MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

UNIT 1 LNCFS LEVEL 3 AND UNIT 2 BASELINE TEST PROGRAM RESULTS

FINAL REPORT

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TABLE OF CONTENTS

TABLE OF CONTENTS (CONT.)

LIST OF TABLES

LIST OF TABLES (CONT.)

LIST OF FIGURES

LIST OF FIGURES (CONT.)

ABBREVIATIONS

ABB CE	Asea Brown Boveri Combustion Engineering
Btu	British Thermal Units
CCOFA	Close-Coupled Over-Fire Air
CEM	Continuous Emissions Monitor
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EPA	U.S. Environmental Protection Agency
ESA	Energy Systems Associates
ESP	Electrostatic Precipitator
kW	Kilowatts
lb	Pounds
LNCFS	Low-NO_x Concentric Firing System
LOI	Loss-on-Ignition
MM	Million
MW	Megawatts
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides, NO + NO_2
NSPS	New Source Performance Standard
NYSEG	New York State Electric and Gas Corporation
O_2	Oxygen
PA	Primary Air
ppm	Parts Per Million
r^2	Regression Correlation Coefficient
rpm	Revolutions Per Minute
scf	Standard Cubic Feet
SO_2	Sulfur Dioxide
SOFA	Separated Over-Fire Air
tph	Tons Per Hour
UARG	Utility Air Regulatory Group
WDPF	Westinghouse Data Acquisition System

ABSTRACT

The effectiveness of Low-NO_x Concentric Firing System Level 3 (LNCFS-3) burner retrofit to reduce NO_x emissions while maintaining high combustion efficiency and acceptable fly ash loss-on-ignition (LOI) was evaluated in the NYSEG Milliken Units 1 and 2 tangentially-fired boilers, each rated at 150 MW net and burning a high volatile (37%-38% dry), medium sulfur (1.6%-2.0% dry) Pittsburgh Seam coal. The NO_x reduction achieved by Unit 1 LNCFS-3 retrofit was assessed based on Unit 2 baseline measurements. Pre-retrofit data showed relatively small differences in NO_x emissions between the two units.

Four test programs were conducted on each unit: diagnostic, long-term, validation and performance. The diagnostic tests were short term (2-4 hours), assessing the impact of operating variables on NO_x emissions and LOI. The variables included boiler load, excess air, coal air flow, burner tilt and reduced load mill pattern. In LNCFS-3, additional variables were tested, including mill classifier speed and overfire air parameters (flow, tilt and yaw). The long-term (60-70 days) tests estimated the achievable annual NO_x emissions. The validation tests re-assessed the impact of the most significant operating variables following long-term testing. These variables were boiler load, excess air and for LNCFS-3 only, mill classifier speed. The performance tests assessed the overall impact of the low-NO_x burner retrofit on NO_x emissions, fly ash LOI, CO emissions and boiler efficiency.

The achievable annual NO_x emissions, estimated using long-term measurements, were 0.61 lb/MM Btu for Unit 2 baseline and 0.39 lb/MM Btu for Unit 1 LNCFS-3.

Limited success was achieved in reproducing the diagnostic test results during the validation test programs because of the difficulty in reproducing the diagnostic test conditions. For example, control of overfire air during the LNCFS-3 diagnostic tests was limited, producing full boiler load LOI above 4%. The limitations were relaxed during the validation tests, producing 0.7%-1.7% (absolute) lower LOI, with a minor effect on NO_x emissions.

At full boiler load (145-150 MW) and 3.0%-3.5% economizer O_2, the LNCFS-3 burner lowered NO_x emissions from a baseline of 0.64 lb/MM Btu to 0.39 lb/MM Btu (39% reduction). At 80-90 MW boiler load and 4.3%-5.0% economizer O_2, the LNCFS-3 burner lowered NO_x emissions from a baseline of 0.58 lb/MM Btu to 0.41 lb/MM Btu (29% reduction). With the LNCFS-3 burner, fly ash LOI below 4% was maintained, and CO emissions did not increase.

The boiler efficiency was 89.3%-89.6% for baseline and 88.3%-88.5% for LNCFS-3. A lower LNCFS-3 boiler efficiency than baseline was attributed to higher post-retrofit flue gas O_2 and higher stack temperatures which accompanied the air heater retrofit. When LNCFS-3 and baseline were compared at similar flue gas temperatures and compositions, estimated LNCFS-3 boiler efficiency was 0.2% (absolute) higher than baseline.

SUMMARY

Introduction

This report presents the results of Milliken Unit 2 baseline and Unit 1 Low-NO_x Concentric Firing System Level 3 (LNCFS-3) test programs. Four test programs were conducted on each unit, including diagnostic, long-term, validation, and performance evaluation. The diagnostic tests were short-term (2-4 hours) statistically designed parametric tests in which the effects of selected process variables on NO_x emissions and fly ash Loss-on-Ignition (LOI) were evaluated. The long-term tests involved 60-70 days of data collection to estimate the achievable annual NO_x emissions. The validation tests were similar to the diagnostic tests in which the effects of selected variables were re-evaluated following the long-term tests. The performance tests evaluated the impact of the LNCFS-3 burner retrofit on boiler performance.

Milliken Units 1 and 2 are rated at 160 MW gross (150 MW net) each. Pre-retrofit data showed that NO_x emissions differences between the two units were small. Unit 2 baseline test results were used to assess the NO_x emissions reduction achieved by Unit 1 LNCFS-3 retrofit while maintaining high combustion efficiency and acceptable fly ash LOI. The coal used was a high volatile (37%-38% dry volatile matter), medium sulfur (1.6%-2.0% dry sulfur) Pittsburgh Seam coal.

Objective

The objective of this study is to evaluate the effectiveness of the LNCFS-3 burner retrofit to reduce NO_x emissions in the NYSEG Milliken Units 1 and 2 tangentially-fired boilers.

Discussion

The results of the diagnostic (Unit 2 baseline and Unit 1 post-retrofit), long-term, validation, and performance evaluation test programs are discussed below.

<u>Unit 2 Baseline Diagnostic Test Program</u>

The Milliken Unit 2 baseline diagnostic test program, conducted during December 6-15, 1993, evaluated the effects of boiler load, excess O_2, coal air flow, burner tilt, and reduced load mill patterns on NO_x emissions and LOI. The following conclusions were reached:

1. Both NO_x and LOI results showed good reproducibility. Uncertainties at 95% confidence were ± 0.016 lb NO_x/MM Btu and ± 0.30% LOI. NO_2 was not measured, and reported NO_x measurements were the sum of both NO and NO_2.

2. Changing fuel air damper position had a significant effect on LOI and a minor effect on NO_x emissions. Increasing fuel air damper position from 2 to 4 increased LOI by 0.5%. The minimum and maximum fuel air damper positions were 1 and 5, respectively.

3. Variation in burner tilt affected NO_x emissions, but not LOI. Changing burner tilt from ± 15° to 0° increased NO_x emissions 0.04 lb/MM Btu.

4. At reduced boiler loads (110 MW and lower), taking the top burner elevation out of service reduced NO_x emissions, but made it difficult to maintain steam temperatures.

5. Higher excess O_2 levels (measured at economizer outlet) increased NO_x emissions and reduced LOI. The results showed that the impact of excess air on NO_x emissions was reduced at lower boiler loads.

6. Higher boiler loads increased NO_x emissions and reduced LOI at the same excess O_2 level.

7. Lower NO_x emissions corresponded to higher LOI. Predictive correlations for NO_x emissions and LOI were derived:

   $$\text{lb } NO_x/\text{MM Btu} = 0.34 - 0.036*O2 + 0.0009*MW*O2 - 0.00017*(TILT)^2 \qquad r^2=91\%$$

   $$\% \text{ LOI} = - 1.2 + 9.4/O2 + 0.25*AIR - 0.024*(MW-140) \qquad r^2=84\%$$

   where O2 is excess O_2 measured at the economizer outlet, MW is boiler load in MW net, TILT is burner tilt in degrees, and AIR is coal air damper position.

8. The short-term, baseline tests indicated that NO_x emissions could be reduced to about 0.54 lb/MM Btu at 140 MW, while maintaining salable fly ash.

Unit 1 Post-Retrofit Diagnostic Test Program

The Milliken Unit 1 post-retrofit diagnostic test program, conducted during March 22-31, 1994, evaluated the effects of boiler load, excess O_2, mill classifier speed, combustion air distribution (SOFA flow, CCOFA flow and coal air flow), burner settings (burner tilt, SOFA tilt and SOFA yaw), and mill patterns on NO_x emissions and LOI. The following conclusions were reached:

1. The post-retrofit tests had a greater level of uncertainty in NO_x emissions and about the same level of uncertainty in LOI, compared to the baseline tests. Uncertainties at 95% confidence were ± 0.027 lb NO_x/MM Btu and ± 0.35% LOI.

2. Gas stratification across the two ducts at the economizer outlet was minor.

3. NO_2 concentrations measured at the economizer outlet were 1-2 ppm.

4. CO variation was not considered in this study because of the low concentrations measured at the economizer outlet (9-23 ppm).

5. Increasing burner tilt below the horizontal position (0°) was estimated to reduce NO_x emissions by 0.007 lb/MM Btu and to reduce LOI by 0.16% per degree change at full boiler load. The impact of burner tilt on main steam temperature limited changes in the burner tilt.

6. Changes in SOFA tilt produced no significant changes in either NO_x emissions or LOI. SOFA yaw changes (relative to the fuel firing angle) did not significantly change NO_x emissions, and increased LOI. The effect on LOI could not be determined with certainty because SOFA yaw changes were accompanied by changes in burner tilt, and the two effects could not be separated. No significant changes in steam temperatures were detected.

7. Greater air staging (air flow through SOFA and CCOFA ports) reduced NO_x emissions and increased LOI. Changes in SOFA damper position had a greater effect on NO_x emissions than changes in CCOFA damper position. The effect on LOI was not statistically significant when the effects of other parameters, such as burner tilt, were accounted for.

8. Taking the upper elevation burners out of service reduced both NO_x emissions and LOI, but the effect was greater on NO_x emissions.

9. Higher excess O_2 increased NO_x emissions and reduced LOI.

10. In general, higher boiler loads increased both NO_x emissions and LOI.

11. Higher mill classifier speeds reduced both NO_x emissions and LOI, but the effect on LOI was more dramatic.

12. The post-retrofit relationship between NO_x and LOI was more complex than the pre-retrofit relationship because of greater sensitivity of the low-NO_x configuration to process variables and coal properties. Fluctuations in coal ash and/or moisture contents had a dramatic effect on LOI and a minor effect on NO_x emissions.

13. Predictive correlations for NO_x emissions and LOI were derived:

$$\text{lb } NO_x/\text{MM Btu} = 0.12 + 0.08*02 + 0.00003*(MW-120)^2 - 0.00093*(RPM-93) + 0.007*TILT \qquad r^2=84\%$$

$$\%\ LOI = 8.1 - 1.08*02 + 0.032*(MW-120) - 0.062*(RPM-93) + 0.155*TILT \qquad r^2=69\%$$

where 02 is excess O_2 measured at the economizer outlet, MW is net MW boiler load, TILT is burner tilt in degrees from the horizontal, and RPM is mill classifier speed.

14. The short-term, post-retrofit LNCFS-3 test program indicated that NO_x emissions could potentially be reduced to about 0.35 lb/MM Btu

at full boiler load, while maintaining salable fly ash.

15. The low-NO_x burner retrofit reduced NO_x emissions from a baseline level of 0.64 lb/MM Btu to a post-retrofit level of 0.39 lb/MM Btu, corresponding to a reduction of about 39%, while maintaining LOI below 4%. The NO_x values were based on short-term test averages and will be verified during the 51-day long-term test. NYSEG believes LNCFS-3 burner retrofit is a cost-effective technology to comply with Title IV of the 1990 Clean Air Act Amendments. To date, burner operations are acceptable.

Long-Term Test Program

The achievable annual NO_x emissions were estimated using long-term (60-70 days) CEM measurements. Specifically:

1. The achievable annual NO_x emissions for Unit 2 baseline were 0.614 lb/MM Btu, with a 95% confidence level of ± 0.023 lb/MM Btu.

2. The achievable annual NO_x emissions for Unit 1 LNCFS-3 were 0.390 lb/MM Btu, with a 95% confidence level of ± 0.003 lb/MM Btu.

Validation Test Program

The validation test programs were conducted after the completion of the long-term tests. The purpose of validation tests was to re-evaluate the effects of selected operating parameters on NO_x emissions and LOI and to verify the diagnostic test results. The validation test results were compared to predictions based on the correlations derived from the diagnostic test results. The test parameters for Unit 2 baseline were economizer O_2 and boiler load. The test parameters for Unit 1 LNCFS-3 were economizer O_2, coal fineness and boiler load. The following conclusions were reached:

1. For Unit 2 baseline, satisfactory predictions were obtained for both NO_x emissions and LOI at full boiler load (140-150 MW), but not at reduced boiler loads. Full boiler load differences between measurements and predictions were less than 0.03 lb NO_x/MM Btu and less than 0.3% (absolute) LOI. The larger differences in reduced boiler load test results were caused by differences in mill operations.

2. For Unit 1 LNCFS-3, satisfactory predictions were obtained for NO_x emissions at full boiler load (145-150 MW). However, predictions for NO_x emissions at reduced boiler loads and all predictions for LOI (full and reduced boiler loads) were not satisfactory. At full boiler load, differences between measured and predicted NO_x emissions were less than 0.036 lb/MM Btu, and measured LOI was consistently lower (0.7%-1.7% absolute) than predicted. Full boiler load differences between measurements and predictions are explained as follows. The diagnostic test conditions produced full boiler load LOI above 4% and were not repeated during the validation test program. The modified operations had a minor effect on NO_x

emissions and a significant effect on LOI. LOI correlations should be adjusted to account for this difference.

Performance Evaluation

The LNCFS-3 performance evaluation included the impact of the LNCFS-3 system on NO_x emissions, boiler efficiency, fly ash LOI and CO emissions. Specifically:

1. At full boiler load (145-150 MW) and 3.0%-3.5% economizer O_2, the LNCFS-3 system lowered NO_x emissions from a baseline 0.64 lb/MM Btu to 0.39 lb/MM Btu (39% reduction). At 80-90 MW boiler load and 4.3%-5.0% economizer O_2, the LNCFS-3 system lowered NO_x emissions from a baseline of 0.58 lb/MM Btu to 0.41 lb/MM Btu (29% reduction).

2. The boiler efficiency was 89.3%-89.6% for baseline and 88.3%-88.5% for the LNCFS-3 system. The LNCFS-3 boiler efficiency was lower than baseline because of higher post-retrofit flue gas O_2 levels and higher stack temperatures which accompanied the air heater retrofit. When the LNCFS-3 system and the baseline were compared at similar flue gas temperatures and compositions, the estimated LNCFS-3 boiler efficiency was 0.2% (absolute) higher than baseline.

3. With the LNCFS-3 system, fly ash LOI below 4% was maintained, and CO emissions did not increase.

SECTION ONE
INTRODUCTION

1.1 Objectives

The Unit 2 baseline and Unit 1 post-retrofit diagnostic tests were conducted as part of the Low-NO_x Concentric Firing System Level 3 (LNCFS-3) evaluation program of the NYSEG Milliken Clean Coal Technology IV Demonstration Project. The overall objective of the LNCFS-3 evaluation program is to demonstrate the effectiveness of the low-NO_x burner retrofit in reducing NO_x emissions in the NYSEG Milliken Units 1 and 2 tangentially-fired boilers, each rated at 160 MW gross. Specifically, the twofold objectives of the diagnostic tests are:

1. **Determine the Effect of Operating Parameters on NO_x and Loss-on-Ignition (LOI):** The parameters for the baseline tests included boiler load, excess O_2 measured at the economizer outlet, coal air damper position, burner tilt, and reduced load mill patterns. The parameters for the LNCFS-3 tests included boiler load, excess O_2 measured at the economizer outlet, mill classifier speed as a measure of coal fineness, combustion air distribution (SOFA flow, CCOFA flow and coal air flow), burner settings (burner tilt, SOFA tilt and SOFA yaw), and mill patterns.

2. **Establish Operating Conditions for Long-Term Testing:** Long-term test results will be used to determine the achievable annual NO_x emissions and to assess the performance of the retrofit LNCFS-3 burners for Units 1 and 2, using Unit 2 test results as a baseline.

1.2 Background

The Milliken pre-retrofit Unit 2 and post-retrofit Unit 1 are described in Table 1.1.

TABLE 1.1 - MILLIKEN PRE-RETROFIT UNIT 2 AND POST-RETROFIT UNIT 1 DESCRIPTION

		Pre-Retrofit Unit 2	Post-Retrofit Unit 1
Mills	**- Type**	CE RB613	Riley Stoker MPS150
	- Quantity	4	4
	- Performance	33,500 lb/h at 57 HGI Coal	36,800 lb/h at 57 HGI Coal
Classifiers	**- Type**	Static	Dynamic, Riley Stoker SLS
	- Quantity	4	4
	- Performance	70% -200 Mesh	93% -200 Mesh
PA Fans	**- Type**	None, Exhausters With Mills	Centrifuged Design, Buffalo Forge
	- Quantity	--	4
	- Performance	--	65,000 lb/h Hot Air
Feeders	**- Type**	Volumetric, Variable Stroke Drive	Gravimetric, Stock Equipment
	- Quantity	4	4
	- Performance	Normal Feed at High Load	20 tons/h
Burners	**- Type**	CE TV Type, Vertical Adjustable	ABB CE LNCFS-3

The LNCFS-3 configuration is expected to reduce NO_x emissions from pre-retrofit levels of 0.56-0.60 lb/MM Btu (at full boiler load and 3%-4% excess O_2) to a design goal of 0.37 lb/MM Btu, while maintaining LOI below the 4% limit required to market the fly ash. The burner retrofit was implemented on Unit 1 during the summer of 1993 and the retrofit on Unit 2 is in progress. The Unit 1 retrofit was accompanied by an upgrade of the ESP and the installation of new coal mills. Two additional burner modifications were required to reduce problems caused by flame attachment to the nozzles. NO_x emissions guarantees were met in January of 1994.

1.2.1 Comparison of Milliken Units 1 and 2 NO_x Emissions

The original plan was to conduct baseline and post-retrofit testing on the same unit. However, there was not sufficient time to conduct Unit 1 baseline testing prior to its retrofit. Consequently, the option of conducting baseline testing on Unit 2 and post-retrofit testing on Unit 1 to evaluate the effectiveness of the low-NO_x burner retrofit was examined. Unit 2 retrofit was scheduled approximately one year after that of Unit 1. A comparison of Units 1 and 2 NO_x emissions was conducted using data from short-term tests (1-3 hours) and long-term measurements (60 days).

Short-term NO_x emissions data were obtained from 1-3 hour tests performed on Unit 1 during August of 1991 and on Unit 2 during December of 1991. The tests were conducted by Performance Testing Services of ABB CE to determine pre-retrofit NO_x levels and to estimate the potential of LNCFS-3 retrofit in reducing NO_x emissions. At 3.5% excess O_2 measured at the economizer outlet, NO_x emissions were estimated at 0.57-0.60 lb/MM Btu at full load (150 MW net generation) and 0.41-0.44 lb/MM Btu at half load. Differences in NO_x emissions between the two units were estimated at less than 0.03 lb/MM Btu. These differences were small relative to variations in NO_x emissions due to changes in excess air, boiler load and burner tilt. However, the interpretations of the short-term tests were limited because of the short duration of the tests (1-3 hours each) and the small number of tests (17 tests), and required verification using long-term data.

Comparison of NO_x emissions from Milliken Units 1 and 2 was also performed using 60 days of continuous emissions monitoring (CEM) and boiler load data. The data were collected during August and September of 1992. NO_x emissions for both units were between 0.64 and 0.68 lb/MM Btu at an average boiler load of 133 MW and 3.5%-4.5% excess O_2 measured at the economizer outlet. The average difference between the two units 30-day rolling averages was 0.024 lb NO_x/MM Btu, with uncertainty of ±0.005 lb NO_x/MM Btu at 95% confidence. Differences in NO_x emissions between the two units were again shown to be less than 0.03 lb/MM Btu, in agreement with the analysis of short-term tests. Consequently, conducting baseline NO_x emissions testing on Unit 2 for comparison with post LNCFS-3 retrofit testing on Unit 1 was an acceptable option.

The diagnostic tests were statistically designed parametric tests in which the effects of selected process variables on NO_x emissions and LOI were evaluated.

1.3 Unit 1 Baseline and Unit 2 Post-Retrofit Diagnostic Tests

Unit 1 baseline and Unit 2 post-retrofit diagnostic tests were designed to provide short-term, parametric data to determine the effects of several boiler operating variables on NO_x emissions and LOI. The results of these two test programs are discussed in Sections 2 and 3, respectively. A discussion of the LNCFS-3 system start-up, installation costs and fuel duct balancing tests is presented in Section 4.

1.4 Long-Term, Validation and Performance Testing

Long-term testing was conducted following the completion of the diagnostic test programs and involved 60-70 days of data collection to estimate the achievable annual NO_x emissions. The validation tests were similar to the diagnostic tests and re-evaluated the effects of selected process variables following the completion of long-term testing. The performance evaluation tests evaluated the impact of the LNCFS-3 burner retrofit on boiler performance, including NO_x and CO emissions, fly ash LOI and boiler efficiency. The results of these test programs are discussed in Section 5.

SECTION TWO
UNIT 2 BASELINE DIAGNOSTIC TESTS

2.1 Experimental Design

Statistically designed baseline diagnostic tests were conducted to examine the effects of boiler load, excess O_2, fuel air flow, burner tilt, and reduced-load mill pattern on NO_x emissions and LOI. The experimental parameter settings are listed in Table 2.1. A high setting of 5% excess O_2 at the economizer outlet was possible at boiler loads of 110 MW and 80 MW, but not at 140 MW because of limited fan capacity and a high value of 4% excess O_2 was used instead.

Each Milliken unit has four elevations of burners, with one coal mill per elevation. Full boiler load required all burners to be in service. Therefore, only the mill pattern with all four mills in service was tested at full load. Alternate mill patterns could be tested at reduced loads, as described in Table 2.1. At intermediate boiler load (110 MW) with three mills in service, four patterns were possible, of which two were tested. At low boiler load (80 MW) with two mills in service, six patterns were possible, of which two were tested. Mill patterns were classified as normal (normal operation at Milliken) when the burners at the lowest elevations were either taken out of service or the coal flow was minimized. Alternate mill patterns were tested in which the burners at the highest elevations were either taken out of service or the coal flow was minimized. Alternate mill patterns were tested for comparison with normal mill patterns, and might not necessarily constitute satisfactory boiler operating conditions.

The baseline test design consisted of three experimental blocks, as seen in Table 2.2. Tests marked by asterisks were replicated to allow independent estimates of the experimental error, and some tests were common to more than one block. The three experimental designs were:

1. Design A, Full Boiler Load Tests: These tests were conducted at 140 MW to examine the effects of three independent variables: excess O_2 measured at the economizer outlet, fuel air damper position and burner tilt. The design consisted of a two-level factorial (Tests 1-8) to estimate linear effects, and additional tests to estimate quadratic effects (Tests 9-15). The entire set is known as a Central Composite Design.

2. Design B, Mill Pattern Tests: This set consisted of four tests to compare different mill patterns at reduced boiler loads (Table 2.1).

3. Design C, Variable Boiler Load Tests: This design consisted of 15 tests, corresponding to a full three-level factorial with respect to variations in boiler load and excess O_2 measured at the economizer outlet.

2.2 Experimental Plan

The baseline diagnostic tests were conducted on Unit 2 between December 6 and 15 of 1993. A total of 30 tests were conducted, each typically 3-4 hours long. A description of the tests is presented in Table 2.3. All reduced boiler load tests were conducted between December 6 and 11. A primary consideration was given to maintaining reliable boiler operation and power generation. Thus, when a set of conditions could not maintain the required steam conditions, the test was terminated as soon as sufficient data were collected.

2.2.1 Measurements

The plant O_2 probe was used to monitor excess O_2 concentrations at the economizer outlet. The plant CEM system was used to measure CO_2, NO_x and SO_2 concentrations at the stack. The system included a non-dispersive infrared CO_2 analyzer, a chemiluminescent NO_x analyzer, and a pulsed fluorescent SO_2 analyzer. A low flow dilution probe was used and no additional conditioning was required. The CEM system passed the Relative Accuracy Test, and was calibrated daily.

Typically, 1.5-2 hours of stack CEM data (collected as 15-minute averages) at steady state conditions were averaged for each test. Steady state behavior was assumed when small changes in NO_x measurements occurred with time (less than 3 ppm change in the hourly average), and typically occurred within 1-2 hours after test conditions were set.

Fly ash was sampled from the ash transport pipe for 30-60 minutes during sequential unloading of the ash from the hoppers to the silo. The sampled ash was subsequently mixed and 4-8 ounces were extracted for moisture, carbon and ash analyses. Daily coal samples were collected and analyzed for moisture, proximate and ultimate compositions, and heating value. The coal and ash analyses are presented in Table 2.4.

2.3 Results and Discussion

A total of 30 baseline tests were conducted, including 7 replicates. Test results are presented in Table 2.5. CO concentrations measured at the economizer outlet were 0-13 ppm for all the tests. Variation in CO was not a consideration in this study.

NO_x emissions in lb/MM Btu were calculated according to EPA Method 19 (40 CFR 60 Appendix A, 1993) using measured NO_x and CO_2 stack compositions, and calculated EPA F_c factors as:

$$\text{lb } NO_x/\text{MM Btu} = 1.194\times10^{-7} \text{ lb } NO_x/\text{scf}_{\text{flue gas}} * \text{ppm } NO_x * F_c * 100/\%CO_2.$$

Where F_c is scf CO_2 per MM Btu, calculated as:

$$F_c = 0.321\times10^{6} * \%C_{coal} \;/\; (\text{Btu/lb})_{coal}.$$

The EPA tabulated F_c value for bituminous coal is 1800. The calculated values used in this study varied between 1780 and 1816 (Table 2.5).

LOI was defined as the percentage of combustibles in the fly ash, calculated as:

$LOI = 100 - \% \; Ash_{fly\ ash,\ dry}$.

2.3.1 Experimental Error

Seven replicated tests were used to estimate the standard deviation of the experimental error (σ_{error}) and the uncertainty in measurement (confidence level), for both NO_x emissions and LOI, as seen in Table 2.6. Calculated σ_{error} values for NO_x and LOI were 0.024 lb/MM Btu and 0.44%, respectively. The uncertainty in measurement is $\pm\ t^*\sigma/\sqrt{N}$, where **N** is the number of replicated tests, and t is a tabulated statistical parameter depending on the degrees of freedom and the desired confidence level. For 7 degrees of freedom and 95% confidence (t = 2.365), the confidence intervals were $NO_x \pm 0.016$ lb/MM Btu and LOI ± 0.30%. Differences between replicated tests for NO_x emissions and LOI averaged 0.024 lb/MM Btu and 0.62%, respectively.

2.3.2 Experimental Results

Replicated results were averaged and the data matrix is presented in Table 2.7. Analysis of the data focussed on variations in NO_x emissions and LOI with respect to changes in the independent variables, namely, boiler load, excess O_2, fuel air flow, and burner tilt (Designs A and C). The effect of mill pattern on NO_x emissions and LOI at reduced loads (110 MW and 80 MW) was also examined (Design B).

Analysis of the test matrix showed that for Designs A and C, there was a strong correlation between NO_x emissions and LOI, and as expected, an inverse relationship was shown (negative correlation coefficient). For Design A, O_2 exhibited strong correlations with both NO_x and LOI. For Design C, boiler load/O_2 interaction factor (MW^*O_2) exhibited strong correlations with both NO_x emissions and LOI.

2.3.3 Effects of Fuel Air Flow and Burner Tilt

The tests of Design A (Table 2.7) examined the effects of fuel air flow and burner tilt on NO_x emissions and LOI at 140 MW boiler load. Excess O_2 was also a variable in this design, but its effect is discussed in more detail in the analysis of Design C where greater variability of excess O_2 was possible.

Regression analyses were used to identify the statistically significant factors affecting NO_x emissions and LOI, starting with a complete quadratic model with respect to the three variables of Design A (fuel air flow, burner tilt and excess O_2). The final correlations for Design A are shown in Table 2.8. AIR is fuel air damper position, TILT is burner tilt in degrees and O2 is excess O_2 measured at the economizer outlet. NO_x variation was directly proportional to linear changes in O_2 (O2), and to quadratic changes in burner tilt (TILT*TILT). LOI variation was directly proportional to both linear and quadratic changes in excess O_2 (O2 and O2*O2), and to linear changes in fuel air damper position (AIR). As discussed later in the derivation of predictive correlations, LOI was correlated with the inverse O_2 factor (1/O2) instead of two quadratic excess O_2 factors (O2 and O2*O2).

Variations in NO_x emissions and LOI with fuel air flow and burner tilt at 3% excess O_2 are shown in Figures 2.1 and 2.2, respectively. Figure 2.1 shows that an increase in fuel air damper position (more air flow) reduced NO_x emissions and increased LOI, but the effect was more significant for LOI. Figure 2.2 shows that changes in burner tilt had a quadratic effect on NO_x emissions and almost no effect on LOI. The highest NO_x emissions were observed at an angle close to zero (horizontal position). These observations are consistent with regression results.

2.3.4 Effects of Mill Pattern

Figure 2.3 is a graphical presentation of Design B (Table 2.7) test results in which two mill patterns at reduced boiler loads (80 MW and 110 MW) were compared at 4% excess O_2, fuel air damper position at 3, and burner tilt at 0. Mill patterns, in which the highest elevation burners were taken out of service, produced lower NO_x emissions than patterns in which the lowest elevation burners were taken out of service (normal operation at Milliken). This can be attributed to air staging effects in which partial combustion occurs when the lower elevation burners are in service, and combustion is completed as air is added at the higher elevations with the burners out of service (zero or minimum coal flow). At 80 MW boiler load, the operators had difficulty maintaining steam temperatures when the highest elevation burners were taken out of service. In general, mill patterns that reduced NO_x emissions increased LOI. However, the effect on LOI can only be viewed qualitatively because of the small number of tests and the uncertainty in LOI measurement.

2.3.5 Effects of Boiler Load and Excess O_2

The tests of Design C (Table 2.7) examined the effects of boiler load and excess O_2 on NO_x emissions and LOI. Fuel air damper position was set at 3, and the burners were in the horizontal position.

Regression analyses were used to identify the statistically significant factors affecting NO_x emissions and LOI, starting with a complete quadratic model with respect to the two variables of Design C (boiler load and excess O_2). The final correlations for Design C are shown in Table 2.8. MW is boiler load and O2 is excess O_2 measured at the economizer outlet. NO_x emissions variation was directly proportional to linear changes in O_2 (O2), and to the interaction term between O_2 and boiler load (MW*O2). LOI variation was directly proportional to the interaction term between O_2 and boiler load (MW*O2). Again, in the derivation of a predictive correlation, LOI correlation MW*O2 was replaced by a simpler correlation with MW and 1/O2.

The effects of excess O_2 (measured at the economizer outlet) on NO_x emissions and LOI at the three tested boiler loads are shown in Figure 2.4. The same data are presented again in Figure 2.5, with respect to variations in boiler load at three excess O_2 levels. As expected, NO_x emissions increased and LOI decreased with increasing excess O_2 levels which corresponded to higher excess air levels. The impact of excess air on NO_x emissions was reduced at lower boiler loads. Higher boiler loads increased NO_x emissions and reduced LOI, most likely due to higher temperatures and improved fuel/air mixing in the firebox.

2.3.6 Variations of NO_x Emissions and LOI

Variations in NO_x emissions and LOI with excess O_2 at 140 MW boiler load are shown in Figure 2.6. Excess O_2 was the most significant parameter affecting both NO_x emissions and LOI. The scatter of the data points was in part due to experimental variation and in part due to the effects of variables of secondary importance, including fuel air flow and burner tilt. The relationship between LOI and NO_x emissions is shown in Figure 2.7, and is approximated by the following linear relationship:

$$LOI = 11 - 14 * NO_x.$$

Where LOI is in % and NO_x is in lb NO_x/MM Btu.

2.3.7 Predictive Correlations for NO_x Emissions and LOI

Two important factors were considered in the development of correlations from the baseline data: the statistical significance of the predictors, and the simplicity of the correlations. Therefore, when satisfactory results were obtained using only main effects, more complex terms were not included. For example, LOI variation with excess O_2 could be better described by the inverse O_2 factor (1/02) than with the quadratic O_2 factor (02*02). Two correlations (one for NO_x, another for LOI) were derived for each Design A and another two were derived for Design C (Table 2.8). The correlations were combined to generate a single correlation for NO_x emissions and another for LOI by taking the better correlation (higher r^2) as a base and including the factors that were not accounted for from the other correlation:

$$\text{lb } NO_x/\text{MM Btu} = 0.34 - 0.036*02 + 0.0009*MW*02 - 0.00017*(TILT)^2 \qquad r^2=91\%$$

$$\% \; LOI = -1.2 + 9.4/02 + 0.25*AIR - 0.024*(MW-140) \qquad r^2=84\%$$

where 02 is excess O_2 measured at the economizer outlet, MW is boiler load in MW net, TILT is burner tilt in degrees, and AIR is fuel air damper position.

Comparisons of measured and predicted NO_x emissions and LOI based on the two derived correlations are presented in Figures 2.8 and 2.9, respectively.

2.4 Conclusions

The Milliken Unit 2 baseline diagnostic tests conducted during December of 1993 were analyzed to determine the effects of boiler load, fuel air flow, excess O_2, burner tilt, and reduced-load mill pattern on NO_x emissions and LOI. The following conclusions were reached:

1. The average difference between replicated tests was 0.024 lb NO_x/MM Btu and 0.62% LOI. The uncertainty at 95% confidence, was ± 0.016 lb NO_x/MM Btu and ± 0.30% LOI.

2. Changing fuel air damper position had a significant effect on LOI and a minor effect on NO_x emissions. Increasing fuel air damper position from 2 to 4 increased LOI 0.5%. The minimum and maximum

(100% air flow) fuel air damper positions were 1 and 5, respectively.

3. Variation in burner tilt had a quadratic effect on NO_x emissions and no significant effect on LOI. Changing burner tilt from ± 15° to 0° increased NO_x emissions 0.04 lb/MM Btu.

4. At reduced boiler loads (110 MW and lower), taking the top burners out of service instead of the bottom burners (normal operation at Milliken) reduced NO_x emissions, but made it difficult to maintain steam temperatures.

5. Increasing excess O_2 increased NO_x emissions and reduced LOI. The impact of excess air on NO_x emissions was reduced at lower boiler loads.

6. At the same excess O_2 level, higher boiler loads increased NO_x emissions and reduced LOI, most likely due to higher temperatures and improved fuel/air mixing in the firebox.

7. Lower NO_x emissions corresponded to higher LOI. The variation at 140 MW boiler loads was approximated by a linear relationship as:

   $LOI = 11 - 14 * NO_x$.

8. The following predictive correlations for NO_x emissions and LOI were derived for normal operation of Unit 2:

   $$\text{lb } NO_x/\text{MM Btu} = 0.34 - 0.036*O2 + 0.0009*MW*O2 - 0.00017*(TILT)^2 \qquad r^2=91\%$$

   $$\%\ LOI = -1.2 + 9.4/O2 + 0.25*AIR - 0.024*(MW-140) \qquad r^2=84\%$$

   where O2 is excess O_2 measured at the economizer outlet, MW is boiler load in MW net, TILT is burner tilt in degrees, and AIR is fuel air damper position.

9. The short-term, baseline tests indicated that NO_x emissions could be reduced to about 0.54 lb/MM Btu at 140 MW, while maintaining salable fly ash.

TABLE 2.1 - UNIT 2 BASELINE TESTS - PARAMETER SETTINGS

	Parameter	Low	Mid	High
1.	Boiler Load, MW Net Generation	80	110	140
2.	Economizer O2, % (Full Load)	2	3	4
	Economizer O2, % (Reduced Load)	3	4	5
3*.	Fuel Air Flow, Damper Opening	2	3	4
4.	Burner Tilt, Degrees	-15	0	+15

5. Mill Patterns - Reduced Boiler Loads Only:

X Coal Flow On
\- Coal Flow Off or Minimum

Pattern (3 Mills) - 110 MW

Burner Elevation	Normal	Alternate
A1	X	-
B2	X	X
A3	X	X
B4	-	X

Pattern (2 Mills) - 80 MW

Burner Elevation	Normal	Alternate
A1	X	-
B2	X	-
A3	-	X
B4	-	X

* The minimum and maximum (100% air flow) fuel air damper positions were 1 and 5, respectively.

TABLE 2.2 - UNIT 2 BASELINE TESTS - STATISTICAL DESIGNS

Design A: **Full Boiler Load Tests**
140 MW, Normal Mill Pattern

No.	O_2	Fuel Air Position	Burner Tilt
1	4	4	15
2	4	4	-15
3	4	2	15
4	4	2	-15
5	2	4	15
6	2	4	-15
7	2	2	15
8	2	2	-15
* 9	4	3	0
*10	2	3	0
11	3	4	0
12	3	2	0
13	3	3	15
14	3	3	-15
*15	3	3	0

Design B: **Mill Pattern Tests**
4% O_2, Fuel Air at 3, Burner Tilt at 0

No.	Boiler Load	Mill Pattern
* 1	110	Normal
2	110	Alternate
* 3	80	Normal
4	80	Alternate

Design C: **Variable Boiler Load Tests**
Normal Mill Pattern; Fuel Air at 3, and Burner Tilt at 0

No.	Boiler Load	O_2
* 1	140	4
* 2	140	3
* 3	140	2
4	110	5
* 5	110	4
6	110	3
7	80	5
* 8	80	4
9	80	3

* Replicated Tests

Tests A9, A10, and A15 are the same as Tests C1, C3, and C2.

Tests B1 and B3 are the same as Tests C5 and C8.

TABLE 2.3 - UNIT 2 BASELINE TESTS - TEST CONDITIONS

		Data Collect		Load	02	Fuel	Tilt	Design No.		
No.	D A T E	Start	End	MW	%	Air	deg	See Table 2		
1	12-06-93	1900	2100	140	3.0	3	0	A15		C2
2	12-06-93	2300	30	110	3.1	3	0			C6
3	12-07-93	400	600	80	3.5	3	0			C9
4	12-07-93	900	1145	140	4.0	2	-15	A 4		
5	12-07-93	1400	1530	140	4.0	2	15	A 3		
6	12-07-93	2315	100	110	4.2	3	0		B2	
7	12-08-93	400	600	80	5.0	3	0			C7
8	12-08-93	900	1200	140	2.1	4	-15	A 6		
9	12-08-93	1300	1430	140	2.9	4	0	A11		
10	12-10-93	2200	2400	110	4.0	3	0		B1	C5
11	12-11-93	300	430	80	4.0	3	0		B3	C8
12	12-11-93	1600	1800	140	1.9	2	-15	A 8		
13	12-10-93	1700	1900	140	3.9	3	0	A 9		C1
14	12-10-93	1000	1200	110	4.0	3	0		B1	C5
15	12-10-93	300	530	80	3.9	3	0		B4	
16	12-11-93	1000	1200	140	3.0	3	0	A15		C2
17	12-11-93	1300	1500	140	2.9	3	15	A13		
18	12-10-93	1300	1500	110	4.7	3	0			C4
19	12-10-93	600	730	80	4.2	3	0		B3	C8
20	12-15-93	600	700	140	3.9	3	0	A 9		C1
21	12-13-93	1630	1830	140	1.9	3	0	A10		C3
22	12-14-93	100	300	140	2.0	4	15	A 5		
23	12-13-93	2100	2230	140	4.0	4	-15	A 2		
24	12-14-93	400	600	140	3.0	3	-15	A14		
25	12-14-93	1000	1115	140	2.1	3	0	A10		C3
26	12-14-93	1300	1430	140	3.0	3	0	A15		C2
27	12-14-93	1600	1745	140	2.1	2	15	A 7		
28	12-14-93	2100	2230	140	3.9	4	15	A 1		
29	12-15-93	000	200	140	2.9	3	0	A15		C2
30	12-15-93	300	430	140	2.9	2	0	A12		

TABLE 2.4 - UNIT 2 BASELINE TESTS - COAL AND ASH ANALYSES

No.	Date Coal Analysis	Fly Ash Analyses Dry %Ash	Dry %C	100-%Ash %LOI
1	12/06/93	97.38	2.14	2.62
2	12/06/93	95.98	3.13	4.02
3	12/07/93	96.57	2.62	3.43
4	12/07/93	98.37	1.26	1.63
5	12/07/93	97.95	1.81	2.05
6	12/07/93	97.29	2.02	2.71
7	12/08/93	96.54	2.21	3.46
8	12/08/93	96.24	2.43	3.76
9	12/08/93	97.04	2.44	2.96
10	12/10/93	96.71	1.41	3.29
11	12/11/93	96.92	2.23	3.08
12	12/11/93	95.60	3.84	4.40
13	12/10/93	97.54	1.68	2.46
14	12/10/93	97.26	1.80	2.74
15	12/10/93	95.64	3.28	4.36
16	12/11/93	97.73	1.75	2.27
17	12/11/93	97.06	2.44	2.94
18	12/10/93	97.83	1.68	2.17
19	12/10/93	96.26	3.07	3.74
20	12/15/93	97.94	1.70	2.06
21	12/13/93	95.00	4.51	5.00
22	12/14/93	94.88	4.54	5.12
23	12/13/93	98.13	1.76	1.87
24	12/14/93	97.22	2.49	2.78
25	12/14/93	96.18	3.44	3.82
26	12/14/93	97.47	2.28	2.53
27	12/14/93	96.61	3.15	3.39
28	12/14/93	97.86	1.85	2.14
29	12/15/93	97.13	2.28	2.87
30	12/15/93	97.88	1.78	2.12

Coal Analyses: Moisture, Btu, Proximate, Ultimate

Date	As Det %H2O	Dry %VM	Dry Btu	Dry %C	Dry %H	Dry %N	Dry %S	Dry %Ash	Dry %O
12/06/93	1.86	37.76	13918	77.39	5.20	1.61	1.93	7.43	6.44
12/07/93	2.33	37.25	13821	76.97	5.14	1.52	1.97	8.41	5.99
12/08/93	2.25	37.72	13946	77.42	5.20	1.61	1.92	7.54	6.31
12/10/93	2.13	38.03	13965	77.86	5.22	1.44	1.87	7.43	6.18
12/11/93	2.11	38.10	13945	77.71	5.21	1.64	1.92	7.63	5.89
12/13/93	1.79	38.43	13905	77.09	5.20	1.54	2.04	7.87	6.26
12/14/93	1.72	38.21	13921	78.74	5.11	1.48	1.99	7.75	4.93
12/15/93	1.86	37.75	13894	77.78	5.12	1.41	2.08	7.99	5.62

TABLE 2.5 - UNIT 2 BASELINE TESTS - TEST RESULTS

No.	STACK CEM CO2 %	STACK CEM SO2 ppm	STACK CEM NOx ppm	Econ O2 %	EPA Fc	NOx lb/MM Btu	SO2 lb/MM Btu	100-%Ash %LOI
1	11.5	1053	329	3.0	1785	0.610	2.713	2.62
2	11.4	1065	293	3.1	1785	0.548	2.768	4.02
3	11.6	1117	243	3.5	1788	0.447	2.858	3.43
4	11.2	1021	331	4.0	1788	0.631	2.705	1.63
5	11.1	1082	317	4.0	1788	0.610	2.893	2.05
6	11.1	1038	210	4.2	1788	0.404	2.775	2.71
7	11.0	995	263	5.0	1782	0.509	2.676	3.46
8	12.9	1174	292	2.1	1782	0.482	2.692	3.76
9	11.9	1097	325	2.9	1782	0.581	2.727	2.96
10	10.7	897	302	4.0	1790	0.603	2.491	3.29
11	10.8	916	246	4.0	1789	0.486	2.519	3.08
12	12.6	1036	296	1.9	1789	0.502	2.442	4.40
13	10.8	918	334	3.9	1790	0.661	2.525	2.46
14	10.8	936	308	4.0	1790	0.609	2.575	2.74
15	10.7	925	166	3.9	1790	0.332	2.568	4.36
16	11.8	999	318	3.0	1789	0.576	2.514	2.27
17	11.8	988	297	2.9	1789	0.538	2.486	2.94
18	10.3	864	313	4.7	1790	0.649	2.492	2.17
19	10.3	899	237	4.2	1790	0.492	2.593	3.74
20	10.8	820	342	3.9	1780	0.673	2.243	2.06
21	12.6	1174	286	1.9	1780	0.482	2.753	5.00
22	12.3	950	263	2.0	1816	0.464	2.328	5.12
23	11.0	970	329	4.0	1780	0.636	2.605	1.87
24	11.5	1088	312	3.0	1816	0.588	2.851	2.78
25	12.3	990	313	2.1	1816	0.552	2.426	3.82
26	11.6	840	336	3.0	1816	0.628	2.183	2.53
27	12.1	917	286	2.1	1816	0.512	2.284	3.39
28	10.8	873	325	3.9	1816	0.652	2.436	2.14
29	11.6	870	328	2.9	1797	0.607	2.237	2.87
30	11.5	836	327	2.9	1797	0.610	2.169	2.12

TABLE 2.6 - UNIT 2 BASELINE TESTS - EXPERIMENTAL ERROR CALCULATIONS

	NO_x Measurements, lb/MM Btu						
Replicates	1	2	3	4	SS	DF	|d|
13, 20	0.661	0.673			0.000072	1	0.012
21, 25	0.482	0.552			0.002404	1	0.069
1 , 16 26, 29	0.610	0.576	0.628	0.607	0.001416	3	0.027
10, 14	0.603	0.609			0.000020	1	0.006
11, 19	0.486	0.492			0.000014	1	0.005

	LOI Measurements						
Replicates	1	2	3	4	SS	DF	|d|
13, 20	2.46	2.06			0.0800	1	0.40
21, 25	5.00	3.82			0.6962	1	1.18
1 , 16 26, 29	2.62	2.27	2.53	2.87	0.1841	3	0.32
10, 14	3.29	2.74			0.1513	1	0.55
11, 19	3.08	3.74			0.2178	1	0.66

		NO_x lb/MM Btu	LOI %
SS = Sum of Squares = $\Sigma\ (y_i - y_{avg})$	$SS_{overall}$	0.003926	1.3293
DF = Degrees of Freedom = No. Replicates - 1	$DF_{overall}$	7	7
σ = Standard Deviation = $\sqrt{}(SS_{overall}/DF_{overall})$	σ	0.024	0.436
95% CI = 95% Confidence Interval = $t*\sigma/\sqrt{N}$	95% CI	0.016	0.298
|d| = Absolute Difference Between Replicates	$\|d\|_{avg}$	0.024	0.621

TABLE 2.7 - UNIT 2 BASELINE TESTS - REDUCED DATA MATRIX

	MW	O2 %	AIR	TILT Deg	NOx lb/MM Btu	LOI %
Design A:						
1	140	3.9	4	15	0.652	2.14
2	140	4.0	4	-15	0.636	1.87
3	140	4.0	2	15	0.610	2.05
4	140	4.0	2	-15	0.631	1.63
5	140	2.0	4	15	0.464	5.12
6	140	2.1	4	-15	0.482	3.76
7	140	2.1	2	15	0.512	3.39
8	140	1.9	2	-15	0.502	4.40
9	140	3.9	3	0	0.667	2.26
10	140	2.0	3	0	0.517	4.41
11	140	2.9	4	0	0.581	2.96
12	140	2.9	2	0	0.610	2.12
13	140	2.9	3	15	0.538	2.94
14	140	3.0	3	-15	0.588	2.78
15	140	3.0	3	0	0.605	2.57
Design B:						
1	110	4.0	3	0	0.606	3.02
2	110	4.2	3	0	0.404	2.71
3	80	4.1	3	0	0.489	3.41
4	80	3.9	3	0	0.332	4.36
Design C:						
1	140	3.9	3	0	0.667	2.26
2	140	3.0	3	0	0.605	2.57
3	140	2.0	3	0	0.517	4.41
4	110	4.7	3	0	0.649	2.17
5	110	4.0	3	0	0.606	3.02
6	110	3.1	3	0	0.548	4.02
7	80	5.0	3	0	0.509	3.46
8	80	4.1	3	0	0.489	3.41
9	80	3.5	3	0	0.447	3.43

MW = Net Boiler Load in Megawatts

O2 = %O2 at Economizer Outlet

AIR = Fuel Air Damper Position : 1 is Minimum, 5 is Maximum

TILT = Burner Tilt in Degrees

TABLE 2.8 - UNIT 2 BASELINE TESTS - NO_x AND LOI CORRELATIONS

FINAL CORRELATIONS, SET A:

NOX = 0.379 + 0.0738 O2 - 0.000170 TILT*TILT

Predictor	Coef	Stdev	t-ratio	p
Constant	0.37899	0.01981	19.13	0.000
O2	0.073814	0.006105	12.09	0.000
TILT*TILT	-0.00016974	0.00004573	-3.71	0.003

s = 0.01878 R-sq = 92.9% R-sq(adj) = 91.7%

LOI = - 1.19 + 9.40 (1/O2) + 0.245 AIR

Predictor	Coef	Stdev	t-ratio	p
Constant	-1.1866	0.4666	-2.54	0.026
(1/O2)	9.4046	0.8749	10.75	0.000
AIR	0.2447	0.1084	2.26	0.043

s = 0.3429 R-sq = 90.9% R-sq(adj) = 89.4%

FINAL CORRELATIONS, SET C:

NOX = 0.336 - 0.0355 O2 + 0.000899 MW*O2

Predictor	Coef	Stdev	t-ratio	p
Constant	0.33599	0.02703	12.43	0.000
O2	-0.035459	0.007356	-4.82	0.003
MW*O2	0.00089917	0.00007020	12.81	0.000

s = 0.01616 R-sq = 96.6% R-sq(adj) = 95.4%

LOI = 3.21 + 9.05 (1/O2) - 0.0240 MW

Predictor	Coef	Stdev	t-ratio	p
Constant	3.2149	0.5923	5.43	0.002
(1/O2)	9.048	1.793	5.05	0.002
MW	-0.023992	0.006267	-3.83	0.009

s = 0.3776 R-sq = 81.7% R-sq(adj) = 75.6%

FIGURE 2.1 - Effect of Fuel Air Flow - Milliken Unit 2, 140 MW, 3% O_2

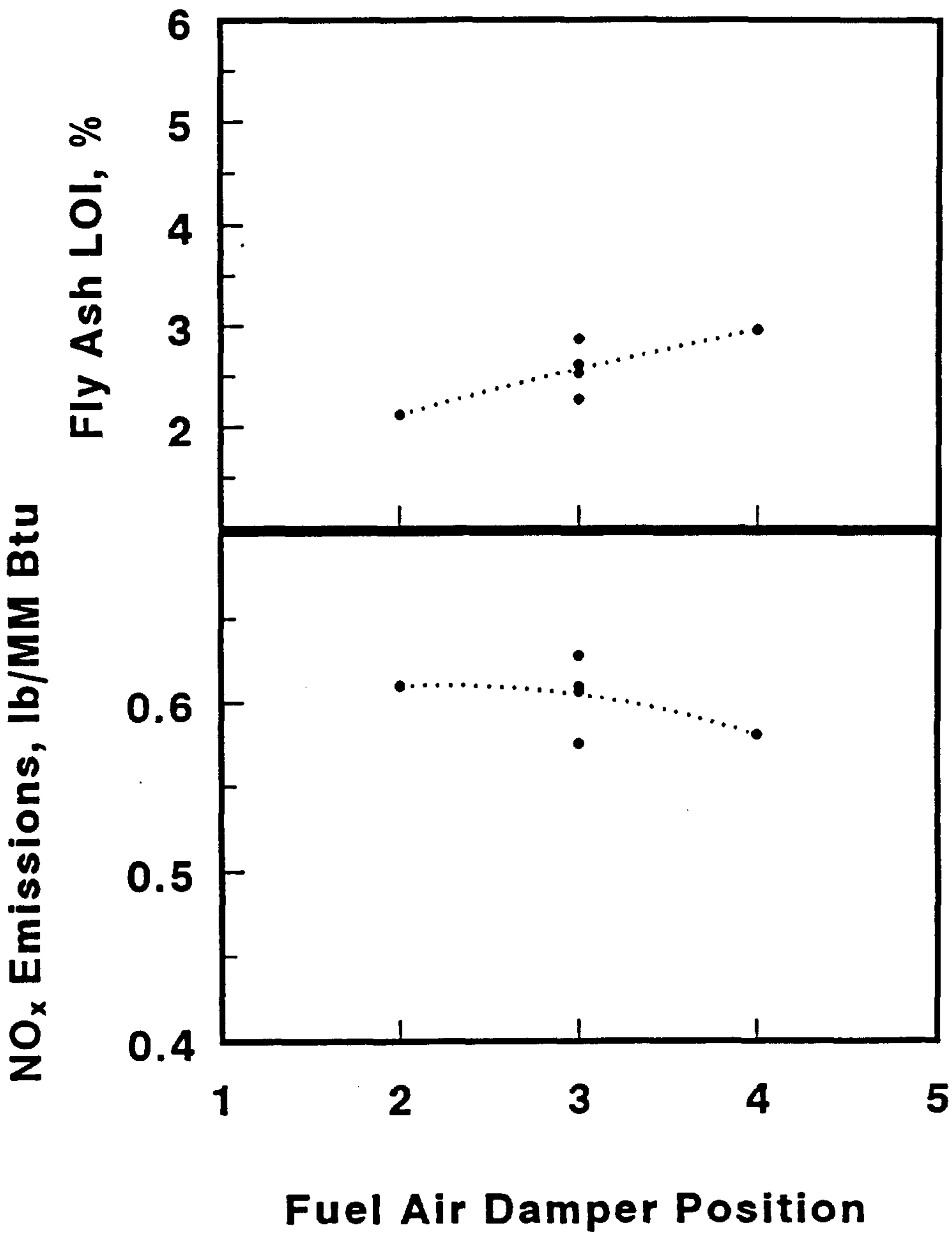


FIGURE 2.2 - Effect of Burner Tilt - Milliken Unit 2, 140 MW, 3% O_2

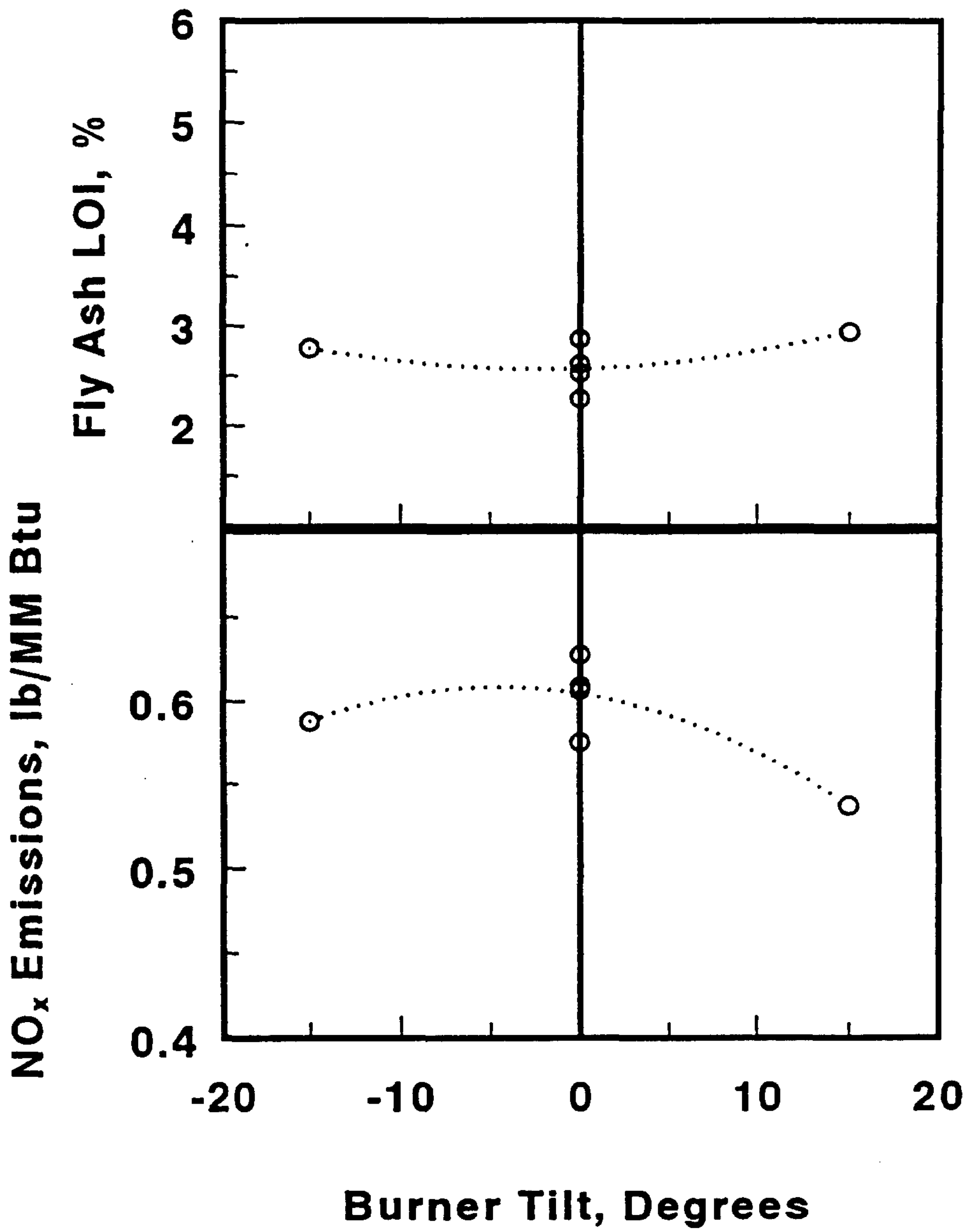


FIGURE 2.3 - Effect of Mill Pattern - Milliken Unit 2, 4% O_2

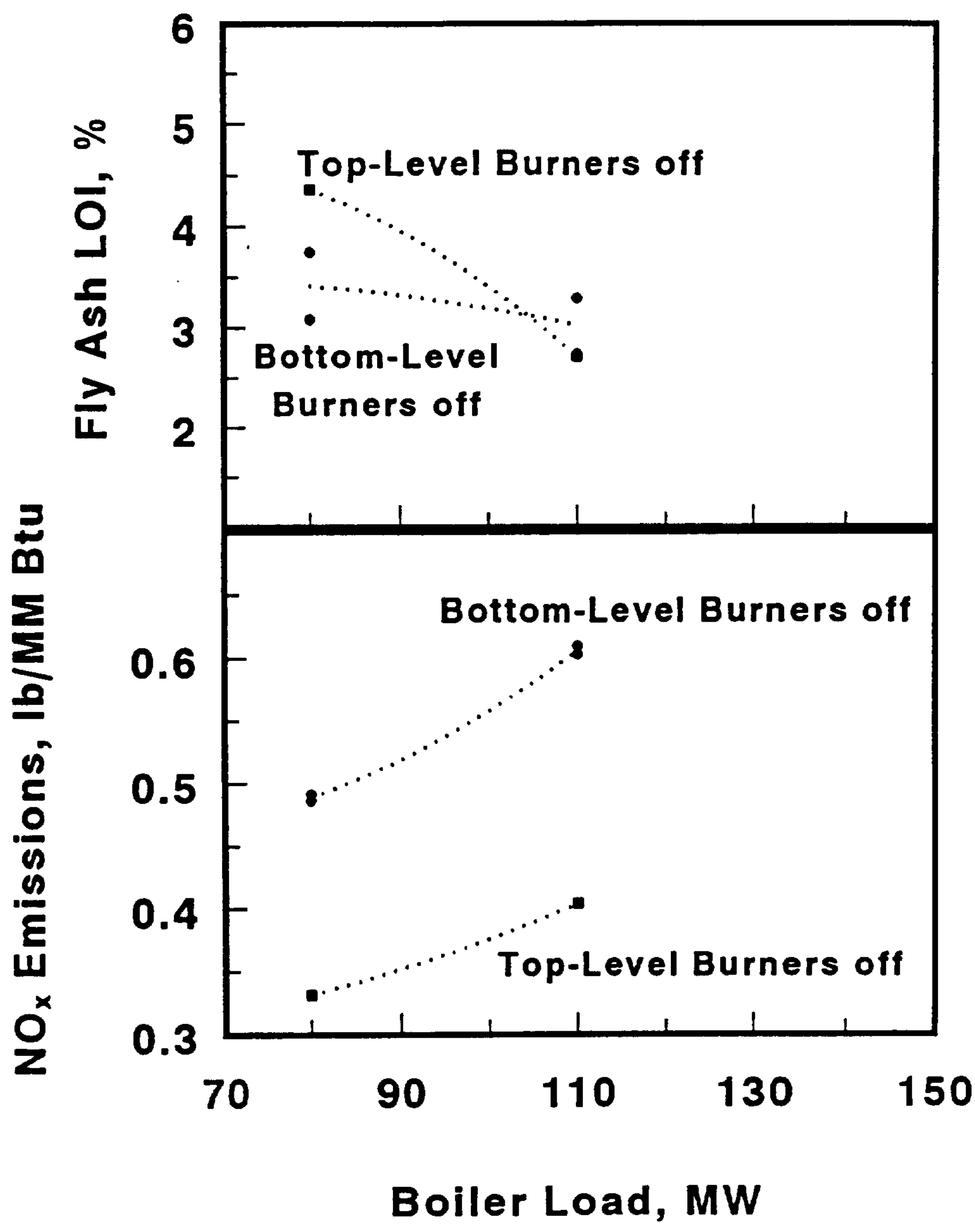


FIGURE 2.4 - Effect of Excess Air - Milliken Unit 2, Parameter: Boiler Load

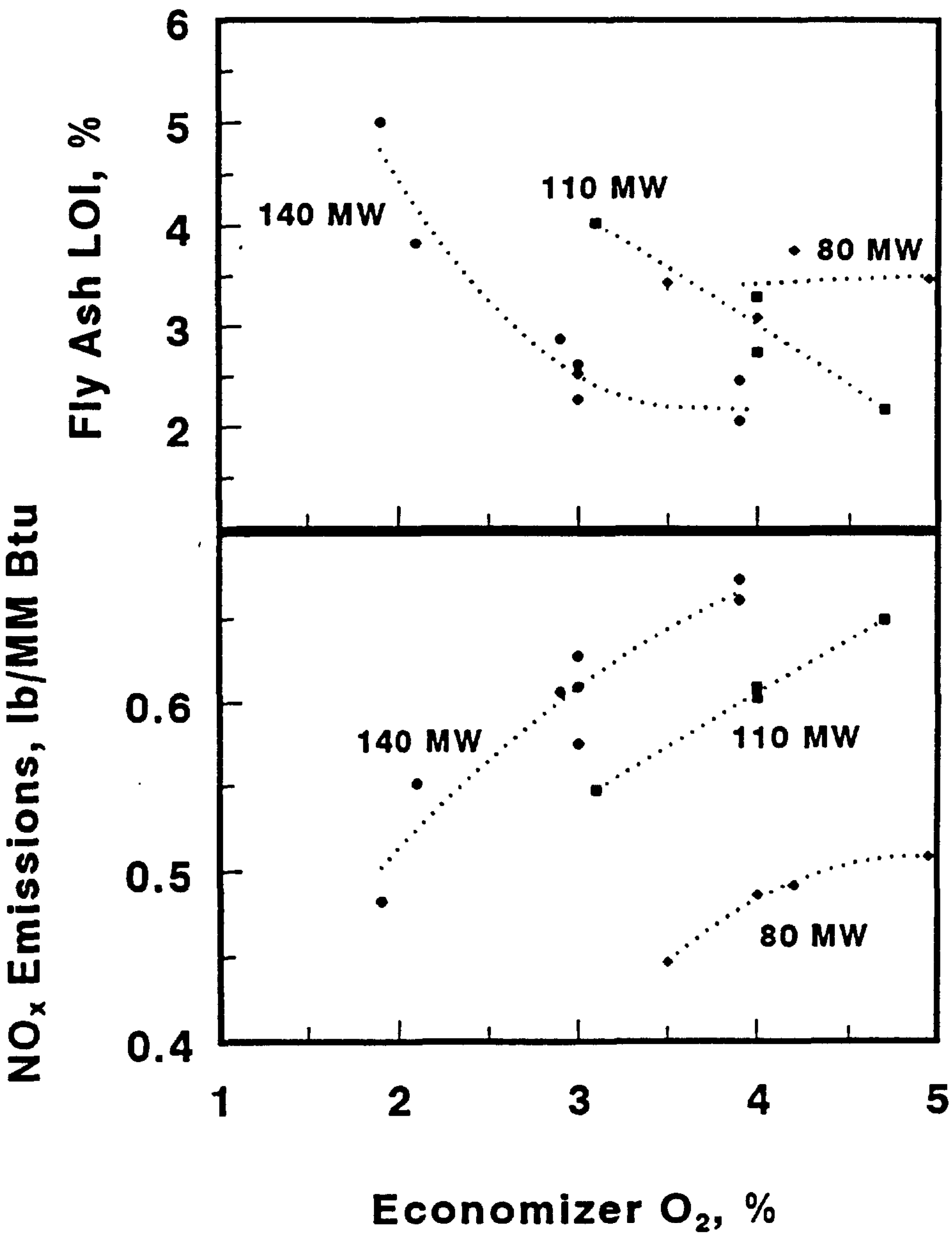


FIGURE 2.5 - Effect of Boiler Load - Milliken Unit 2, Parameter: $\%O_2$

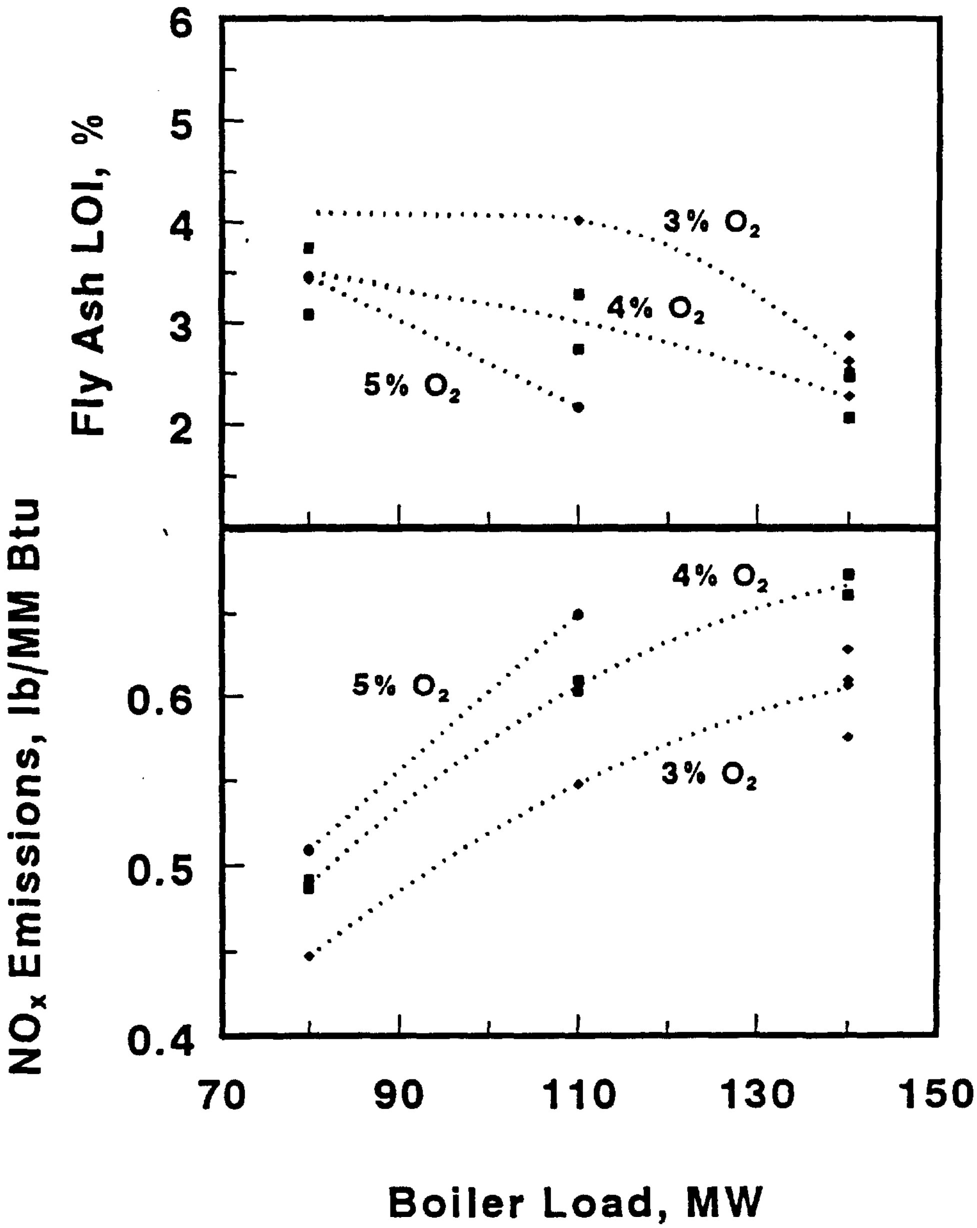


FIGURE 2.6 - Effect of Excess Air -
Milliken Unit 2, 140 MW

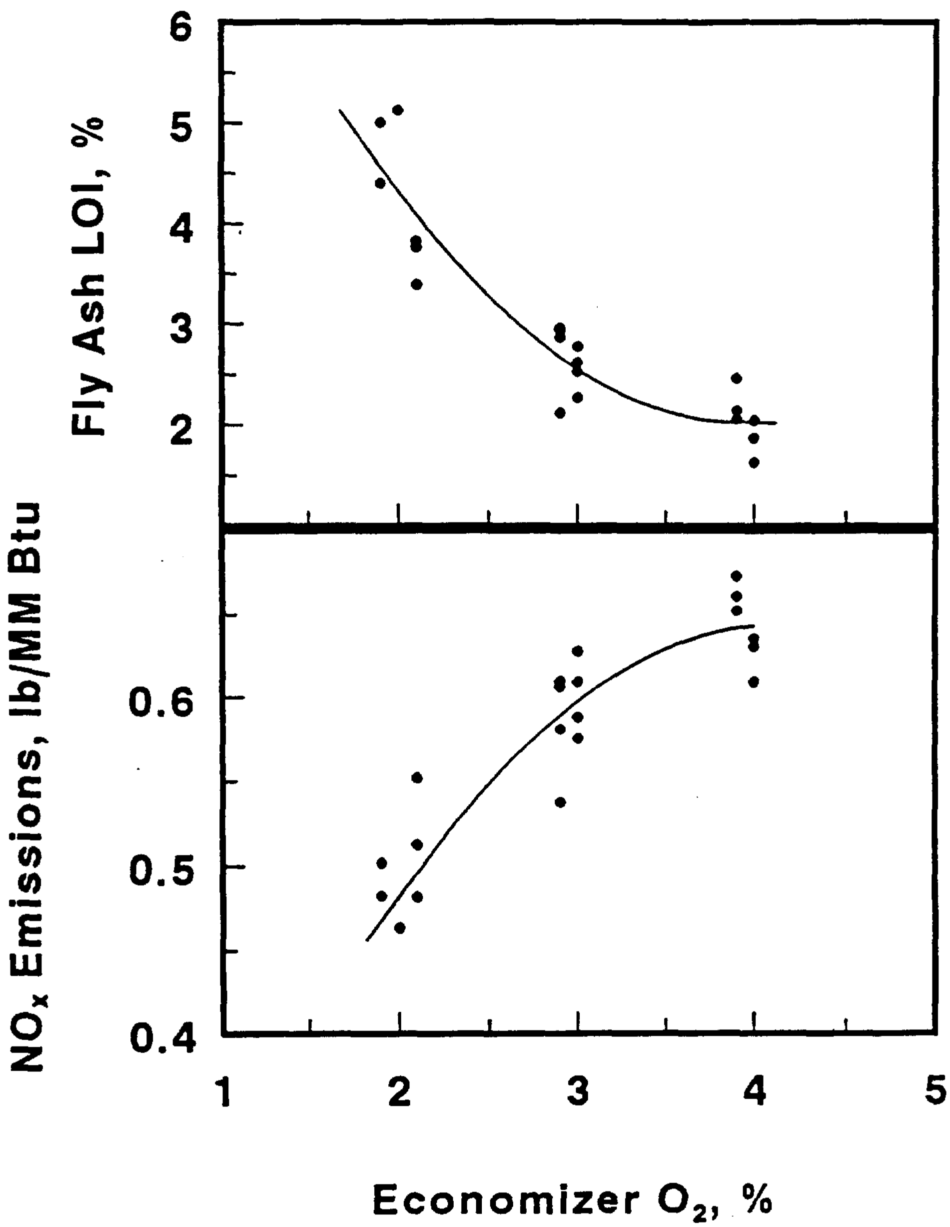


FIGURE 2.7 - LOI Variation with NO_x - Milliken Unit 2, 140 MW

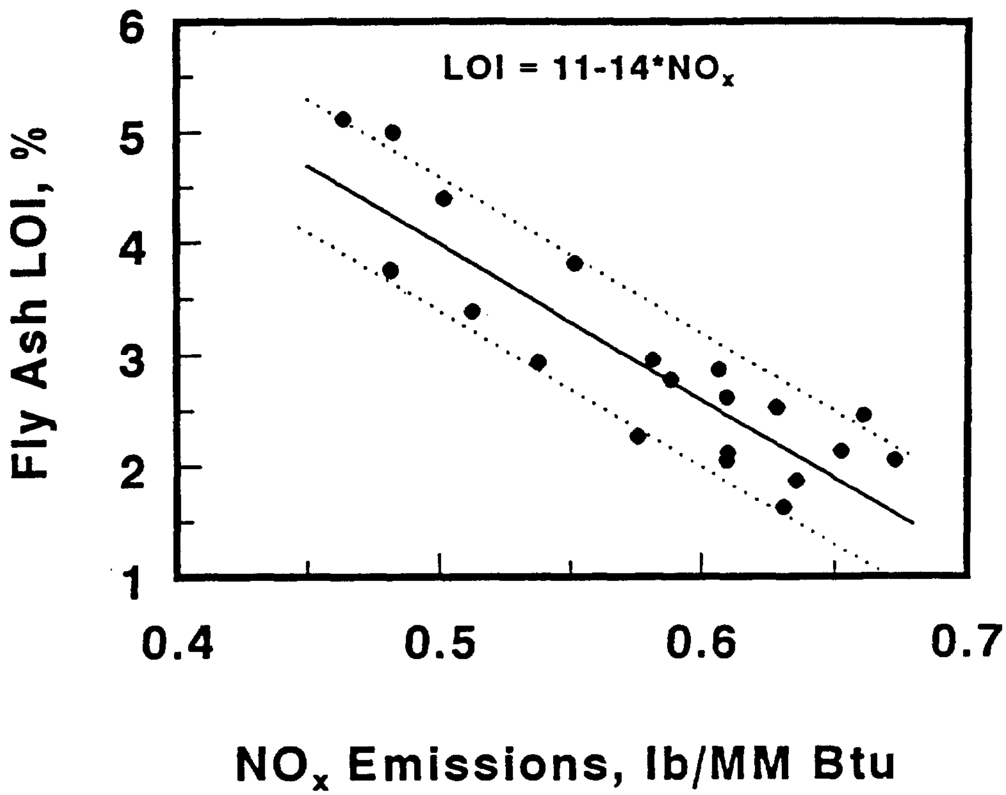


FIGURE 2.8 -
Predicted Vs. Measured NO_x Emissions -
Milliken Unit 2, Dec 93 Baseline Tests

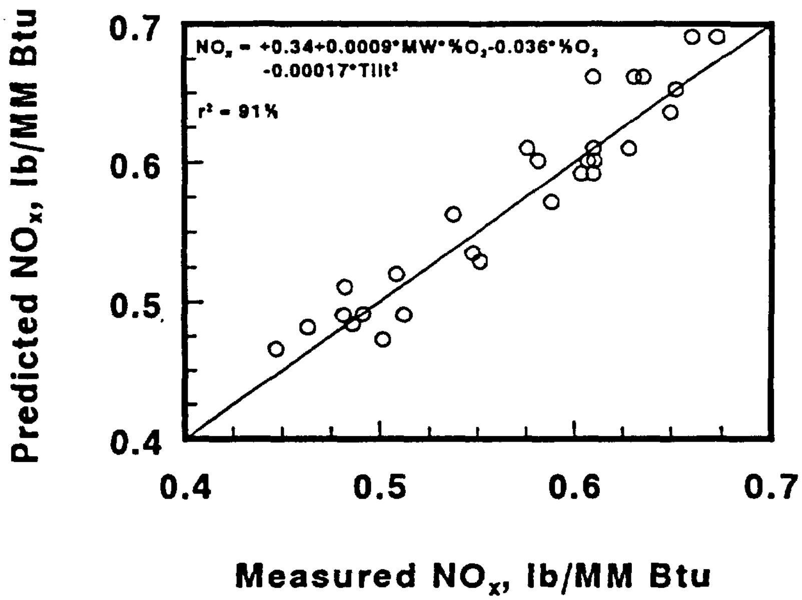
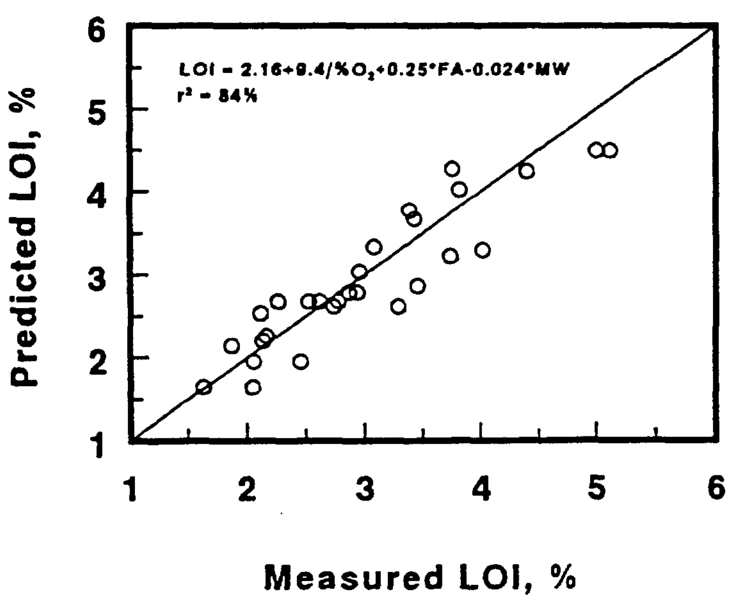


FIGURE 2.9 -Predicted Vs.Measured LOI - Milliken Unit 2, Dec 93 Baseline Tests



SECTION THREE
UNIT 1 POST-RETROFIT DIAGNOSTIC TESTS

3.1 Experimental Design

The statistically designed LNCFS-3 diagnostic test program examined the effects of boiler load, excess O_2, mill classifier speed, combustion air distribution (SOFA flow, CCOFA flow and coal air flow), burner settings (burner tilt, SOFA tilt and SOFA yaw), and mill load patterns on NO_x emissions and LOI. The experimental parameter settings are listed in Table 3.1. A high setting of 4.3% excess O_2 at the economizer outlet at 148 MW boiler load was limited by fan capacity. Direct measurements of combustion air flows (SOFA, CCOFA and coal air) were not possible, and qualitative designations of minimum, baseline and maximum were used for the following three parameters: SOFA/CCOFA ratio, SOFA+CCOFA flow and coal air flow.

New coal mills were installed on Unit 1, one for each of the four elevations of burners. The new coal mills made it possible to test mill patterns at full load with one mill out of service, in addition to the normal operational mode with all mills in service. This option was not available for baseline testing on Unit 2 with the older coal mills, where operation at boiler loads above 135 MW required all four mills. Four configurations were possible by taking one mill out of service, as described in Table 3.1. Operation at reduced boiler loads (120 MW and 90 MW) required only three mills in service, with the lowest mill taken out of service for normal operation at Milliken. Alternate (other than normal) mill patterns at 90 MW and mill patterns with only two mills in service were not tested because of expected problems with flame stability and the coal mills tripping.

The post-retrofit test design consisted of three experimental blocks, as described in Tables 3.2, 3.3 and 3.4. Tests marked by asterisks were replicated to allow an independent estimate of the experimental error, and some tests were common to more than one design. The three experimental designs were:

1. Design A, Full Boiler Load Tests (Table 3.2): These 17 tests were conducted at 148 MW to examine positive and negative variations in each parameter from baseline settings. The tests provided a measure of the relative contribution of the parameters to variations in NO_x emissions and LOI. The independent parameters were excess O_2, burner tilt, SOFA tilt, SOFA yaw, SOFA/CCOFA ratio, SOFA+CCOFA flow, coal air flow and mill classifier speed.

2. Design B, Mill Pattern Tests (Table 3.3): This set consisted of 8 tests operated with one mill out of service, including 4 possible mill patterns at 148 MW (Tests 1-4) and 4 possible mill patterns at 120 MW (Tests 5-8).

3. Design C, Variable Boiler Load Tests (Table 3.4): This design included 19 tests, with the most significant parameters affecting NO_x emissions and LOI as the independent variables, namely, boiler load, excess O_2 and mill classifier speed. The design consisted of

a full three-level factorial with respect to variations in boiler load and excess O_2 (Tests 1-9) at a typical mill classifier setting of 93 rpm, with additional tests (Tests 10-19) to evaluate the effect of variations in mill classifier speed. A full quadratic model with respect to the independent variables could be derived from these tests.

3.2 Experimental Plan

The LNCFS-3 diagnostic tests were conducted on Unit 1 between March 22 and 31 of 1994. A total of 52 tests were conducted, each typically 2-3 hours long. The tests are described in Table 3.5, and the experimental conditions are presented in Table 3.6. In general, tests at 120 MW and 90 MW boiler loads were conducted between 9 p.m. and 6 a.m. A primary consideration was given to maintaining reliable boiler operation and power generation. When a set of test conditions could not maintain the required steam conditions, the test was terminated as soon as sufficient data was collected.

3.2.1 Measurements

Two CEM systems were used for the LNCFS-3 diagnostic tests. One system, designated as the ESA system, was operated at the economizer outlet. The other system was the plant stack CEM.

The ESA CEM system was used to measure O_2, CO, CO_2, and NO_x concentrations at the economizer outlet. The system included an electrochemical O_2 analyzer, non-dispersive infrared CO and CO_2 analyzers, and a chemiluminescent NO_x/NO analyzer. It allowed multi-point monitoring of emissions at 36 sampling locations (18 per duct), available as individual point measurements or as a composite. The flows at the sampling locations were individually measured and controlled. Individual point measurements were made for selected tests (Tests 7, 8, 11, and 12) to determine the extent of gas stratification at the economizer outlet and to detect burner balancing problems. Concentration measurements across the duct (Table 3.7) indicated that gas stratification at the economizer outlet was minor. Composite measurements were made for all the tests.

The sampled gases were conditioned by removing moisture before reaching the flow indicators and the gaseous analyzers. This sampling method reduced the overall NO_x measurement accuracy due to the loss of some NO_2 in the water condensate. NO_2 concentrations were estimated at 1-2 ppm, corresponding to less than 1% of NO levels. This was verified experimentally by measuring NO_2 under baseline conditions (Test 47) using a second sampling system consisting of 3 probes with heated lines and a moisture freeze-out system so that the gas sample was either heated or dry at all locations before reaching the analyzer. NO_x and NO measurements were indistinguishable, supporting the initial estimate of 1-2 ppm NO_2, calculated as the difference between NO_x and NO concentrations.

The ESA CEM data were collected every 10 seconds, averaged and recorded every 10 minutes. Certification of this system was performed prior to testing, including Relative Accuracy Test. An instrument error check was performed twice daily using zero, mid and high span gases, according to EPA Protocol 1. A system bias check was performed weekly using zero and mid span gases.

The plant O_2 probe was used to monitor O_2 concentrations at the economizer outlet. The plant CEM system was used to measure CO_2, NO_x and SO_2 concentrations at the stack. The system included a non-dispersive infrared CO_2 analyzer, a chemiluminescent NO_x analyzer, and a pulsed fluorescent SO_2 analyzer. A low flow dilution probe was used and no additional conditioning was required. The CEM system passed the Relative Accuracy Test, and was calibrated daily.

Process and CEM data were acquired using the plant Westinghouse data acquisition system (WDPF). Typically, 1-2 hours of test data at steady state conditions were averaged for each test. Steady state conditions for a test were assumed when small changes in NO_x measurements occurred with time (less than 3 ppm change in the hourly average), and typically occurred within 1-2 hours after test conditions were set.

Fly ash was sampled from the ash transport pipe during unloading of the first ESP hopper ("C" hopper) to the ash silo. For tests at 148 MW, a cyclone was used to collect a second fly ash sample from the ash transport pipe for 30-60 minutes during sequential unloading of all ash hoppers to the silo, and then extracting a 4-8 ounce sample. The ash samples were subsequently analyzed for moisture, carbon and ash contents, as presented in Table 3.8.

Daily coal samples were collected and analyzed for moisture, proximate and ultimate compositions, and heating value, as presented in Table 3.9.

3.3 Results and Discussion

A total of 52 post-retrofit diagnostic tests were conducted, including 6 replicates. Gas analyses and test process data are presented in Tables 3.10 and 3.11, respectively. CO measurements at the economizer outlet (ESA CEM system) were 9-23 ppm for all the tests. Thus, CO variation was not a consideration in this study.

The calculation of NO_x emissions in lb/MM Btu from measured NO_x concentrations depends on the availability of CEM and coal analysis data according to EPA Method 19 (40 CFR 60 Appendix A, 1993). The calculations are presented below:

NO_x emissions are calculated using CO_2 measurements as:

$$\text{lb } NO_x/\text{MM Btu} = 1.194\times10^{-7} \text{ lb } NO_x/\text{scf}_{\text{flue gas}} * \text{ppm } NO_x * F_c * 100/\%CO_2.$$

Where F_c is scf CO_2 per MM Btu. A tabulated value for F_c is used, or it can be calculated from coal analysis data as:

$$F_c = 0.321\times10^6 * \%C_{\text{coal}}/(\text{Btu/lb})_{\text{coal}}.$$

The EPA tabulated F_c value for bituminous coal is 1800. The calculated F_c values (Table 3.9) varied between 1788 and 1817, differing by less than 1% from the tabulated value.

NO_x emissions are calculated using O_2 measurements as:

$$\text{lb } NO_x/\text{MM Btu} = 1.194\times10^{-7} \text{ lb } NO_x/\text{scf}_{\text{flue gas}} * \text{ppm } NO_x * F_d * 20.9/(20.9-\%O_2).$$

Where F_d is scf dry gas per MM Btu. A tabulated value for F_d is used, or it can be calculated from coal analysis data as:

$$F_d = 10^6*(3.64*\%H_{coal}+1.53*\%C_{coal}+0.57*\%S_{coal}+0.14*\%N_{coal}-0.46*\%O_{coal})/(Btu/lb)_{coal}.$$

The EPA tabulated F_d value for bituminous coal is 9780.

LOI was defined as the percentage of combustibles in the fly ash, calculated as:

$$LOI = 100 - \%\ Ash_{fly\ ash,\ dry}.$$

3.3.1 Data Evaluation

Two sources of CEM data (economizer outlet and stack) were available, and two ash samples were collected for tests at 148 MW boiler load. Furthermore, NO_x emissions could be calculated using different data sets. Therefore, a comparative evaluation of the different data sets was conducted.

NO_x emissions data in lb/MM Btu at the stack (calculated from the tabulated F_c value, and measured NO_x and CO_2 concentrations) were extracted at one-minute intervals from the plant data acquisition system and averaged for each test. The data set was consistent with NO_x emissions calculated from 15-minute averages of CO_2 and NO_x plant CEM measurements (similar data reduction procedure to the Unit 2 baseline tests).

Two ash samples were collected for tests at 148 MW boiler load (Table 3.8), one during unloading of the first ESP hopper (referred to as "C" hopper ash), and a second sample during sequential unloading of all ash hoppers (referred to as cyclone collected ash). Only "C" hopper samples were collected for all the tests (except Test 16). Typically, LOI checks at the plant are performed on ash collected during unloading of the first ESP hopper. The two ash samples were collected at 148 MW boiler load to compare LOI of cyclone collected ash to that of "C" hopper ash. The carbon in the ash was related to LOI as:

Cyclone Collected Ash: $LOI = 1.056*\%C_{ash} + 0.57$ $\quad r^2 = 81.5\%,\ n = 30$

"C" Hopper Ash: $LOI = 1.043*\%C_{ash} + 0.21$ $\quad r^2 = 99.6\%,\ n = 51$

Cyclone collected ash typically had 0.5%-2.0% higher LOI than "C" hopper ash, with an average difference of 1.2%. The "C" hopper ash data were used in analyzing the results.

3.3.2 Experimental Error

Six replicated tests were used to estimate the standard deviation of the experimental error (σ_{error}) and the uncertainty in measurement (confidence level), for both NO_x emissions and LOI, as seen in Table 3.12. Calculated σ_{error} values for NO_x emissions and LOI were 0.035 lb/MM Btu and 0.45%, respectively. The uncertainty in measurement is $\pm\ t*\sigma/\sqrt{N}$, where **N** is the number of replicated tests, and t is a tabulated statistical parameter depending on the degrees of freedom and the desired confidence level. For 6 degrees of freedom and 95% confidence (t = 2.447), the confidence intervals were $NO_x \pm 0.027$ lb/MM Btu and

LOI ± 0.35%. Differences between replicated tests for NO_x and LOI averaged 0.044 lb/MM Btu and 0.6%, respectively. The uncertainty in measuring LOI for the post-retrofit tests was comparable to that for the baseline tests. However, the uncertainty in measuring NO_x was significantly greater for the post-retrofit tests than for the baseline tests, mostly likely due to the sensitivity of NO_x emissions to a larger number of parameters in a low-NO_x configuration.

3.3.3 Experimental Results

Replicated results were averaged and the reduced data matrix is presented in Table 3.13. Analysis of the data focused on the effect of the independent variables on NO_x emissions and LOI. The independent parameters were boiler load, excess O_2, burner tilt, SOFA tilt, SOFA yaw, SOFA/CCOFA ratio, SOFA+CCOFA flow, coal air flow and mill classifier speed. The effect of mill load pattern on NO_x emissions and LOI was also examined (Design B).

Analysis of the test results of Designs A and C showed that, in general, LOI increased as NO_x emissions decreased. However, weak correlation coefficients were obtained, suggesting a more complex relationship between NO_x and LOI, relative to that observed in baseline testing. For Design A, burner tilt exhibited strong correlations with both NO_x emissions and LOI. For Design C, O_2 exhibited strong correlations with both NO_x emissions and LOI.

3.3.4 Effects of Combustion Air Distribution and Burner Tilt

The tests of Design A (Table 3.13) examined the effects of burner tilt, SOFA tilt, SOFA yaw, SOFA/CCOFA ratio, SOFA+CCOFA flow, and coal air flow on NO_x emissions and LOI at 148 MW boiler load. Excess O_2 and mill classifier speed were also variables in this design, but their effects are discussed in more detail in the analysis of Design C where greater variability of these two parameters was possible.

Regression analyses were used to identify the statistically significant factors affecting NO_x emissions and LOI, starting with a linear model with respect to the eight independent variables of Design A. The final correlations for Design A are shown in Table 3.14. O2 is excess O_2 measured at the economizer outlet, S refers to SOFA flow, C refers to CCOFA flow, and TILT is burner tilt in degrees. Four variables had significant effects on NO_x emissions, namely, excess O_2, burner tilt, SOFA/CCOFA ratio, and SOFA+CCOFA flow. Each exhibited about the same level of significance. Only burner tilt had a clearly significant effect on LOI.

Variations in NO_x emissions and LOI with burner tilt settings (burner tilt and SOFA tilt) and SOFA yaw at 148 MW are shown in Figures 3.1 and 3.2, respectively. Other parameters were set at baseline conditions. Figure 3.1 shows that lowering the burner tilt below the horizontal reduced both NO_x emissions and LOI, possibly because of greater residence time in the burner zone, whereas changes in SOFA tilt produced no significant effects. Figure 3.2 shows that higher SOFA yaw angles in the positive or negative direction relative to the fuel firing angle increased LOI and produced minor changes in NO_x emissions. The effect of SOFA yaw on LOI is inconsistent with regression results. Automatic variation in burner tilt (control algorithm) was required to maintain main steam temperature. Consequently, a change in SOFA yaw was accompanied by a change in burner tilt

(Table 3.13), and the two effects could not be separated. Thus, the impact of SOFA yaw changes on LOI (Figure 3.2) could not be determined with certainty.

Figure 3.3 shows the effect of combustion air distribution on NO_x emissions and LOI. Qualitative designations were used for the different levels of SOFA/CCOFA ratio, SOFA+CCOFA flow and coal air flow, since a quantitative measure of these variables was not available. As expected, higher SOFA/CCOFA ratios and higher SOFA+CCOFA flows reduced NO_x emissions and increased LOI because of greater staging of the combustion air. Regression results suggested that the effect of these two parameters was mainly on NO_x emissions. Again, automatic variation in burner tilt (control algorithm) was required to maintain main steam temperature. Therefore, changes in over-fire air flows (SOFA and/or CCOFA flows) were accompanied by changes in burner tilt (Table 3.13), and the two effects could not be separated. Changes in coal air produced small changes in both NO_x emissions and LOI (Figure 3.3).

3.3.5 Effects of Mill Pattern

Figure 3.4 is a graphical presentation of the test results of Design B (Table 3.13) in which four mill load patterns were tested with three mills in service at both 148 MW and 120 MW boiler loads. Other parameters were set at baseline conditions. A mill bias parameter ß, was used, defined as the distance between the center of mass of the coal flow and the center of the burner zone divided by half the length of the burner zone. This is the same parameter used by Levy, et al., ("NO_x Control and Performance Optimization Through Boiler Fine-Tuning," paper presented at the 1993 Joint Symposium on Stationary Combustion NO_x Control, Miami Beach, Florida, May 24-27, 1993). This parameter is a measure of the vertical distribution of the coal input into the boiler with respect to the center of the burner zone. It is calculated using measured coal feed rates in tons per hour (tph) through the individual mills (A1, B2, A3, and B4) as:

$$\beta = (tph_{A1} + tph_{B2}/3 - tph_{A3}/3 - tph_{B4}) / tph_{total}.$$

The tested mill patterns and the corresponding ß values are shown in Table 3.3. The results shown in Figure 3.4 indicate a strong effect of mill load pattern on both NO_x emissions and LOI. Lower NO_x emissions and lower LOI were obtained at negative ß which corresponded to the upper mills being out of service, with more effective air staging results. Partial combustion accompanied by low NO_x emissions occurs when the lower mills are in service, and combustion is completed as air is added without the coal when a mill at a higher elevation is out of service.

3.3.6 Effects of Boiler Load and Excess O_2

The tests of Design C (Table 3.13) examined the effects of the three most significant parameters affecting NO_x emissions and LOI, namely, boiler load, excess O_2 and mill classifier speed. Other parameters were set at baseline conditions.

Regression analyses were used to identify the statistically significant factors affecting NO_x emissions and LOI, starting with a complete quadratic model with respect to the three independent variables of Design C (boiler load, excess O_2, and mill classifier speed). The final correlations for Design C are shown in Table 3.14. 02 is excess O_2 measured at the economizer outlet, MW is net boiler load, and RPM is mill classifier speed. Except for a dependence of NO_x emissions on quadratic changes in boiler load, quadratic effects and two-parameter interaction effects were not statistically significant. NO_x emissions were directly proportional to linear changes in excess O_2 and mill classifier speed. LOI was directly proportional to linear changes in excess O_2, boiler load and mill classifier speed.

The effects of excess O_2 on NO_x emissions and LOI at the three tested boiler loads (148 MW, 120 MW and 90 MW) are shown in Figure 3.5. As expected, NO_x emissions increased and LOI decreased at higher excess O_2 levels which corresponded to greater excess air. The effects of boiler load changes on NO_x emissions and fly ash LOI, shown in Figure 3.6, were due to two opposing effects. Reduced boiler loads corresponded to lower boiler peak temperatures, and greater overall air/fuel separation (due to air flow through burners taken out of service, without coal flow), which reduced NO_x emissions and increased LOI. Furthermore, at reduced boiler loads, the SOFA air flows and SOFA fractions (of the overall combustion air flow) were lower, which increased NO_x emissions and reduced LOI. The overall effect of boiler load changes (Figure 3.5) was an increase in LOI with increasing boiler load and a quadratic change in NO_x emissions with minimum values obtained at intermediate boiler loads.

The effects of excess O_2 on NO_x emissions and LOI at various mill classifier speeds (72 rpm, 93 rpm and 108 rpm) at 148 MW and 120 MW are shown in Figure 3.7. As expected, higher mill classifier speeds reduced both NO_x emissions and LOI, with a more significant effect on LOI. Higher classifier speeds corresponded to higher pulverized coal fineness.

The results of Design C are presented again in Figures 3.8 and 3.9, showing variations in NO_x emissions and LOI with respect to mill classifier speed at fixed excess O_2 (3.3% nominal) and two boiler loads (Figure 3.8), and at different excess O_2 levels (3.0%, 3.4% and 4.5% nominal) at 120 MW (Figure 3.9). The trends seen in Figures 3.8 and 3.9 are consistent with the observations described earlier.

3.3.7 Variations of NO_x Emissions and LOI

The post-retrofit test results were used to identify conditions that would reduce NO_x emissions while maintaining acceptable unit performance, including salable fly ash, with emphasis on full boiler load (148 MW). Excess O_2 was a significant parameter affecting both NO_x emissions and LOI. This parameter is typically used to select a suitable trade-off between decreasing NO_x emissions and increasing LOI as excess air is reduced. However, the post-retrofit relationship between NO_x emissions and LOI was more complex than the pre-retrofit relationship where a simple inverse relationship was observed. This was attributed to greater sensitivity of post-retrofit NO_x emissions and LOI to process variables, including coal properties, coal fineness and burner tilt.

During the post-retrofit testing, the fly ash LOI was generally above 4% at full boiler load. However, coal composition is an uncontrolled parameter that would greatly affect LOI. Specifically, an increase in ash and/or moisture contents of the coal would decrease LOI, and might be a determining factor in maintaining fly ash LOI below 4%. After the diagnostic tests were completed, the impacts of moisture and ash contents of the coal on flame ignition and LOI were examined. Consequently, a coal with higher ash and higher moisture contents (relative to the coal burned during the post-retrofit tests) was specified, which produced acceptable LOI (below 4%) and acceptable flame ignition point

Increasing mill classifier speed and increasing burner tilt position below the horizontal (negative angles) reduced both NO_x emissions and LOI.

Greater air staging reduced NO_x emissions, with greater sensitivity to changes in SOFA rather than CCOFA. Greater air staging also increased LOI, but the effect was not statistically significant when the effects of other parameters, such as burner tilt, were accounted for.

3.3.8 Predictive Correlations for NO_x Emissions and LOI

One set of correlations (one for NO_x and another for LOI) was derived from Design A and another set was derived from Design C, as shown in Table 3.14. The correlations were combined to generate a single correlation for NO_x emissions and another for LOI by taking the correlation of Design C and adding the factors that were not accounted for from the correlation of Design A. As discussed earlier, typical air staging settings would not be used for long-term operation, and thus, air staging parameters (SOFA/CCOFA and SOFA+CCOFA) were not included in the final correlations. Thus, burner tilt was the only factor that was extracted from the correlation of Design A for both NO_x emissions and LOI. The following correlations were obtained:

$$\text{lb } NO_x/\text{MM Btu} = 0.12 + 0.08*02 + 0.00003*(MW-120)^2 - 0.00093*(RPM-93) + 0.007*TILT \qquad r^2=84\%$$

$$\%\ LOI = 8.1 - 1.08*02 + 0.032*(MW-120) - 0.062*(RPM-93) + 0.155*TILT \qquad r^2=69\%$$

where 02 is excess O_2 measured at the economizer outlet, MW is net boiler load, TILT is burner tilt in degrees from the horizontal, and RPM is mill classifier speed.

Comparisons of measured and predicted NO_x emissions and LOI based on the two derived correlations are presented in Figures 3.10 and 3.11, respectively.

3.4 Conclusions

The Unit 1 post-retrofit diagnostic tests conducted during March of 1994 were analyzed to determine the effects of boiler load, excess O_2, mill classifier speed, combustion air distribution (SOFA flow, CCOFA flow and coal air flow), burner settings (burner tilt, SOFA tilt and SOFA yaw), and mill load patterns on NO_x emissions and LOI. The following conclusions were reached.

1. The average difference between replicated tests was 0.044 lb NO_x/MM Btu and 0.6% LOI. The uncertainty at 95% confidence was ± 0.027 lb NO_x/MM Btu and ± 0.35% LOI. The reproducibility in NO_x emissions had greater uncertainty for the post-retrofit tests than that for the

baseline tests because of NO_x sensitivity to a larger number of parameters in the low-NO_x configuration. The uncertainty in measuring LOI was about the same for the post-retrofit and the baseline tests.

2. Concentration measurements across the two ducts at the economizer outlet showed minor gas stratification.

3. NO_x and NO measurements (in ppm) at the economizer outlet were indistinguishable. NO_2 concentrations, calculated as the difference between NO_x and NO, were estimated at 1-2 ppm.

4. CO was not a consideration in this study, because its concentration at the economizer outlet was always low, varying between 9 ppm and 23 ppm.

5. Increasing burner tilt below the horizontal position reduced NO_x emissions by 0.007 lb/MM Btu per degree change and reduced LOI by 0.16% per degree change.

6. Changes in SOFA tilt produced no significant changes in either NO_x emissions or LOI. SOFA yaw changes (relative to the fuel firing angle) did not significantly change NO_x emissions, and increased LOI. The effect on LOI could not be determined with certainty because SOFA yaw changes were accompanied by changes in burner tilt, and the two effects could not be separated.

7. Greater air staging reduced NO_x emissions, with greater sensitivity to changes in SOFA rather than CCOFA. Greater air staging also increased LOI, but the effect was not statistically significant when the effects of other parameters, such as burner tilt, were accounted for.

8. Taking the upper elevation burners out of service reduced both NO_x emissions and LOI because of more effective air staging. The effect was greater on NO_x emissions. The effect can be quantified if a mill bias parameter is used (see Section 3.3.5).

9. Higher excess O_2 increased NO_x emissions and reduced LOI (see Item 13).

10. In general, higher boiler loads increased both NO_x emissions and LOI (see Item 13).

11. Higher mill classifier speeds (finer coal) reduced both NO_x emissions and LOI, with a more dramatic effect on LOI (see Item 13).

12. The post-retrofit relationship between NO_x and LOI was more complex than the simple trade-off that was observed in baseline testing where NO_x emissions decreased and LOI increased as excess air was reduced. This was attributed to greater sensitivity of the low-NO_x

configuration to process variables, including coal properties. Higher ash and/or moisture coal contents would reduce LOI, with a minor effect on NO_x emissions.

13. The following predictive correlations for NO_x emissions and LOI were derived for normal operation of Unit 1:

$$\text{lb } NO_x/\text{MM Btu} = 0.12 + 0.08*O2 + 0.00003*(MW-120)^2 - 0.00093*(RPM-93) + 0.007*TILT \qquad r^2=84\%$$

$$\%\ LOI = 8.1 - 1.08*O2 + 0.032*(MW-120) - 0.062*(RPM-93) + 0.155*TILT \qquad r^2=69\%$$

where O2 is excess O_2 measured at the economizer outlet, MW is net MW boiler load, TILT is burner tilt in degrees from the horizontal, and RPM is mill classifier speed.

14. During several short-term tests, NO_x emissions were below 0.37 lb/MM Btu. However, fly ash LOI at full boiler load was generally above 4% during the LNCFS-3 optimization test period. After the optimization test program was completed, a series of tests firing coals with higher ash and/or higher moisture contents than the coal burned during the optimization test period achieved less than 4% LOI. The current practice is to operate with optimized LNCFS-3 burner settings and fire a nominal 13,000 Btu/lb (as fired) coal.

15. The short-term, post-retrofit LNCFS-3 test program indicated that NO_x emissions could potentially be reduced to about 0.35 lb/MM Btu at full boiler load, while maintaining salable fly ash.

16. The low-NO_x burner retrofit reduced NO_x emissions from a baseline level of 0.64 lb/MM Btu to a post-retrofit level of 0.39 lb/MM Btu, corresponding to a reduction of about 39%, while maintaining LOI below 4%. The NO_x values were based on short-term test averages and will be verified during the 51-day long-term test. NYSEG believes LNCFS-3 burner retrofit is a cost-effective technology to comply with Title IV of the 1990 Clean Air Act Amendments. To date, burner operations are acceptable.

TABLE 3.1 - UNIT 1 POST-RETROFIT TESTS - PARAMETER SETTINGS

Parameter	Low	Mid	High
1. Boiler Load, MW Net Generation	90	120	148
2. Economizer O2, % (148 MW)	2.8	3.3	4.3
Economizer O2, % (120 MW)	3.0	3.4	4.5
Economizer O2, % (90 MW)	3.1	3.9	4.9
3. Burner Tilt, Degrees From Horizontal	-10	0	10
4. SOFA Tilt, Degrees From Horizontal	-10	5	10
5. SOFA Yaw, Degrees From Firing Angle	-12	0	12
6. SOFA/CCOFA Ratio -1 Minimum SOFA, Maximum CCOFA 0 Baseline 1 Maximum SOFA, Minimum CCOFA	-1	0	1
7. SOFA+CCOFA Flow -1 Minimum SOFA+CCOFA 0 Baseline 1 Maximum SOFA+CCOFA	-1	0	1
8. Coal Air Flow -1 Minimum Coal Air, 35% Open Damper 0 Baseline 1 Maximum Coal Air, 100% Open Damper	-1	0	1
9. Mill Classifier Speed, rpm	70	93	110

10. Mill Patterns: X Coal Flow On
- Coal Flow Off

Burner Elevation	Mill Pattern (3 Mills) 1	2	3	4
A1	X	X	X	-
B2	X	X	-	X
A3	X	-	X	X
B4	-	X	X	X

Normal Mill Pattern: Full Load, All Elevations in Service
Reduced Load, Pattern 1

TABLE 3.2 - UNIT 1 POST-RETROFIT TESTS - DESIGN A, FULL BOILER LOAD TESTS

Boiler Load at 148 MW, With All Burner Elevations in Service

Test No.	ECON 02 %	MAIN TILT deg	SOFA TILT deg	SOFA YAW deg	SOFA/ CCOFA RATIO	SOFA+ CCOFA FLOW	COAL AIR FLOW	MILL CLASS rpm
* 1	3.3	0	5	0	Mid	Mid	Mid	93
* 2	4.3	0	5	0	Mid	Mid	Mid	93
* 3	2.8	0	5	0	Mid	Mid	Mid	93
4	3.3	+10	5	0	Mid	Mid	Mid	93
5	3.3	-10	5	0	Mid	Mid	Mid	93
6	3.3	0	+10	0	Mid	Mid	Mid	93
7	3.3	0	-10	0	Mid	Mid	Mid	93
8	3.3	0	5	+12	Mid	Mid	Mid	93
9	3.3	0	5	-12	Mid	Mid	Mid	93
10	3.3	0	5	0	High	Mid	Mid	93
11	3.3	0	5	0	Low	Mid	Mid	93
12	3.3	0	5	0	Mid	High	Mid	93
13	3.3	0	5	0	Mid	Low	Mid	93
14	3.3	0	5	0	Mid	Mid	High	93
15	3.3	0	5	0	Mid	Mid	Low	93
16	3.3	0	5	0	Mid	Mid	Mid	110
17	3.3	0	5	0	Mid	Mid	Mid	70

* Replicated Tests

TABLE 3.3 - UNIT 1 POST-RETROFIT TESTS - DESIGN B, MILL PATTERN TESTS

No.	LOAD NET MW	MILL PATTERN No.	MILL BIAS PARAMETER(ß+)
1	148	1	0.250
2	148	2	0.083
3	148	3	-0.083
4	148	4	-0.250
* 5	120	1	0.250
6	120	2	0.083
7	120	3	-0.083
8	120	4	-0.250

Mill Patterns: X Coal Flow On
- Coal Flow Off

Burner Elevation	Mill Pattern (3 Mills) 1	2	3	4
A1	X	X	X	-
B2	X	X	-	X
A3	X	-	X	X
B4	-	X	X	X

Normal Mill Pattern: Full Load, All Elevations in Service
Reduced Load, Pattern 1

* Replicated Tests

+ $\beta = (tph_{A1} + tph_{B2}/3 - tph_{A3}/3 - tph_{B4}) / tph_{total}$.

TABLE 3.4 - UNIT 1 POST-RETROFIT TESTS - DESIGN C, VARIABLE BOILER LOAD TESTS

Other Settings: 0 Burner Tilt, 5 SOFA Tilt, 0 SOFA Yaw, Auto Damper Positions

No.	LOAD NET MW	ECON O2 %	MILL CLASS rpm
*# 1	148	4.3	93
*# 2	148	3.3	93
*# 3	148	2.8	93
4	120	4.5	93
*+ 5	120	3.4	93
6	120	3.0	93
7	90	4.9	93
8	90	3.9	93
9	90	3.1	93
#10	148	3.3	110
11	90	3.9	110
12	120	4.5	110
13	120	3.0	110
14	120	3.4	110
#15	148	3.3	70
16	90	3.9	70
17	120	4.5	70
18	120	3.0	70
19	120	3.4	70

* Replicated Tests

Tests C2, C1, C3, C10, C15 are the same as Tests A1, A2, A3, A16, A17.

+ Test C5 is the same as Test B5.

TABLE 3.5 - UNIT 1 POST-RETROFIT TESTS - TEST DESCRIPTION

Test No.	Data Collection DATE	Data Collection Time	Boiler Load	Description of the Test	Design No. Tables 2-4
1	03/22/94	14:00-16:00	Full	Baseline	A 1, C 2
2	03/22/94	17:00-19:00	Full	Maximum Overfire Air (SOFA+CCOFA)	A12
3	03/22/94	22:30-00:00	Mid	Baseline	B 5, C 5
4	03/23/94	01:15-02:30	Mid	High O2 (4.5%)	C 4
5	03/23/94	03:30-05:15	Mid	Low O2 (2.8%)	C 6
6	03/23/94	09:00-11:00	Full	Minimum Overfire Air (SOFA+CCOFA)	A13
7	03/23/94	12:00-14:00	Full	High O2 (4.3%)	A 2, C 1
8	03/23/94	14:45-16:45	Full	Low O2 (2.7%)	A 3, C 3
9	03/23/94	18:00-19:15	Full	High SOFA Tilt (+10 deg)	A 6
10	03/23/94	22:15-00:00	Low	Baseline	C 8
11	03/24/94	00:45-02:30	Low	Low O2 (3.0%)	C 9
12	03/24/94	03:30-05:00	Low	High O2 (5.0%)	C 7
13	03/24/94	12:30-14:00	Full	SOFA Yaws From Top -12 -12 -12 Deg	A 9
14	03/24/94	15:45-17:00	Full	SOFA Yaws From Top +12 +6 0 Deg	A 8
15	03/24/94	17:45-19:00	Full	SOFA Yaws From Top 0 -6 -12 Deg	
16	03/24/94	22:30-00:00	Mid	Mill B2 Off	B 7
17	03/25/94	01:30-03:00	Mid	Mill A3 Off	B 6
18	03/25/94	04:00-05:30	Mid	Mill A1 Off	B 8
19	03/25/94	09:30-10:45	Full	Low Coal Air (35% Open)	A15
20	03/25/94	12:00-13:30	Full	High Coal Air (100% Open)	A14
21	03/25/94	15:00-16:15	Full	High Fine (110 rpm) Mid O2 (3.3%)	A16, C10
22	03/26/94	09:30-11:00	Mid	High Fine (110 rpm) Mid O2 (3.4%)	C14
23	03/26/94	12:15-14:00	Mid	Low Fine (70 rpm) Mid O2 (3.4%)	C19
24	03/26/94	15:15-16:45	Mid	Maximum Overfire Air (SOFA+CCOFA)	
25	03/26/94	17:30-19:00	Mid	Baseline	B 5, C 5
26	03/27/94	11:45-13:00	Full	Baseline	A 1, C 2
27	03/27/94	14:00-15:00	Full	High O2 (4.3%)	A 2, C 1
28	03/27/94	16:00-17:00	Full	Low SOFA Tilt (-10 deg)	A 7
29	03/28/94	09:30-11:00	Full	Low Fine (70 rpm) High O2 (4.3%)	
30	03/28/94	12:45-14:15	Full	High Fine (110 rpm) Low O2 (2.8%)	
31	03/28/94	15:15-17:00	Full	Maximum SOFA, Minimum CCOFA	A10
32	03/28/94	17:45-19:15	Full	Minimum SOFA, Maximum CCOFA	A11
33	03/29/94	09:30-11:00	Full	Mill A1 Off	B 4
34	03/29/94	12:30-14:30	Full	Mill B2 Off	B 3
35	03/29/94	15:45-17:00	Full	Mill A3 Off	B 2
36	03/29/94	18:30-19:30	Full	Mill B4 Off	B 1
37	03/29/94	23:30-00:00	Low	SOFA Yaws From Top +12 +12 +12 Deg	
38	03/30/94	02:00-03:00	Low	SOFA Yaws From Top -12 -12 -12 Deg	
39	03/30/94	01:00-01:30	Low	SOFA Yaws From Top +12 0 -12 Deg	
40	03/28/94	22:30-23:30	Mid	High Fine (110 rpm) Low O2 (3.0%)	C13
41	03/29/94	01:15-02:30	Mid	Low Fine (70 rpm) High O2 (4.5%)	C17
42	03/29/94	03:15-04:00	Mid	Low Fine (70 rpm) Low O2 (3.0%)	C18
43	03/29/94	05:00-06:15	Mid	High Fine (110 rpm) High O2 (4.5%)	C12
44	03/30/94	09:15-10:45	Full	Low Fine (70 rpm) Mid O2 (3.3%)	A17, C15
45	03/30/94	12:15-13:45	Full	High Burner Tilt (+10 deg)	A 4
46	03/30/94	17:45-19:30	Full	Low Burner Tilt (-10 deg)	A 5
47	03/30/94	15:30-16:30	Full	Baseline	A 1, C 2
48	03/30/94	23:15-00:30	Low	High Fine (110 rpm) Mid O2 (3.9%)	C11
49	03/31/94	02:15-03:30	Low	Low Fine (70 rpm) Mid O2 (3.9%)	C16
50	03/31/94	04:30-06:00	Low	Maximum Overfire Air (SOFA+CCOFA)	
51	03/31/94	08:15-10:00	Full	Baseline	A 1, C 2
52	03/31/94	10:30-12:00	Full	Low O2 (2.7%)	A 3, C 3

TABLE 3.6 - UNIT 1 POST-RETROFIT TESTS - EXPERIMENTAL TEST CONDITIONS

Test No.	LOAD NET MW	ECON O2 %	MAIN TILT deg	SOFA TILT deg	SOFA YAW deg	SOFA/ CCOFA RATIO	SOFA+ CCOFA FLOW	COAL AIR FLOW	MILL CLASS rpm
1	148	3.32	-1	5	0	0	0	0	93
2	148	3.29	-1	5	0	0	1	0	93
3	121	3.41	-1	5	0	0	0	0	94
4	121	4.46	0	6	0	0	0	0	93
5	120	2.78	0	5	0	0	0	0	94
6	148	3.29	8	14	0	0	-1	0	93
7	147	4.30	8	13	0	0	0	0	92
8	149	2.71	5	10	0	0	0	0	92
9	149	3.26	1	9	0	0	0	0	92
10	93	3.91	2	7	0	0	0	0	90
11	92	3.10	3	7	0	0	0	0	90
12	91	4.90	1	7	0	0	0	0	90
13	148	3.29	9	14	Comb1	0	0	0	93
14	148	3.26	7	12	Comb2	0	0	0	93
15	149	3.23	5	10	Comb3	0	0	0	92
16	121	3.43	8	13	0	0	0	0	94
17	124	3.40	6	12	0	0	0	0	94
18	119	3.39	8	12	0	0	0	0	95
19	148	3.31	0	5	0	0	0	-1	93
20	147	3.29	0	5	0	0	0	1	93
21	149	3.30	0	5	0	0	0	0	108
22	123	3.43	3	8	0	0	0	0	107
23	119	3.43	6	11	0	0	0	0	74
24	122	3.42	7	12	0	0	0	0	95
25	121	3.44	6	11	0	0	0	0	96
26	149	3.34	0	3	0	0	0	0	93
27	148	4.26	0	3	0	0	0	0	93
28	150	3.27	0	-10	0	0	0	0	93
29	145	4.26	2	6	0	0	0	0	72
30	147	2.81	-2	3	0	0	0	0	108
31	146	3.34	1	6	0	1	0	0	93
32	147	3.30	-5	0	0	-1	0	0	93
33	146	3.39	-1	5	0	0	0	0	100
34	149	3.31	0	6	0	0	0	0	100
35	151	3.27	0	6	0	0	0	0	99
36	147	3.29	0	6	0	0	0	0	100
37	93	3.81	4	9	Comb1	0	0	0	91
38	92	3.90	2	8	Comb2	0	0	0	92
39	93	3.86	3	9	Comb3	0	0	0	91
40	121	3.03	-1	4	0	0	0	0	108
41	120	4.52	-4	1	0	0	0	0	73
42	119	3.12	0	6	0	0	0	0	77
43	121	4.39	-3	2	0	0	0	0	106
44	147	3.28	3	8	0	0	0	0	72
45	150	3.33	6	1	0	0	0	0	92
46	149	3.35	-7	1	0	0	0	0	93
47	149	3.34	0	1	0	0	0	0	93
48	90	3.95	2	1	0	0	0	0	108
49	90	4.00	0	3	0	0	0	0	72
50	91	3.79	0	5	0	0	0	0	91
51	149	3.32	-1	5	0	0	0	0	93
52	147	2.75	0	5	0	0	0	0	93

TABLE 3.7 - UNIT 1 POST-RETROFIT TESTS - GAS STRATIFICATION DATA

	Test 7: Full Load, High O2				Test 8: Full Load, Low O2				Test 11: Low Load, Low O2				Test 12: Low Load, High O2			
Probe	% O2	ppm CO	% CO2	ppm NOx	% O2	ppm CO	% CO2	ppm NOx	% O2	ppm CO	% CO2	ppm NOx	% O2	ppm CO	% CO2	ppm NOx
0	7.65	10	11.65	265	5.19	14	13.79	246	5.31	9	13.76	253	7.16	9	12.09	291
1	5.68	12	13.33	323	3.58	17	14.99	260	4.15	11	14.70	270	5.98	10	13.12	313
2	6.63	15	12.52	288	4.88	19	13.93	233	4.54	11	14.34	270	6.06	10	13.04	309
3	6.33	12	12.76	294	3.76	15	14.85	253	4.33	10	14.52	273	6.18	9	12.95	306
4	5.47	14	13.47	306	3.87	18	14.82	262	4.09	12	14.67	278	6.02	10	13.02	309
5	5.05	15	13.78	309	3.66	18	14.94	262	3.91	12	14.82	279	5.66	11	13.31	312
6	5.55	12	13.38	284	3.74	15	14.91	264	4.25	8	14.53	277	6.08	9	12.99	314
7	5.25	13	13.62	294	3.68	16	14.89	269	3.76	9	14.88	279	5.76	9	13.26	319
8	5.17	14	13.65	296	3.60	17	14.98	260	3.70	11	14.95	274	5.78	9	13.22	322
9	5.78	13	13.16	286	3.72	15	14.90	257	4.35	10	14.42	276	5.96	8	13.04	317
10	5.05	13	13.76	294	3.44	16	15.06	259	3.89	10	14.76	281	5.96	8	13.07	321
11	5.31	13	13.53	295	3.89	16	14.77	259	4.15	10	14.59	279	6.02	9	12.99	325
12	5.96	12	13.04	289	3.89	14	14.73	247	4.52	10	14.31	278	6.23	8	12.84	312
13	5.03	13	13.72	300	3.09	16	15.35	265	3.78	10	14.85	289	5.66	9	13.30	330
14	5.33	12	13.50	302	3.15	17	15.26	259	4.03	10	14.72	284	5.76	8	13.22	334
15	6.31	12	12.69	275	4.25	19	14.39	238	5.43	9	13.70	258	6.51	8	12.60	310
16	5.74	15	13.16	283	3.52	23	14.96	248	4.70	11	14.36	278	5.90	10	13.11	320
17	6.00	16	12.94	284	3.54	39	14.96	245	4.72	11	14.35	272	6.00	9	12.98	317

Number = Probe Location at Economizer Outlet:
P = Utility Port Location

North (B) Duct

	2		5		8
	1		4		7
	0		3		6
P	P	P	P	P	P

South (A) Duct

11		14		17	
10		13		16	
9		12		15	
P	P	P	P	P	P

TABLE 3.8 - UNIT 1 POST-RETROFIT TESTS - FLY ASH ANALYSES

Test	Cyclone Collected Ash			ESP Hopper "C" Ash		
	Dry	Dry	100-%Ash	Dry	Dry	100-%Ash
No.	%C	%Ash	LOI	%C	%Ash	LOI
1	5.34	93.82	6.18	4.24	95.44	4.56
2	4.78	94.79	5.21	4.35	95.18	4.82
3				4.36	95.14	4.86
4				2.68	97.05	2.95
5				4.34	95.23	4.77
6	4.60	94.35	5.65	3.58	96.03	3.97
7	4.16	95.18	4.82	4.32	95.24	4.76
8	7.11	91.98	8.02	5.83	93.75	6.25
9	6.06	93.30	6.70	4.34	95.19	4.81
10				2.94	96.69	3.31
11				3.77	95.81	4.19
12				2.29	97.45	2.55
13	5.12	93.25	6.75	4.66	94.84	5.16
14	6.59	92.58	7.42	6.46	93.00	7.00
15	6.90	92.10	7.90			
16				4.37	95.31	4.69
17				4.80	94.73	5.27
18				5.36	94.12	5.88
19	4.90	94.51	5.49	2.96	96.77	3.23
20	6.18	92.91	7.09	3.15	96.67	3.33
21	4.07	95.07	4.93	4.42	95.32	4.68
22	3.95	95.57	4.43	3.00	96.70	3.30
23	6.53	92.68	7.32	5.83	93.81	6.19
24	5.61	93.78	6.22	5.66	94.18	5.82
25	5.22	94.03	5.97	5.36	94.20	5.80
26	5.83	93.59	6.41	4.60	94.94	5.06
27	5.03	94.10	5.90	3.70	95.96	4.04
28	4.65	94.93	5.07	4.30	95.25	4.75
29	6.33	92.47	7.53	5.30	94.21	5.79
30	6.23	93.12	6.88	3.63	96.03	3.97
31	5.78	93.46	6.54	4.58	94.98	5.02
32	3.82	95.80	4.20	2.19	97.72	2.28
33	5.06	94.28	5.72	4.78	94.80	5.20
34	5.57	93.35	6.65	5.43	94.13	5.87
35	5.30	94.32	5.68	5.44	94.19	5.81
36	5.46	93.90	6.10	6.52	93.10	6.90
37				3.62	96.00	4.00
38				3.35	96.35	3.65
39				3.51	96.07	3.93
40				2.99	96.70	3.30
41				4.30	95.21	4.79
42				5.84	93.66	6.34
43				2.16	97.56	2.44
44	6.52	92.24	7.76	6.55	92.97	7.03
45	5.63	92.70	7.30	6.16	93.44	6.56
46				4.04	95.49	4.51
47	4.56	92.90	7.10	4.29	95.18	4.82
48				2.36	97.28	2.72
49				2.09	97.60	2.40
50				1.79	97.91	2.09
51				3.68	95.90	4.10
52				5.66	93.94	6.06

TABLE 3.9 - UNIT 1 POST-RETROFIT TESTS - COAL ANALYSES

Coal Analyses: Moisture, Btu, Proximate, Ultimate

Date	As Det %H2O	Dry %VM	Dry Btu	Dry %C	Dry %H	Dry %N	Dry %S	Dry %Ash	Dry %O	EPA Fc Factor
03/22/94	1.69	37.38	14057	78.69	5.17	1.59	1.65	6.85	6.05	1797
03/23/94	1.71	37.57	14081	78.83	5.22	1.39	1.66	6.36	6.54	1797
03/24/94	1.56	38.08	14073	78.40	5.14	1.48	1.55	6.30	7.13	1788
03/25/94	1.59	37.71	14113	79.04	5.21	1.37	1.61	6.11	6.66	1798
03/26/94	1.58	37.71	13948	77.95	5.12	1.40	1.63	7.02	6.88	1794
03/27/94	1.62	37.35	13817	77.15	5.08	1.42	1.61	7.85	6.89	1792
03/28/94	1.68	38.17	14041	78.46	5.16	1.46	1.61	6.72	6.59	1794
03/29/94	1.61	38.05	14045	78.80	5.22	1.35	1.58	6.52	6.53	1801
03/30/94	1.77	37.78	14052	78.87	5.17	1.35	1.52	6.52	6.57	1802
03/31/94	1.73	37.30	13966	79.05	5.16	1.34	1.62	6.97	5.86	1817

TABLE 3.10 - UNIT 1 POST-RETROFIT TESTS - GAS ANALYSES DATA

Test No.	ECON O2 %	Energy Systems Associates O2 %	CO ppm	CO2 %	NOx ppm	Milliken Plant CEM's CO2 %	NOx ppm	SO2 ppm	WDPF NOx lb/MM Btu
1	3.32	4.31	19	14.30	251	11.70	221	842	0.401
2	3.29	4.45	23	14.11	213	11.57	189	836	0.346
3	3.41	3.93	9	14.78	238	11.59	201	851	0.372
4	4.46	5.00	9	13.91	276	10.96	232	791	0.451
5	2.78	3.41	14	15.07	227	11.93	190	851	0.340
6	3.29	4.49	12	14.16	346	11.60	306	824	0.564
7	4.30	5.55	14	13.44	291	10.92	257	771	0.503
8	2.71	3.66	19	14.98	247	12.30	218	868	0.380
9	3.26	4.41	14	14.42	261	11.69	227	819	0.418
10	3.91	5.17	10	13.96	273	10.87	225	770	0.445
11	3.10	4.31	10	14.59	264	11.30	222	805	0.415
12	4.90	6.00	10	13.05	307	10.34	261	726	0.539
13	3.29	4.57	18	14.24	274	11.61	242	834	0.443
14	3.26	4.42	14	14.52	260	11.70	226	839	0.414
15	3.23	4.40	15	14.38	251	11.53	219	832	0.404
16	3.43	4.72	11	13.97	281	11.08	242	789	0.468
17	3.40	3.98	11	14.55	266	11.33	226	814	0.425
18	3.39	3.48	18	14.98	231	11.58	196	835	0.360
19	3.31	4.75	9	14.02	256	11.41	223	823	0.414
20	3.29	4.46	11	14.07	255	11.82	222	849	0.401
21	3.30	4.32	10	14.35	242	11.96	212	820	0.376
22	3.43	4.36	11	14.42	244	11.50	216	886	0.401
23	3.43	4.42	14	14.33	275	11.39	244	886	0.456
24	3.42	4.55	15	14.26	204	11.20	180	885	0.344
25	3.44	4.08	15	14.62	259	11.48	229	886	0.424
26	3.34	4.51	16	13.96	267	11.31	240	798	0.459
27	4.26	5.66	16	13.00	294	10.62	266	737	0.535
28	3.27	3.91	17	14.56	254	11.70	228	831	0.414
29	4.26	5.22	15	13.69	292	10.89	232	710	0.518
30	2.81	3.90	16	14.64	213	12.11	195	815	0.343
31	3.34	4.58	18	14.14	184	11.64	170	827	0.315
32	3.30	4.42	15	14.36	268	11.75	249	825	0.451
33	3.39	4.32	16	14.43	207	11.61	186	795	0.341
34	3.31	4.42	17	14.31	227	11.66	206	788	0.377
35	3.27	4.15	20	14.65	245	11.85	218	816	0.392
36	3.29	4.17	17	14.71	226	11.87	204	828	0.368
37	3.81	4.88	15	14.23	300	10.97	263	798	0.514
38	3.90	4.92	15	14.23	282	11.00	249	788	0.488
39	3.86	4.95	15	14.19	289	10.93	255	790	0.497
40	3.03	4.00	14	14.81	206	11.85	186	811	0.337
41	4.52	5.57	15	13.58	278	10.83	256	757	0.505
42	3.12	4.11	14	14.71	219	11.88	203	825	0.358
43	4.39	5.44	13	13.71	253	10.94	229	728	0.448
44	3.28	4.35	15	14.56	248	11.78	227	870	0.410
45	3.33	4.32	19	14.55	279	11.85	255	851	0.461
46	3.35	4.24	13	14.57	205	11.80	187	867	0.336
47	3.34	4.65	12	14.31	251	11.77	223	859	0.408
48	3.95	4.85	13	14.07	264	10.91	238	774	0.466
49	4.00	4.78	13	14.09	269	10.91	239	823	0.472
50	3.79	4.96	11	13.93	235	10.70	208	768	0.414
51	3.32	4.05	16	14.56	225	12.01	204	883	0.366
52	2.75	3.59	18	14.81	216	12.36	195	900	0.337

TABLE 3.11 - UNIT 1 POST-RETROFIT TESTS - TEST PARAMETERS

Test No	Coal Feed tph	Primary Air kpph	Primary Air F	Sec Air kpph	Stack Gas Flow scfm	Stack Gas Flow F	Gross Load MW	Air HTR Outlet F	Main Steam F	Main Steam psig	Main Steam kpph	Reheat Steam psig	Reheat Steam F	Dampers, % Open SOFA UP	SOFA MID	SOFA LOW	CCOFA UP	CCOFA LOW
1	51	221	158	936	406	295	151	311	1002	1838	1055	448	1002	12	38	53	53	14
2	50	224	157	947	406	296	151	311	1005	1838	1057	449	1005	18	48	56	61	14
3	41	225	157	753	339	279	123	297	1006	1826	838	355	1003	2	35	42	50	9
4	40	223	157	812	354	282	124	299	1005	1826	839	356	1002	3	34	42	50	8
5	39	223	157	728	332	284	123	303	1005	1825	831	353	1004	4	34	42	49	7
6	52	223	157	948	410	312	152	309	994	1839	1063	452	997	7	12	11	37	6
7	52	221	158	1026	308	366	151	308	997	1838	1059	450	993	9	35	50	50	9
8	51	221	158	914	392	293	152	307	1001	1839	1064	453	1005	9	34	50	50	9
9	51	219	157	949	402	291	152	307	1003	1839	1065	453	1004	9	34	49	50	9
10	32	209	157	615	288	276	96	293	1000	1816	631	269	979	2	28	41	50	9
11	33	209	157	569	265	274	95	297	972	1816	636	270	942	3	3	41	50	9
12	33	209	157	639	297	273	94	292	979	1816	625	267	961	3	3	42	50	9
13	51	217	159	949	401	297	151	312	1000	1838	1060	451	1004	9	35	50	50	9
14	50	216	159	950	397	297	151	311	1001	1838	1058	449	1000	9	35	50	50	9
15	49	214	159	951	400	296	152	311	1004	1838	1060	451	1005	8	35	49	50	9
16	42	224	158	795	356	276	124	291	1005	1825	840	356	1001	2	35	42	50	9
17	43	223	162	785	357	273	127	291	1005	1829	868	368	997	3	35	43	50	9
18	42	225	160	739	344	278	122	298	1004	1825	833	351	991	3	35	42	50	9
19	52	223	159	944	397	292	151	310	1005	1837	1054	448	1003	9	35	49	50	9
20	53	222	159	928	364	316	150	308	997	1837	1052	447	997	8	35	49	50	9
21	51	221	159	926	314	337	151	308	1000	1838	1066	453	998	9	35	50	50	9
22	41	232	157	765	350	280	126	298	1005	1827	856	363	1005	4	43	43	58	13
23	42	235	156	744	344	278	121	297	999	1824	829	350	992	9	45	44	59	14
24	42	235	157	779	351	278	125	298	1005	1826	846	359	1004	19	49	59	64	11
25	43	235	157	755	347	279	124	299	1005	1826	845	358	1004	3	35	43	50	10
26	51	218	158	968	419	293	152	309	1005	1839	1066	453	1004	10	35	50	50	9
27	51	219	158	1063	433	294	151	307	1005	1838	1058	450	1004	10	35	50	50	9
28	51	224	158	942	399	296	153	312	1004	1839	1074	457	1006	10	35	50	50	9
29	49	223	158	977	413	292	147	307	1005	1836	1027	437	1007	12	36	49	46	6
30	48	220	158	910	399	291	150	309	993	1837	1045	447	1005	13	37	53	45	5

TABLE 3.11 (Continued)

Test No	Coal Feed tph	Primary Air kpph	Primary Air F	Sec Air kpph	Stack Gas Flow scfm	Stack Gas Flow F	Gross Load MW	Air HTR Outlet F	Main Steam F	Main Steam psig	Main Steam kpph	Reheat Steam psig	Reheat Steam F	Dampers, % Open SOFA UP	SOFA MID	SOFA LOW	CCOFA UP	CCOFA LOW
31	52	226	158	941	404	293	149	309	1000	1837	1038	442	1001	48	73	73	8	9
32	50	221	157	942	402	293	150	310	1005	1837	1051	446	1004	6	7	7	98	95
33	52	243	157	929	398	286	149	300	1002	1836	1039	441	1004	9	35	49	49	10
34	52	247	156	952	402	286	152	301	1003	1838	1062	451	1003	8	35	49	49	10
35	50	240	159	953	404	289	154	303	1002	1840	1081	459	1002	8	34	49	48	10
36	51	249	156	924	400	286	150	301	993	1837	1051	447	995	7	34	50	48	10
37	33	217	157	597	286	275	96	293	1006	1815	630	268	998	2	28	41	26	10
38	34	217	156	590	290	276	96	294	1004	1815	626	267	995	3	29	42	29	9
39	34	219	156	595	285	275	95	294	1004	1815	627	268	995	3	29	41	28	9
40	42	232	157	748	341	278	124	296	1003	1826	842	357	1004	4	35	42	50	10
41	43	236	157	817	356	277	123	295	1003	1824	832	353	1006	4	34	42	50	10
42	44	240	157	748	341	276	122	293	1004	1824	833	351	990	4	34	42	50	10
43	44	233	156	818	371	277	124	293	1003	1826	841	357	1006	5	34	43	50	10
44	53	229	155	927	405	293	150	310	999	1838	1054	448	996	9	34	49	49	8
45	50	225	155	937	404	295	153	312	1003	1839	1071	456	1008	8	34	49	49	8
46	50	221	156	935	405	293	152	311	992	1839	1068	455	995	6	34	49	48	8
47	52	225	155	946	403	294	153	310	1000	1839	1069	455	1006	7	34	50	49	8
48	33	208	152	580	280	276	93	296	991	1815	618	263	969	2	27	21	50	2
49	34	209	152	571	276	271	94	290	1003	1815	612	261	993	4	27	24	52	5
50	35	212	152	581	277	272	94	293	1003	1816	612	262	998	5	6	34	93	8
51	50	224	157	916	396	292	151	311	1002	1838	1059	450	1003	12	36	52	49	8
52	52	223	157	889	391	293	150	312	1001	1837	1048	445	1002	13	37	53	49	7

TABLE 3.12 - UNIT 1 POST-RETROFIT TESTS - EXPERIMENTAL ERROR CALCULATIONS

Replicates	NO_x Measurements, lb/MM Btu 1	2	3	4	SS	DF	|d|
7, 27	0.503	0.535			0.001	1	0.032
8, 52	0.380	0.337			0.001	1	0.043
1, 26 47, 51	0.401	0.459	0.408	0.366	0.004	3	0.047
3, 25	0.372	0.424			0.001	1	0.052

Replicates	LOI Measurements 1	2	3	4	SS	DF	|d|
7, 27	4.76	4.04			0.259	1	0.72
8, 52	6.25	6.06			0.018	1	0.19
1, 26 47, 51	4.56	5.06	4.82	4.10	0.507	3	0.52
3, 25	4.86	5.80			0.442	1	0.94

		NO_x lb/MM Btu	LOI %
SS = Sum of Squares = Σ $(y_i - y_{avg})$	$SS_{overall}$	0.007	1.226
DF = Degrees of Freedom = No. Replicates -1	$DF_{overall}$	6	6
σ = Standard Deviation = $\sqrt{(SS_{overall}/DF_{overall})}$	σ	0.035	0.452
95% CI = 95% Confidence Interval = $t^*\sigma/\sqrt{N}$	95% CI	0.027	0.350
$\|d\|$ = Absolute Difference Between Replicates	$\|d\|_{avg}$	0.044	0.593

TABLE 3.13 - UNIT 1 POST-RETROFIT TESTS - REDUCED DATA MATRIX

No.	LOAD NET MW	ECON O2 %	MAIN TILT deg	SOFA TILT deg	SOFA YAW deg	SOFA/ CCOFA RATIO	SOFA+ CCOFA FLOW	COAL AIR FLOW	MILL CLASS rpm	WDPF NOx lb/MM Btu	LOI %
Design A:											
1	149	3.33	-0	4	0	0	0	0	93	0.409	4.63
2	148	4.28	4	8	0	0	0	0	93	0.519	4.40
3	148	2.73	3	8	0	0	0	0	93	0.358	6.16
4	150	3.33	6	1	0	0	0	0	92	0.461	6.56
5	149	3.35	-7	1	0	0	0	0	93	0.336	4.51
6	149	3.26	1	9	0	0	0	0	92	0.418	4.81
7	150	3.27	0	-10	0	0	0	0	93	0.414	4.75
8	148	3.26	7	12	6	0	0	0	93	0.414	7.00
9	148	3.29	9	14	-12	0	0	0	93	0.443	5.16
10	146	3.34	1	6	0	1	0	0	93	0.315	5.02
11	147	3.30	-5	0	0	-1	0	0	93	0.451	2.28
12	148	3.29	-1	5	0	0	1	0	93	0.346	4.82
13	148	3.29	8	14	0	0	-1	0	93	0.564	3.97
14	147	3.29	0	5	0	0	0	1	93	0.401	3.33
15	148	3.31	0	5	0	0	0	-1	93	0.414	3.23
16	149	3.30	0	5	0	0	0	0	108	0.376	4.68
17	147	3.28	3	8	0	0	0	0	72	0.410	7.03
Design B:											
1	147	3.29	0	6	0	0	0	0	100	0.368	6.90
2	151	3.27	0	6	0	0	0	0	99	0.392	5.81
3	149	3.31	0	6	0	0	0	0	100	0.377	5.87
4	146	3.39	-1	5	0	0	0	0	100	0.341	5.20
5	121	3.43	3	8	0	0	0	0	95	0.398	5.33
6	124	3.40	6	12	0	0	0	0	94	0.425	5.27
7	121	3.43	8	13	0	0	0	0	94	0.468	4.69
8	119	3.39	8	12	0	0	0	0	95	0.360	5.88
Design C:											
1	148	4.28	4	8	0	0	0	0	93	0.519	4.40
2	149	3.33	-0	4	0	0	0	0	93	0.409	4.63
3	148	2.73	3	8	0	0	0	0	93	0.358	6.16
4	121	4.46	0	6	0	0	0	0	93	0.451	2.95
5	121	3.43	3	8	0	0	0	0	95	0.398	5.33
6	120	2.78	0	5	0	0	0	0	94	0.340	4.77
7	91	4.90	1	7	0	0	0	0	90	0.539	2.55
8	93	3.91	2	7	0	0	0	0	90	0.445	3.31
9	92	3.10	3	7	0	0	0	0	90	0.415	4.19
10	149	3.30	0	5	0	0	0	0	108	0.376	4.68
11	90	3.95	2	1	0	0	0	0	108	0.466	2.72
12	121	4.39	-3	2	0	0	0	0	106	0.448	2.44
13	121	3.03	-1	4	0	0	0	0	108	0.337	3.30
14	123	3.43	3	8	0	0	0	0	107	0.401	3.30
15	147	3.28	3	8	0	0	0	0	72	0.410	7.03
16	90	4.00	0	3	0	0	0	0	72	0.472	2.40
17	120	4.52	-4	1	0	0	0	0	73	0.505	4.79
18	119	3.12	0	6	0	0	0	0	77	0.358	6.34
19	119	3.43	6	11	0	0	0	0	74	0.456	6.19

TABLE 3.14 - UNIT 1 POST-RETROFIT TESTS - NO_x AND LOI CORRELATIONS

FINAL CORRELATIONS, SET A:

NOX = 0.0811 - 0.0771 (S+C) + 0.0967 O2 - 0.0912 (S/C) + 0.00710 TILT

Predictor	Coef	Stdev	t-ratio	p
Constant	0.08108	0.06273	1.29	0.221
(S+C)	-0.07706	0.01634	-4.72	0.000
O2	0.09672	0.01883	5.14	0.000
(S/C)	-0.09123	0.01566	-5.83	0.000
TILT	0.007097	0.001399	5.07	0.000

s = 0.02133 R-sq = 91.4% R-sq(adj) = 88.5%

LOI = 4.58 + 0.155 TILT

Predictor	Coef	Stdev	t-ratio	p
Constant	4.5784	0.3015	15.18	0.000
TILT	0.15541	0.06732	2.31	0.036

s = 1.149 R-sq = 26.2% R-sq(adj) = 21.3%

FINAL CORRELATIONS, SET C:

NOX = 0.118 + 0.0805 O2 + 0.000031 (MW-120)*(MW-120) - 0.000929 (RPM-93)

Predictor	Coef	Stdev	t-ratio	p
Constant	0.11796	0.02932	4.02	0.001
O2	0.080456	0.007901	10.18	0.000
(MW-120)2	0.00003088	0.00001196	2.58	0.021
(RPM-93)	-0.0009290	0.0003936	-2.36	0.032

s = 0.02120 R-sq = 89.3% R-sq(adj) = 87.1%

LOI = 8.11 - 1.08 O2 + 0.0318 (MW-120) - 0.0624 (RPM-93)

Predictor	Coef	Stdev	t-ratio	p
Constant	8.110	1.021	7.94	0.000
O2	-1.0756	0.2764	-3.89	0.001
(MW-120)	0.031809	0.008263	3.85	0.002
(RPM-93)	-0.06238	0.01300	-4.80	0.000

s = 0.6988 R-sq = 80.7% R-sq(adj) = 76.8%

FIGURE 3.1 - Effect of Burner Tilt -
Milliken Unit 1, Main and SOFA Tilts

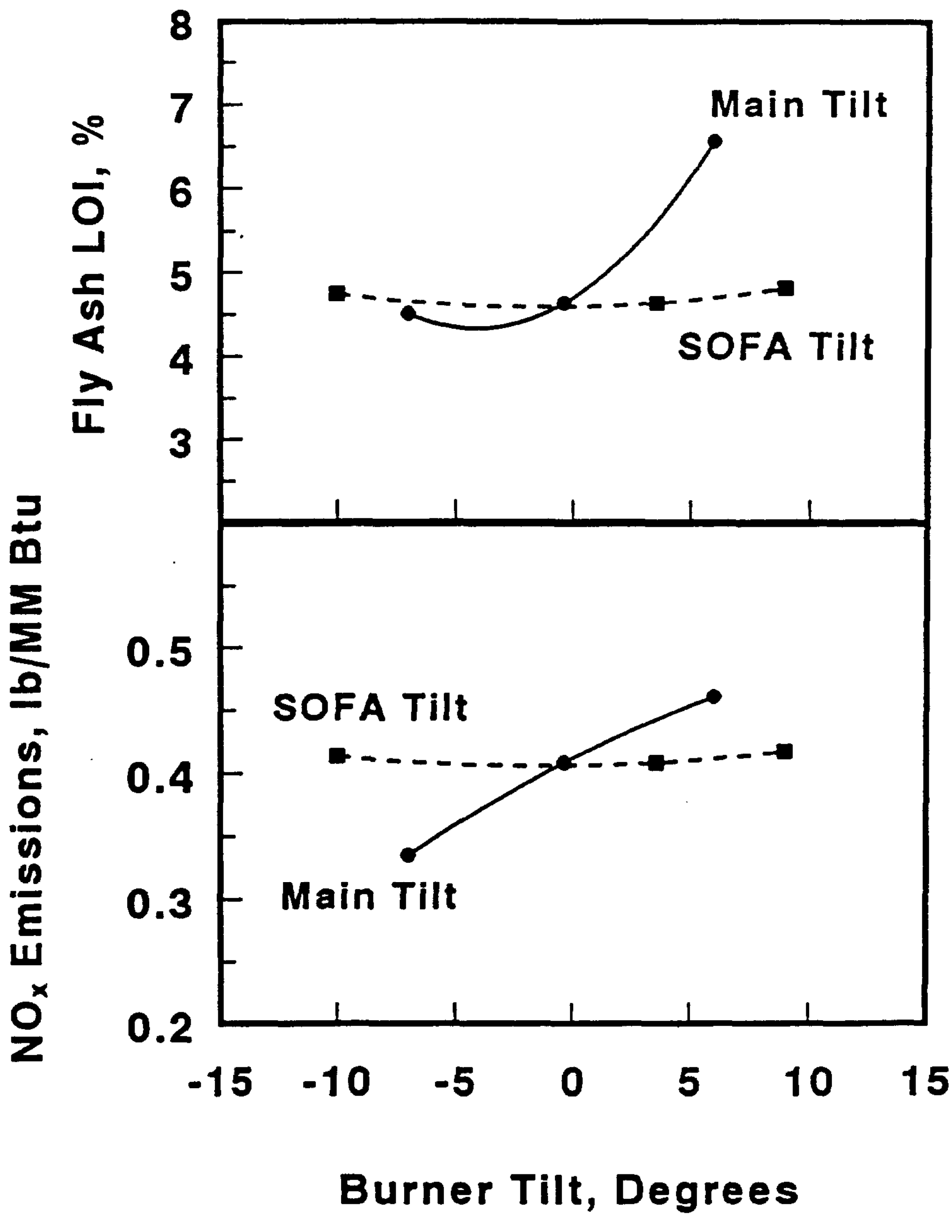


FIGURE 3.2 - Effect of SOFA Yaw - Milliken Unit 1, SOFA Yaw

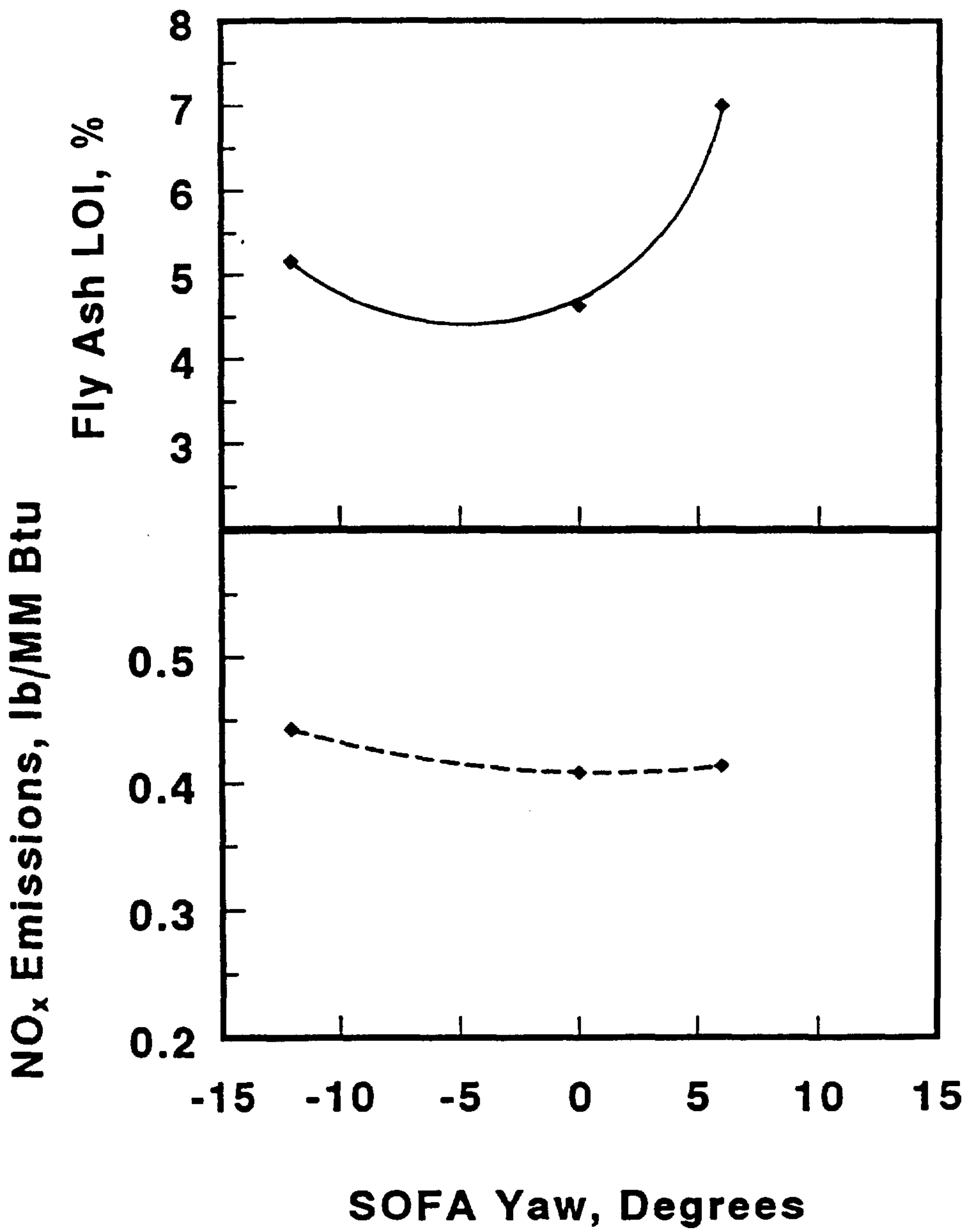


FIGURE 3.3 - Effect of Air Distribution-
Milliken #1: SOFA/CCOFA Split, Coal Air

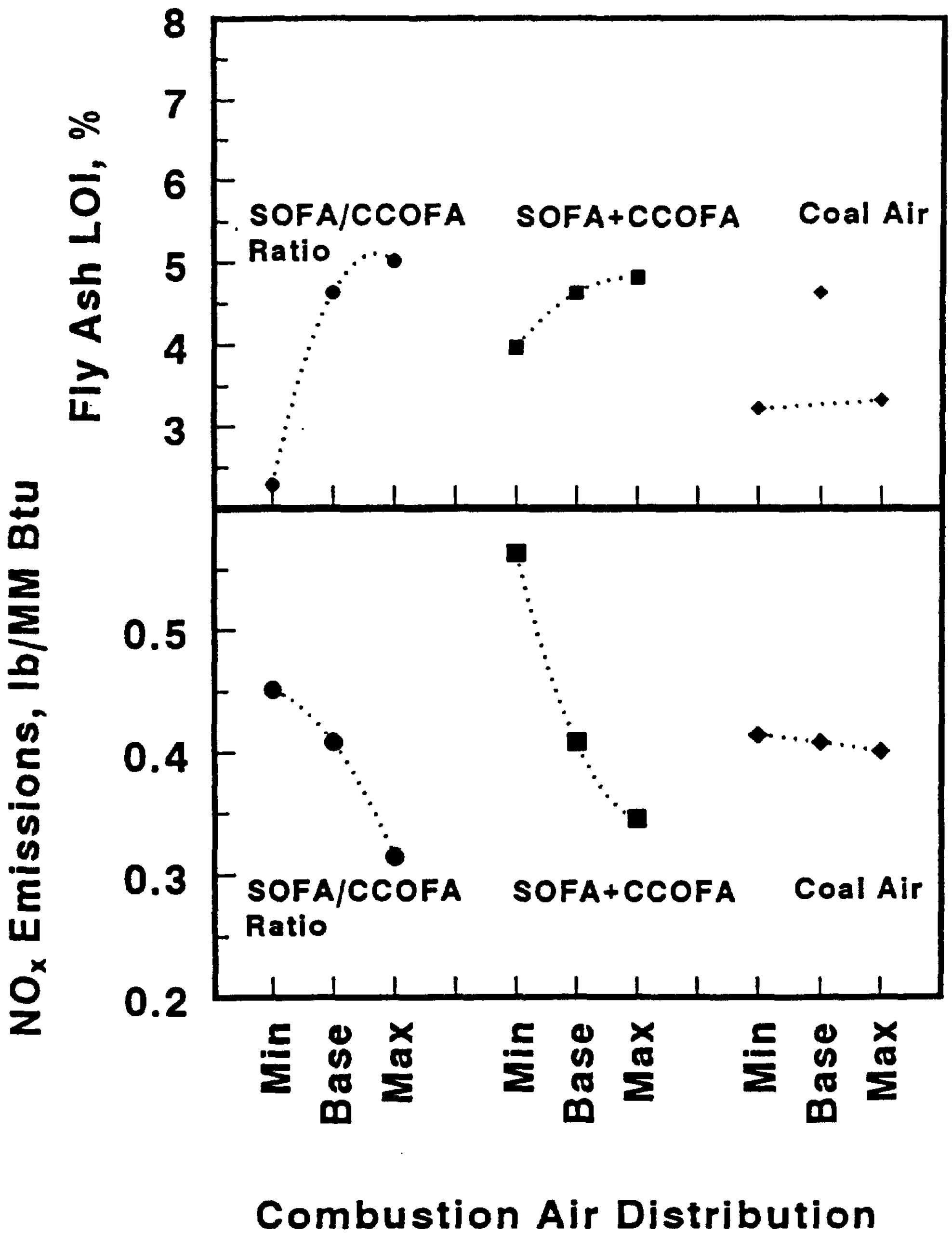


FIGURE 3.4 - Effect of Mill Pattern - $\beta=(A1+B2/3-A3/3-B4)_{tph}/TOTAL_{tph}$

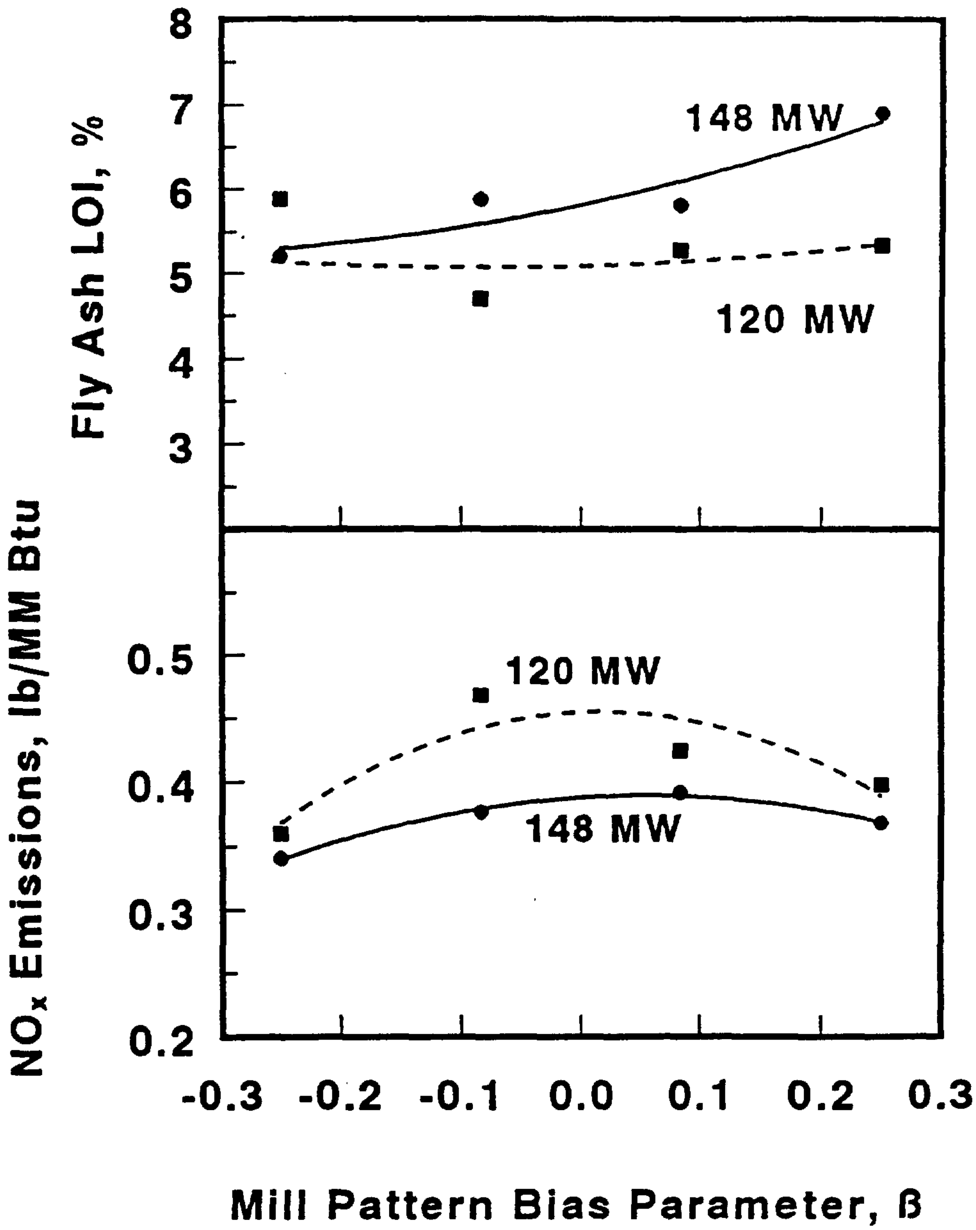


FIGURE 3.5 - Effect of Excess Air - Milliken Unit 1, Parameter: Boiler Load

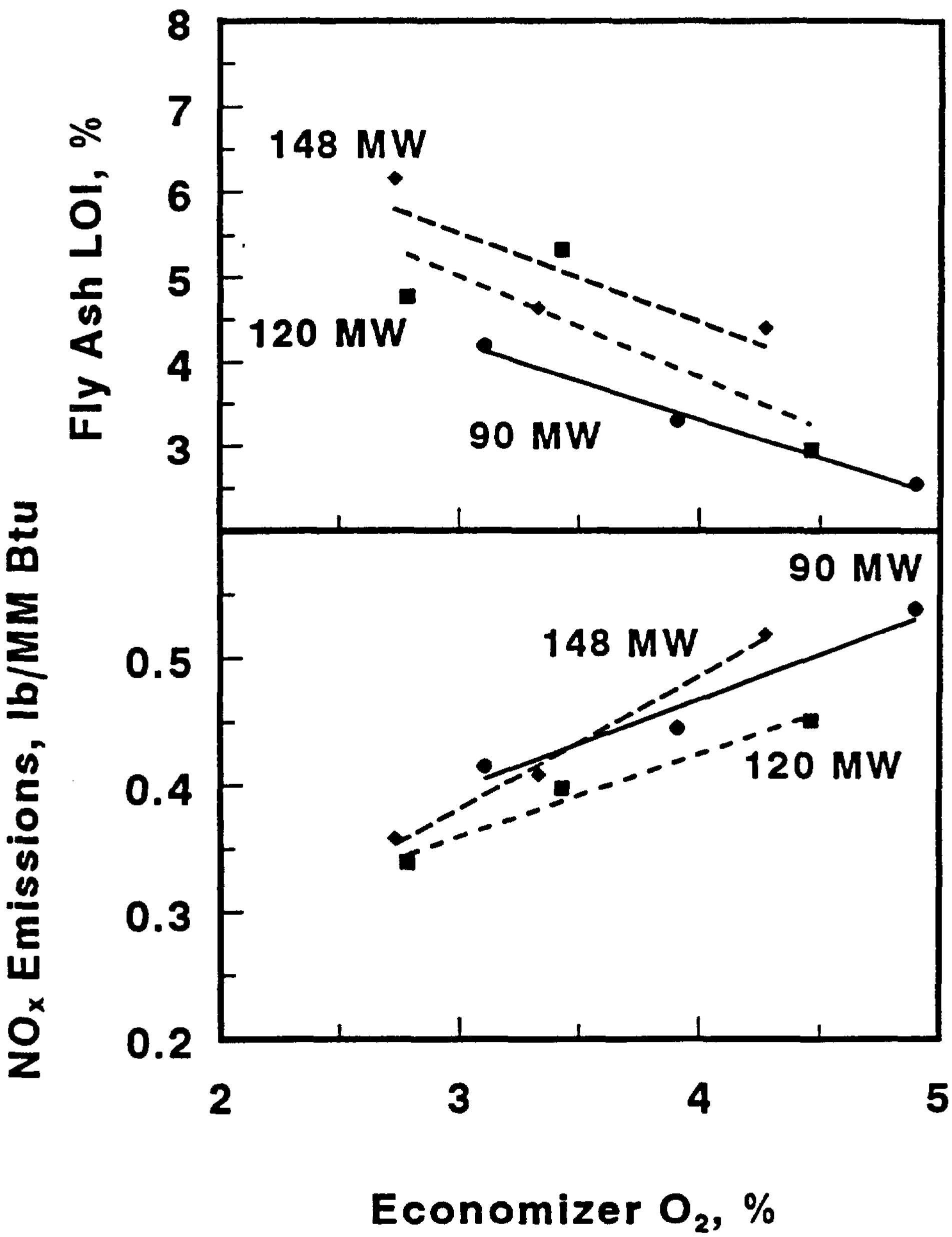


FIGURE 3.6 - Effect of Boiler Load - Milliken Unit 1, Parameter: $\%O_2$

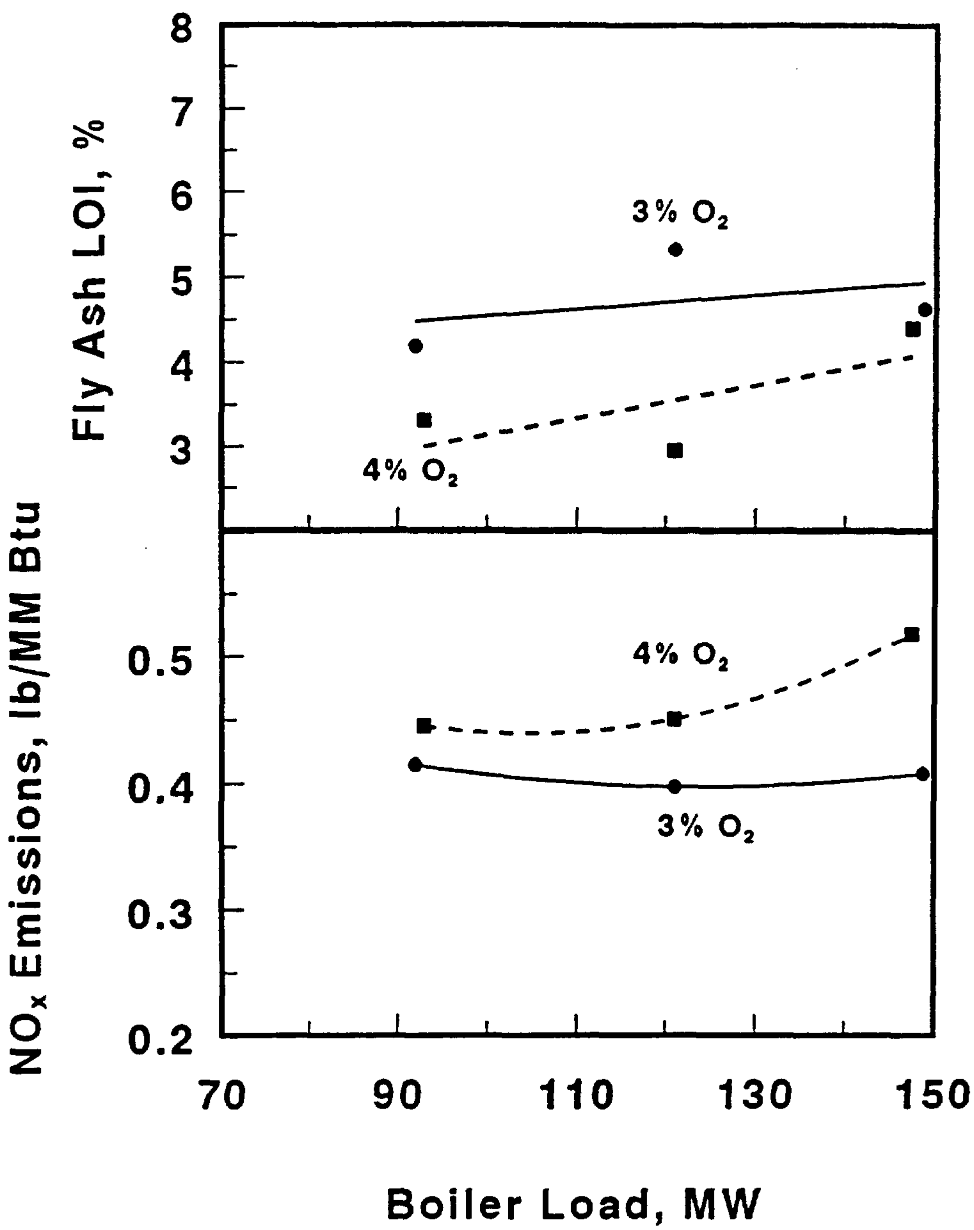


FIGURE 3.7 - Effect of Excess Air - Milliken Unit 1, Parameter: Mill rpm

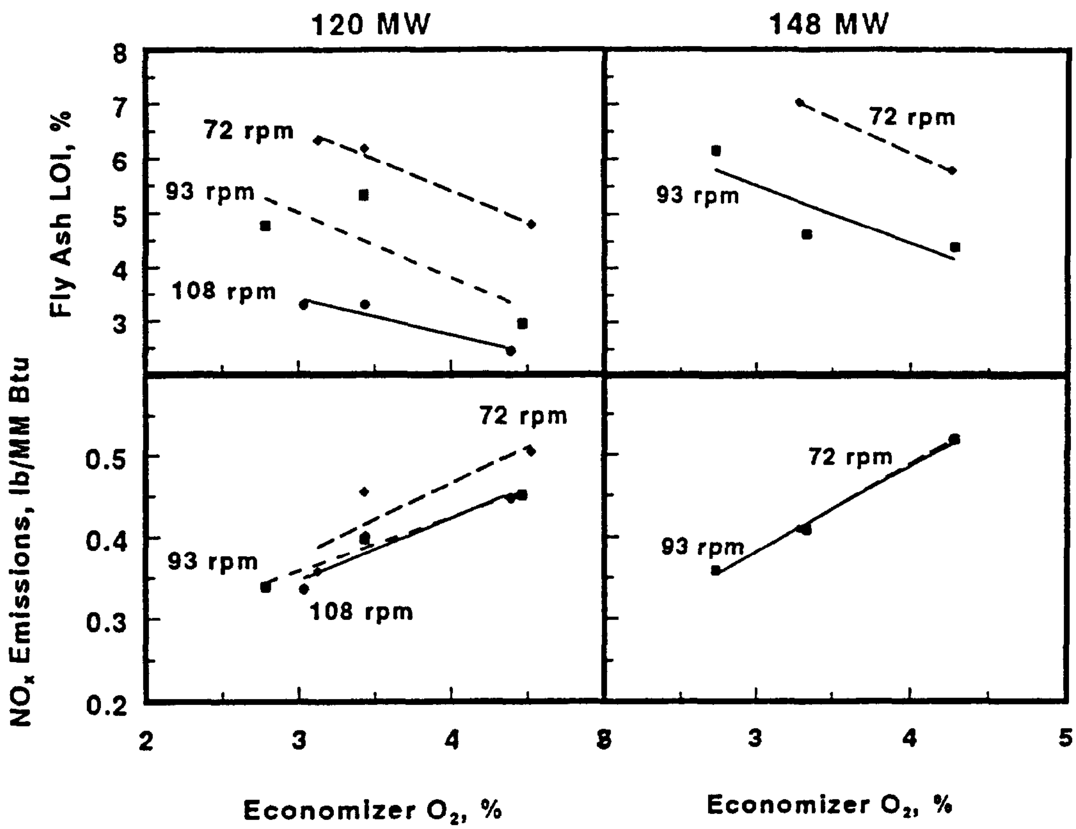


FIGURE 3.8 -
Effect of Coal Fineness, 3.3% O_2 -
Milliken Unit 1, Parameter: Boiler Load

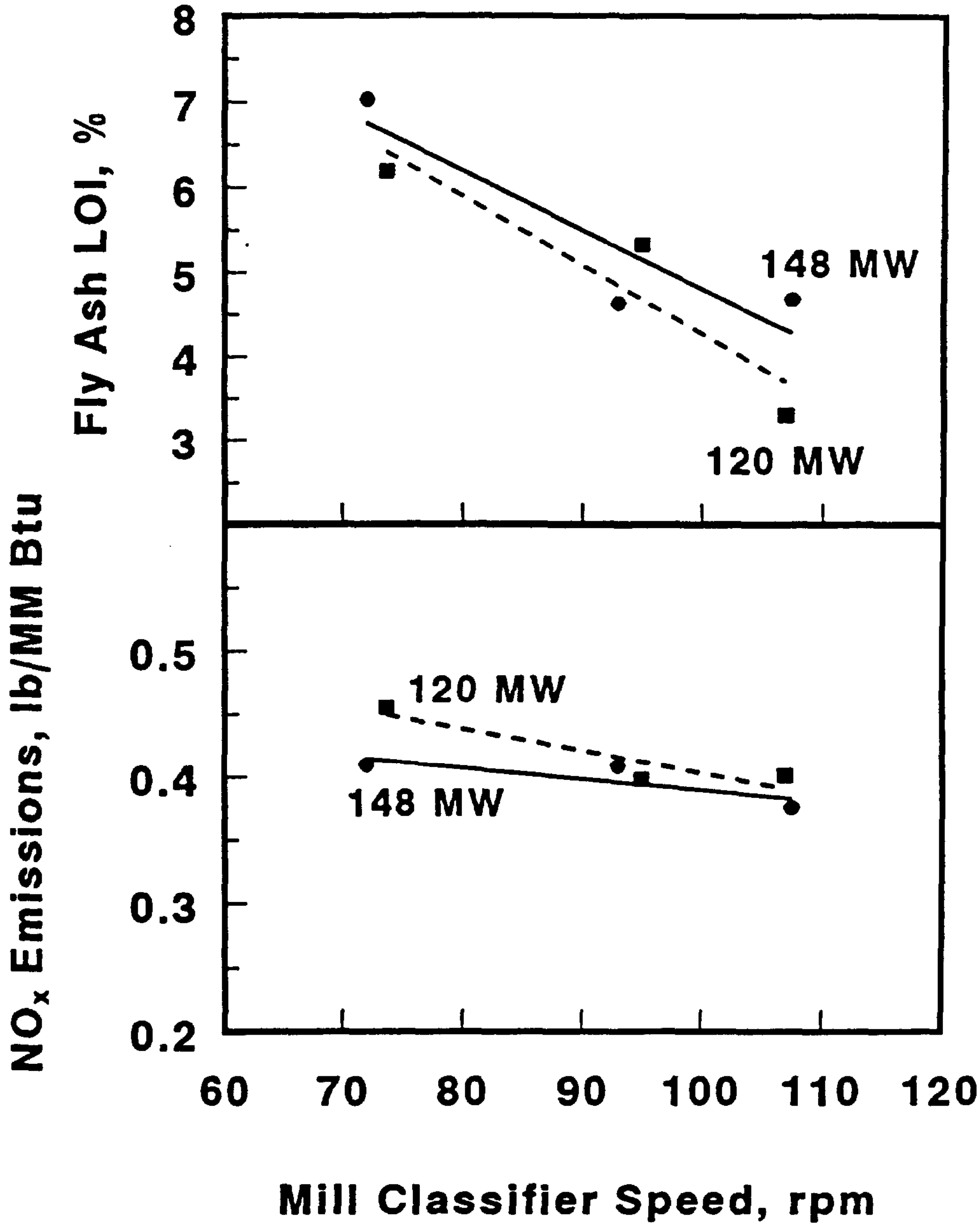


FIGURE 3.9 -
Effect of Coal Fineness, 120 MW -
Milliken Unit 1, Parameter: O_2

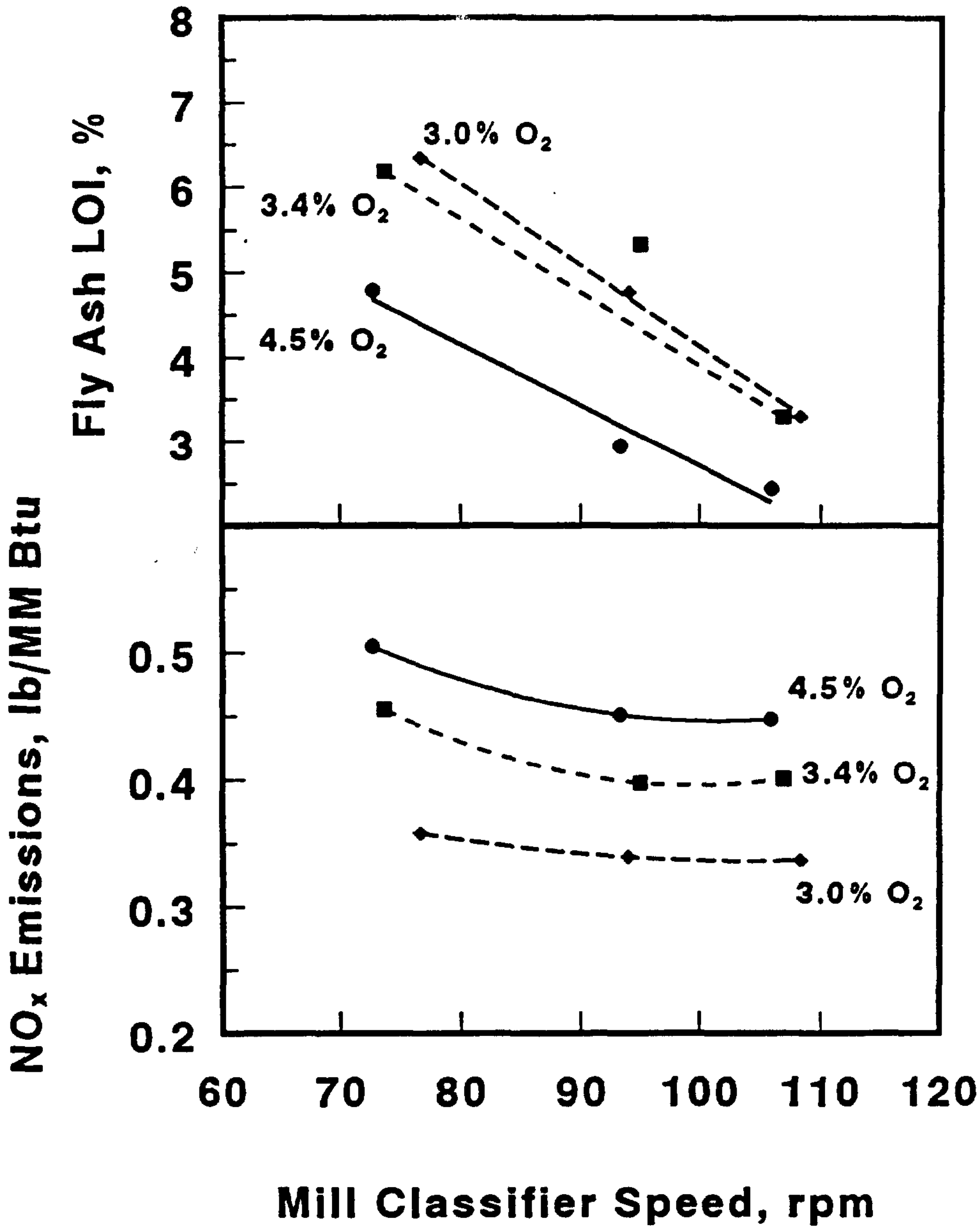


FIGURE 3.10 -
Predicted Vs. Measured NO_x Emissions -
Milliken Unit 1, 3-94 Post-Retrofit Test

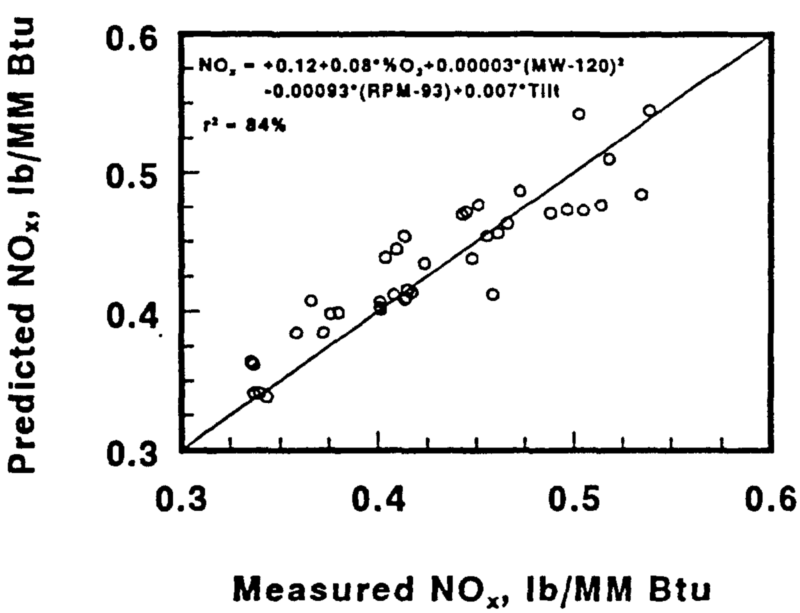
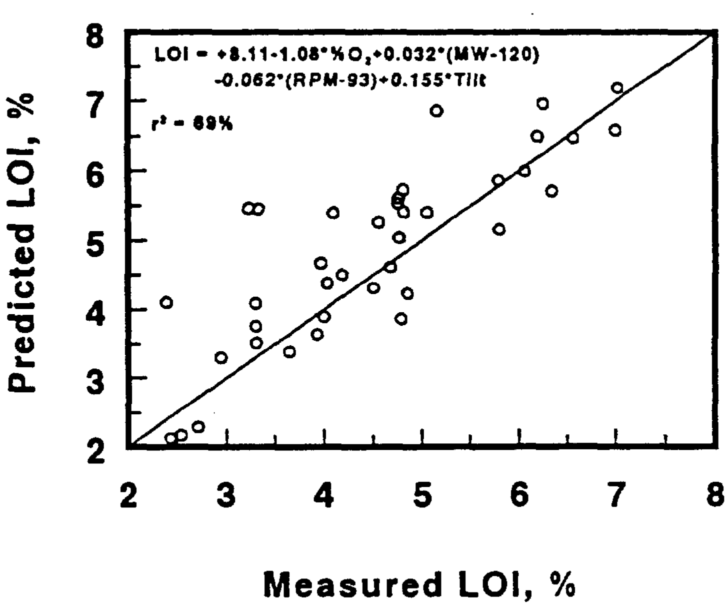


FIGURE 3.11-Predicted Vs.Measured LOI -
Milliken Unit 1, 3-94 Post-Retrofit Test



SECTION FOUR
LNCFS-3 SYSTEM START-UP, INSTALLATION COSTS AND FUEL DUCT BALANCING TESTS

4.1 LNCFS-3 System Start-Up

The post-retrofit design fuel pipe velocity based on coal specifications supplied by NYSEG was 75-85 ft/s, compared to a pre-retrofit velocity of about 100 ft/s. The post-retrofit fuel pipe velocity range achieved satisfactory transport of the coal without particle fallout in the fuel pipe, while maintaining the desired primary air-to-fuel ratio.

After the burner system was placed in operation, flame attachment to the burner coal bucket was observed. To reduce the problem, the coal nozzle diameter was reduced to increase the fuel velocity and move the ignition point away from the coal bucket. This action did not correct the problem due to turbulence within the coal bucket. The design of the coal bucket was changed to eliminate the turbulence. The combination of the higher fuel velocity and redesigned coal bucket permitted burner operation with the ignition point between two to four feet from the face of the coal bucket.

4.2 LNCFS-3 Installation Costs

The economic impacts of a low-NO_x burner retrofit consist of the capital costs for the burner installation, changes in annual operating and maintenance costs, and lost generation charges. In the interim report, only the capital costs will be reported. After one year of operation, the annual operating and maintenance costs will be estimated.

4.2.1 Capital Costs

The capital costs are shown by category for Milliken Unit 1 in Table 4.1. The installation cost includes the replacement of four wind boxes, the installation of four new SOFA ports and SOFA ducts, field piping modifications, and wiring of the damper drives. The total capital cost is about $4.0 million or $26.56/kW. The expected range for LNCFS-3 capital costs is $15-25/kW.

Wind box and duct work installation required asbestos removal. The wind boxes were rigged and installed from outside the boiler, requiring only temporary removal of some structural steel. The turbine overhaul was completed during the scheduled retrofit outage. During the outage, the following subsystems were replaced: burners, coal mills, ESP upgrades, and a new electronic control system. An LNCFS-3 retrofit should require about an eight week outage.

TABLE 4.1 - MILLIKEN UNIT 1 RETROFIT COSTS	
Category	**Cost**
Material Supply	$1,744,659
Installation Labor	$1,364,027
ABB CE Engineering	$729,000*
NYSEG Engineering	$146,800
Total	$3,984,364
Cost Per kW	$26.56/kW
* The Unit 1 ABB CE Engineering costs are for Unit 1. The Unit 2 ABB CE Engineering costs are zero because identical burners are installed in Units 1 and 2.	

4.3 Unit 2 Baseline Pulverized Coal Balancing Tests

The SMG 10 probe was used to determine the fuel and air split among the four burner elevations and among the four corners of the fire box. The mill balance tests were conducted at 140 MW and 115 MW boiler loads, corresponding to Unit 2 baseline diagnostic Tests 2 and 14, respectively.

4.3.1 Full Boiler Load Test - Four Mills in Service

The mill balance measurements at 140 MW boiler load with four mills in service were performed during Unit 2 baseline diagnostic Test 2. An evaluation of the coal flow distribution among the four elevations showed that the flow to each of the top three mills was within ±1.5% of the average coal flow. The flow through the bottom mill was 15% higher than the average, corresponding to about 2.5 tons per hour higher coal flow than the other mills. Coal flows among the four corners were within ±4.0% of the average coal flow. Comparing the coal flows through the 16 individual ducts showed that 15 flows were within ±10% of the average. The flow though duct B1 of the top mill was 15.4% below the mill average.

4.3.2 Intermediate Boiler Load Test - Top Three Mills in Service

The mill balance measurements at 115 MW boiler load with the top three burner elevations in service were performed during Unit 2 baseline diagnostic Test 14. An evaluation of the coal flow distribution among the three elevations showed that the flows were within ±3.6% of the average coal flow. Coal flows among the four corners were within ±9.5% of the average coal flow. Comparing the coal flows through the 16 individual ducts again showed that the flow though duct B1 of the top mill was 13.2% below the mill average. The other flows were within ±10% of the average.

4.4 Unit 1 Post-Retrofit Pulverized Coal Balancing Tests

The SMG 10 probe was used to determine the fuel and air split among the four burner elevations and among the four corners of the fire box. The mill balance tests were conducted at 148 MW boiler load during Unit 1 post-retrofit diagnostic Test 1. Measurements at reduced boiler loads were not made due to problems with the test equipment. The air seal could not be properly made between the SMG 10 probe and the coal pipe. Consequently, the coal dust was sprayed over the boiler floor and testing was discontinued.

4.4.1 Full Boiler Load Test - Four Mills in Service

The mill balance measurements at full boiler load of 148 MW with four burner elevations in service were performed during Unit 1 post-retrofit diagnostic Test 1. The coal flows to the four mills were within ±11.5% of the average coal flow. At each elevation, the coal flows to the four corners were within ±9.0% of the average coal flow.

SECTION FIVE
LONG-TERM, VALIDATION AND PERFORMANCE TESTING

5.1 Long-Term Testing

The purpose of the long-term test is to estimate the achievable annual NO_x emissions and to determine NO_x reductions due to the LNCFS-3 retrofit. The achievable annual emissions are estimated using CEM data collected over 51 days, which is a minimum time requirement to adequately describe the time dependence of the data. This was demonstrated in a statistical evaluation of long-term CEM data conducted by The Control Technology Committee of the Utility Air Regulatory Group (UARG).

The long-term tests were conducted on pre-retrofit Unit 2 (baseline) and post-retrofit (LNCFS-3) Unit 1 under operating conditions that maintained salable fly ash (LOI less than 4%) and reliable boiler operation. The tests met the UARG minimum requirement of 51 days of CEM measurements. The long-term measurements for Unit 2 were collected for 71 days between March 22 and May 31, 1994. The fuel air damper position was 3 (an intermediate setting between minimum and maximum positions of 1 and 5, respectively) and the wind box tilt position was automatic, typically varying between +10° and +15°. The long-term measurements for Unit 1 were collected for 59 days between May 23 and July 20, 1994. The mill classifier speed varied between 104 and 106 rpm and the wind box tilt position was automatic, typically varying between -6° and +2°.

The long-term data were collected as 15-minute averages and were subsequently combined into hourly averages. The data were grouped by boiler load range in increments of 5 MW, and averaged for each group as shown in Table 5.1. The variations of both NO_x emissions and economizer O_2 with boiler load are shown in Figure 5.1. At the same boiler load, baseline and post-retrofit economizer O_2 level were generally different. Consequently, direct comparison of baseline and post-retrofit NO_x emissions (Table 5.1 and Figure 5.1) can be misleading. Further analysis of the data was necessary to estimate NO_x reductions due to the LNCFS-3 retrofit as is further discussed.

The achievable annual NO_x emissions were calculated based on 30-day rolling averages obtained from the long-term CEM data. A 30-day rolling average is obtained by averaging 30 continuous daily averages following the initial 30-day lapse and rolling the average from day to day. The daily averages were calculated from the hourly averages. The achievable annual NO_x emissions for pre-retrofit (baseline) Unit 2 was 0.614 lb/MM Btu with an uncertainty of ± 0.023 lb/MM Btu at 95% confidence. That corresponded to 134 MW boiler load and 3.11% O_2 at the economizer outlet. The achievable annual NO_x emissions for post-retrofit (LNCFS-3) Unit 1 was 0.390 lb/MM Btu with an uncertainty of ± 0.003 lb/MM Btu at 95% confidence. That corresponded to 134 MW boiler load and 3.72% O_2 at the economizer outlet. The LNCFS-3 burner system achieved 36% NO_x reduction. However, direct comparison of baseline and post-retrofit NO_x emissions can be misleading, since the corresponding economizer O_2 levels were different. Further evaluation of the long-term data to calculate NO_x reductions at the same economizer O_2 levels is discussed in Section 5.3.1 evaluating the performance of the low-NO_x burner retrofit.

5.2 Validation Test Programs

The validation test programs are limited tests of the diagnostic test conditions. The effects of the dominant parameters affecting NO_x emissions and LOI (based on the diagnostic test results) were re-evaluated. The validation tests were conducted following the completion of the long-term tests. The objective of these tests is to validate the previous results, to characterize any changes that might have occurred during the long-term tests, and to test the predictive correlations derived from the diagnostic tests.

5.2.1 Unit 2 Baseline Validation Test Program

The dominant parameters affecting NO_x emissions and LOI in the Unit 2 baseline diagnostic test program were excess O_2 and boiler load. Five validation tests were conducted during May 22-23, 1994, during which the economizer O_2 was varied between 2% and 4% and the boiler load was varied between 80 MW and 145 MW. The test results are presented in Table 5.2. The mill patterns used during the validation test program were the same as those used during the diagnostic test program (normal operation as listed in Table 2.1), with the exception of Validation Test 1 (80 MW boiler load). The test condition could not be maintained with two mills in service (as in the diagnostic 80 MW tests) and was conducted with three mills in service (mill B4 out of service).

Comparisons between measured and predicted NO_x emissions and LOI as a function of economizer O_2 at 140 MW and as a function of boiler load at 4% economizer O_2 for the baseline validation tests are presented in Figures 5.2 and 5.3, respectively. The predictions are based on the diagnostic test program correlations (Section 2.3.7). At 128-143 MW boiler load, there are good agreements between measured and predicted NO_x emissions and LOI at various economizer O_2 levels (see Figure 5.2). The differences between measurements and predictions were less than 0.03 lb/MM Btu for NO_x emissions and less than 0.3% (absolute) for LOI, which were within the experimental uncertainties of ± 0.016 lb NO_x/MM Btu (0.032 lb/MM Btu difference) and ± 0.30% LOI (0.6% difference) at 95% confidence (Section 2.3.1). The differences between measurements and predictions increased with decreasing boiler load (see Figure 5.3). The poor prediction at 80 MW was partially due to the difficulty in repeating the diagnostic test program mill pattern with two mills (A3 and B4) out of service (see Table 2.1). The validation test at 80 MW was conducted with only one mill (B4) out of service.

5.2.2 Unit 1 LNCFS-3 Validation Test Program

The dominant parameters affecting NO_x emissions and LOI in the Unit 1 LNCFS-3 diagnostic test program were excess O_2, mill classifier speed and boiler load. Eight validation tests were conducted during October 17-19, 1995, during which the economizer O_2 was varied between 2.8% and 4.3%, the mill classifier speed was varied between 70 and 110 rpm, and the boiler load was varied between 90 MW and 150 MW. The test results are presented in Table 5.3.

There were several operations and LNCFS-3 control differences between the validation and the diagnostic test programs, including mill patterns, the control of CCOFA and SOFA air flows and the changes associated with reducing the boiler load. During the validation test program, coal mill B2 mechanical problems limited its use. Consequently, only Tests 4, 5 and 6 were conducted with all four mills in service. The remaining tests were conducted with mill B2 out of service. Furthermore, during the validation test program, greater control of air staging (two CCOFA and three SOFA air flows) was possible (compared to the diagnostic test program). This operation achieved LOI below 4% at full boiler load, which was not possible during the diagnostic test program. Specifically, the air staging ports were operated with the two CCOFA ports fully open and the upper two SOFA ports fully closed, thus limiting the air staging control to the lowest SOFA port to achieve the desired LOI. In addition, the control algorithm used during the diagnostic test program made it difficult to separate the effects of boiler load and air staging, since a drop in boiler load was accompanied by reductions in SOFA air flows. This association between changes in boiler load and air staging was significantly reduced during the validation test program. This was a consequence of the additional control of air staging which achieved LOI below 4%.

Comparisons between measured and predicted NO_x emissions and LOI as a function of economizer O_2 at full boiler load (145-150 MW), as a function of mill classifier speed at full boiler load, and as a function of boiler load are presented in Figures 5.4, 5.5 and 5.6, respectively. The predictions are based on the diagnostic test correlations (Section 3.3.8). At full boiler load, there were good agreements between measured and predicted NO_x emissions at various economizer O_2 levels and at various mill classifier speed settings (Figures 5.4 and 5.5, respectively). The differences between measured and predicted NO_x emissions were less than 0.036 lb/MM Btu, which were within the experimental uncertainty of ± 0.027 lb NO_x/MM Btu (0.054 lb/MM Btu difference) at 95% confidence (Section 3.3.2). However, measured LOI values were 0.7%-1.7% (absolute) lower than predicted. These differences are attributed to the operation of the air staging ports (CCOFA ports fully open and using only the lowest SOFA port) during the validation test program which corresponded to longer furnace residence times (compared to the diagnostic test program). Longer coal particle residence times under the high temperatures in the furnace enhance carbon burnout and reduce LOI.

The discrepancy between measured and predicted LOI as a function of economizer O_2 levels (Figure 5.4) was attributed to the operation of the staging ports (as discussed earlier) and to the different mill patterns used (compared to the diagnostic test program). The predictions were based on the diagnostic test results in which all four mills were in service, whereas the validation tests were conducted with three mills in service (B2 out of service).

At reduced boiler loads (120 MW and 90 MW), measured NO_x emissions were lower than predicted and measured LOI values were higher than predicted (see Figure 5.6). The predictions are based on the diagnostic test correlations (Section 3.3.8), and the measured values are the validation test results. The discrepancy between measurements and predictions were attributed to the effects associated with boiler load changes, which differed between the diagnostic and the validation test programs. Specifically, during the diagnostic test program, a drop in boiler load was accompanied by lower SOFA air flows. The reduction in air staging with lower SOFA air flows would favor higher NO_x emissions and lower LOI, whereas the reduction in boiler load might have the opposite effect on NO_x

and LOI because of lower furnace temperatures. This association between changes in boiler load and air staging was significantly reduced during the validation tests so that mainly the effect of boiler load was observed.

5.3 LNCFS-3 Performance Evaluation

The LNCFS-3 performance evaluation included the NO_x control effectiveness and the impact of the LNCFS-3 system on the boiler efficiency. The LNCFS-3 system did not increase fly ash LOI and did not increase CO emissions. For both baseline and the LNCFS-3 system, LOI values were less than 4% and measured CO concentrations were less than 25 ppm.

5.3.1 NO_x Control

The NO_x reduction capability of the LNCFS-3 system was evaluated during the short-term diagnostic test programs (2-4 hours each) and the long-term test program (60-70 days). In both cases, Unit 2 baseline and Unit 1 LNCFS-3 test results were compared.

The variations of NO_x emissions and LOI with economizer O_2 for Unit 2 baseline and Unit 1 LNCFS-3 diagnostic tests at full boiler load (140-150 MW) are presented in Figure 5.7. The LNCFS-3 test results include tests where the overfire air (SOFA and CCOFA) flows and mill classifier speeds were similar. At the same economizer O_2 level, the scatter of the data was partly due to experimental variation and partly due to the variation of other parameters, such as burner tilt. During the diagnostic test programs, the LNCFS-3 system lowered NO_x emissions 0.15-0.22 lb/MM Btu and increased LOI 2.4%-3.2% (absolute). A simple inverse relationship was observed between baseline NO_x emissions and LOI, which could be approximated by a linear function (Section 2.3.6). The post-retrofit relationship between NO_x emissions and LOI was more complex because of greater sensitivity to operating parameters (Section 3.3.7). An example is the burner tilt which had a significant effect on NO_x emissions and a minor effect on LOI during baseline testing, and significant effects on both NO_x emissions and LOI during LNCFS-3 testing. Increasing the LNCFS-3 burner tilts below the horizontal (negative tilt) was effective in reducing both NO_x emissions and LOI, but also had an impact on the main steam temperature. It should be emphasized that during the LNCFS-3 diagnostic test program, LOI was generally above 4% at full boiler load and better control of the air staging (CCOFA and SOFA air flows) was necessary to lower the LOI below 4%. Consequently, the effectiveness of the LNCFS-3 burner retrofit was evaluated using the long-term data.

The long-term test program (60-70 days) was used to evaluate the effectiveness of the LNCFS-3 system in reducing NO_x emissions. The long-term hourly averaged Unit 2 baseline and Unit 1 LNCFS-3 data at full boiler load (145-150 MW) were grouped by economizer O_2 range and averaged for each group as shown in Table 5.4. The long-term NO_x emissions data at full boiler load as a function of economizer O_2 are shown in Figure 5.8. At low boiler load (80-90 MW), the long-term data were treated in a similar fashion, but only one economizer O_2 range (4.3%-5.0%) was included because of the relatively small number of data (less than 50). At full boiler load (145-150 MW) and at 3.0%-3.5% economizer O_2, the LNCFS-3 system lowered NO_x emissions from a baseline 0.64 lb/MM Btu to 0.39 lb/MM Btu, corresponding to 39% reduction. At 80-90 MW boiler load and at 4.3%-5.0% economizer O_2, the LNCFS-3 system lowered NO_x emissions from a baseline of 0.58 lb/MM Btu to 0.41 lb/MM Btu, corresponding to 29% reduction. The effectiveness of the LNCFS-3 system was lower at reduced boiler load.

In summary, following the LNCFS-3 burner retrofit, NO_x emissions below 0.4 lb/MM Btu could be achieved, while maintaining marketable fly ash (LOI less than 4%). To date, burner operations are acceptable.

5.3.2 Boiler Efficiency

The impact of the low-NO_x burner retrofit on boiler efficiency was estimated at full boiler load (140-150 MW). Three baseline boiler performance tests were conducted on Unit 2 between April 18 and 20, 1994. After installing the LNCFS-3 system, two boiler performance tests were conducted on Unit 1 on October 21, 1995. The test data and the boiler efficiency results (calculations based on ASME Abbreviated Efficiency Test) are presented in Table 5.5. The baseline boiler efficiency was between 89.3% and 89.6%. The LNCFS-3 boiler efficiency was between 88.3% and 88.5%. The reduction in LNCFS-3 boiler efficiency relative to baseline was attributed to higher post-retrofit flue gas O_2 levels and higher stack temperatures relative to baseline. Unit 1 air heater was retrofitted with new air heater baskets and seals. The cause of the elevated air heater flue gas exit temperatures is under investigation. The LNCFS-3 stack temperatures were 21-31 °F higher than baseline, which resulted in 0.8% (absolute) lower boiler efficiency. Furthermore, the LNCFS-3 system corresponded to higher excess O_2 levels than baseline, which resulted in 0.4% (absolute) lower boiler efficiency. Consequently, if the flue gas exit temperatures and the flue gas O_2 concentrations were the same for the LNCFS-3 system and the baseline, LNCFS-3 boiler efficiency 0.2% (absolute) higher than baseline would be expected.

TABLE 5.1 - LONG-TERM NO_x EMISSIONS

Load Range MW	No. Hourly Averages	Load MW	02 %	NOx lb/MM Btu	σ* NOx lb/MM Btu
Unit 2 Baseline					
78-84	96	81	4.72	0.573	0.052
85-89	27	87	4.60	0.537	0.063
90-94	23	92	4.47	0.579	0.039
95-99	22	97	3.90	0.575	0.044
100-104	22	102	3.61	0.565	0.033
105-109	27	107	3.52	0.587	0.036
110-114	96	112	3.47	0.586	0.037
115-119	57	117	3.29	0.573	0.033
120-124	37	122	3.10	0.583	0.033
125-129	45	127	2.92	0.580	0.037
130-134	58	132	2.96	0.591	0.040
135-139	76	138	2.89	0.610	0.038
140-144	277	143	2.84	0.621	0.042
145-151	760	147	2.74	0.628	0.039
Unit 1 Post-Retrofit					
77-84	36	81	4.73	0.413	0.082
85-89	33	87	4.66	0.400	0.051
90-94	27	92	4.22	0.399	0.021
95-99	34	96	4.15	0.397	0.022
100-104	26	101	3.92	0.421	0.113
105-109	19	108	3.98	0.405	0.118
110-114	105	112	3.87	0.391	0.046
115-119	90	117	3.87	0.390	0.034
120-124	64	121	3.74	0.384	0.020
125-129	41	127	3.72	0.391	0.029
130-134	100	131	3.66	0.384	0.026
135-139	97	137	3.61	0.385	0.032
140-144	117	142	3.63	0.389	0.022
145-150	563	147	3.62	0.390	0.026

* σ = Standard Deviation

TABLE 5.2 - UNIT 2 BASELINE VALIDATION TEST RESULTS

Test No.	Date	Time	Mill Out	Load MW	O2 %	Fuel Air	Tilt deg	STACK CEM CO2 %	STACK CEM NOx ppm
1	05/22/94	12:30-14:30	B4	81	4.0	3	14	10.23	244
2	05/22/94	18:00-20:00	B4	105	3.7	3	14	10.71	269
3	05/23/94	11:00-12:30	-	143	3.0	3	0	11.30	309
4	05/23/94	16:30-18:30	-	143	2.0	3	10	11.84	277
5	05/23/94	20:00-22:00	-	128	4.1	3	13	10.41	302

Test No.	Measured NOx lb/MM Btu	Predicted NOx lb/MM Btu	Measured LOI %	Predicted LOI %
1	0.513	0.454	1.48	3.32
2	0.540	0.523	2.28	2.93
3	0.588	0.618	2.92	2.61
4	0.503	0.508	4.30	4.18
5	0.623	0.636	2.27	2.13

Coal Analysis: Dry Basis

DATE	VM %	Btu	C %	H %	N %	S %	Ash %	O %	As Det H2O %
05/22/94	38.03	13944	78.50	4.94	1.47	2.00	7.19	5.90	1.71
05/23/94	37.88	13946	78.10	5.04	1.48	1.97	7.25	6.16	1.80

TABLE 5.3 - UNIT 1 LNCFS-3 VALIDATION TEST RESULTS

Test No.	Date	Time	Mill Out	Load MW	O2 %	Mill rpm	Burner Tilt Main Deg	Burner Tilt SOFA Deg	Dampers, % Open SOFA Up	SOFA Mid	SOFA Low	CCOFA Up	CCOFA Low
1	10/17/95	12:00-13:00	B2	145	2.84	95	-7	-2	3	1	80	100	100
2	10/17/95	15:00-17:00	B2	145	3.49	95	-7	-2	3	1	80	100	100
3	10/17/95	18:00-20:00	B2	144	4.27	95	-7	-2	3	1	80	100	100
4	10/18/95	11:00-13:00	-	146	3.51	110	-7	-2	3	1	81	100	100
5	10/18/95	14:00-16:00	-	147	3.50	95	-7	-2	3	1	81	100	100
6	10/18/95	17:00-19:00	-	147	3.49	69	-7	-2	3	1	81	100	100
7	10/19/95	01:00-03:00	B2	121	3.53	95	-7	-2	3	1	81	100	100
8	10/19/95	04:00-06:00	B2	91	3.79	95	-5	0	3	1	81	100	100

Test No.	Measured NOx lb/MM Btu	Predicted NOx lb/MM Btu	Measured LOI %	Predicted LOI %
1	0.351	0.315	3.63	4.64
2	0.386	0.367	2.96	3.93
3	0.436	0.428	2.38	3.04
4	0.357	0.356	2.11	2.98
5	0.370	0.370	2.20	3.96
6	0.378	0.395	3.94	5.58
7	0.320	0.351	3.75	3.10
8	0.310	0.413	2.52	2.19

Coal Analysis: Dry Basis

DATE	VM %	Btu	C %	H %	N %	S %	Ash %	O %	As Det H2O %	Total H2O %
10/17/94	38.95	14010	79.02	5.14	1.57	1.85	7.05	5.36	1.75	6.96
10/18/94	39.15	14020	78.64	5.16	1.59	1.88	7.06	5.68	1.65	6.27
10/19/94	38.50	13990	78.87	5.04	1.58	1.86	7.23	5.43	1.67	6.39

TABLE 5.4 - LNCFS-3 IMPACT ON NO_x EMISSIONS

O2 Range %	No. Hourly Averages	Load MW	O2 %	NOx lb/MM Btu	σ^* NOx lb/MM Btu
Unit 2 Baseline at 145-150 MW					
2.5-2.6	190	146	2.56	0.623	0.039
2.7	134	146	2.70	0.628	0.035
2.8	110	146	2.80	0.635	0.034
2.9	68	146	2.90	0.639	0.038
3.0-3.1	97	147	3.05	0.638	0.043
3.2-3.3	41	147	3.26	0.642	0.039
Unit 1 Post-Retrofit at 145-150 MW					
3.2-3.3	60	147	3.30	0.391	0.016
3.4-3.5	82	147	3.43	0.388	0.041
3.6	223	147	3.61	0.389	0.022
3.7-3.8	149	147	3.78	0.392	0.028
Unit 2 Baseline at 80-90 MW					
4.3-5.0	47	84	4.66	0.578	0.065
Unit 1 Post-Retrofit at 80-90 MW					
4.3-5.0	39	85	4.74	0.410	0.050

Effectiveness of LNCFS-3 Retrofit in Reducing NOx Emissions:

Reduction at 145-150 MW and 3.0-3.5% O2 = 39.0%

Reduction at 80-90 MW and 4.3-5.0% O2 = 29.0%

* σ = Standard Deviation

TABLE 5.5 - LNCFS-3 IMPACT ON BOILER EFFICIENCY

	Unit 2 Baseline			Unit 1 LNCFS-3	
Test:	1	2	3	1	2
Measured Data					
Gas Temp at ESP Inlet, °F	264	266	258	289	287
Flue Gas: % Volume					
CO2	12.5	12.4	12.4	11.7	11.3
O2	7.0	7.1	7.1	7.6	8.0
CO	0.0	0.0	0.0	0.0	0.0
N2	80.5	80.5	80.5	80.7	80.7
Coal Analysis (dry)					
% Carbon	77.89	77.86	77.85	78.78	78.78
% Hydrogen	5.25	5.25	5.24	4.98	4.98
% Nitrogen	1.55	1.53	1.43	1.57	1.57
% Sulfur	1.74	1.84	1.83	1.92	1.92
% Oxygen	6.42	6.41	6.44	5.36	5.36
% Ash	7.15	7.11	7.21	7.39	7.39
% Volatile Matter	37.35	37.49	37.27	38.49	38.49
Btu/lb	13934	13955	13949	13970	13970
Moisture (wet)	7.00	7.00	7.00	7.80	7.80
Ash Analysis					
% Ash	96.03	94.61	95.59	96.29	96.51
% Carbon	3.43	4.85	3.84	2.99	3.01
% Sulfur	0.34	0.34	0.37	0.43	0.33
Calculated Data, Basis of 1 lb as-fired Fuel					
Dry Refuse, lb	0.069	0.069	0.070	0.070	0.070
Carbon Burnout, lb	0.72	0.72	0.72	0.72	0.72
Dry Gas, lb	14.697	14.791	14.802	15.708	16.238
Heat Losses, %					
1. Dry Gas	5.01	5.09	4.87	6.12	6.26
2. Moisture in Fuel	0.61	0.61	0.61	0.69	0.69
3. Hydrogen in Fuel	3.84	3.83	3.82	3.67	3.66
4. Flue Gas CO	0.00	0.00	0.00	0.00	0.00
5. unburned combustible	0.26	0.38	0.30	0.24	0.24
6. Radiation	0.21	0.21	0.21	0.21	0.21
7. Moisture in Air	0.12	0.12	0.12	0.12	0.12
8. Unmeasured Losses	0.50	0.50	0.50	0.50	0.50
Efficiency, %	89.45	89.26	89.57	88.46	88.31

FIGURE 5.1 - Long-Term Gas Emissions

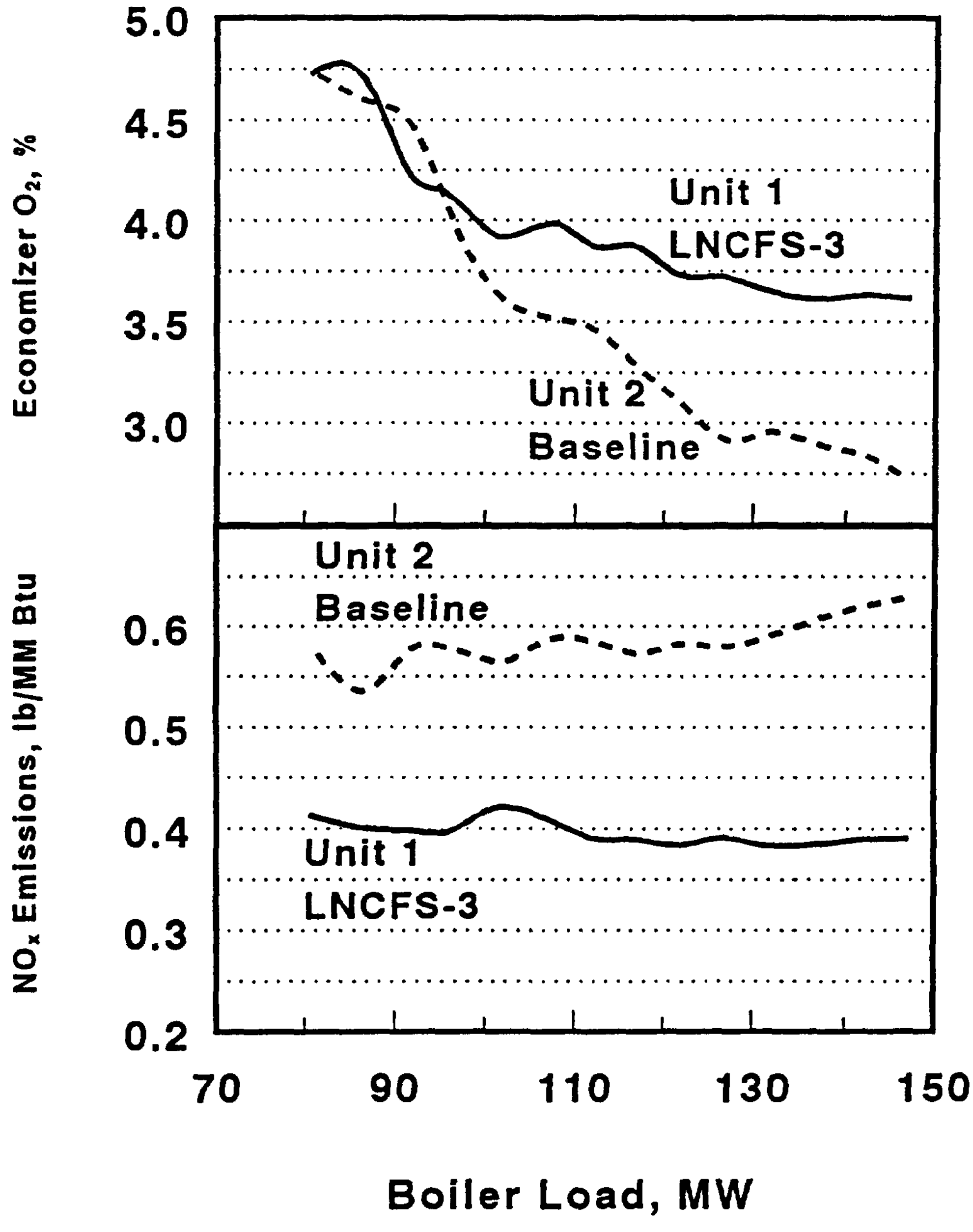


FIGURE 5.2 - Effect of Excess Air -
Unit 2 Baseline Validation Test, 140 MW

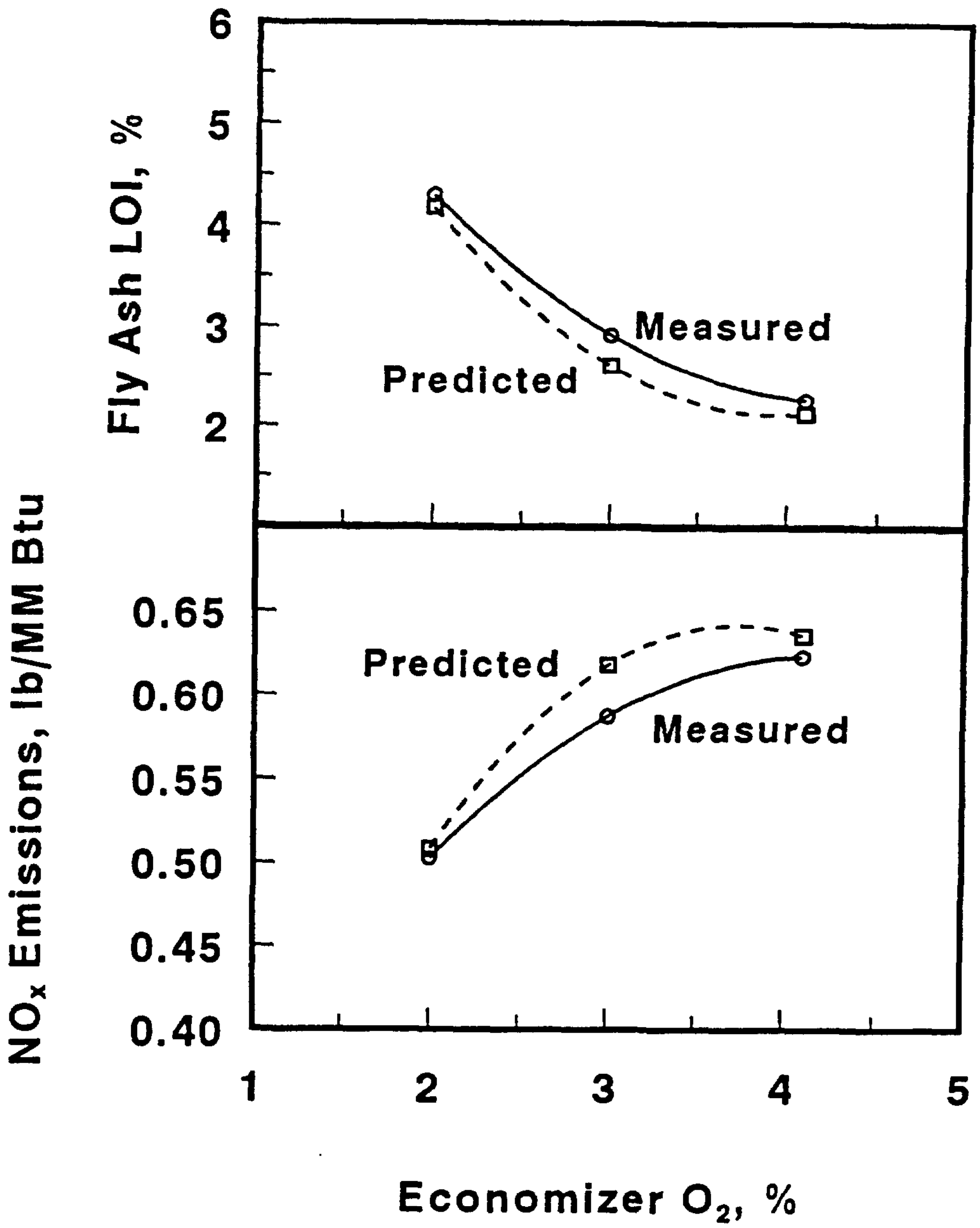


FIGURE 5.3 - Effect of Boiler Load - Unit 2 Baseline Validation Test, 4% O2

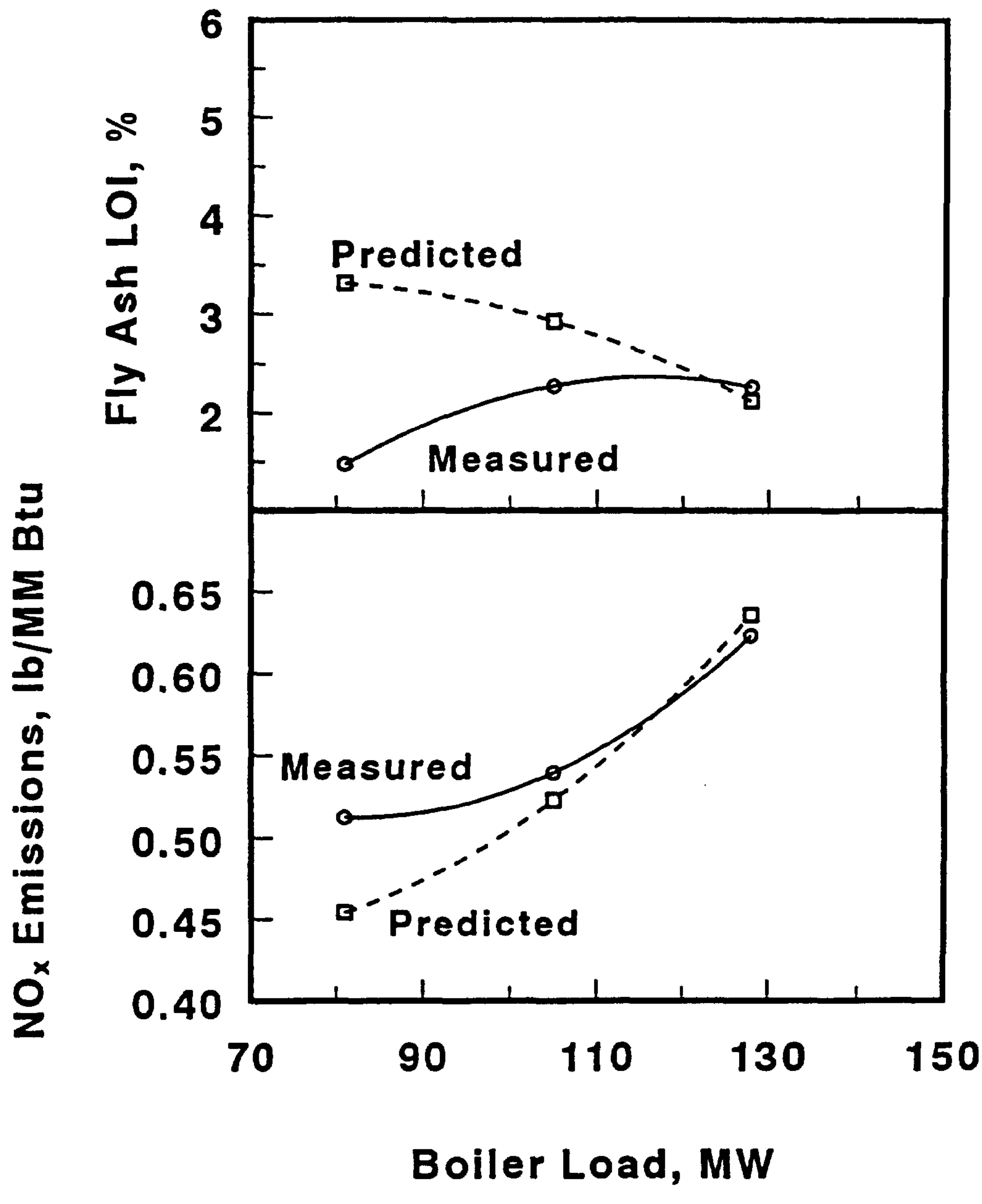


FIGURE 5.4 - Effect of Excess Air -
Unit 1 LNCFS-3 Validation Test, 145 MW

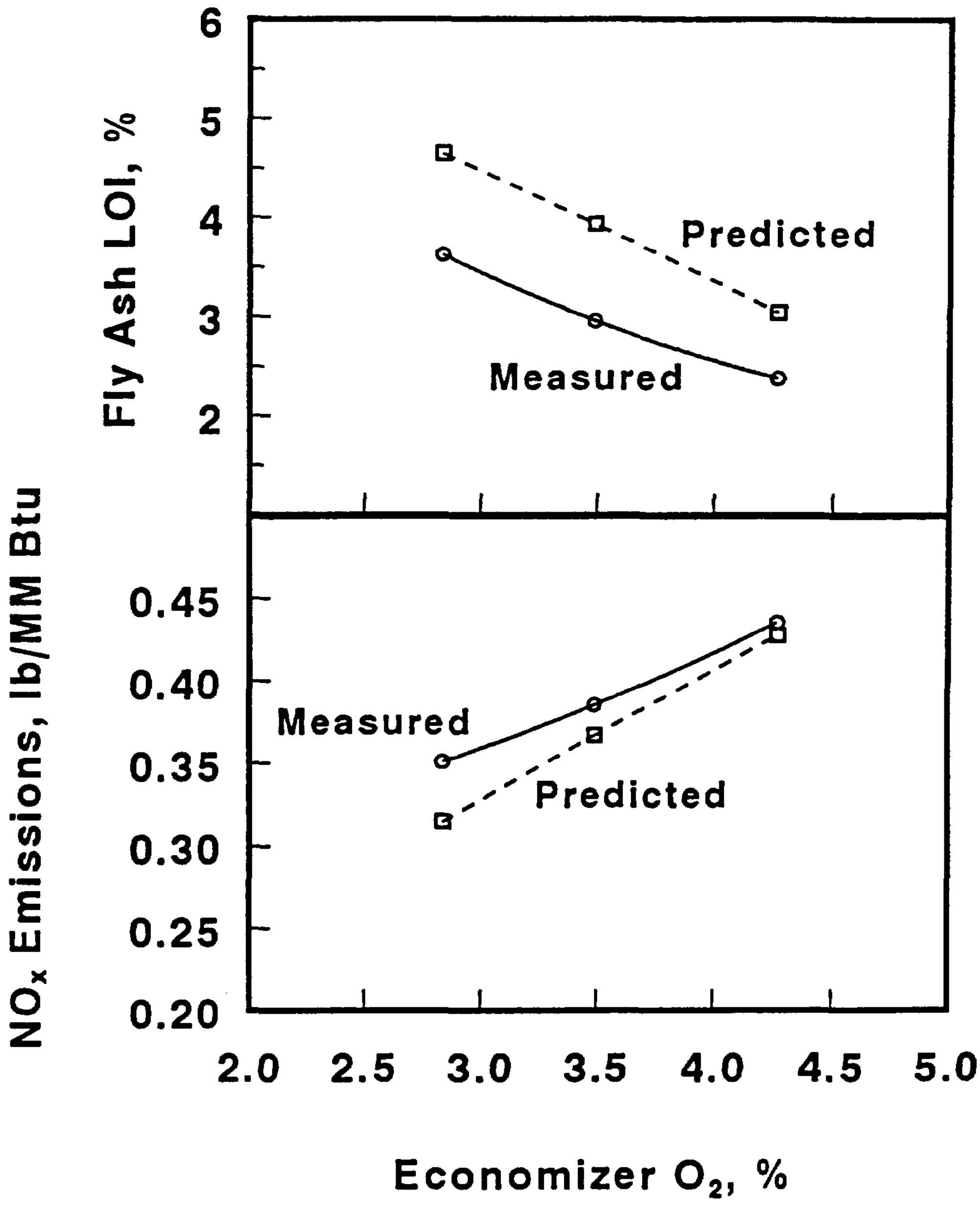


FIGURE 5.5 - Effect of Mill rpm -
Unit 1 LNCFS-3 Validation Test

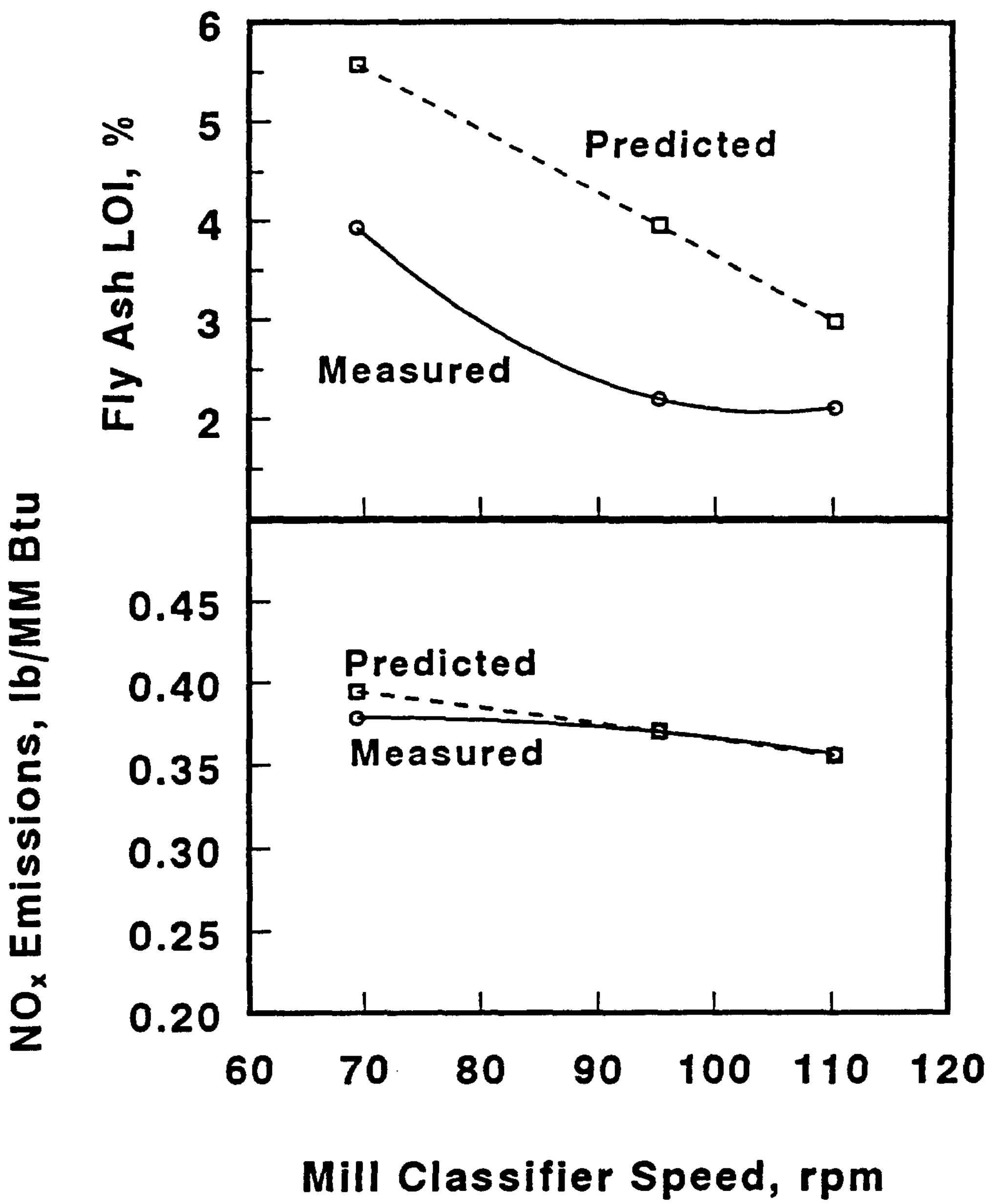


FIGURE 5.6 - Effect of Boiler Load -
Unit 1 LNCFS-3 Validation Test, 3.5% O2

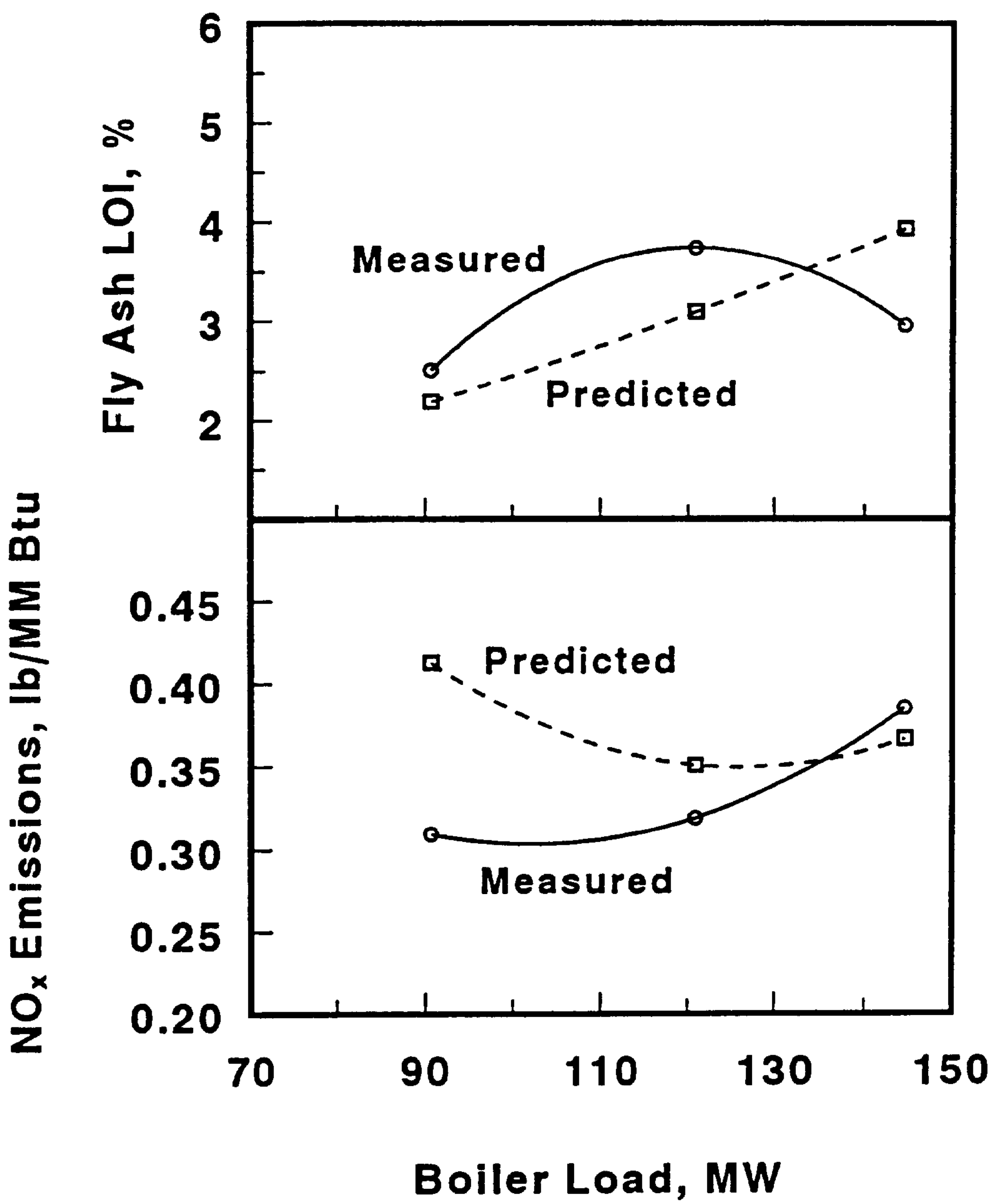


Figure 5.7 - Comparing Short-Term NO_x Emissions at 145-150 MW

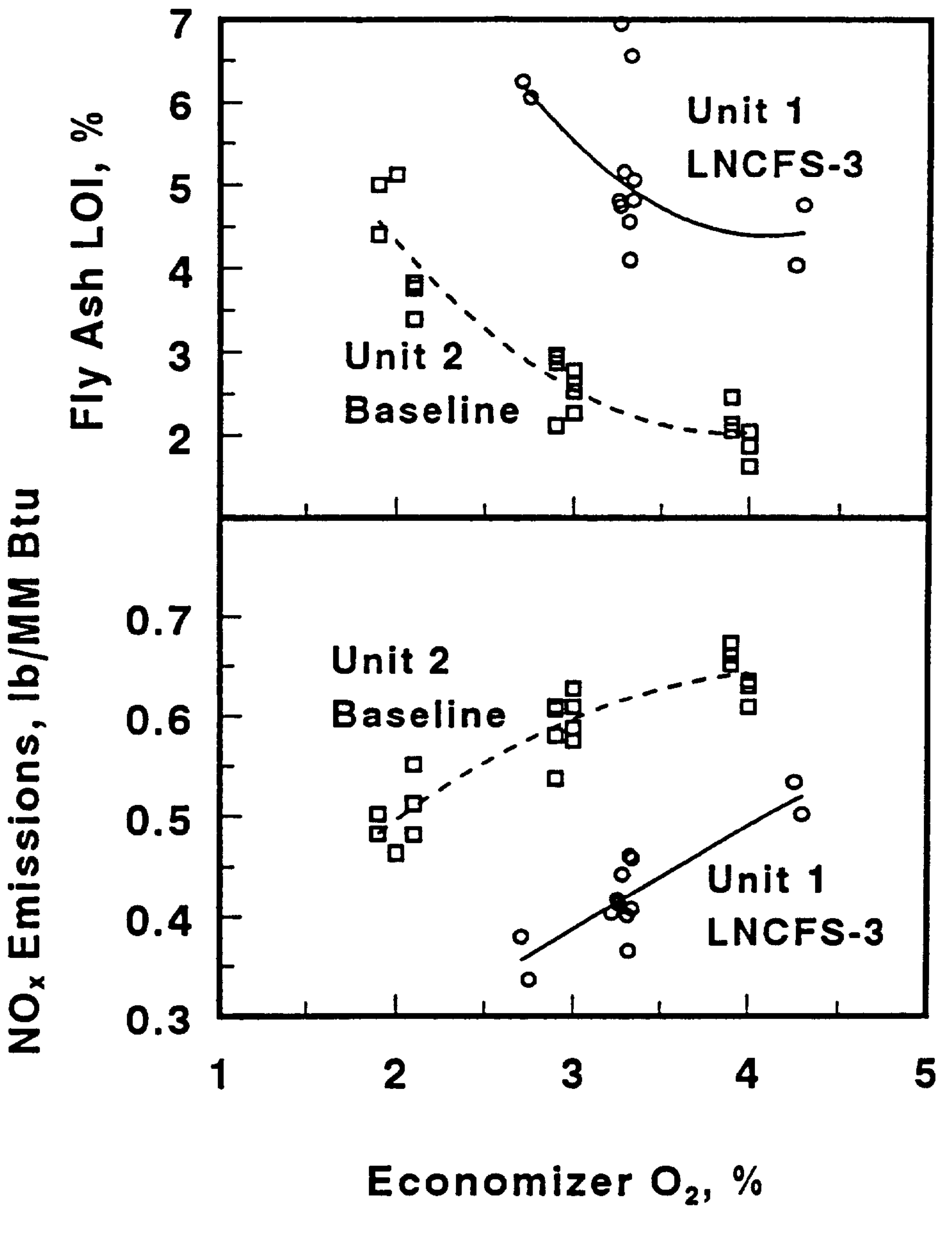


Figure 5.8 - Comparing Long-Term NO_x Emissions at 145-150 MW