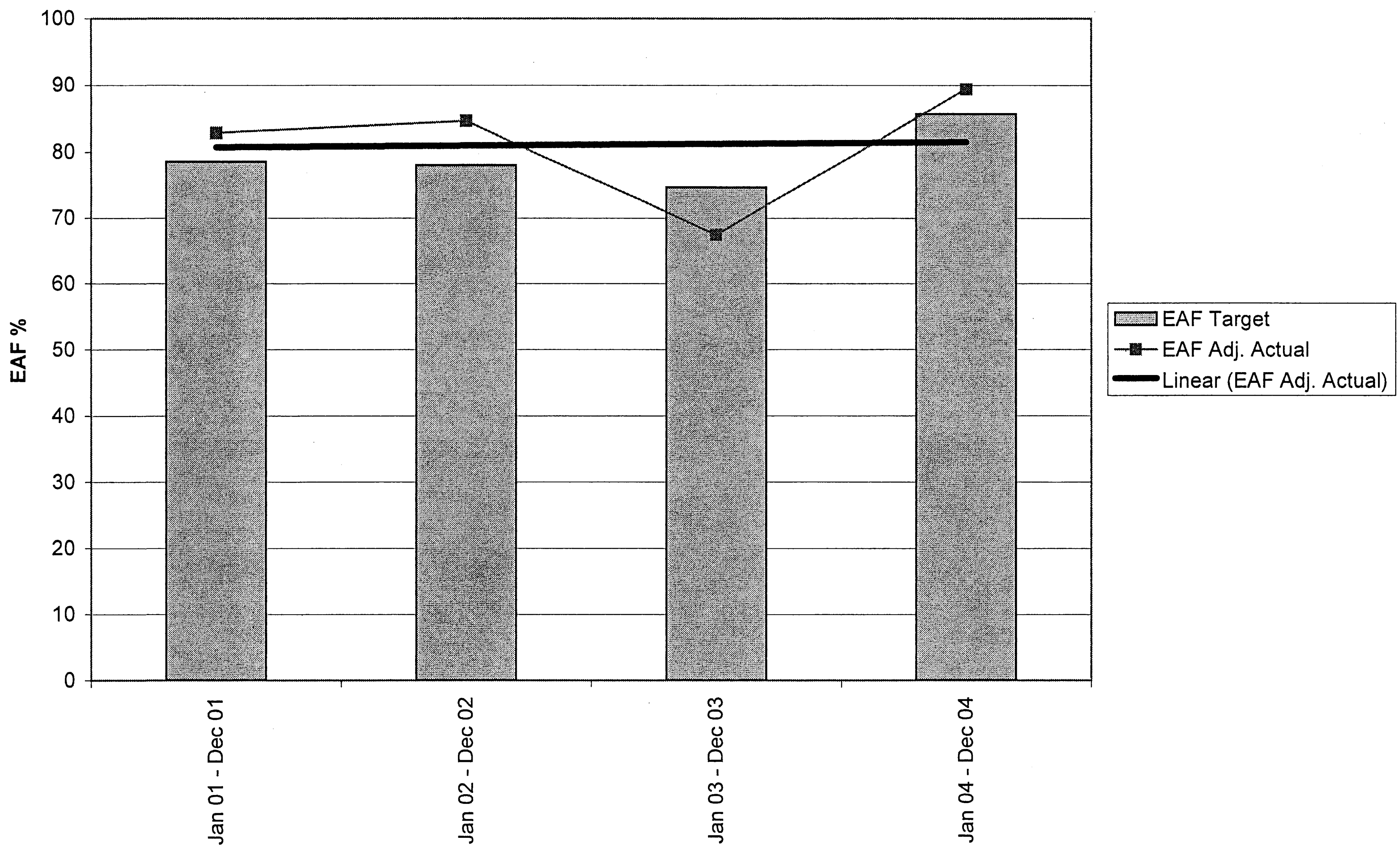


Big Bend 4 EAF Analysis
EAF %
100
90
80
70
60
50
40
30
20
10
0
Oct 89 - Sep 90
Oct 90 - Sep 91
Oct 91 - Sep 92
Oct 92 - Sep 93
Oct 93 - Sep 94
Oct 94 - Sep 95
Oct 95 - Sep 96
Oct 96 - Sep 97
Oct 97 - Sep 98
Jan 99 - Dec 99
Jan 00 - Dec 00
Jan 01 - Dec 01
Jan 02 - Dec 02
Jan 03 - Dec 03
Jan 04 - Dec 04
EAF Target
EAF Adj. Actual
Linear (EAF Adj. Actual)

Big Bend 4 Heat Rate Analysis



Polk 1 EAF Analysis



Polk 1 Heat Rate Analysis