ULTRA LOW NOx INTEGRATED SYSTEM FOR NOx EMISSION CONTROL FROM COAL-FIRED BOILERS

FINAL REPORT

SUBMITTED BY

ALSTOM POWER INC.
POWER PLANT LABORATORIES
2000 DAY HILL ROAD
WINDSOR, CT 06095

Galen H. Richards
Charles Q. Maney
Richard W. Borio

ALSTOM POWER INC.
PERFORMANCE PROJECTS
2000 DAY HILL ROAD
WINDSOR, CT 06095

Robert D. Lewis

PREPARED FOR

U.S. DEPARTMENT OF ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY
PITTSBURGH, PENNSYLVANIA 15236
(COOPERATIVE AGREEMENT NO. DE-FC26-00NT40754)

REPORT SUBMITTAL DATE: December 30, 2002
PROJECT PERFORMANCE PERIOD: FEBRUARY 11, 2000 – December 31, 2002
PPL REPORT NO. PPL-02-CT-19

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ACKNOWLEDGEMENTS

Financial support of this project was provided by DOE National Energy Technology Laboratory (COOPERATIVE AGREEMENT NO. DE-FC26-00NT40754) and ALSTOM Power Inc. The contribution of Kennecott Energy to this project (donation of 300 tons of their Cordero Rojo coal including transportation from the Powder River Basin) is also greatly appreciated.

The contributions of the utility advisory committee to the success of this project are also recognized. The following organizations and consultants participated in the two (2) advisory committee meetings:

- U.S. DOE – NETL
- Consumers Energy
- Indianapolis Power & Light
- PacifiCorp.
- Reliant Energy
- Janos M. Beér – Massachusetts Institute of Technology
- ALSTOM Power Environmental Systems
- ALSTOM Power Performance Projects

The assistance from Progress Materials in evaluating their Carbon Burn Out™ device for use with the Ultra Low NOx Integrated System is also appreciated.

John L. Marion, the ALSTOM Power Program Manager, also contributed to the success of this project as did Douglas Hart and Gary Camody from ALSTOM Power Performance Projects and Bob Hilton from ALSTOM Power Environmental Systems.

The efforts of the following project task leaders are recognized:

- Nsakala ya Nsakala – Fuels Characterization Task
- Joseph W. Quinn and William R. Hocking – Advanced Sensors and Controls Task
- Mark Palkes – Engineering and Economic Analysis Task

Finally, the contributions of the project team members and test crews who actually executed the project work are greatly appreciated.

PUBLIC ABSTRACT

ALSTOM Power Inc.'s Power Plant Laboratories, working in concert with ALSTOM Power's Performance Projects Group, has teamed with the U.S. Department of Energy's National Energy Technology Laboratory (DOE NETL) to conduct a comprehensive study to develop/evaluate low-cost, efficient NOx control technologies for retrofit to pulverized coal fired utility boilers. The objective of this project was to develop retrofit NOx control technology to achieve less than 0.15 lb/MMBtu NOx (for bituminous coals) and 0.10 lb/MMBtu NOx (for subbituminous coals) from existing pulverized coal fired utility boilers at a cost which is at least 25% less than SCR technology. Efficient control of NOx is seen as an important, enabling step in keeping coal as a viable part of the national energy mix in this century, and beyond.

Presently 57% of U.S. electrical generation is coal based, and the Energy Information Agency projects that coal will maintain a lead in U.S. power generation over all other fuel sources for decades (EIA 1998 Energy Forecast). Yet, coal-based power is being strongly challenged by society's ever-increasing desire for an improved environment and the resultant improvement in health and safety. The needs of the electric-utility industry are to improve environmental performance, while simultaneously improving overall plant economics. This means that emissions control technology is needed with very low capital and operating costs.

This project has responded to the industry's need for low NOx emissions by evaluating ideas that can be adapted to present pulverized coal fired systems, be they conventional or low NOx firing systems. The TFS 2000™ firing system has been the ALSTOM Power Inc. commercial offering producing the lowest NOx emission levels. In this project, the TFS 2000™ firing system served as a basis for comparison to other low NOx systems evaluated and was the foundation upon which refinements were made to further improve NOx emissions and related combustion performance.

Three coals were evaluated during the bench-scale and large pilot-scale testing tasks. The three coals ranged from a very reactive Powder River Basin coal (PRB) to a moderately reactive Midwestern bituminous coal (HVB) to a less reactive medium volatile Eastern bituminous coal (MVB). Bench-scale testing was comprised of standard ASTM properties evaluation, plus more detailed characterization of fuel properties through drop tube furnace testing and thermogravimetric analysis.

Pilot-scale testing in ALSTOM Power's Boiler Simulation Facility (BSF) evaluated a number of low NOx subsystems under realistic boiler combustion system conditions at a large pilot-scale of 50-60 MMBtu/hr (15-18 MW_t). Among the technologies evaluated in the BSF were finer coal grinding, oxidative pyrolysis burners, windbox auxiliary air optimization, and various burner zone firing arrangements in concert with strategic deployment of overfire air.

Computational fluid dynamics (CFD) was used to evaluate the effectiveness of a number of overfire air schemes prior to testing in the BSF. Other technologies, such as an advanced boiler control system, coal and air flow balancing, and a Carbon Burn Out™ combustor, were

also evaluated. An advanced boiler control system was conceptually developed to achieve optimal boiler performance, with regard to NOx and other control targets, under all boiler operating conditions.

Bench-scale characterization of the three test coals showed that both NOx and combustion performance are a strong a function of coal properties. More reactive coals evolved more of their fuel bound nitrogen in the substoichiometric main burner zone than less reactive coals, resulting in lower NOx emissions. From a combustion point of view, the more reactive coal also showed lower carbon in ash and CO values than the less reactive coals at any given main burner zone stoichiometry. According to bench-scale results, the PRB coal was found to be the most amenable to both low NOx, and acceptably low combustibles in the flue gas, in an air staged low NOx system. The MVB coal, by contrast, was predicted to be the most challenging of the three coals, with the HVB coal predicted to fall in between the PRB and MVB coals.

Pilot-scale test results fell largely in line with predictions from bench-scale testing as far as differences in coal properties were concerned. The most reactive coal (PRB) showed the lowest NOx, followed by the moderately reactive HVB and least reactive MVB coals. From the standpoint of combustibles in the flue gas, the PRB showed the lowest combustibles (carbon in ash and CO), followed by the HVB and MVB coals. Fifteen different variables were studied during pilot-scale testing, the results of which are contained in the report.

The combination of firing system modifications resulting in the lowest NOx emissions is referred to as the Ultra Low NOx Integrated System. In general, firing system modifications, which reduce NOx emissions, also result in higher levels of carbon in the fly ash. When both NOx and combustion efficiency were equally weighed, the standard TFS 2000™ set of operating conditions/system components gave the best results for the HVB and MVB coals and the Ultra Low NOx Integrated System gave the best results on the PRB coal. Many of the firing system components developed in this project can also be applied to the TFS 2000™ firing system, resulting in improved NOx emissions without significantly impacting the carbon in fly ash levels.

An engineering systems analysis and economic evaluation was performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). The various NOx reduction alternatives were evaluated as retrofit options for three tangential-fired utility boilers in the U.S.: (1) a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, (2) a 500 MW boiler in the Midwestern U.S. firing a Midwestern bituminous coal, and (3) a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). The objective of the Engineering Systems Analysis and Economics Task was to evaluate the economics of various NOx reduction options to gain insight into the optimum NOx reduction strategy for different pulverized coal-fired units.

Results from this economic analysis showed that switching to a PRB coal, in concert with installation of either a TFS 2000™ System or Ultra Low NOx Integrated System, was the most cost effective option (75-80% less than the cost of an SCR) if the cost of shipping the PRB coal to a particular site was not prohibitive. However, it was recognized that the optimum NOx reduction strategy is unit, site, and system specific.

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EXECUTIVE SUMMARY

Background

The U.S. power generation industry is undergoing complex change from demands for deregulation and environmental sustainability. Deregulation is forcing economic efficiency with ever-increasing sensitivity to minimizing capital investment, reducing operational costs, and controlling uncertainty and resultant financial risk. In this environment, existing coal-fired power plants with paid down capital investments may enjoy a favorable role in base load generation due to low fuel costs, high availability and capacity factor, and generally low cost of electricity production. Presently 57% of U.S. electrical generation is coal based, and the Energy Information Agency projects that coal will maintain a lead in U.S. power generation over all other fuel sources for decades (EIA 1998 Energy Forecast). Yet, coal-based power is being strongly challenged by society's ever- increasing desire for an improved environment and the resultant improvement in health. Therefore, the needs for the electric-utility industry are to improve environmental performance, while simultaneously improving overall plant economics. This means that emissions control technology is needed with very low capital and operating costs.

The negative health effects and resulting costs of NOx emissions are well documented. Relatively low levels of ozone, of which NOx is a prominent precursor, can create respiratory problems. NOx contributes to acid rain and to the nitrate pollution problems in critical waterways. NOx emissions are also the precursor of nitrate particulate emissions, a contributor to ambient fine particulate.

The U.S. electric-utility industry has made considerable strides in controlling emissions of NOx as well as sulfur dioxide (SO_2) and particulate matter (PM) since the passage of the Clean Air Act (CAA) in 1970. The 1990 Clean Air Act Amendment (CAAA) Title I, Urban Air Quality, and anticipated future National Ambient Air Quality Standards (NAAQS) go further in forcing NOx emissions reductions.

Table E-1: Utility NOx Control ($Millions of USD)

Order year	LNB	SCR Systems	SNCR Systems	Reburn and Others	Controls Only	Total
1999	492	355	42	60	56	1005
2000	174	555	70	60	20	879
2001	212	555	70	60	20	917
2002	212	610	70	90	20	1002

Boiler owners must also anticipate future regulations. Table E-1 reflects the anticipation that the Electric Utility industry will make reductions in NOx by the use of both combustion modifications and post combustion control equipment (McIlvaine Company, 1999). The cost of a SCR system can vary significantly with the difficulty of the retrofit and typical costs range from 100-150 $/kW. ALSTOM Power and other equipment suppliers have all seen large demands for SCR systems in 1999 - 2001.

The impact of impending regulations is difficult to determine. In many ways utility boiler owners are the best source of knowledge about possible environmental control strategies for their various regulatory and cost structures. A survey conducted by ALSTOM Power of over 20 customers located in the Ozone Transport Region and in Texas, including Investor Owned Utilities, Public Owned Utilities, and Industrial customers showed:

- Customers anticipate that NOx trading will be integral to their compliance strategy.
- Most customers saw themselves as net buyers of NOx credits with prices expected in the $1,000 to $3,500 / ton NOx range.
- Utilities want alternatives to SCR, especially for units that are not base loaded.
- Utilities are comfortable with fuel switching strategies as part of a compliance strategy.
- Utilities and industrial boiler operators see limited use of SNCR and gas reburn.
- All customers would be pleased to have additional options for achieving lower cost NOx compliance at the 0.15 lb/MMBtu level.

These environmental factors and utility owner interests have served as important inputs to the work undertaken in this project.

Objectives

The overall goal of the proposed project was to develop low-cost, efficient NOx control technologies for retrofit to coal fired utility boilers as a means to keep coal a viable part of the national energy mix in the next century and beyond. Toward that end, the following specific project objectives were set by ALSTOM Power, in concert with the U.S. DOE, for work that was performed in response to the above goal:

- Develop retrofit NOx control technology to achieve less than 0.15 lb/MMBtu NOx from existing tangentially-fired utility boilers when firing bituminous coals

- Develop retrofit NOx control technology to achieve less than 0.10 lb/MMBtu NOx from existing tangentially- fired utility boilers when firing subbituminous or lignitic coals

- Achieve economics, which are at least 25% lower cost than the SCR-only technology

- Validate NOx control technology through large (15 MWt) pilot scale demonstration

- Evaluate engineering feasibility and economics for several scenarios of technology components and component integration for representative plant cases with both bituminous and subbituminous coals

Work Scope

The basis for development of the Ultra Low NOx Integrated System was to evaluate a number of components/processes with the potential to further, incrementally reduce NOx, using the TFS 2000™ low NOx systemas a foundation upon which to build. Three coals were evaluated during the bench-scale and pilot-scale testing tasks. The three coals ranged from a very reactive subbituminous coal from the Powder River Basin (PRB) to a moderately reactive Midwestern high volatile bituminous coal (HVB) to a less reactive medium volatile Eastern bituminous coal (MVB).

Key tasks within the project were:

- Bench-scale analysis/characterization of the three test coals
- Development of low NOx subsystems/processes
- Pilot-scale testing of the integrated system
- Engineering systems analysis and economics

Bench-scale analysis involved standard ASTM coal characterization, plus more comprehensive characterization of fuel bound nitrogen release and char reactivity through testing in ALSTOM Power's Drop Tube Furnace and Thermogravimetric Analyzer (TGA) apparatuses.

Low NOx subsystems included design/testing of an oxidative pyrolysis burner, modifications to and testing of various overfire air and burner zone components/configurations, evaluation of the benefits of finer coal grinding, and ammonia injection. The benefits of employing a fluidized bed (Progress Materials) for oxidizing unburned carbon in the fly ash was evaluated primarily through economic analysis.

Large pilot-scale testing (50-60 MMBtu) was a focal point in this project, inasmuch as it afforded the opportunity to obtain experimental results from the various low NOx subsystems at a commercially significant scale. Among the key variables evaluated during this work were main burner zone stoichiometry, staged residence time, fuel fineness and specific windbox arrangements in the fuel-rich zone. In the burnout zone, overfire air location and velocity was among the important variables. Ammonia injection was briefly evaluated, both in the lower furnace and above the windbox for possible additional NOx reduction.

The engineering systems analysis and economics evaluation was performed to evaluate combinations of various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System and selective catalytic reduction (SCR). The various NOx reduction alternatives were evaluated as retrofit options for three (3) tangential-fired utility boilers in the U.S.: (1) a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, (2) a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and (3) a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB).

Bench-Scale Test Results

Bench-scale test results showed that both NOx and combustion performance are very much a function of coal properties, particularly coal reactivity. More reactive coals evolved more of their fuel bound nitrogen in the main burner zone than less reactive coals (see Figure E-1). From a combustion point of view, the more reactive coal showed lower carbon in ash and CO values than the less reactive coals at any given stoichiometry. Figure E-2 shows the relative reactivities of the three coals as determined by the burnoff weight loss in a TGA apparatus.

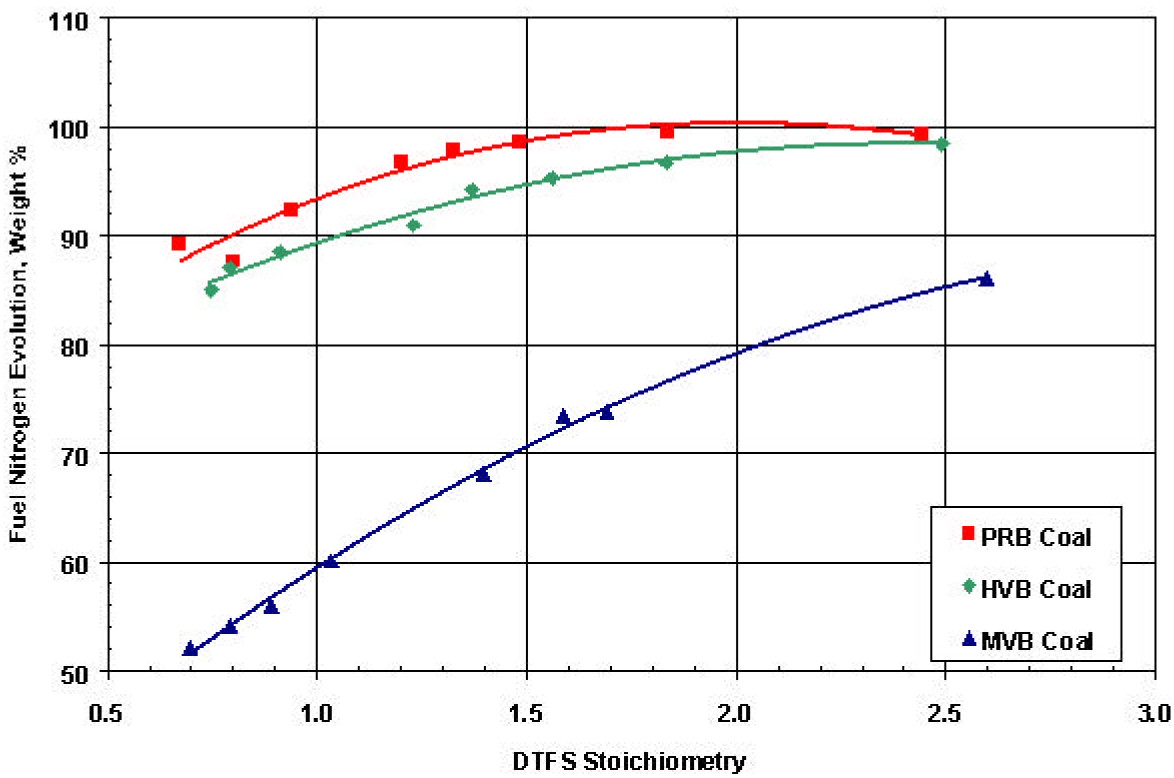

Figure E-1: Fuel Bound Nitrogen Conversion vs. Stoichiometry.

Based on the bench-scale evaluation, the PRB coal would be the most amenable to operation in a staged air, low NOx combustion system. The combination of early devolatilization, with commensurately high quantities of fuel bound nitrogen being released early in the combustion process, coupled with a highly reactive char, indicate that significant NOx reduction can occur without penalties of high unburned carbon or CO for the PRB coal. The MVB coal, by contrast, would be the most challenging of the three coals regarding the task of achieving low NOx in an air staged, low NOx system while maintaining acceptable levels of unburned carbon and CO levels. The HVB coal would fall in between the PRB and MVB coals regarding its NOx and combustion performance in an air staged low NOx combustion system.

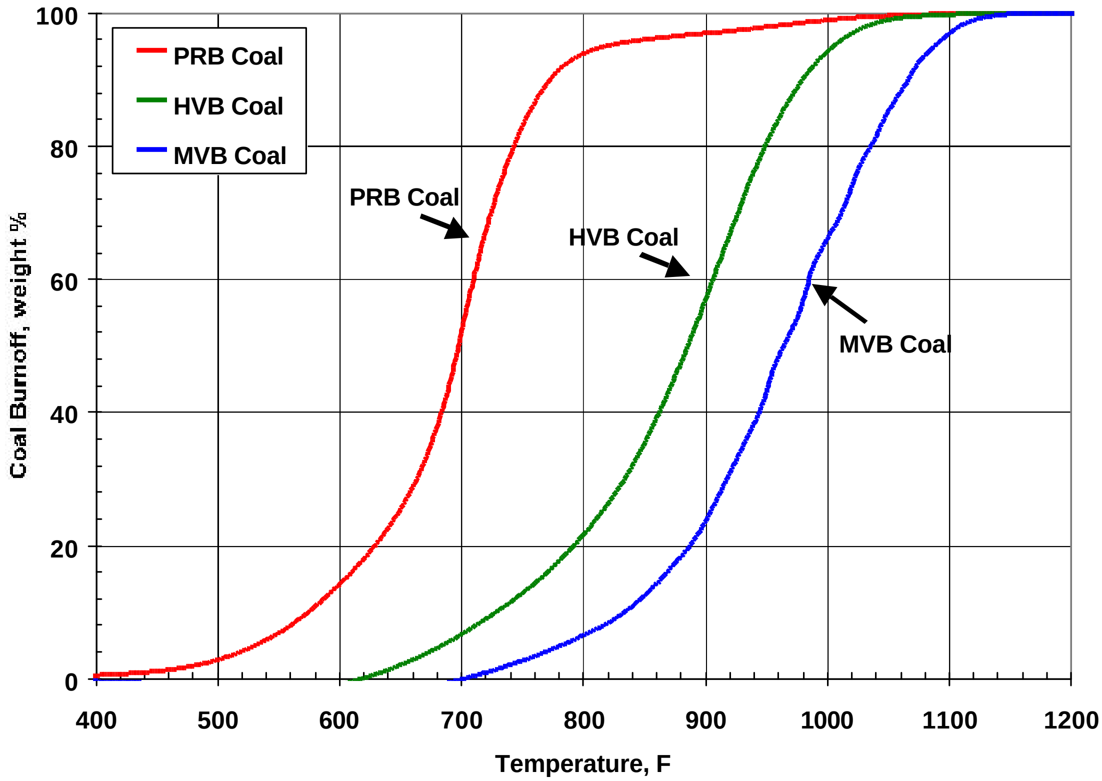

Figure E-2: Fuel Burnoff as a Function of Temperature (TGA).

Employment of ultra-fine coal grinding in the case of the MVB coal was found to provide better carbon burnout, similar to that of the HVB coal. However, finer grinding of the MVB coal did not increase high temperature volatile matter release, or nitrogen conversion to gaseous species during pyrolysis testing.

Bench-scale results provided a sound, fundamental understanding of NOx-related results from pilot-scale tests; fuel bound nitrogen conversion for the MVB coal, for example, was shown to be about 60% of that found for the PRB and HVB coals. This finding constitutes a major reason for the higher NOx emissions when firing the MVB coal under an air staged system, relative to the HVB and PRB coals.

Pilot-Scale Test Results

Pilot-scale testing in ALSTOM Power's Boiler Simulation Facility (BSF) afforded the opportunity to evaluate a number of burner zone windbox and overfire air component arrangements. The BSF is a water-cooled, atmospheric pressure, balanced draft, combustion test facility designed to replicate the time - temperature - stoichiometry history of a typical utility boiler. The BSF replicates all major attributes of a utility boiler including a "V" hopper, an arch, and appropriate (simulated) superheater, reheater, and economizer surface. For pulverized coal firing the BSF is nominally rated at a 50 million Btu/hr (15 MW_t).

Some overfire air arrangements were initially evaluated by computational fluid dynamics (CFD) thereby serving as a guide to specific testing in the BSF. Pilot-scale test results fell largely in line with predictions from bench-scale testing as far as differences in coal properties were concerned, the most reactive PRB coal showing the greatest NOx reduction, followed by the moderately reactive HVB, and least reactive MVB coals (see Figure E-3).

Figure E-3 shows NOx as a function of main burner zone (MBZ) stoichiometry for the three coals tested. Interestingly, but not surprisingly, the optimum stoichiometry, from a NOx point of view, is different for the three coals. The least reactive coal required a lower stoichiometry to achieve the lowest NOx values than the more reactive coals.

Obtaining lower NOx through an air staging process normally comes with some impact to carbon in ash and carbon monoxide, albeit to different degrees, depending on the coal properties. Figure E-4 shows the relationship between carbon in ash (CIA), as a function of stoichiometry, for the three test coals. Owing to its relatively low char reactivity (Figure E-2), the MVB coal shows the greatest increase in carbon loss as main burner zone (MBZ) stoichiometry decreases. The PRB coal, by contrast, shows very little impact of decreasing stoichiometry on CIA as measured in the BSF. The HVB coal falls about midway between the other two coals, with regard to CIA.

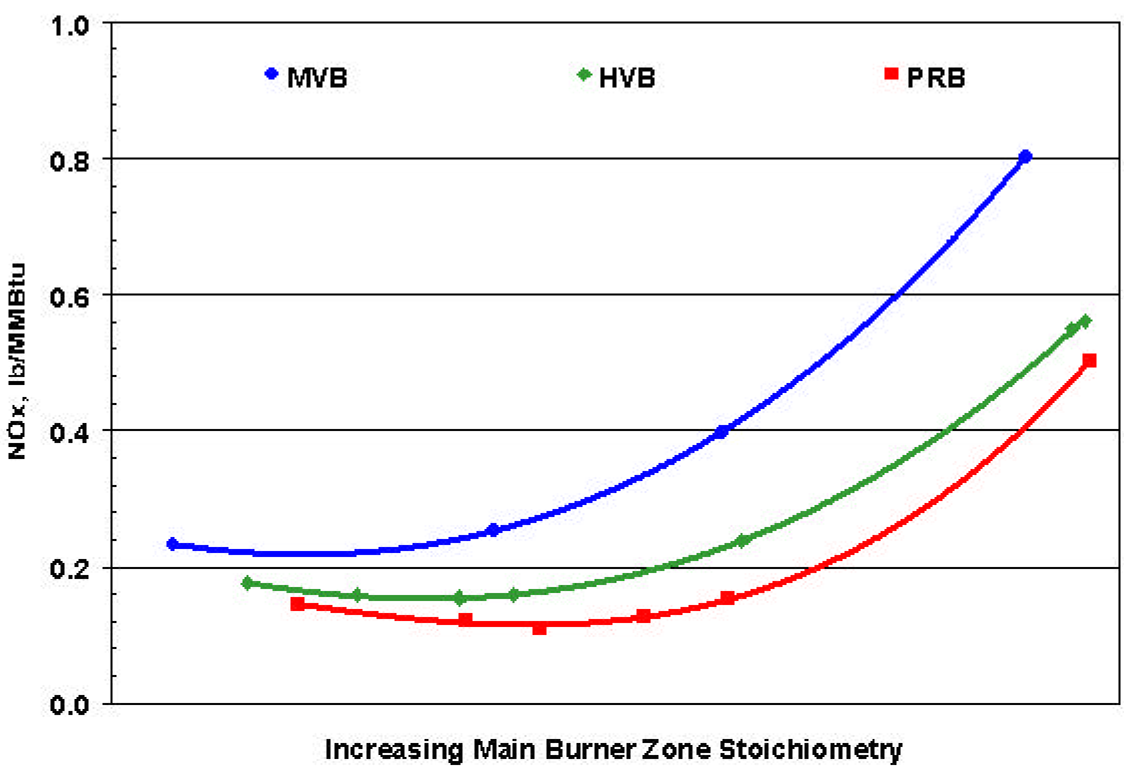

Figure E-3: NOx versus Main Burner Zone Stoichiometry.

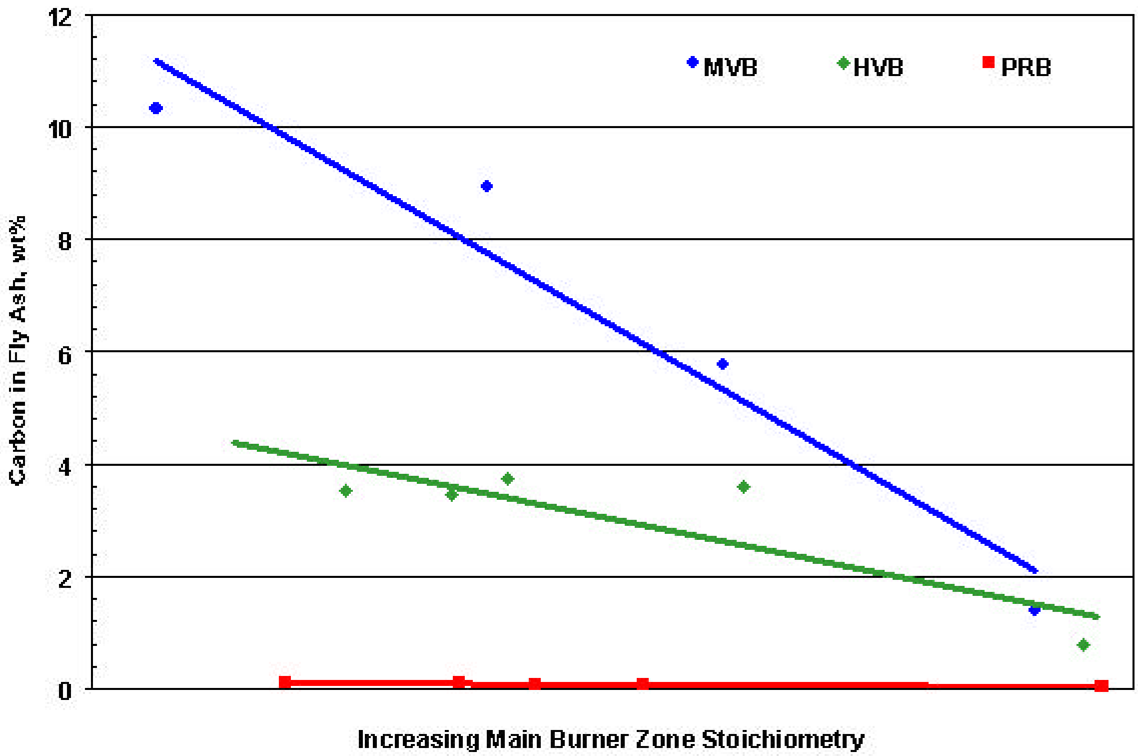

Figure E-4: Carbon in Ash vs. MBZ Stoichiometry.

Along with main zone burner stoichiometry, staged residence time is an important parameter for achieving low NOx in an air-staged system. In this report, staged residence time is defined as the plug flow residence time from the top coal elevation to the first elevation of overfire air. Figure E-5 shows NOx as a function of staged residence time at the optimum stoichiometries for the particular coal. For each of the coals, initial increases in staged residence time have a greater effect on the extent of NOx reduction. The impact of staged residence time is most pronounced for the MVB and HVB coals. For all coals the rate of NOx reduction tapers off with increasing staged residence time.

Increased coal fineness was evaluated as a means to reduce CIA and CO levels, but was found to reduce NOx emissions as well. Finer grinding can influence NOx in the following ways: (1) allow more aggressive stoichiometries while maintaining acceptable CIA and CO values, and (2) promote greater fuel nitrogen release through higher flame temperatures and greater particle surface area for char combustion. Figure E-6 is a summary of baseline NOx levels for each coal, along with NOx values attained for the TFS 2000™ system and minimum NOx achieved with the Ultra Low NOx Integrated System. In the case of the least reactive MVB coal, a micro-fine coal grind was also tested.

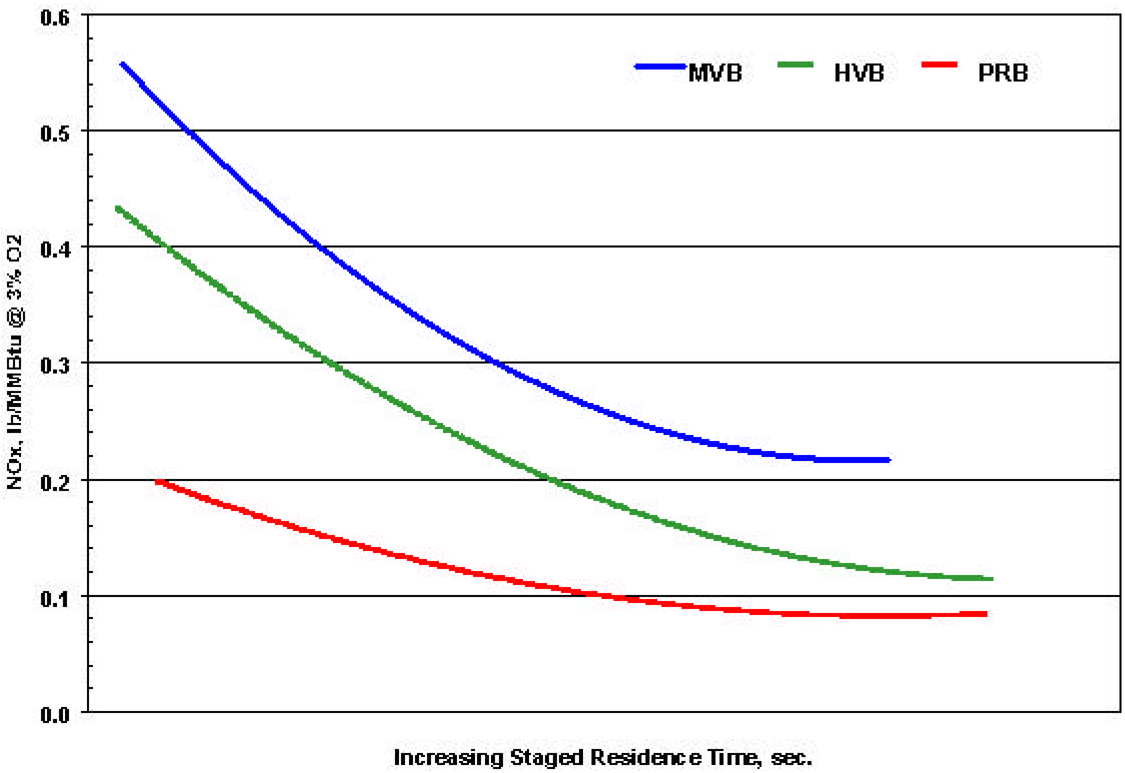

Figure E-5: NOx as a Function of Staged Residence Time.

The minimum NOx values for the Ultra Low NOx Integrated System were on the order of 0.03 lb/MMBtu lower than those achieved with the standard TFS 2000™ system. However, the carbon in ash values associated with the minimum NOx were about twice what was achieved with the standard TFS 2000™ system, which could be problematic in the case of HVB and MVB coals. When both NOx and combustion performance (CIA and CO) were equally weighed, the standard TFS 2000™ set of operating conditions/system components gave the best results for the HVB and MVB coals, with the Ultra Low NOx Integrated System giving the best results on the PRB coal.

Absolute NOx and carbon in ash emissions levels are a strong function of the boiler design, including furnace height, furnace cross sectional area, firing zone heat release rates, etc. The BSF is a large pilot-scale test facility that was designed to span the available range of time-temperature histories of commercial utility boilers. As such, the minimum NOx and carbon in ash levels achieved in the BSF may be lower than what can be obtained in many commercial utility boilers, but illustrate the limits of what is possible with combustion modifications. Also, testing various SOFA conditions and staged residence times allows the BSF results to predict firing system performance on a large range of utility boilers. The relative results generated with different firing system configurations in the BSF are broadly applicable and illustrate the effectiveness of firing system modification, including those achieved with the commercial TFS 2000™ system in lowering NOx emissions.

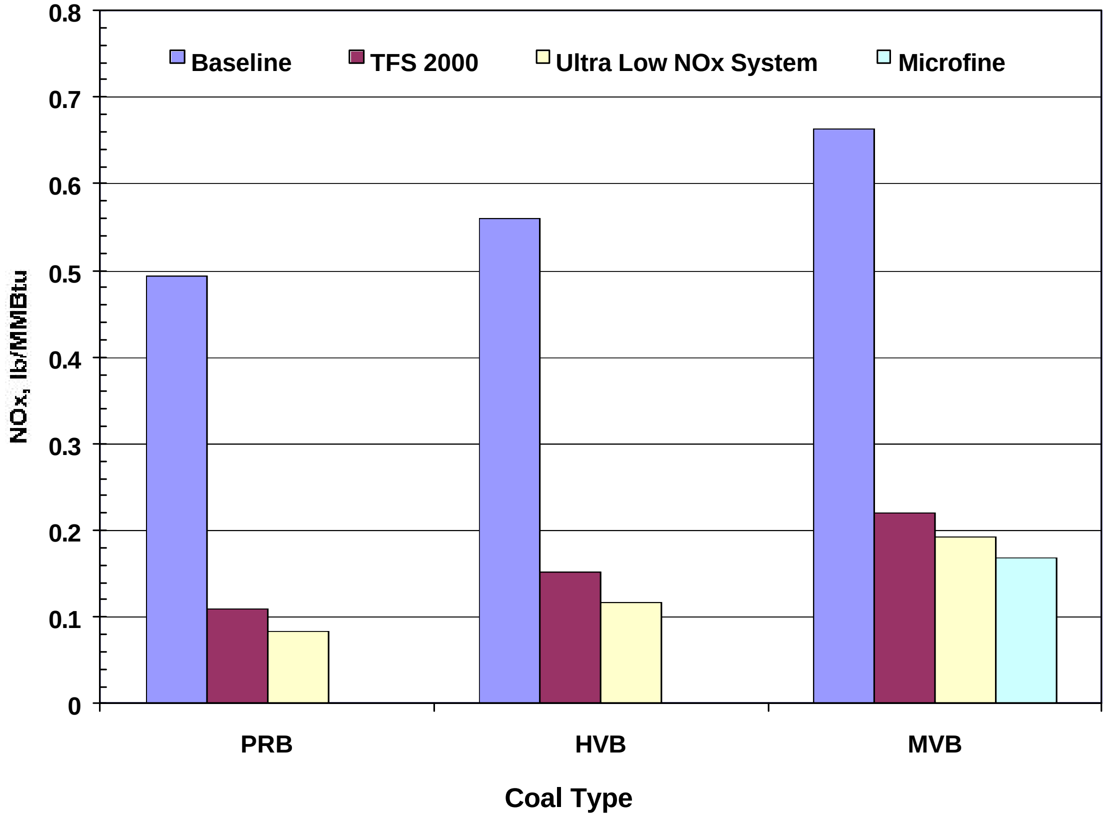

Figure E-6: NOx Emissions from BSF Combustion Testing.

Engineering System Analysis and Economics

An engineering systems analysis and economic evaluation was performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). As expected, the optimum NOx reduction strategy was unit and fuel specific for the three (3) tangential-fired utility boilers evaluated in this study: (1) a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, (2) a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and (3) a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). This study was performed to provide guidance in developing a NOx compliance strategy. However, individual utility NOx compliance strategies must also account for current and anticipated local and national emissions regulations, the potential of NOx credit trading, and the impact of utility deregulation, etc. which may be unit, site, fuel, and system specific.

The most attractive NOx compliance strategy for the Western unit firing a PRB fuel was the Ultra Low NOx Integrated System. Reasonable delivered fuel costs and generous boiler sizes make fuel switching to PRB coals an attractive option for many Midwestern units. For

Eastern U.S. units, the option of fuel switching to a PRB coal was found to be very sensitive to the delivered fuel price, since fuel cost is the largest single expense for a utility boiler. The capital cost of an SCR installation ($100 /kW) was shown to be 4-5 times that of the cost of typical low NOx firing system modifications. NOx reduction economics were found to be very sensitive to the projected price of NOx credits as well as to the potential market for selling excess credits.

Overall Project Conclusions

The overall goal of the proposed project was to develop low-cost, efficient NOx control technologies for retrofit to coal fired utility boilers as a means to keep coal a viable part of the national energy mix in the next century and beyond. Specific project objectives have been listed below with the commensurate project achievement:

- Objective: Develop retrofit NOx control technology to achieve less than 0.15 lb/MMBtu NOx from existing tangentially-fired utility boilers when firing Eastern bituminous coals

- Achievement: For the two bituminous coals tested in the BSF, one high volatile (HVB) and one medium volatile (MVB), the specific target above was met for the HVB coal (0.12 lb/MMBtu) while 0.17 lb/MMBtu was achieved for the MVB coal. The results of the large pilot-scale testing suggest that the target of 0.15 lb/MMBtu may be realistic for highly reactive bituminous coals. However, given the range and importance of specific coal properties on NOx and combustion performance, as well as the specific boiler designs, it becomes difficult to project the emissions performance of the new firing system technology to the tangentially-fired utility boiler market.

- Objective: Develop retrofit NOx control technology to achieve less than 0.10 lb/MMBtu NOx from existing tangentially- fired utility boilers when firing western, subbituminous or lignitic coals

- Achievement: When tested in the BSF the subbituminous (PRB) coal gave NOx values as low as 0.08 lb/MMBtu for the Ultra Low NOx Integrated System.

- Objective: Achieve economics which are at least 25% lower cost than the SCR-only technology

- Achievement: Capital costs for the TFS 2000™ or the Ultra Low NOx Integrated System are well under the target of "25% less than an SCR-only" installation based on commercial costing information. For the Eastern bituminous and subbituminous coal cases (taken from Section 7.0) the TFS 2000™ and Ultra Low NOx Integrated System are about 78% less than an SCR-only case; for the Midwestern coal case the TFS 2000™ and Ultra Low NOx Integrated System are on the order of 87% less than an SCR-only case.

- Objective: Validate NOx control technology through large (15 MW_t) pilot scale demonstration

- Achievement: Credible results have been obtained from ALSTOM Power's 15 MW_t pilot-scale facility on NOx emissions for the various derivatives of the low NOx systems tested. It is recognized that absolute NOx and carbon in ash emissions levels are a function of the boiler design, including furnace height, furnace cross sectional area, firing zone heat release rates, etc. Since the Boiler Simulation Facility was designed to span a range of time-temperature histories of commercial utility boilers, NOx and carbon in ash levels are often lower than what might be obtained in commercial utility boilers. However, relative results of the BSF are broadly applicable and illustrate the effectiveness of firing system modification, including those achieved with the commercial TFS 2000™ system in lowering NOx emissions and suggest that additional NOx reduction over the commercially available firing system is possible.

- Objective: Evaluate engineering feasibility and economics for several scenarios of technology components and component integration, for representative plant cases with both bituminous and subbituminous coals

- Achievement: Engineering systems analyses and economic evaluations were performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). Optimum NOx reduction strategy was unit and fuel specific for the 3 tangential-fired utility boilers evaluated in this study, a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). Utility NOx reduction strategies must also account for current and anticipated local and national emissions regulations, potential of NOx credit trading, utility deregulation, etc. which may be unit, site, fuel, and system specific.

Results from this project have directly, and positively benefited the performance of ALSTOM Power's family of low NOx firing systems, specifically the TFS 2000™ and CFS™ systems. For those boilers firing PRB type coals, for example, results from this project have shown how modifications can be made to enhance performance of the LNCFS™ firing system. Lastly, fine grinding has been shown to improve performance with lower reactivity coals in concert with the TFS 2000™ firing system.

1.0 INTRODUCTION

The U.S. power generation industry is undergoing complex change from demands for deregulation and environmental sustainability. Deregulation is forcing economic efficiency with ever-increasing sensitivity to minimizing capital investment, reducing operational costs, and controlling uncertainty and resultant financial risk. In this environment, existing coal-fired power plants with paid down capital investments may enjoy a favorable role in base load generation due to low fuel costs, high availability and capacity factor, and generally low cost of electricity production. Presently 57% of U.S. electrical generation is coal based, and the Energy Information Agency projects that coal will maintain a lead in U.S. power generation over all other fuel sources for decades (EIA 1998 Energy Forecast). Yet, coal-based power is being strongly challenged by society's ever- increasing desire for an improved environment and the resultant improvement in health. Therefore, the needs for the electric-utility industry are to improve environmental performance, while simultaneously improving overall plant economics. This means that emissions control technology is needed with very low capital and operating costs.

The negative health effects and resulting costs of NOx emissions are well documented. Low levels of ozone, of which NOx is a prominent precursor, can create respiratory problems. NOx contributes to acid rain and to the nitrate pollution problems in critical waterways. NOx emissions are also the precursor of nitrate particulate emissions, a contributor to ambient fine particulate. Fine particulate has been identified as a significant factor in the mortality of thousands of people per year..

The U.S. electric-utility industry has made considerable strides in controlling emissions of NOx as well as sulfur dioxide (SO_2) and particulate matter (PM) since the passage of the Clean Air Act (CAA) in 1970. The 1990 Clean Air Act Amendment (CAAA) Title I, Urban Air Quality, and anticipated future National Ambient Air Quality Standards (NAAQS) go further in forcing NOx emissions reductions. Under Title I, the U.S. EPA has issued a State Implementation Plan (SIP) call for 22 Eastern states and the District of Colombia to reduce both NOx and VOC's from existing plants on the basis of ozone non-attainment in the northeast (see Figure 1.0-1).

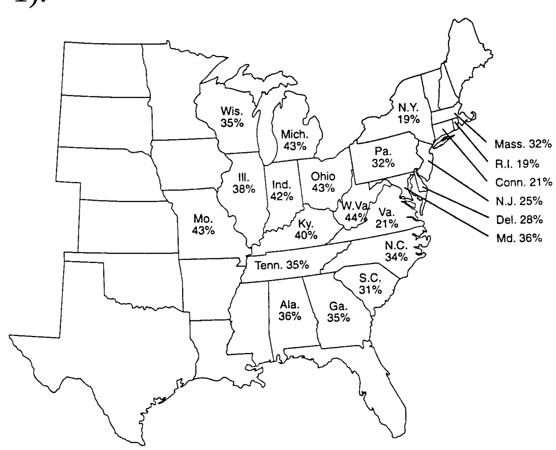

Figure 1.0-1: Further NO_x Reduction under EPA Ozone Transport Rules

The CAAA in 1990 has resulted in a reduction of NOx emissions of 400,000 tons/year between 1996 and 1999 under Title IV ("Acid Rain"), Phase I, and an additional 1,200,000 tons/year under Title IV Phase II. Under Title IV Phase II tangentially fired units, all of which were manufactured by ALSTOM Power (formerly ABB Combustion Engineering and Combustion Engineering Inc.), will need to operate at NOx emissions levels below 0.40 lb/MMBtu, while wall fired units, made by a number of manufacturers including ALSTOM Power, will need to operate at NOx emissions levels below 0.46 lb/MMBtu.

The Ozone Transport Assessment Group (OTAG) is expected to eventually include a total of 38 states. The corresponding market includes more than 880 coal fired power plants. Of these plants, approximately 40% are tangential fired boilers, as shown in Figure 1.0-2 (ALSTOM Power Marketing, 1999).

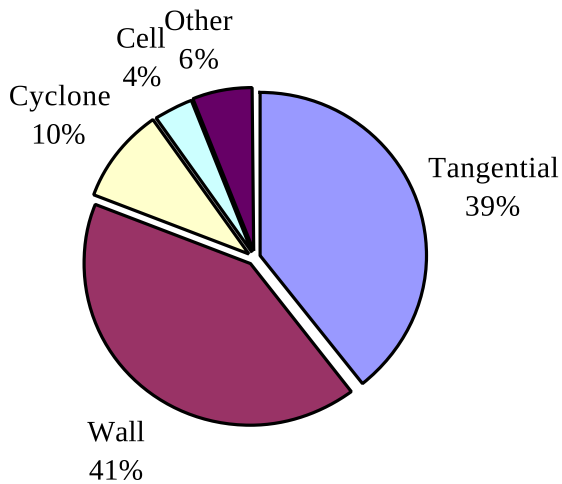

Figure 1.0-2: Population of Coal-Fired Boilers Affected by Title I CAAA

In addition, boiler owners must also anticipate future regulations. Table 1.0-1 reflects the anticipation that the Electric Utility industry will make reductions in NOx by the use of both combustion modifications and post combustion control equipment (McIlvaine Company). The cost of a SCR system is less than originally anticipated by utilities and EPA, although still relatively expensive. ALSTOM Power and other equipment suppliers have all seen large demands for SCR systems in 1999 - 2001.

Table 1.0-1: Utility NOx Control ($Millions of USD)

Order year	LNB	SCR Systems	SNCR Systems	Reburn and Others	Controls Only	Total
1999	492	355	42	60	56	1005
2000	174	555	70	60	20	879
2001	212	555	70	60	20	917
2002	212	610	70	90	20	1002

The impact of impending regulations is difficult to determine. In many ways utility boiler owners are the best source of knowledge about possible environmental control strategies for their various regulatory and cost structures. A survey conducted by ALSTOM Power of over 20 customers located in the Ozone Transport Region and in Texas, including Investor Owned Utilities, Public Owned Utilities, and Industrial customers showed:

- Customers anticipate that NOx trading will be integral to their compliance strategy.
- Most customers saw themselves as net buyers of NOx credits with prices expected in the $1,000 to $3,500 / ton NOx range.
- Utilities want alternatives to SCR, especially for units that are not base loaded.
- Utilities are comfortable with fuel switching strategies as part of a compliance strategy.
- Utilities and industrial boiler operators see limited use of SNCR and gas reburn.
- All customers would be pleased to have additional options for achieving lower cost NOx compliance at the 0.15 lb/MMBtu level.

These environmental factors and utility owner interests have served as important inputs to the work undertaken in this project.

1.1 Background

This section will describe ALSTOM Power's traditional approach for addressing customer environmental compliance needs, specifically NOx reduction. Knowledge of ALSTOM Power's traditional approach will provide a useful foundation for understanding how the project for the Ultra Low NOx Integrated System was conceived.

ALSTOM Power's approach for solving environmental compliance needs has been to create a total environmental solutions team that utilizes the full range of specific product resources and talents throughout the company. This team begins a compliance strategy by considering all of the potential places within the steam generating system where NOx can be affected and controlled. An evaluation is made of the fuel selected and its preparation, pulverization, and combustion characteristics. All feasible options for in-furnace NOx control are reviewed for reduction efficiency and potential impact on steam generator performance. Post-combustion technologies are also a major component of the evaluation. ALSTOM Power has expertise in post combustion systems including SCR, SNCR and hybrid technologies. A total approach to integrated controls and measurement is an integral part of this evaluation. This approach provides the flexibility to invest capital on equipment that provides the most cost-effective NOx reduction strategy, thus minimizing the total capital and operating costs for system-wide compliance.

ALSTOM Power has supported customer requirements to address CAAA of 1990 rules by offering a broad line of low NOx firing system products. Customer requirements have been met in many cases with in-furnace solutions alone. With the wide variety of tangential fired boiler designs of varying vintage, along with a broad range of coals being fired, ALSTOM Power developed and provides a family of low NOx firing system products which includes LNCFS™ Levels I, II, and III, LNCFS™-P2, and TFS2000™R technology for retrofit.

Figure 1.1-1 documents the firing systems available with the ALSTOM Power family. Each of these low NOx firing system products utilizes the same basic design features of early fuel devolatilization/fuel-bound nitrogen release, and local and/or global combustion air staging. The differences among the options available occur in the tradeoffs between the extent of NOx emissions reduction and the complexity and cost of material modification and retrofit requirements.

Standard Windbox	LNCFSÔ P2	LNCFSÔ Level I	LNCFSÔ Level II	LNCFSÔ Level III	TFS2000Ô R
					SOFA
					SOFA
			SOFA	SOFA	SOFA
			SOFA	SOFA	SOFA
AIR	VCCOFA	CCOFA	CCOFA	CCOFA	CCOFA
COAL	P2 COAL	CCOFA	COAL	CCOFA	COAL
AIR	CFSÔ Air	COAL	CFSÔ Air	COAL	CFSÔ Air
COAL	P2 COAL	COAL	COAL	COAL	COAL
AIR	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air
COAL	P2 COAL	COAL	COAL	COAL	COAL
AIR	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air
COAL	P2 COAL	COAL	COAL	COAL	COAL
AIR	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air	CFSÔ Air
COAL	P2 COAL	COAL	COAL	COAL	COAL
AIR	AIR	AIR	AIR	AIR	AIR

Figure 1.1-1: Schematic of Firing System Arrangements for LNCFSÔ Family of Low NOx Technology.

Figure 1.1-2 shows the relative costs and reduction efficiencies of ALSTOM Power's low NOx solutions, all based on a typical single furnace 200 MW boiler (Lewis, et al., 2002). Baseline uncontrolled NOx emissions from tangentially fired boilers typically range from 0.7 – 1.0 lb/MMBtu, depending upon the unit design and the coal fired. The percent decrease in NOx emissions from baseline is also unit and fuel specific.

ALSTOM Power has been supplying overfire air-based NOx reduction systems since 1970 and has been supplying its family of LNCFS™ NOx control firing systems since 1980. Over two-hundred-twenty-five (225) coal-fired tangential boilers have incorporated these systems, representing over 65,000 MWe of generating capacity. These unit retrofits range in size from 44 MWe industrial to a 900 MWe supercritical, divided unit. The retrofit experience covers an extensive range of coal types from lignites to bituminous (Jennings, 2002, Lewis, et al., 2002).

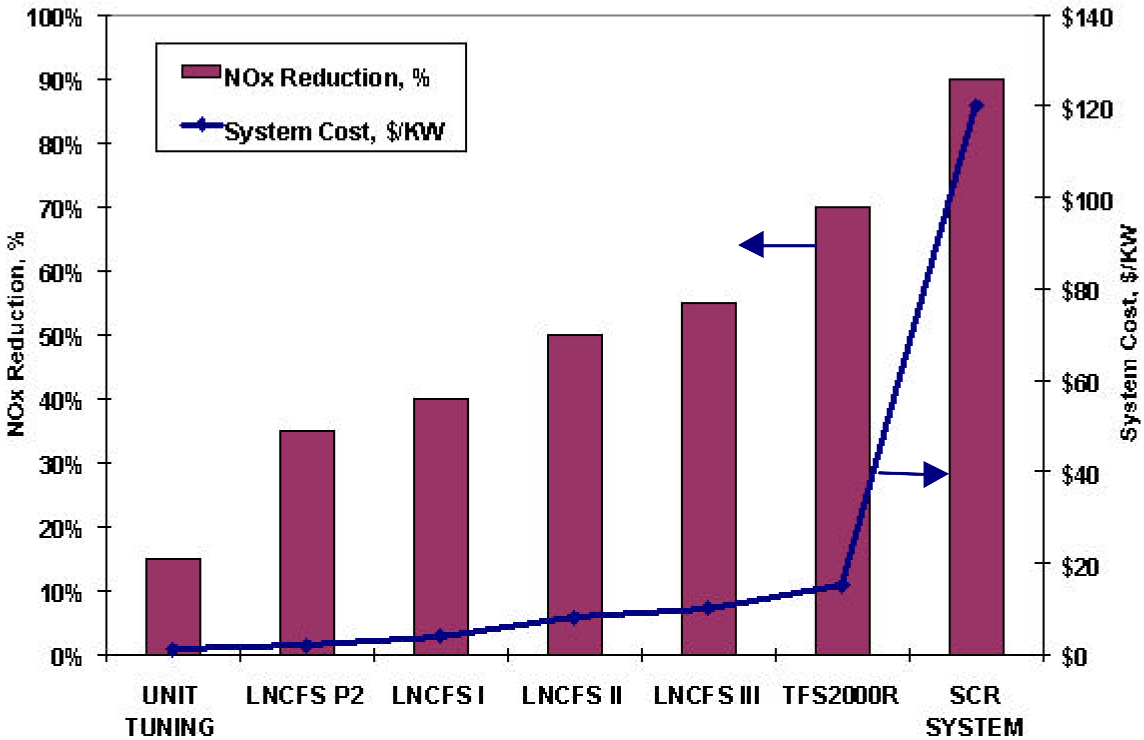

Figure 1.1-2: NOx Reduction System Cost vs. Performance (Lewis, et al., 2002).

TFS 2000™R represents the most aggressive NOx reduction firing system technology available and includes features to mitigate changes in unburned carbon in fly ash and carbon monoxide emissions from units firing high and low rank coals, respectively. NOx emissions levels below 0.15 lb/10^6 Btu are currently achieved and maintained on a continuous basis in more than nineteen (19) units firing lower ranked coals.

Prior to the demonstrated success of ALSTOM Power's low NOx firing system technology, it was universally thought that installation of an SCR would be required to achieve this low level of NOx emissions. The success of ALSTOM Power's low NOx firing technology used in concert with high reactivity low rank coals represents an order of magnitude of potential cost savings available by avoiding an SCR installation while maintaining NOx emissions below 0.15 lb/MMBtu.

Of the more than 225 units (65,000 MWe) retrofitted with ALSTOM Power low NOx technology, over 20,000 MWe and 47 units include the use of low rank, high reactivity coals. Of these 47 units, only 17 were originally designed for PRB or lignite coal. The remaining 30 units have been converted from their original design for firing bituminous coals. A summary list of ALSTOM Power retrofits of low NOx systems on units firing high reactivity low rank coals is shown in Table 1.1-1.

Table 1.1-1: ALSTOM Power Low NOx Retrofits with High Reactivity Coal.

ALSTOM Power PRB & Lignite Low NOx Retrofits					
Rank	Fuel Type	Unit Size MWe	Status	OFA Type	EPA 3rd Qtr 2001 NOx Lb/MMBtu
1	PRB	600	Complete	SOFA	0.10
2	PRB	600	Complete	SOFA	0.11
3	PRB	600	Complete	SOFA	0.11
4	PRB	600	Complete	SOFA	
5	PRB	600	Complete	SOFA	0.12
6	PRB	580	Complete	SOFA	0.12
7	PRB	325	Complete	SOFA	0.13
8	PRB	600	Complete	SOFA	0.13
9	PRB	600	Complete	SOFA	0.14
10	PRB	600	Complete	SOFA	0.14
11	PRB	165	Complete	CCOFA	0.14 (CS)
12	PRB	165	Complete	CCOFA	0.14 (CS)
13	PRB	165	Complete	CCOFA	0.14 (CS)
14	PRB	165	Complete	CCOFA	0.14 (CS)
15	PRB	165	Complete	CCOFA	0.14 (CS)
16	PRB	165	Complete	CCOFA	0.14 (CS)
17	PRB	600	Complete	SOFA	0.15
18	PRB	600	Complete	SOFA	0.15
19	PRB	520	Complete	CCOFA	0.15
20	PRB	200	Complete	SOFA	0.16
21	PRB	290	Complete	SOFA	0.16
22	Lignite	750	Complete	SOFA	0.16
23	Lignite	575	Complete	SOFA	0.16
24	PRB	150	Complete	SOFA	0.17
25	PRB	275	Complete	SOFA	0.18
26	PRB	580	Complete	SOFA	0.18
27	PRB	275	Complete	SOFA	0.19
28	PRB	400	Complete	CCOFA	0.2 (CS)
29	PRB	400	Complete	CCOFA	0.2 (CS)
30	PRB	325	Complete	SOFA	0.22
31	PRB	200	Complete	SOFA	0.23
32	PRB	150	Complete	CCOFA	0.24
33	PRB	125	Complete	CCOFA	0.25
34	PRB	675	Complete	CCOFA	0.34
35	Lignite	50	Complete	CCOFA	0.37
36	PRB	700	Complete	SOFA	N.A.
37	PRB	265	Complete	SOFA	N.A.

38	Lignite	575	Complete	SOFA	N.A.
39	PRB	500	Spring 2002	SOFA	N.A.
40	PRB	325	Fall 2002	SOFA	N.A.
41	PRB	325	Spring 2002	SOFA	N.A.
42	Lignite	750	Spring 2002	SOFA	N.A.
43	Lignite	720	Spring 2002	SOFA	N.A.
44	Lignite	575	Fall 2002	SOFA	N.A.
45	PRB	275	Spring 2002	SOFA	N.A.
46	PRB	600	Fall 2002	SOFA	N.A.
47	PRB	600	Fall 2003	SOFA	N.A.
Total		**20,045**			

CCOFA = Close Coupled Overfire Air
SOFA = Separated Overfire Air
CS = Common Stack

TFS 2000™R System Design

The TFS2000™R firing system is the most aggressive example of ALSTOM Power's LNCFS™ technology. The design philosophy of the TFS 2000™R firing system (Figure 1.1-3) is based on the integration of precise furnace stoichiometry control, pulverized coal fineness control, initial combustion process control, and concentric firing via CFS™ (Jennings, 2002).

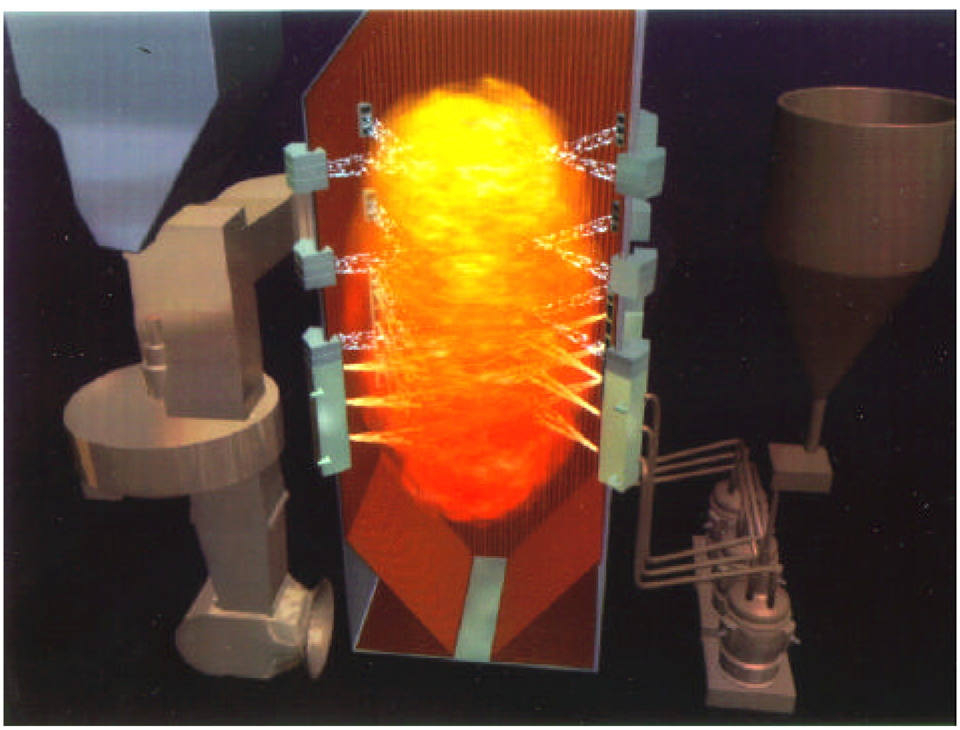

Figure 1.1-3: TFS 2000Ô R Low NOx Firing System.

This represents the most advanced in-furnace combustion NOx control system. Multiple levels of separated over-fire air (SOFA) are used to maximize NOx reductions while limiting CO emissions or increases in unburned carbon. Depending on the type of coal, DYNAMIC™ Classifiers may be added to the pulverizers to control coal fineness and further limit unburned carbon or to increase pulverizer capacity for low rank coal conversions.

Table 1.1-2 lists the top eighteen (18) lowest NOx emitting, coal fired generating power plants in the U.S. for the 2nd quarter 2001 (latest available information) emissions average based on U.S. EPA reporting criteria. Twelve (12) of the top eighteen (18) lowest NOx emitting, coal fired plants in the U.S. were retrofitted with ALSTOM Power low NOx technology, and fire Powder River Basin fuel.

Table 1.1-2: Top 18 Coal Fired Power Plants for 2nd Quarter 2001 with Lowest NOx (based on U.S. EPA reporting).

U.S. EPA Quarterly Results				
Coal Plant Rank	Plant	State	ALSTOM Power Technology	EPA lb/10^6 Btu
1	Labadie	Missouri	**Yes**	0.10
2	Bay Shore	Ohio	CFB	0.10
3	Polk	Florida	Combined Cycle	0.11
4	Labadie	Missouri	**Yes**	0.11
5	Labadie	Missouri	**Yes**	0.11
6	Rush Island	Missouri	**Yes**	0.12
7	Rush Island	Missouri	**Yes**	0.12
8	Labadie	Missouri	**Yes**	0.13
9	Waukegan	Illinois	**Yes**	0.13
10	Baldwin	Illinois	**Yes**	0.14
11	Merrimac	New Hampshire	SNCR	0.14
12	Dubuque	Iowa	WBF	0.14
13	Newton	Illinois	**Yes**	0.15
14	TNP	Texas	CFB	0.16
15	Neil Simpson	Wyoming	DB-LNBO	0.16
16	St. Clair	Michigan	**Yes**	0.16
17	Milton L. Kapp	Iowa	**Yes**	0.16
18	Newton	Illinois	**Yes**	0.17

1.2 Project Overview

The Ultra Low NOx Integrated System schematically represented by Figure 1.2-1, is an aggressively air staged, in furnace NOx reduction system designed to meet or exceed 0.15 lb/MMBtu NOx for tangentially fired boilers firing a wide range of coals. This system has built upon the performance of commercially available ALSTOM Power low NOx firing system technology, making it suitable for commercial deployment by 2002. The foundation for the Ultra Low NOx Integrated System is ALSTOM Power's field-proven TFS 2000™ low NOx firing system.

The project plan called for the Ultra Low NOx Integrated System to improve NOx reduction over ALSTOM Power's current TFS 2000™ system through advances in several areas that overcome present constraints. The combination of improvements in both components and processes, described below, are based on fundamentally sound principles which are known to lower NOx formation and/or to improve NOx destruction, while minimizing negative impacts on the balance of plant.

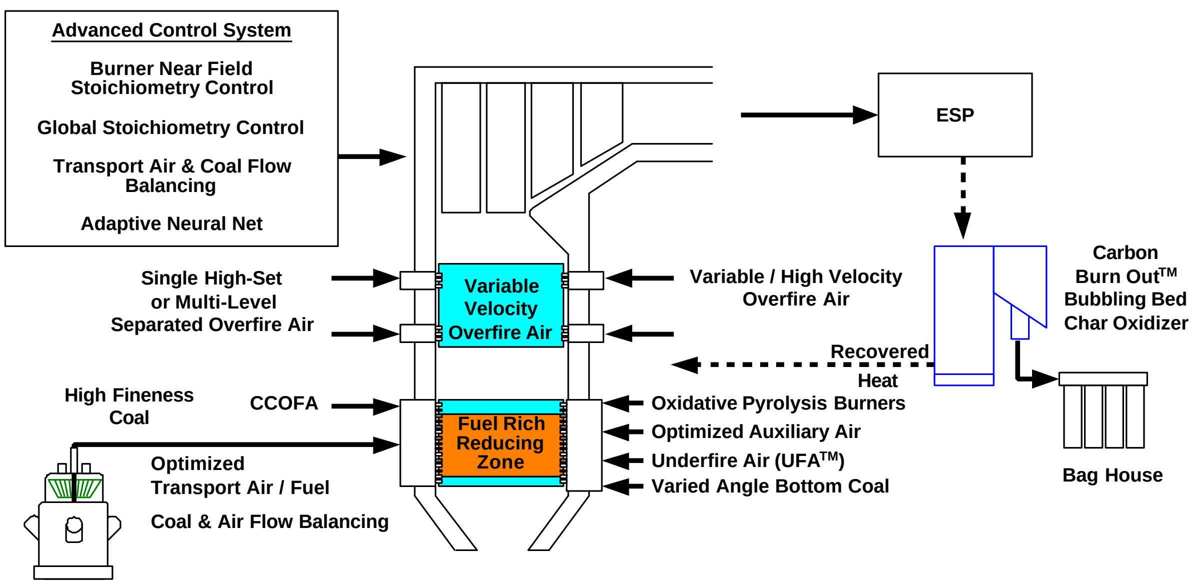

Figure 1.2-1: Ultra Low NOx Integrated System Schematic.

These studied improvements included milling system enhancements, both to the mill internals and coal particle size classification processes. ALSTOM Power's DYNAMIC™ classifier, for example, was used to produce a finer coal product with more rigorous control over particle top size. Additionally, pulverized coal transport air quantities (lower transport air to coal mass ratios) were evaluated to determine possible favorable impacts on NOx emissions.

Low NOx oxidizing pyrolysis burners, based on ALSTOM Power's LNCFS™-P2 coal nozzle tips, were designed to promote higher fuel-bound nitrogen release through more rapid heating of coal particles in the near-burner zone, coupled with the generation of additional near-burner turbulence to create a more uniform, high intensity, fuel rich zone. The low NOx oxidizing pyrolysis burners were tested in ALSTOM Power's Boiler Simulation Facility (BSF), a large pilot-scale test furnace.

High velocity overfire air (HVOFA) was evaluated through CFD modeling as well as through pilot-scale testing. The premise was that more rapid burnout higher in the furnace would be achieved through more intense air mixing and longer residence times could be maintained in the lower, fuel-rich furnace, all while not unduly sacrificing carbon burnout or CO emissions. ALSTOM Power's patented Concentric Firing System (CFS™) was included in this study to provide additional, near field air staging while forming an oxidizing environment near the waterwalls to mitigate against the possibility of waterwall wastage.

For particularly unreactive coals, where higher levels of unburned carbon in the fly ash might prevent selling the ash to cement manufacturers, a bubbling bed Carbon Burn Out™ combustor, developed by Progress Materials, was evaluated as a means by which carbon in ash may be reduced to acceptable levels.

An advanced neural net control system was conceptually developed as a means by which NOx emissions could be maintained by controlling both local and global stoichiometries over the range of boiler operating loads, and to provide for fault tolerant operation as planned and unplanned system upsets occur. The ABB pfMaster online coal flow meter was also evaluated during the large pilot-scale combustion testing. Also, a methodology was developed for advanced signal processing from standard flame scanners to infer local stoichiometry which may prove useful for unit tuning/optimization.

An engineering systems analysis and economic evaluation was performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). The various NOx reduction alternatives were evaluated as retrofit options for 3 tangential-fired utility boilers in the U.S.: (1) a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, (2) a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and (3) a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). The units selected are representative of a large number of the pulverized coal-fired utility boilers in the U.S.

In order to assure the success and commercial applicability of results from this project, ALSTOM Power assembled a project team of cognizant members from various ALSTOM Power and external groups. ALSTOM Power led this effort from their Power Plant Laboratories (PPL) in Windsor, CT, in conjunction with the following project team members:

ALSTOM Power Performance Projects
ALSTOM Power Environmental Systems
U.S. DOE National Energy Technology Laboratory
Progress Materials, Inc.

Each of these organizations brought unique skills and competencies to the project, and collectively they have represented the range of system component needs from the coal pile to the flue duct. ALSTOM Power Performance Projects provides boiler products and services to the electric power industry, including the fuel preparation and handling and low NOx firing system equipment proposed herein. ALSTOM Power Environmental Systems is active in providing environmental control solutions to industry, including SCR, and provided cost and operating information to the project for use in the evaluation of competing approaches. Progress Materials, Inc. developed a unique post-furnace fly ash oxidation process which was evaluated in the project, primarily through the Engineering and Economic Analysis evaluation task.

To assure that the Ultra Low NOx Integrated System met the intended needs of the project sponsors and pulverized coal-fired power plant owners, an advisory committee was formed to review project plans, provide input to system design and analysis, and review project results. The advisory committee included representatives from the project team, the U.S. Department of Energy, utility plant owners, and selected consultants from the Massachusetts Institute of Technology and the University of Massachusetts.

2.0 OBJECTIVES

The goal of the project was to develop low-cost, efficient NOx control technologies for retrofit to coal fired utility boilers as a means to keep coal a viable part of the national energy mix in the next century and beyond. Toward that end, the following specific project objectives were set by ALSTOM Power, in concert with the U.S. DOE, for work to be performed in response to the above goal:

- Develop retrofit NOx control technology to achieve less than 0.15 lb/MMBtu NOx from existing tangentially-fired utility boilers when firing bituminous coals

- Develop retrofit NOx control technology to achieve less than 0.10 lb/MMBtu NOx from existing tangentially- fired utility boilers when firing subbituminous or lignitic coals

- Achieve economics which are at least 25% lower cost than the SCR-only technology

- Validate NOx control technology through large (15 MWt) pilot scale demonstration

- Evaluate engineering feasibility and economics for several scenarios of technology components and component integration, for representative plant cases with both bituminous and subbituminous coals

3.0 STATEMENT OF WORK

The following outline is adapted from the modified Statement of Work that was accepted by DOE through Amendment 005 to Cooperative Agreement DE-FC26-00NT40754. The outline, along with the major task objectives, provides an overview of how the project was structured and executed.

1.0 Test Fuels Characterization

The objective of this task is to quantify the chemical composition and resultant reactivities of the test coals in support of the design of experiments and the analysis of experimental data associated with pilot scale combustion testing. In addition, this data will support the development of performance predictive tools for commercial system design.

- 1.1 Test Coal Selection
- 1.2 ASTM Analyses
- 1.3 DTFS Pyrolysis
- 1.4 TGA Char Reactivity & BET Surface Area
- 1.5 Petrographic Analysis
- 1.6 Data Reduction
- 1.7 Task Report

2.0 Low NOx System Design

The objective of this task is to identify and evaluate subsystem designs for use in an integrated ultra-low NOx system. Toward this end, work performed under this task will focus on refining key design concepts and subsystem attributes for application to the pilot scale demonstration testing and commercial (field) units.

- 2.1 Fuel Preparation and Transport
  - 2.1.1 Fuel - Air Separator
  - 2.1.2 Mill Enhancements
  - 2.1.3 Data Reduction, Analysis and Reporting
- 2.2 Oxidative Pyrolysis Burners

2.3 Global Mixing Process Improvement

2.3.1 Global Mixing Process Modeling

2.3.2 Model Verification

2.3.3 Data Reduction, Analysis and Reporting

2.4 Advanced Control System

2.4.1 Neural Net Optimization and Advanced Control Technology

2.4.2 Advanced Sensor Systems

2.4.2.1 Advanced Flame Scanner

2.4.2.2 Coal Flow Sensor

2.4.2.3 Carbon in Ash Sensor

2.4.3 Task Data Reduction, Analysis and Reporting

3.0 Large Pilot Scale Combustion Testing

The objective of this task is to quantify individual component and integrated ultra-low NOx system design and operating parameters versus performance utilizing ALSTOM Power's 15 MWt Boiler Simulation Facility (BSF). This work will be performed as a means to optimize system and component operation, and generate data at a scale suitable to support scale-up to commercial installations.

3.1 Test Planning

3.2 Facility Preparation

3.2.1 Fuels Preparation Testing

3.2.2 Firing System Modification

3.2.3 Instrumentation and Control

3.3 Combustion Testing

3.3.1 Test Period 1

3.3.2 Test Period 2

3.4 Facility Clean-up

3.5 Task Data Reduction, Analysis and Reporting

4.0 Bubbling Bed Char Oxidation (Carbon Burn Out™) Feasibility Study

The objective of this work was modified by mutual consent between the DOE and ALSTOM Power to serve primarily as one of the alternatives to be considered in the Engineering Systems Analysis and Economics task (Task 5).

4.1 Analysis and Reporting

5.0 Engineering Systems Analysis and Economics

The objective of this task is to quantify the economics for commercial application of various project derived ultra-low NOx components and integrated system approaches in order to identify those that meet or exceed 0.15 lb./ million BTU NOx emissions limits at a cost that is 25% less than the current DOE defined state-of-the-art control technology of SCR.

5.1 Subsystem Analysis

5.2 Integrated System Design Analysis

5.3 Task Report

6.0 Advisory Panel

An advisory panel will be formed to provide comment and focus throughout the project to assure that it meets commercial needs and to provide input to the commercialization plan. The panel will meet at least three times during the course of the project including: (1) the beginning of the project, (2) the middle of the test program, and (3) the conclusion of the test program to review the results and provide input as to the recommendations for the final commercial system design.

7.0 Final Project Report

The objective of this task is to generate a final project report for submission to the funding agencies in fulfillment of the project objectives.

7.1 Subtask Report Compilation

7.2 Project Final Report Generation

8.0 Project Management

8.1 Work Plan Management

8.2 Monthly Reporting

8.3 Technology Transfer

8.3.1 Semi-Annual Review Meeting

8.3.2 Paper Presentation

8.4 QA / QC Implementation

4.0 TEST FUELS CHARACTERIZATION

Characterization of three test fuels was carried out by a combination of standard ASTM tests, petrographic analysis, testing in ALSTOM Power's Drop Tube Furnace System-1 (DTFS-1), and testing in a Perkin-Elmer thermogravimetric analyzer (TGA). Standard ASTM and petrographic maceral analyses for the candidate coals were used to characterize them from a "properties" point of view. Testing in the DTFS-1 and TGA apparatuses provided performance oriented information primarily related to combustion with specific emphasis on fuel bound nitrogen evolution, NOx formation, and unburned carbon in the fly ash. Fuel property information, in concert with performance-related data from the DTFS-1 and TGA, helped to facilitate planning for the large pilot-scale testing and provide fundamental information geared toward understanding and interpretation of results from the pilot-scale tests.

4.1 Objectives

The objective of this task was to quantify the chemical composition and resultant reactivities of the test coals in support of formulation of the experimental plan and the analysis / interpretation of experimental data associated with pilot scale combustion testing. In addition, this data will support the development of performance predictive tools for commercial system design.

4.2 Test Coal Selection

Three coals were selected for testing which represent the range of coals being burned by utility companies in the U.S. Also from the standpoint of NOx reduction, the three coals represent varying degrees of difficulty in terms of achieving low NOx, commensurate with acceptable unburned carbon and carbon monoxide levels. The following three test coals were selected: (1) a subbituminous coal from the Powder River Basin (designated as PRB coal), (2) a high volatile Midwestern bituminous coal (designated as HVB coal), and (3) a medium volatile Eastern bituminous coal (designated as MVB coal).

4.3 Standard ASTM Analyses

Each of the three coals was subjected to standard ASTM fuel analyses including ultimate, proximate, heating value, grindability, ash fusion temperatures, and ash composition. The results of ASTM testing are shown in Table 4.3-1 and Table 4.3-2. For air-staged, low NOx firing systems, a key parameter from the ASTM analysis is the volatile matter content (VM). The volatile matter content of the MVB coal expressed on a dry, ash-free basis (daf) is about 60% of that for the HVB and PRB coals. The combination of the low volatile content and the higher FC/VM ratio for the MVB coal is an indication that it represents a greater challenge when it comes to unburned carbon and CO emissions, under aggressive staged firing conditions, as compared to the PRB and HVB coals.

Of the three coals, the HVB coal has the highest fuel nitrogen content, expressed as lb/MMBtu, although the values of the other two coals are fairly close to that of the HVB coal (1.15 vs. 0.99 and 0.98 for PRB and MVB coals, respectively). Fuel nitrogen content is an important factor in determining the NOx emissions from a pulverized coal-fired utility boiler as nitrogen in the fuel can be readily oxidized to NOx, especially during char combustion.

Table 4.3-1: ASTM Coal Analyses.

Coal Property	PRB Coal	HVB Coal	MVB Coal
Moisture	32.7	10.9	3.6
Volatile Matter	29.1	35.2	22.1
Fixed Carbon (Diff.)	33.2	47.2	58.2
Ash	5	6.7	16.1
Hydrogen	3.2	4.6	3.8
Carbon	46.7	66.7	69.8
Sulfur	0.3	2.3	1.9
Nitrogen	0.8	1.4	1.2
Oxygen (Diff.)	11.3	7.4	3.6
VM, %daf	46.7	42.7	27.5
Carbon, %daf	75.0	80.9	86.9
Sulfur, %dry	0.4	2.6	2.0
HHV, Btu/lb, As Received	8042	12137	12292
HHV, Btu/lb, daf	12909	14729	15308
Hardgrove Grindability Index (HGI)	53	49	80
O/N Ratio	14.13	5.29	3.00
FC/VM Ratio	1.14	1.34	2.63
N Loading (lb/MMBtu)	0.99	1.15	0.98

Of the three coals, the MVB coal has the highest Hardgrove Grindability Index (HGI), namely 80 vs. 53 and 49 for the PRB and HVB coals, respectively. Hence, of the three coals, the MVB coal requires the least amount of grinding energy to achieve a given particle size. This is advantageous since, of the three coals being tested, the MVB coal would be the one most likely to require finer grinding to produce acceptable carbon loss under conditions of aggressive staged air firing. Additionally, the MVB coal has the highest heating value, which would also be advantageous if finer grinding were required. Specifically if mill capacity were a potential problem, the MVB coal's higher heating value would work in favor of a lesser impact on mill capacity than a lower heating value fuel.

Table 4.3-2 shows the ash properties of the three test coals, namely ash fusibility temperatures and ash composition. The ash from the PRB coal has low fusibility temperatures, typical of subbituminous coals from the U.S. The relatively small difference between the initial temperature (IT) and the fusion temperature (FT) of 44 °F means the deposits from this coal have the potential to build a relatively thin, runny deposit, if not properly managed. The HVB and MVB coals, by contrast, with higher fusibility temperatures, coupled with greater differences between the IT and FT (140 °F and 120 °F, respectively) have the potential for producing relatively thick, highly viscous deposits, if not properly managed.

Table 4.3-2: Coal Ash Fusibilities and Composition.

ASH FUSIBILITY (Reducing)	PRB Coal	HVB Coal	MVB Coal
I.T. (°F)	2180	2340	2560
S.T. (°F)	2195	2395	2580
H.T. (°F)	2210	2420	2615
F.T. (°F)	2225	2480	2680
DT = F.T.-I.T.	45	140	120
ASH COMP. (Wt.%, Dry)			
SiO_2	30.8	38.4	51.6
Al_2O_3	17.9	23.6	27.6
Fe_2O_3	5.9	29.5	12.1
CaO	25.9	1.9	1.1
MgO	3.7	0.5	0.9
Na_2O	1.2	0.3	0.3
K_2O	0.4	1.3	2.9
TiO_2	1.4	0.9	1.3
P_2O_5	1.2	0.8	0.5
SO_3	8.8	0.8	0.5
MnO	0.1	0.1	0.1
TOTAL	97.3	98.1	98.9

Of the three coals, the HVB coal is most likely to be adversely affected by a reducing atmosphere in a staged air low NOx firing system because of the substantial iron content in the ash, at almost 30% (see Table 4.3-2). Of the common constituents in coal ash, iron is most significantly affected by changes from an oxidizing to a reducing atmosphere, namely its effect on melting temperatures. However, it should be noted that ALSTOM Power low NOx firing systems minimize the potential for reducing conditions near the furnace walls through the use of CFS™ air, combustion air directed toward the lower furnace walls in low NOx firing systems.

Table 4.3-3 shows slagging and fouling propensity for the three test coals as determined by ALSTOM Power design standards. These design standards combine indices based on the bulk ash compositions, ash fusion temperatures, and industrial experience. The slagging and fouling indices shown in the table indicate a low slagging and fouling potential for the HVB coal, a high slagging and medium fouling potential for the HVB coal (due to high iron content), and a high slagging and fouling potential for the PRB coal (due to high alkali content).

Table 4.3-3: Slagging and Fouling Propensity.

Coal	Slagging	Fouling
PRB	High	High
HVB	High	Med
MVB	Low	Low

4.4 Petrographic Analysis

Petrographic analysis has been used through the years as a pragmatic means to understand coal behavior relative to its use in coke making, combustion, and liquefaction processes. It is being used in this project as a predictive tool for assessing potential carbon loss in pulverized coal firing.

By way of relevant background, researchers have recognized that the carbonaceous content of coal is far from uniform and that the unburned carbon is, essentially, the least reactive portion that is selectively left at the end of the combustion process. In an attempt to better understand coal reactivity and to develop a better method for predicting carbon loss, ALSTOM Power had performed microscopic studies of coals, chars, and fly ashes. It has been postulated that a link between the morphological characteristics of a coal and the late phase combustion reactivity can be made through an understanding of the maceral and crystalline characteristics of a coal or a char (Sandia National Laboratories, 1995).

The principal measurements from a petrographic analyses are the vitrinite, liptinite, and fusinite contents and an optical property called the mean-max vitrinite reflectance (R_o). The sum of vitrinite and liptinite comprises the "highly reactive" component of coal. The fusinite is, on the other hand, commonly known as "inertinite," as it is relatively inert. It is has been postulated that following the disposition of these petrographic components (vitrinite, liptinite, fusinite, and mean-max vitrinite reflectance) during the combustion process could give a clue to the kinetic behavior of the parent coal. Hence, an attempt is underway at ALSTOM Power to correlate these parameters and/or combinations thereof with coal combustion parameters (reactivities, unburned carbon emissions, etc.).

Petrographic analysis was carried out on each of the three coals. Samples of the PRB, HVB and MVB coals were sent to an independent lab for petrographic analysis. Results are shown in Table 4.4-1.

Table 4.4-1: Petrographic Analyses.

COAL PETROGRAPHY	PRB Coal	HVB Coal	MVB Coal
Reactive Macerals			
Vitrinite	74.4	70.4	71.5
Exinite	0.7	5.5	1.2
Resinite	0.0	0.1	0.0
Semifusinite	2.9	2.1	1.6
Sub-Total	78.0	78.1	74.3
Inert Macerals			
Semifusinite	5.8	4.2	4.7
Micrinite	4.9	7.8	9.4
Fusinite	7.1	4.7	3.8
Mineral Matter	4.2	5.2	7.8
Sub-Total	22.0	21.9	25.7
Mean Max. Vitrinite Reflectance, %	0.41	0.45	1.27

Previous work at ALSTOM Power's Power Plant Laboratories has shown a relationship between the petrographic results, in particular the vitrinite mean-max reflectance (R_o), and the measured amount of unburned carbon in the fly ash for a given coal based on Drop Tube Furnace testing. Figure 4.4-1 is a plot of unburned carbon, as measured in the DTFS, versus the mean-max vitrinite reflectance. In addition to the three test coals (PRB, HVB and MVB), data from other coal blends and reference fuels have been added to the plot for comparative purposes. As seen in the figure, the relationship is quite good; some variation is seen with coals having lower vitrinite reflectance values.

The PRB and HVB coals each had relatively low mean max reflectance values, 0.41 and 0.45, respectively, but the HVB coal showed a significantly higher carbon loss in the DTFS than the PRB coal. The low carbon in ash for the PRB coal was not unexpected as the PRB coal is a subbituminous coal which is highly reactive. As shown in Figure 4.4-1, the vitrinite reflectance for the MVB coal (by contrast to the PRB and HVB coals) was much higher, with a correspondingly higher carbon loss, as measured in the DTFS.

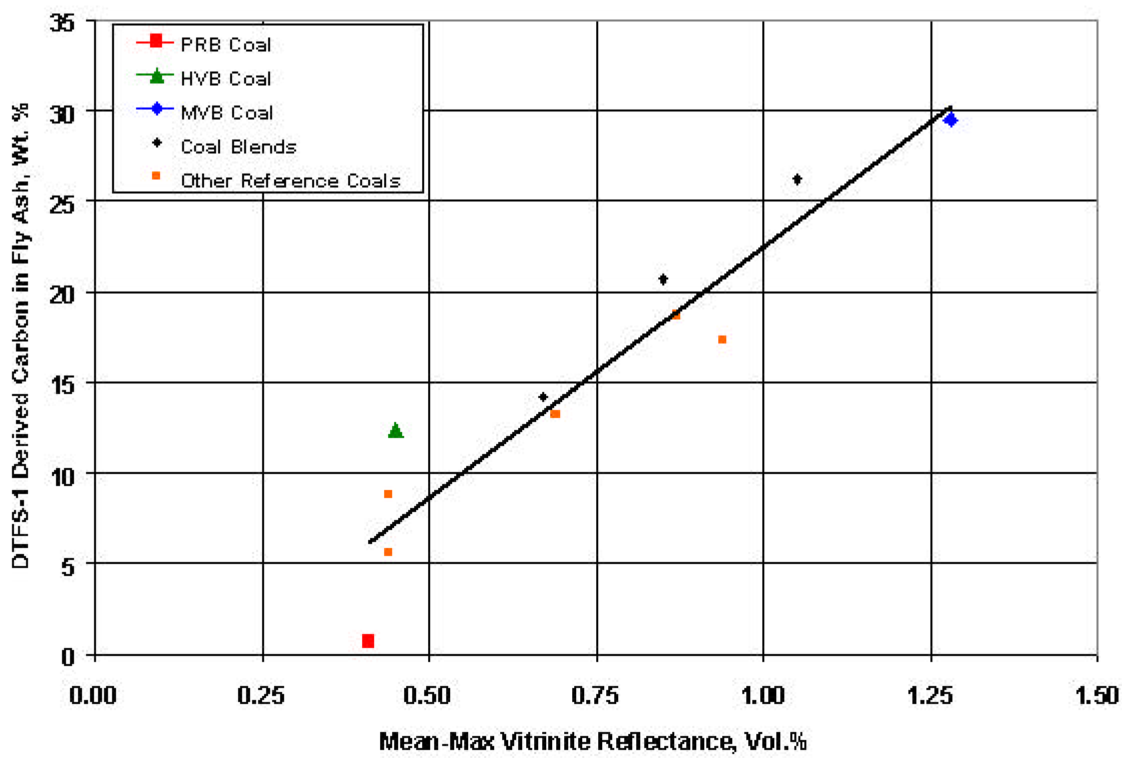

Figure 4.4-1: UBC in the Fly Ash vs. Vitrinite Reflectance.

From the results of the petrographic analysis, the MVB coal is expected to have a higher carbon loss under staged, low NOx firing system conditions than the PRB and HVB coals. These results are consistent with expectations derived from ASTM analysis, specifically that the MVB coal, of the three coals evaluated, will represent the greatest challenge in terms of maintaining unburned carbon emissions under staged conditions during the pilot-scale test campaign.

4.5 Drop Tube Furnace Testing

High temperature devolatilization, fuel nitrogen conversion. and combustion tests were carried out in ALSTOM Power's drop tube furnace, which approximates the time/temperature conditions that would exist in an actual furnace. Since volatile matter release is a function of the heating rate and temperature, the high temperature volatile yield obtained in a combustion environment can differ significantly from those determined under ASTM testing conditions. Likewise, in trying to approximate commercial furnace combustion conditions in a bench-scale apparatus it is important to simulate time/temperature histories that exist in commercial furnaces which employ suspension firing.

The following list documents the range of experiments performed in the Drop Tube Furnace System -1 (DFTS-1) to characterize the test fuels:

- High Temp VM (Pyrolysis in N_2) and Fuel N Conversion (Combustion in O_2/Ar) on:
  - PRB, HVB and MVB Coals (200 x 400 mesh)
- High Temp VM (Pyrolysis in N_2) on Size Graded Samples:
  - MVB Coal Only (270 x 400, - 400 mesh)
- Unburned Carbon/CO Analysis (Combustion in Air) on:
  - PRB, HVB and MVB Coals (200 x 400 mesh)

4.5.1 Technical Approach

ALSTOM Power's Drop Tube Furnace System-1 (DTFS-1) is comprised of a 1-inch inner diameter horizontal tube gas pre-heater and a 2-inch inner diameter vertical tube test furnace (Figure 4.5.1-1) for providing controlled temperature conditions to study devolatilization, gasification and/or combustion phenomena. This entrained flow reactor, which is electrically heated with silicon carbide elements, is capable of heating reacting particles to temperatures of up to 2650 ^{o}F with particle residence times of up to about one second. These conditions simulate the rapid combustion that occurs under suspension firing conditions in commercial pulverized coal-fired boilers.

DTFS-1 testing is normally used to derive quantitative information on the impact of various operating parameters such as particle size, stoichiometry and temperature/time history on unburned carbon in the fly ash and gaseous (NOx, CO and SO_2) emissions.

Figure 4.5.1-1: ALSTOM Power's Drop-Tube Furnace System (DTFS-1).

The DTFS-1 testing procedure entails the following: (1) the fuel is fed at a precisely known rate through a water-cooled injector into the test furnace reaction zone; (2) the fuel and its carrier gas are allowed to rapidly mix with a pre-heated down-flowing secondary gas stream; (3) devolatilization, gasification or combustion is allowed to occur for a specific time (dictated by the transit distance); (4) reactions are rapidly quenched by aspirating the gas/particulate stream into a water-cooled sampling probe; (5) the solids are separated from gaseous products in a filter medium; and, (6) an aliquot of the effluent gas stream is sent to a dedicated Gas Analysis System for on-line determination of NOx, SO_2, O_2, CO_2, CO, and THC (total hydrocarbons) concentrations. A data acquisition system records, on demand, all relevant test data for subsequent retrieval and processing.

An ash tracer technique (Badzioch and Hawksley, 1970; Nsakala, et at., 1977) is used in conjunction with the proximate analyses of feed samples and chars subsequently generated in the DTFS-1 to calculate the devolatilization, gasification or combustion efficiency as a function of operational parameters (particle temperature, particle residence time, fuel fineness, reaction medium, etc.). A proprietary software package can, alternatively, use concentration values of CO_2, CO, and THC (if available) in the effluent gas streams to calculate carbon conversion rates under prevailing conditions.

Each of the three coals (PRB, HVB and MVB) was tested in the DTFS-1 at a particle size of 200x400-mesh (X_{mean} ~60 μm). For the MVB coal, two additional size fractions were tested, namely 270x400-mesh (X_{mean} ~ 45 μm) and -400-mesh (X_{mean} ~ 30 μm). The rationale for conducting more tests on size-graded samples for the MVB coal, and not the other two coals, was that ASTM analyses indicated that the MVB coal would present a greater challenge under air staged, low NOx firing conditions relative to unburned carbon and NOx. By having more information on the MVB coal as a function of particle size, judgements could be made regarding possible benefits of finer grinding.

Prepared samples for each of the coals were fed through the DTFS-1 for measurement of fuel nitrogen conversion, high temperature devolatilization (pyrolysis testing) and unburned carbon analysis (combustion in air). Subsequently, the chars from the pyrolysis and combustion testing were analyzed to determine fuel nitrogen conversion, volatile yield and coal reactivity.

4.5.2 Drop Tube Furnace Results

Two major reaction phenomena take place during pulverized coal combustion: (1) volatile matter release and combustion in the gas phase; and (2) heterogeneous char oxidation. The later step is much slower than the former step and hence is the rate-limiting step during pulverized coal combustion. Therefore, maximizing the volatile matter yield is beneficial to the overall scheme of coal combustion under low NOx conditions. In particular, early stage fuel nitrogen release under substoichiometric conditions increases the potential for lower nitrogen oxide formation. The ASTM has a protocol that measures volatile matter in a fixed bed. This protocol is believed to oftentimes underestimate the volatile matter yield that would occur under actual suspension firing conditions since it may lead to volatile matter cracking and secondary reactions. As such, the volatile matter yields obtained in dilute phase systems, such as the DTFS-1, tend to be greater than (or at a minimum, equal to) those measured by the ASTM method (Nsakala, et al., 1986).

Figure 4.5.2-1 shows the high temperature volatile matter yield obtained for the three test coals under pyrolysis conditions in the DTFS-1. The test coals were pyrolyzed in nitrogen at 2650°F for a residence time of about 0.5 second. A decision was made to use the 200x400 mesh fraction as the "standard" size cut for DTFS-1 testing since it is reasonably representative of the total coal feed. Furthermore, it allows results from all coals that will be tested to be compared with one another on a reasonably consistent particle size basis.

The measured high temperature volatile matter yields are, respectively, 20%, 34% and 22% greater than ASTM volatile matter yields for the PRB, HVB and MVB coals.

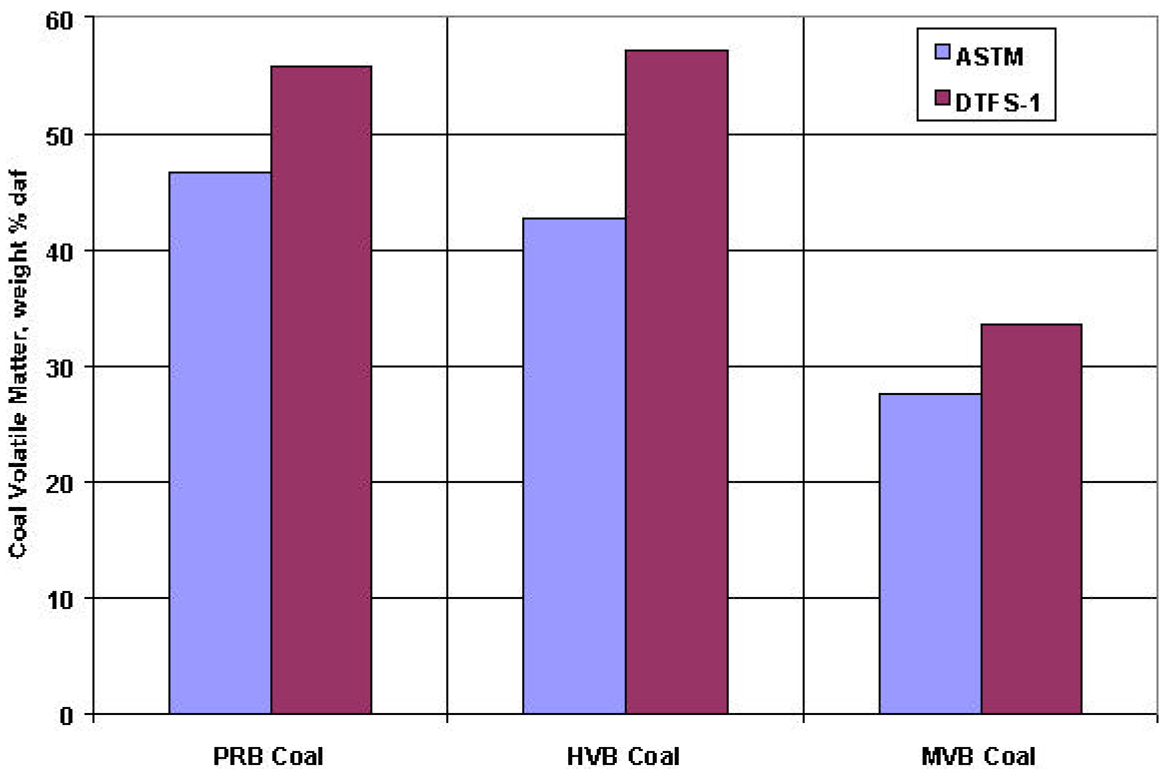

Figure 4.5.2-1: Drop Tube Furnace VM Yield vs. ASTM VM Yield.

The MVB coal represents the test coal with the lowest volatile matter yield, both under ASTM and high temperature pyrolysis conditions, yet still shows a significant increase from ASTM to high temperature volatile yields. As previously noted, since fuel nitrogen evolution is generally proportional to volatile matter yield (advantageous from an air staged, low NOx system point of view) it was decided to determine if coal particle size would favorably impact volatile matter evolution for MVB coal.

Figure 4.5.2-2 shows high temperature volatile matter yield test results (pyrolysis in N_2 @ 2650^{o}F for ~0.5 second residence time) for three different particle size fractions for MVB coal, and shows a corresponding comparison with ASTM-generated volatile matter for the same size fractions. The ASTM volatile matter (dry, ash-free basis) was very consistent, at about 27%, for all three size cuts, and the DTFS volatile yield (daf basis) was very similar, 35% and 34%, respectively, for the 200x400 and – 400 mesh cuts. The DTFS volatile yield for the 270x400 size cut was a bit lower at 31%. No definitive answer can be given for the difference between DTFS volatile matter results for the 270 x 400 mesh size fraction versus the other two size fractions. It could be speculated that the 270 x 400 mesh fraction may be the least representative of the total coal because it represents the smallest weight fraction, compared with the other two size fractions, or the difference could simply be due to normal experimental error.

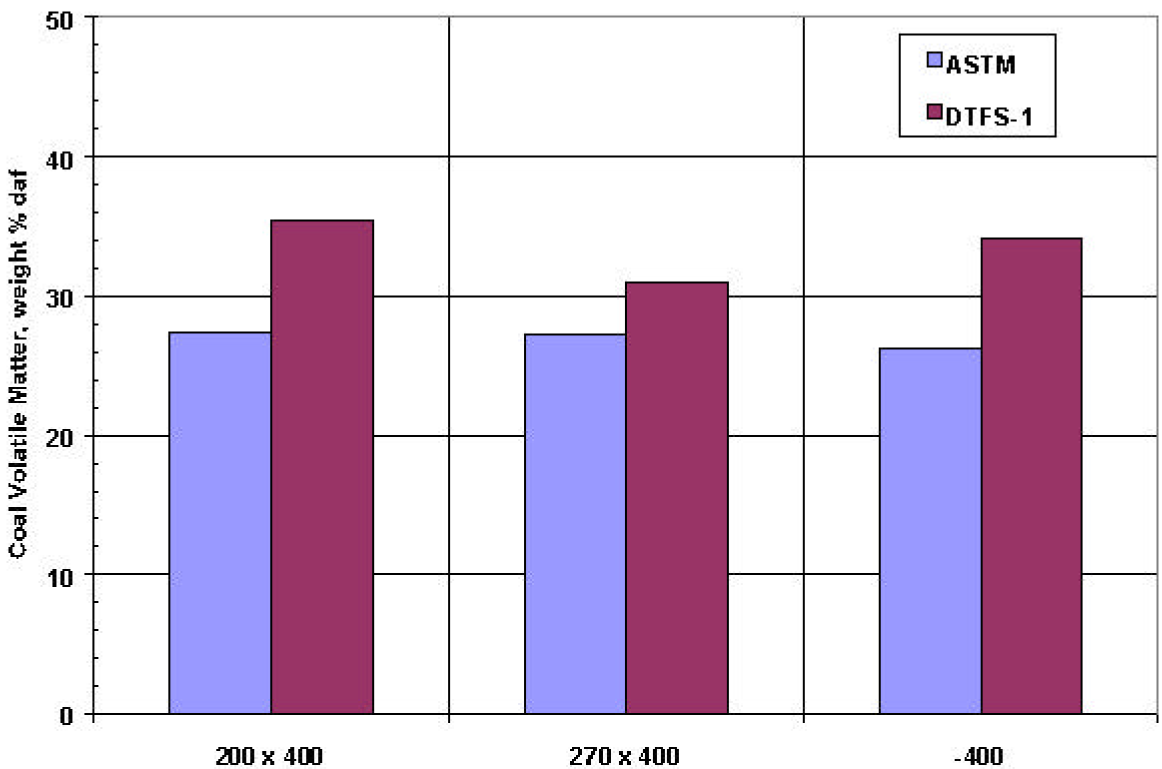

Figure 4.5.2-2: DTFS VM Yield vs. Coal Grind for the MVB Coal.

As previously noted, the high temperature volatile yield is important from a NOx point of view. The greater the proportion of nitrogen that is released during early stages of combustion, the greater the opportunity to prevent formation of nitrogen oxides by virtue of forming molecular nitrogen in the reducing zones of the furnace. The nitrogen that remains with the char is more likely to be oxidized to NO when the overfire air is introduced in the boiler.

Figure 4.5.2-3 shows fuel bound nitrogen evolution for the three coals versus stoichiometry, as determined in the DTFS-1. Conditions for determining fuel bound nitrogen evolution were: testing in a mixture of 6.5% O_2/93.5% Ar at 2650 ^oF and for a residence time of about 0.5 second. The PRB and HVB coals both show higher fuel nitrogen evolution for all stoichiometries, as compared with the MVB coal. The difference in fuel bound nitrogen evolution between the PRB and HVB coals versus the MVB coal is even greater at lower stoichiometries. For example, the PRB and HVB coals show fuel bound nitrogen evolution (expressed as a percentage of total) of about 90% and 85%, respectively, at a 0.75 stoichiometry versus an evolution of about 53% for MVB coal. What this implies is that a greater portion of the fuel bound nitrogen in PRB and HVB coals has the opportunity to be reduced to molecular nitrogen under staged conditions, the result being lower NOx. The MVB coal, by contrast, does not release as much of its fuel nitrogen under substoichiometric conditions, and hence does not offer the opportunity to convert as much of the fuel nitrogen to molecular nitrogen. The nitrogen remaining in the char from the MVB coal would be more likely to be oxidized to NO after the addition of the overfire air. Based on the DTFS-1 data, the MVB coal would be expected to have higher NOx emissions than PRB and HVB coals under the same firing conditions.

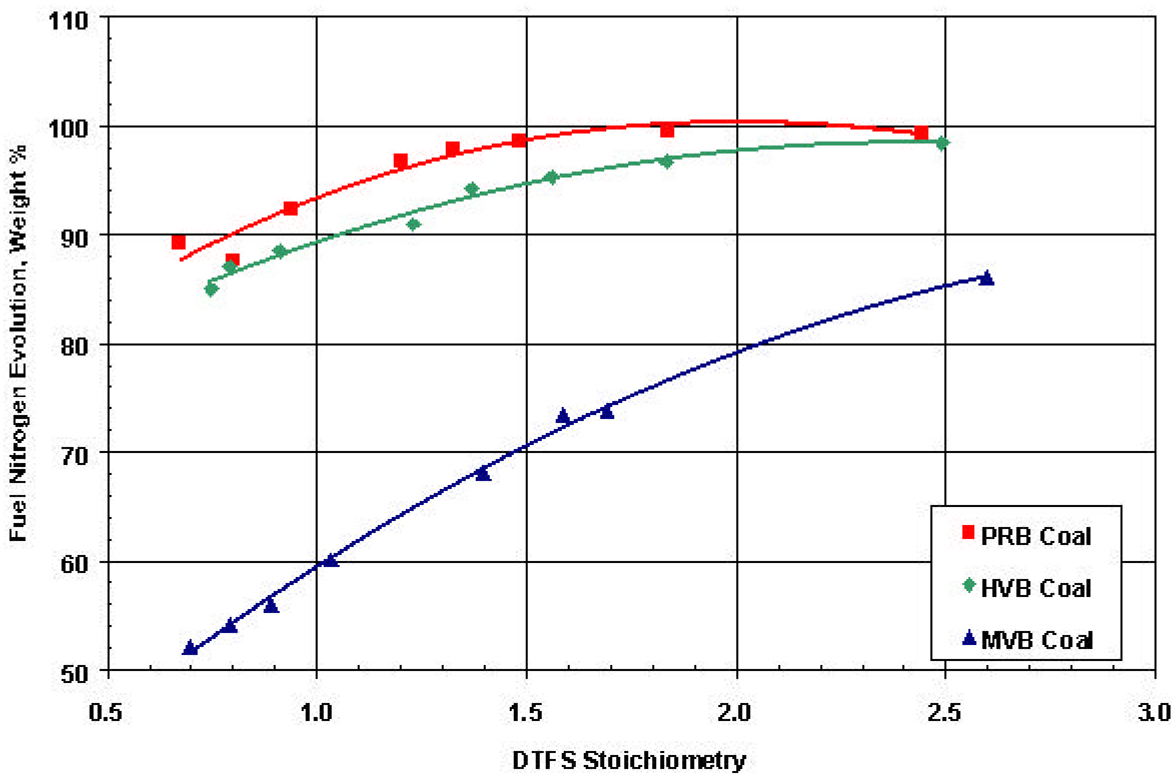

Figure 4.5.2-3: Fuel Bound Nitrogen Conversion versus Stoichiometry.

Figure 4.4.2-4 shows fuel bound nitrogen release in another way, namely as a function of carbon conversion efficiency. If the data points in Figure 4.4.2-4 were to fall on the 45° angle line this would mean that fuel bound nitrogen is proportional to carbon conversion. However, in looking at Figure 4.4.2-4 it can be seen that fuel bound nitrogen evolution is proportional to or exceeds carbon conversion for the PRB and HVB coals. By contrast the fuel bound nitrogen evolution for the MVB coal lags the carbon conversion efficiency. For example, when carbon conversion is about 80% for the MVB coal, only about 56% of its fuel bound nitrogen was released. The nitrogen remaining in the char would be more likely to be form NOx. Based on the DTFS-1 data, the MVB coal would be expected to have higher NOx emissions than the PRB and HVB coals, under the same firing conditions.

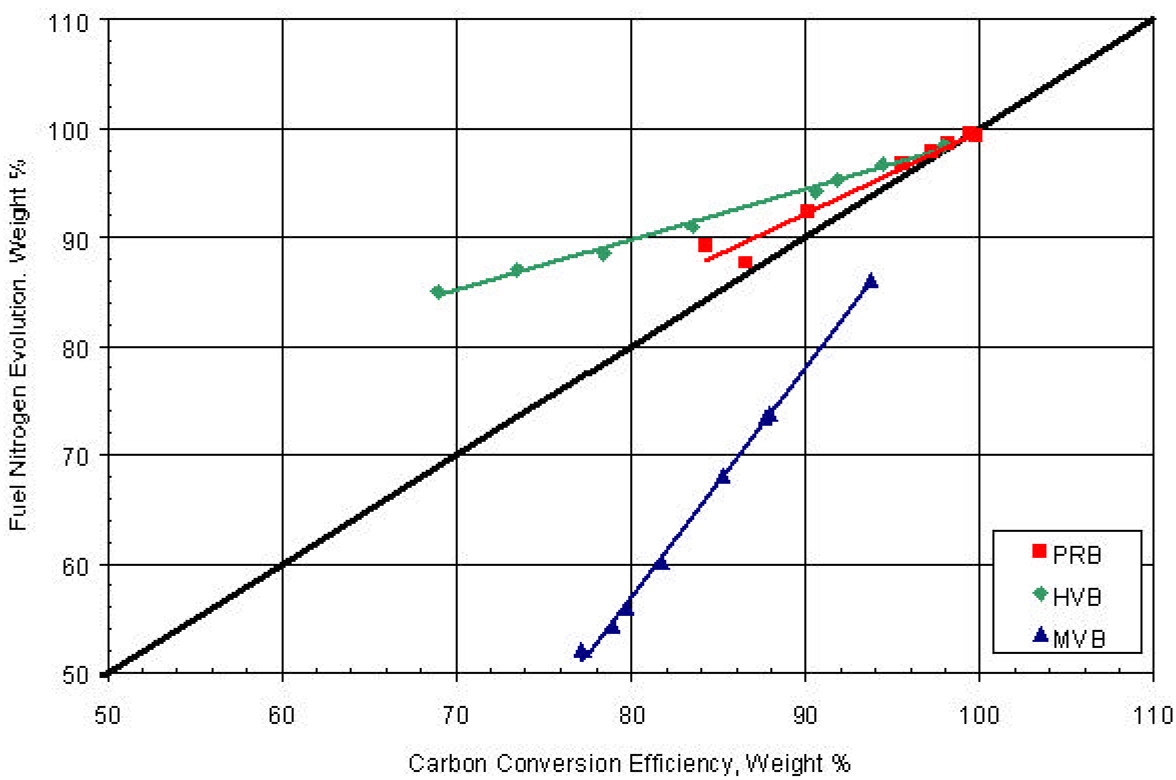

Figure 4.5.2-4: Fuel Nitrogen Evolution as a Function of Carbon Conversion Efficiency.

The DTFS-1 was also used to determine fuel nitrogen conversion coefficients for the three test fuels. Fuel nitrogen conversion efficiencies can be shown as conversion to all nitrogen species, or specifically conversion to NOx. Fuel nitrogen conversion is much greater for coal than it is for char. The reason for this is that nitrogen associated with coal volatile matter is more easily evolved during combustion than is the nitrogen associated with the carbon structure of the char (char having essentially no volatile matter).

Figure 4.5.2-5 shows the fuel nitrogen conversion coefficients for the 3 coals as a function of stoichiometry. The fuel nitrogen conversion coefficient is defined as the fraction of fuel bound nitrogen that forms NOx, normalized by the heating value of the coal. Note that there is no nitrogen in the oxidizing stream available to form thermal NOx as the experiments were performed in an O_2/Ar environment. The conditions for testing were the same as outlined for testing to determine fuel bound nitrogen evolution to all gas species (See Figure 4.5.2-3). The PRB, HVB and MVB coals have very similar fuel nitrogen (to NOx) conversion coefficients.

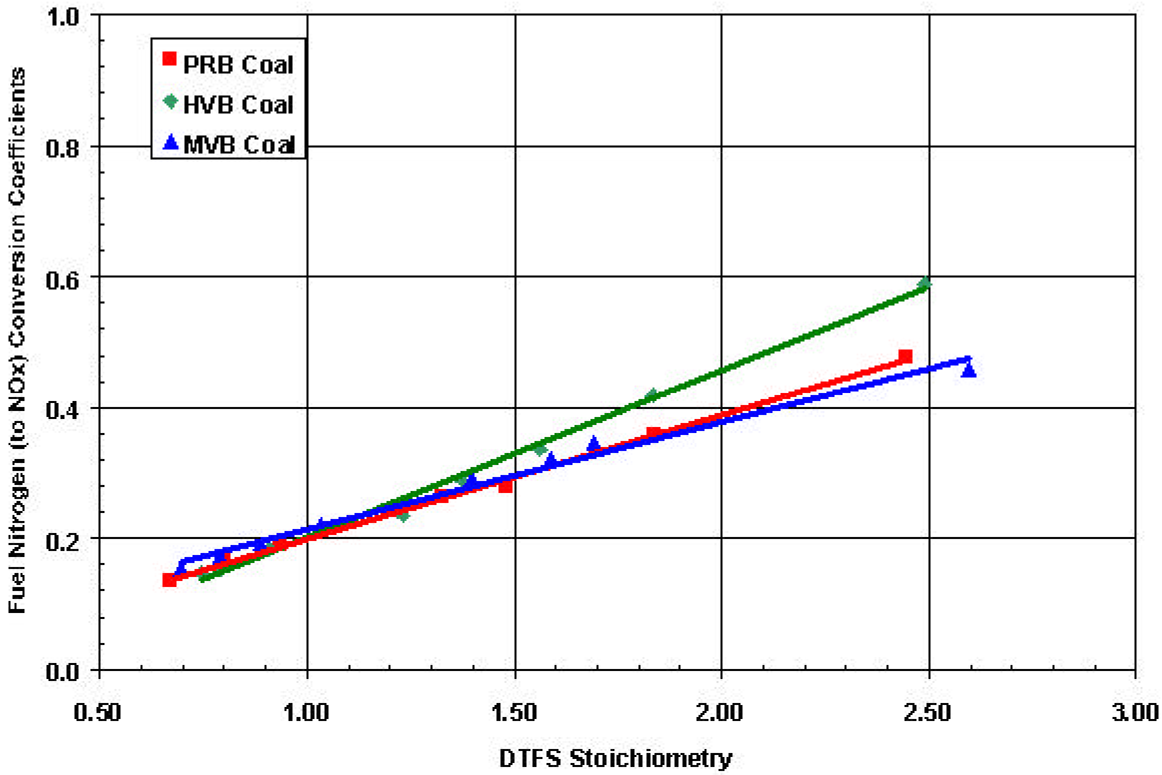

Figure 4.5.2-5: Fuel Nitrogen to NOx Conversion Coefficients.

Although the specific conversion fractions of “evolved” fuel nitrogen to NOx are quite similar for the three coals, it must be noted that the total amount of “evolved” fuel bound nitrogen (with the volatile matter) is much lower for the MVB coal than for the PRB and HVB coals, as shown in Figure 4.5.2-3. Additionally, it can be pointed out that the evolution of fuel bound nitrogen from char is much slower than from coal (i.e., with volatile matter intact). In this regard the MVB coal produced approximately 61% char, versus 44% and 43% char for the PRB and HVB coals, respectively, in the DTFS-1 high temperature pyrolysis tests (see Figure 4.5.2-2). As previously noted, fuel bound nitrogen that evolves from the char does not have the same opportunity to be reduced to molecular nitrogen as does fuel bound nitrogen coming off with the volatile matter. Char-bound nitrogen is generally released under oxidizing conditions, resulting in higher NOx emissions.

Drop Tube Furnace testing was also used to determine unburned carbon for the three test coals as a function of combustor stoichiometry for a given residence time. Conditions for unburned carbon determination were the same as that used for nitrogen conversion evaluation, namely combustion in a gas mixture of 6.5% O_2/93.5% Ar at a temperature of 2650 ^oF for a residence time of 0.5 second. The plots in Figure 4.5.2-6 show the PRB coal to be the most reactive and the MVB coal to be the least reactive of the three coals tested. Since achieving low NOx through air staging is always a tradeoff between achieving low NOx versus maintaining acceptable carbon losses and CO levels, the MVB coal would present the greatest challenge in maintaining acceptable carbon loss at stoichiometries that would also produce the lowest NOx levels.

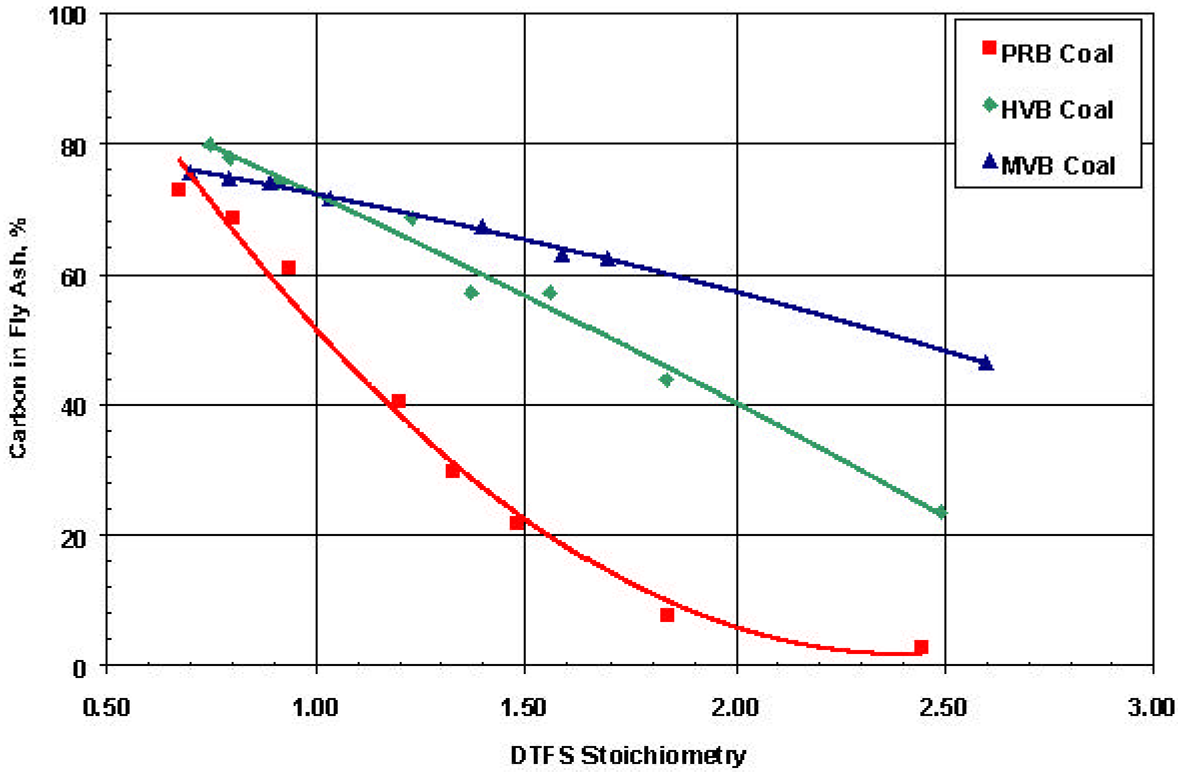

Figure 4.5.2-6: Unburned Carbon vs. Stoichiometry as Measured in DTFS-1.

Figure 4.5.2-7 is a plot of carbon monoxide versus stoichiometry, as measured in the drop tube furnace. Interestingly, the CO is much higher for the more reactive coal (PRB coal) at the lower stoichiometries, but as stoichiometry is increased the MVB coal (least reactive) shows higher CO levels. This is logical since the more reactive coal burns to a greater extent, even under fuel rich conditions, the result being an abundance of CO. By contrast the MVB coal burns to the least extent, and under fuel rich conditions produces less CO. Carbon monoxide levels shown at higher stoichiometries provide a good indication of the relative CO that would be expected at the tail end of the combustion process for the three coals, namely that the MVB coal is likely to have the highest CO levels of the three coals, under the same firing conditions (assuming perfect SOFA mixing). However in utility boilers, CO emissions are often influenced by the extent of SOFA mixing and are impacted by fuel and air imbalances in the unit. Thus, the more reactive subbituminous coals, which have higher CO emissions at substoichiometric furnace conditions, may have higher CO at the furnace outlet if mixing or unit conditions are less than optimal.

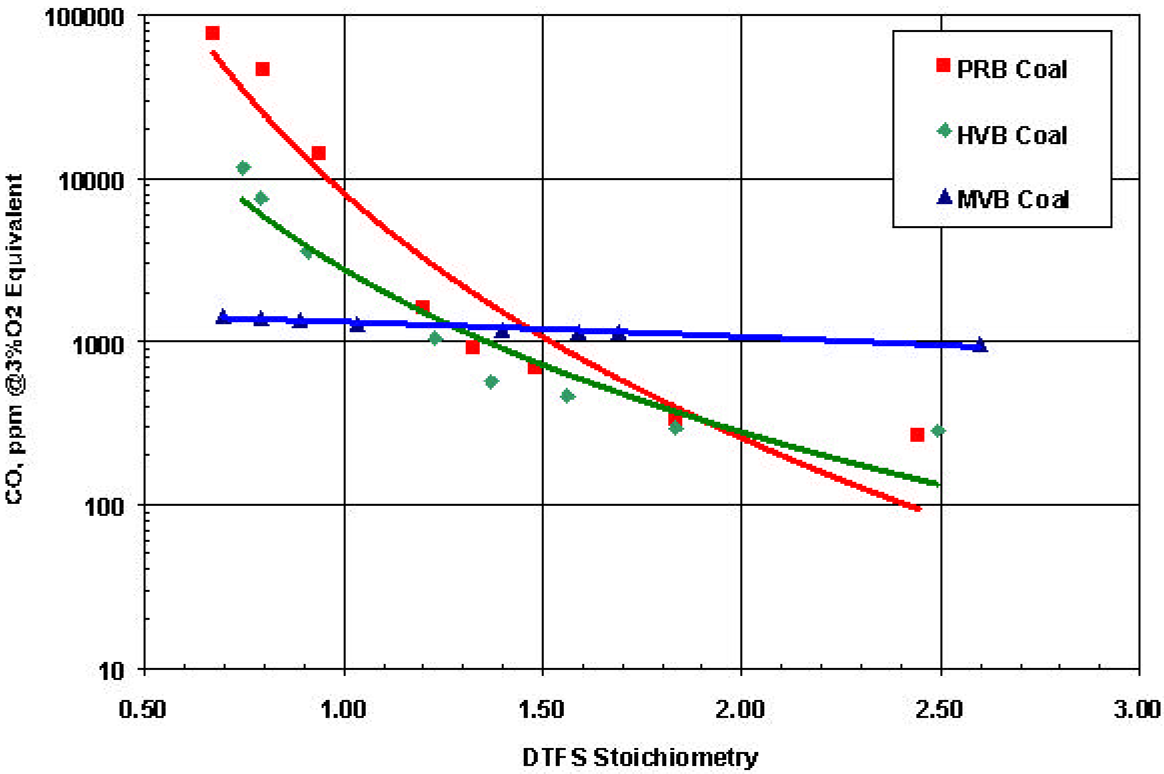

Figure 4.5.2-7: CO versus Stoichiometry as Measured in the DTFS-1.

4.6 TGA Coal Reactivity & BET Surface Area

To further characterize coal reactivity, each of the three coals was tested in a thermogravimetric analyzer (TGA). The surface areas of the chars produced from high temperature pyrolysis in the drop tube furnace were also determined using a Quantasorb analyzer. This section will document the measurement techniques and present the TGA and BET surface area results.

The following list documents the range of TGA tests performed to characterize the reactivity of the 3 test fuels:

- Non-Isothermal Reactivity on:
  - PRB, HVB and MVB Coals (200 x 400 mesh)
- Isothermal Reactivity on:
  - Chars from PRB, HVB and MVB Coals (200 x 400 mesh)
  - Char from MVB Coal Only (270 x 400 mesh, -400 mesh)

4.6.1 Technical Approach

ALSTOM Power uses a Perkin-Elmer TGA Model 7 (Figure 4.6.1-1) to obtain specific reactivity parameters of fuels and limestones. The TGA can also be used to derive the "micro-proximate" analyses of coals and coal chars based on a test protocol developed in-house. Testing was conducted as follows. About 4-6 mg of sample was placed in the TGA sample pan. Sample quantity was chosen such that when distributed over the bottom of the sample pan it was essentially a monolayer, thus minimizing O_2 mass transfer control phenomenon during combustion. Equal amounts of nitrogen (which serves to protect the balance) and air are allowed to pass through the reaction tube containing the coal sample. The temperature control mechanism is actuated, such that the heating rate is maintained at 10°C/min from room temperature to the completion of combustion. Both weight loss and rate of weight loss are monitored and recorded throughout the combustion process. The information from this testing can be used to derive combustion efficiency curves and "pseudo" surface reaction kinetic parameters.

Figure 4.6.1-1: Thermogravimetric Analyzer (TGA).

4.6.2 Thermogravimetric Analysis (TGA) Results

Figure 4.6.2-1 shows burnout profiles of the three test coals (200 x 400 mesh) at a heating rate of 10 degrees Celcius per minute in the Perkin Elmer TGA apparatus. The PRB coal is seen to start losing weight (burning) at considerably lower temperatures than the HVB and MVB coals. Early weight loss is driven by evolution and burning of the volatile matter, followed by burning of the resultant char. Based on this it can be deduced that the PRB coal begins the devolatilization process at lower temperatures than the other two coals, and proceeds to burn a more reactive char more quickly than in the case of the HVB and MVB coals.

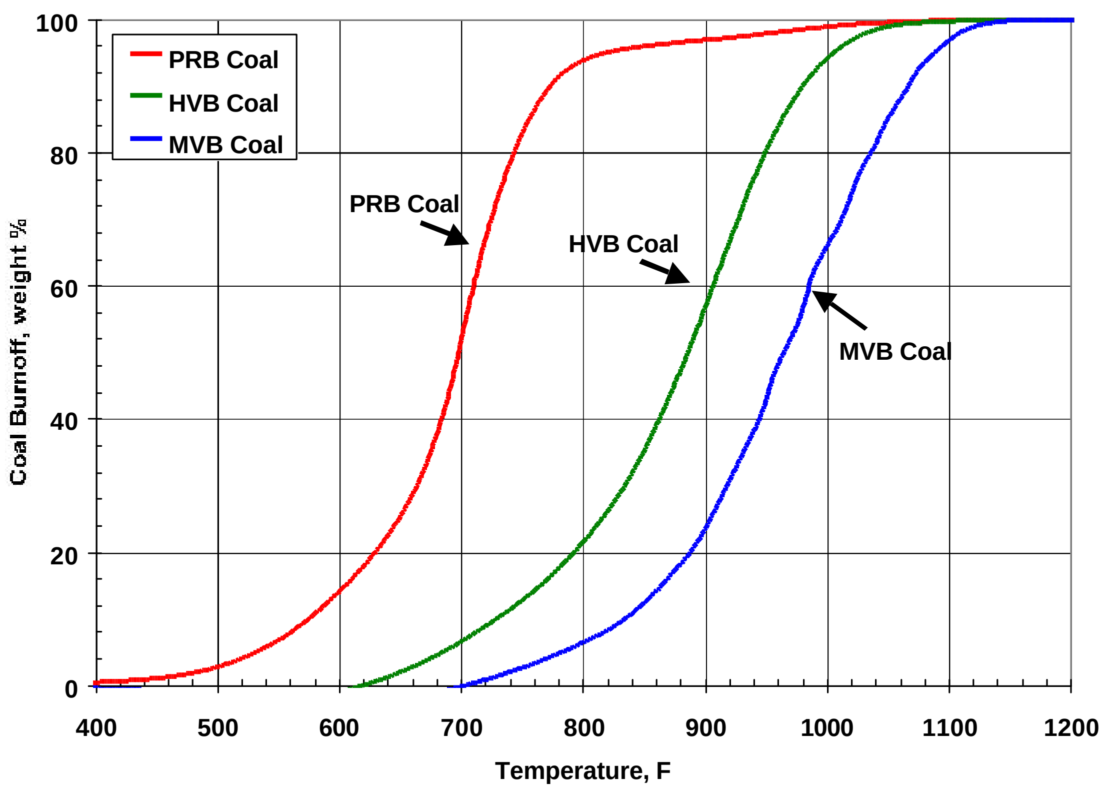

Figure 4.6.2-1: Fuel Burnoff as a Function of Temperature.

Figure 4.6.2-2 shows the burnoff rate for the three test coals. Again, as in the previous figure, PRB coal is shown to react more quickly and with more intensity (as demonstrated by the higher, narrower peak) than the other two coals. HVB and MVB coals, by contrast, show significant combustion to occur at higher temperatures, and the lower peaks denote less combustion intensity.

Figure 4.6.2-3 shows burnoff profiles from the TGA for chars produced from the three test coals under isothermal conditions, i.e., at a constant temperature of 1200 °F. Chars were prepared by pyrolyzing PRB, HVB and MVB coals in the DTFS-1 at 2650 °F in an inert (nitrogen) atmosphere. The significance of this test is that it eliminates any reaction from the volatile matter; the burnoff profiles are determined strictly by the reactivity of the char, thereby permitting only char reactivities to be compared. PRB coal has the most reactive char of the three coals evaluated with burnout being essentially completed after about 7 minutes. Compared to the char from PRB coal, HVB coal char requires about twice the time (~15 minutes) to complete combustion and MVB coal char requires about triple the time (~23 minutes) for its char to be completely burned.

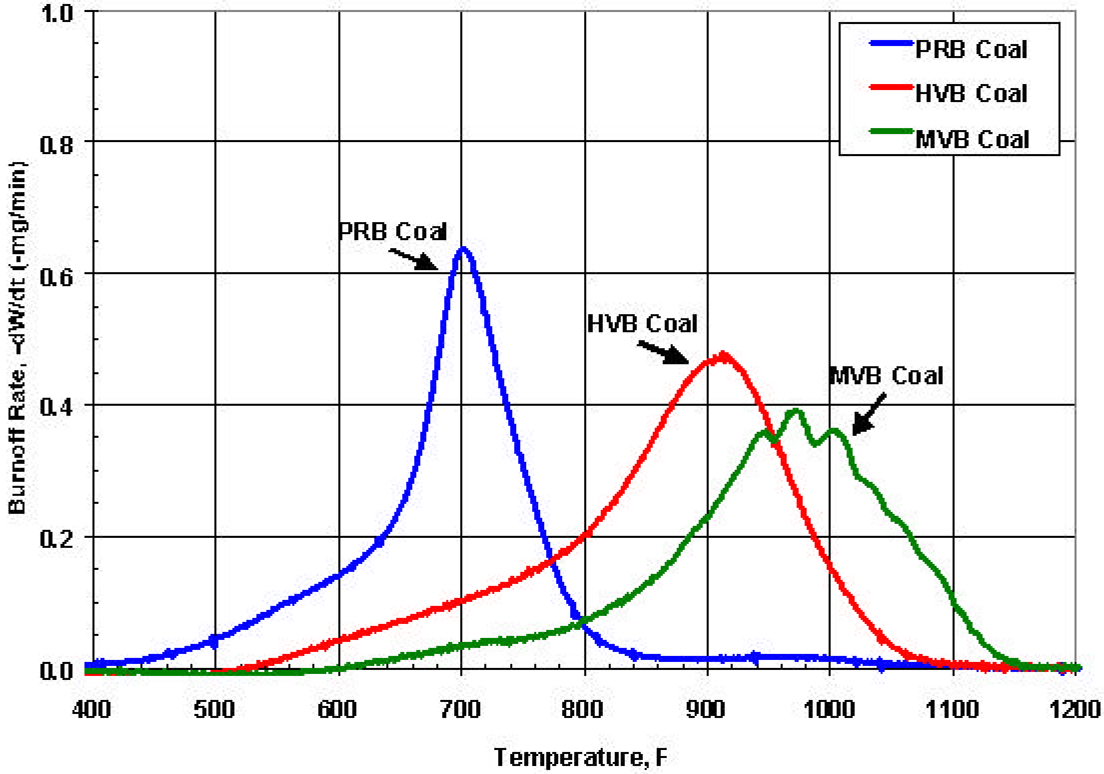

Figure 4.6.2-2: Fuel Burnoff Rate as a Function of Temperature.

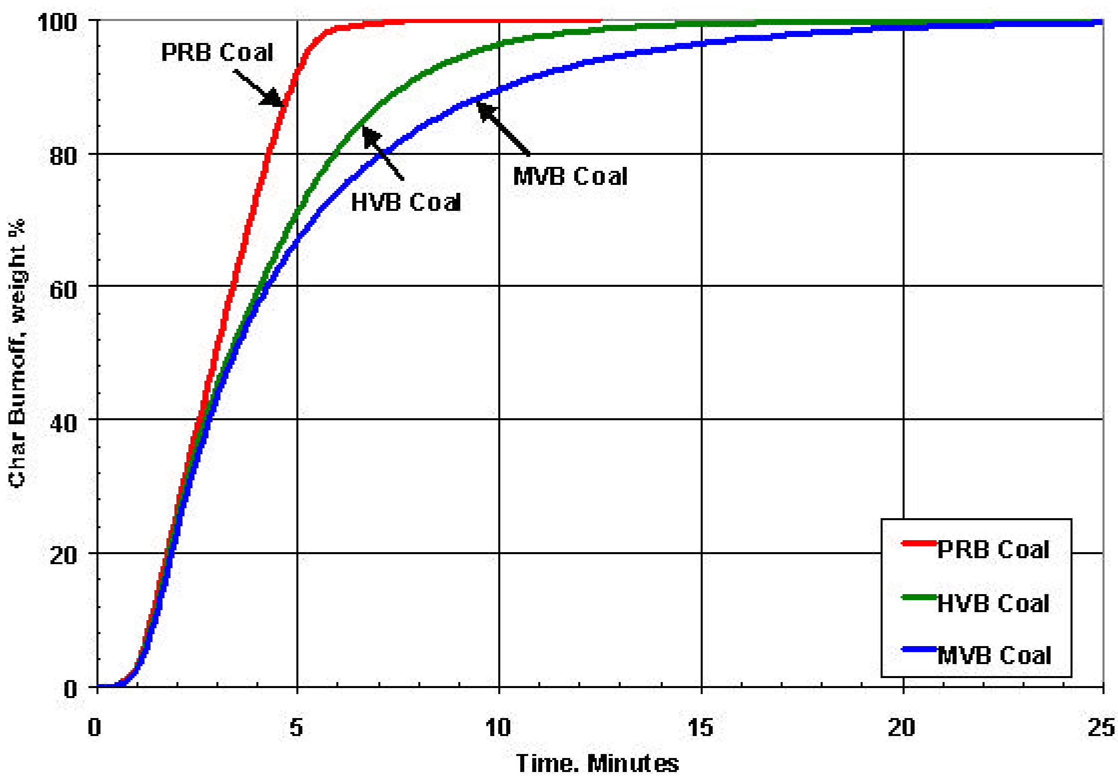

Figure 4.6.2-3: Char Burnoff as a Function of Time at 1200 °F.

BET surface area measurements were also made of the chars from the 3 test coals. Table 4.6.2-1 shows surface area values for chars, prepared in the DTFS-1, for each of the coals. The surface area data corroborates the reactivity results from both TGA and DTFS-1 testing. The PRB coal char shows significantly greater surface area than the char from the HVB coal, which in turn shows significantly greater surface area compared with the char from the MVB coal. These surface area measurements are consistent with the swelling characteristics of the coals as a function of rank. When the volatile matter is released from the non-swelling PRB coal, the resultant char is highly porous with an abundance of small pores that result in a high surface area available for char combustion. The MVB coal, on the other hand, is a swelling coal which passes through a “plastic” phase during devolatilization. This plasticity results in the closing of pores in the MVB coal char and a decrease in the char surface area. The HVB coal falls between the PRB and the MVB coals in its behavior during devolatilization.

Table 4.6.2-1: BET Surface Area Measurements of Coal Chars.

Coal Char	BET Surface Area (m^2/g, daf basis)
PRB Coal	78
HVB Coal	34
MVB Coal	12

Given that the MVB coal char was the least reactive of the three chars tested, further TGA testing was conducted on size graded fractions of char from the MVB coal to determine if finer particle sizes would yield significantly better results. Figure 4.6.2-4. shows char burnoff as a function of time at 1200 ^oF for three different particle sizes. Char from the 200x400-mesh coal was found to be less reactive than char from the 270x400-mesh coal, which was less reactive than char from the -400-mesh coal. At the high fineness (-400 mesh), char generated from the MVB coal showed a burnoff rate that is comparable, or slightly better, than the HVB coal char when tested at a size of 200x400-mesh. Note that the change in char burnoff is not due to a modification of the intrinsic char reactivity caused by grinding, but rather due to an increase in the surface area of the char as the particles become smaller. These results suggest that significant improvement in unburned carbon in the fly ash under staged combustion conditions can be achieved via improved coal particle fineness for the MVB coal, as compared to operation with a standard commercial grind.

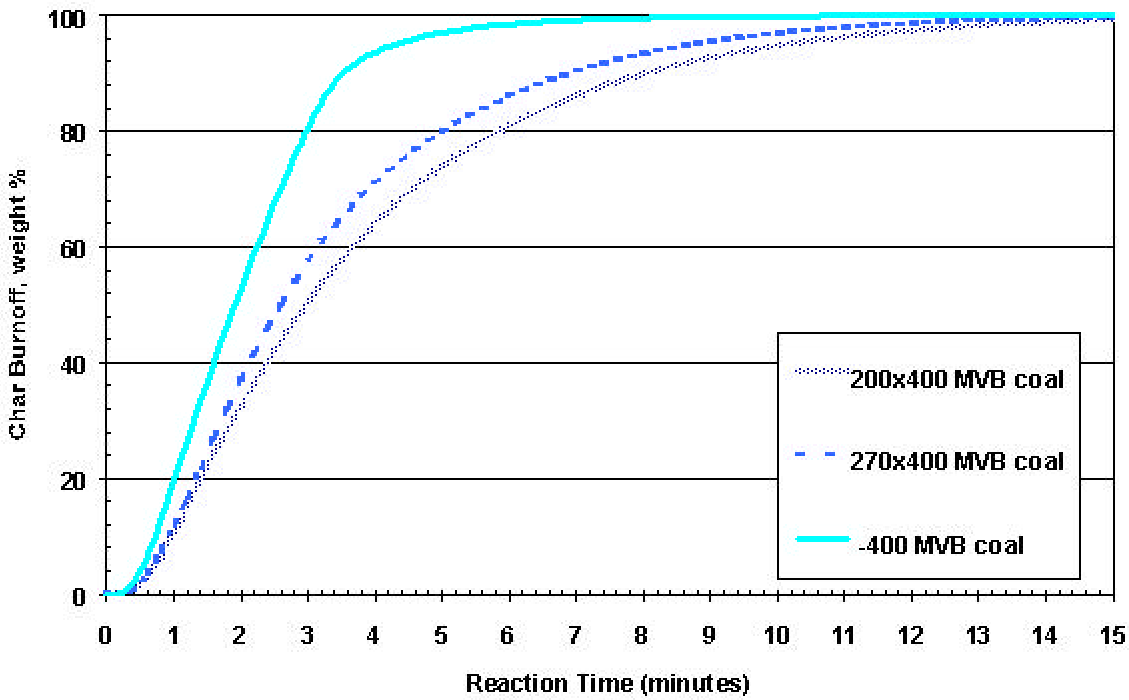

Figure 4.6.2-4: TGA Oxidation vs. Particle Size for MVB Coal Char

4.7 Conclusions

Results from the "Test Fuels Characterization" section have achieved the stated task objectives of: (1) quantifying fuel properties, (2) providing definitive information from bench-scale testing on nitrogen conversion and relevant combustion-related parameters under air staged, low NOx firing conditions, (3) providing guidance and understanding regarding pilot-scale test planning and results interpretation.

Relative to performance in a staged air low NOx combustion system, the PRB coal would be the most amenable. The combination of early devolatilization, with commensurately high quantities of fuel bound nitrogen being released early in the combustion process, coupled with a highly reactive char, indicate that significant NOx reduction can occur without penalties of high unburned carbon or CO. The MVB coal, by contrast, would be the most challenging of the three coals regarding the task of achieving low NOx in an air staged, low NOx system while maintaining acceptable levels of unburned carbon and CO levels. The HVB coal would fall in between the PRB and MVB coals regarding its NOx and combustion performance in an air staged low NOx combustion system. While these observations with coal rank are largely not new and novel, they add to a proprietary database of coal properties that assist in understanding and predicting coal specific behavior in commercial utility boilers.

The trends found during bench-scale characterization, in particular results from the DTFS-1 and TGA, are consistent with those found during pilot-scale testing in the BSF, as will be shown later in Section 6.0.

Specific, key findings were as follows:

- The PRB coal should result in the lowest NOx emissions, under air staged conditions, commensurate with maintaining acceptable unburned carbon and CO levels in the flue gas.

- The MVB coal represents the greatest challenge in terms of achieving low NOx, under staged air firing conditions, both from the standpoint of early and significant fuel nitrogen release (to form molecular nitrogen) and in maintaining acceptable unburned carbon.

- Employment of ultra-fine coal grinding in the case of the MVB coal would provide better carbon burnout, similar to that of the HVB coal. Finer grinding for MVB coal did not increase high temperature volatile matter release, nor nitrogen conversion to gaseous species during pyrolysis testing.

- The HVB coal would fall somewhere in between the PRB and MVB coals in terms of its expected low NOx performance and unburned carbon and CO emission levels under air staged firing conditions.

- Results of bench-scale testing provided reliable indications of expected results during pilot-scale testing.

- Bench-scale results have provided a sound, fundamental understanding of NOx-related results from pilot-scale tests. Fuel bound nitrogen conversion for the MVB coal, for example, was shown to be significantly lower (about 55% versus 85-90% for the PRB and HVB coals) than the other two test coals, a major reason for its higher NOx emissions despite firing under an air staged system.

5.0 LOW NOx SUBSYSTEMS

The Low NOx Subsystems section represents the ideas that were considered for possible implementation to effect improvements to the TFS 2000™ low NOx system. Ideas ranged from process oriented technologies, such as finer grinding of coal, more strategic use of overfire air, deployment of SNCR in various forms, and downstream oxidation of unburned carbon, to hardware improvements such as the oxidative pyrolysis burner, to conceptual system improvements such as the advanced control system.

Many of the ideas were evaluated during pilot-scale testing in the BSF. A number of overfire air configurations were tested, while still more configuration concepts were evaluated through CFD modeling. Various grinds (particle sizes) of pulverized coal were tested, including a microfine grind for the least reactive (MVB) coal tested. The oxidative pyrolysis burner was designed, built and tested. The use of high temperature, in-furnace injection of ammonia for further NOx reduction was part of the pilot-scale testing program.

Other ideas were not tested in the BSF, but were evaluated by other means. For example, although the new, advanced control system was not tested in the BSF, a key element of the advanced control system, the ability to measure and control individual coal feed rates, was evaluated. The oxidation of unburned carbon in a downstream fluidized bed (Progress Materials) was not tested, but was evaluated in the “Engineering Systems Analysis and Economics” task utilizing available data from separate demonstration testing.

The sections that follow identify each of the new ideas and discusses the rationale for possible improvement to the low NOx system. In some cases the ideas might be more aligned with combustion-related benefits, which indirectly, favorably impact NOx. The subsections on “Overfire Air Injection” (5.3) and “Advanced Control System” (5.6) are more lengthy since, in part, these ideas have been evaluated by means other than pilot-scale testing.

5.1 Objective

The overall objective of this task was to identify and evaluate subsystem designs for use in an Ultra-Low NOx Integrated System. Work in this task has focused on refining key design concepts and subsystem attributes for application to the pilot-scale demonstration testing and commercial units.

5.2 Fuel Preparation & Transport

Fuel preparation for testing in the BSF was accomplished using a small-commercial scale ALSTOM Power HP pulverizer located in ALSTOM Power’s Pulverizer Development Facility (PDF). Specifically, PRB, HVB and MVB coals were pulverized in the PDF up to a fineness of 85% through 200 mesh. A coarser grind (65% -200 mesh) was also prepared for the very reactive PRB coal. The pulverized coal product was sent to a storage silo for subsequent testing in the BSF. In addition 20 tons of MVB coal were sent to ALSTOM Power's Air Preheater Company - Raymond Operation for ultra fine grinding, namely 96% through 325 mesh, for one of the tests in the BSF.

Objective

The objective of this task was to design and/or select, from on-going internal mill development projects, mill enhancements to decrease particle top size and mass mean diameter for increased volatile yield and decreased carbon heat loss.

It should be noted that the initial objective for this task included the design of an air separation system to allow a reduction of the mill transport air/coal mass ratio. However, a decision was made (with the DOE concurrence) to eliminate this subtask in favor of accomplishing the same end objective in another (less costly) way. For pilot-scale test purposes, the effect of reduced transport air (TA) to fuel ratio on NOx emissions under deeply staged conditions was tested by simply adjusting the output of the transport air fan. As coal is indirectly fed into the BSF from coal storage silos, significant variation in the TA:Fuel ratio could be achieved without using a fuel/air separation system.

Pulverizer Background

This section briefly describes vertical spindle mills, the type of pulverizer used at ALSTOM Power. Figure 5.2-1 illustrates a typical pulverizer, in this case a shallow-bowl mill equipped with a static classifier. Each vertical spindle mill has the following basic operational features:

- Coal fed to the center of the rotating bowl is thrown radially outward to pass under heavily loaded rolls, thus being pulverized.
- Pulverized coal passes over the rim of the bowl and is swept upward by an annular flow of hot air from a plenum below the bowl.
- Coarser particles fall back into the crushing zone for further grinding.
- Finer particles are carried by the air stream to the size classifier (solids/air separator).
- Coarse particles rejected by the classifier are returned to the grinding zone of the mill.
- Fine particles leaving the classifier represent the final, dried product with the desired particle size.

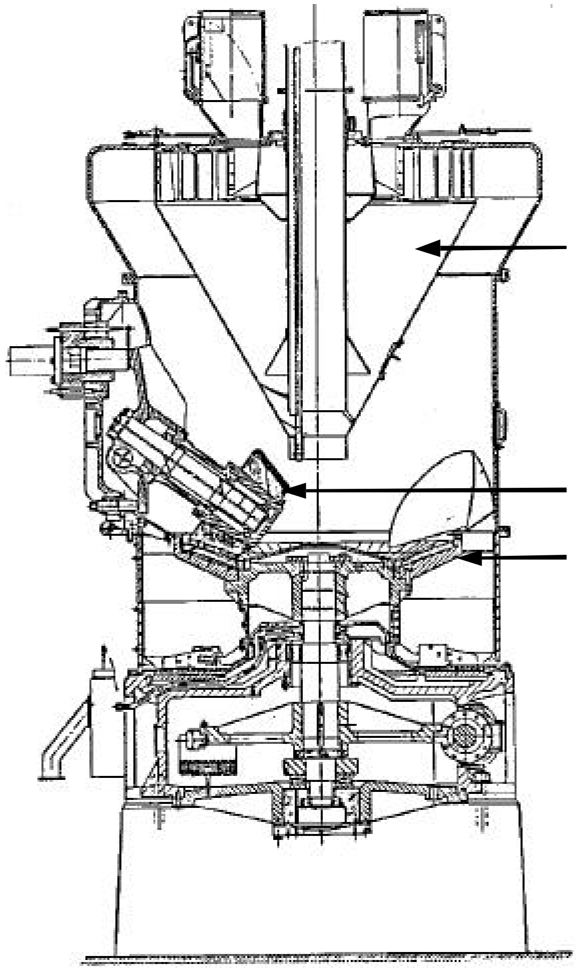

Figure 5.2-1: Pulverizer with Static Classifier.

Figure 5.2-2 illustrates the same mill type (vertical spindle), but in this case equipped with a DYNAMIC™ classifier. DYYNAMIC™ classifiers represent a significant innovation to coal pulverizing technology and practice. This is due to the ability of these classifiers to more effectively remove large particles (> 149 microns) from pulverized coal (which is necessary to reduce carbon loss) and their ability to yield finer fuels (>85 weight percent smaller than 74 microns) without a significant loss of pulverizer throughput.

A typical DYNAMIC™classifier is a rotating squirrel-cage device with multiple vanes set at an angle, with respect to its axis, and has the shape of a cylinder or truncated cone. The top (larger diameter section for a truncated cone shape) of the classifier is closely fitted to the inside roof of the pulverizer and surrounds the exit fuel pipes. The bottom of the classifier is sealed, with allowance for the pulverizer inlet (crushed) coal feed pipe. Thus, coal from the crushing zone of the mill, upon being air-swept up to the classifier, can exit the pulverizer only by passing through the classifier vanes. Fuel fineness is controlled by the classifier's rotational speed; the faster the speed, the finer the coal product. Particles unable to pass through the vanes fall back to the crushing zone for further size reduction.

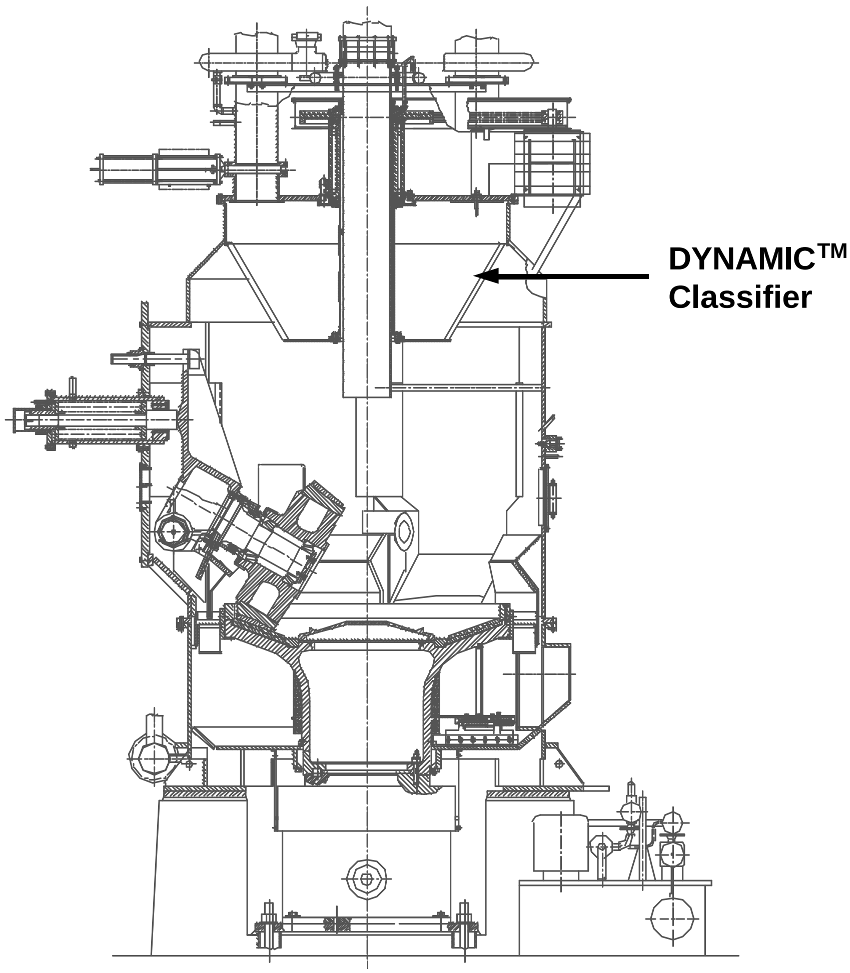

Figure 5.2-2: Pulverizer with DYNAMICÔ Classifier.

ALSTOM Power's Pulverizer Development Facility (PDF)

A process flow diagram of the PDF is seen in Figure 5.2-3. The heart of the facility is an HP 323 Pulverizer; a 3-journal, 32 inch-bowl commercial mill. Its design and location allow for easy interchange of various mill components (e.g. DYNAMIC™ classifiers or grinding rolls). Mill performance results from the PDF are readily scaleable to larger industrial and utility size pulverizers.

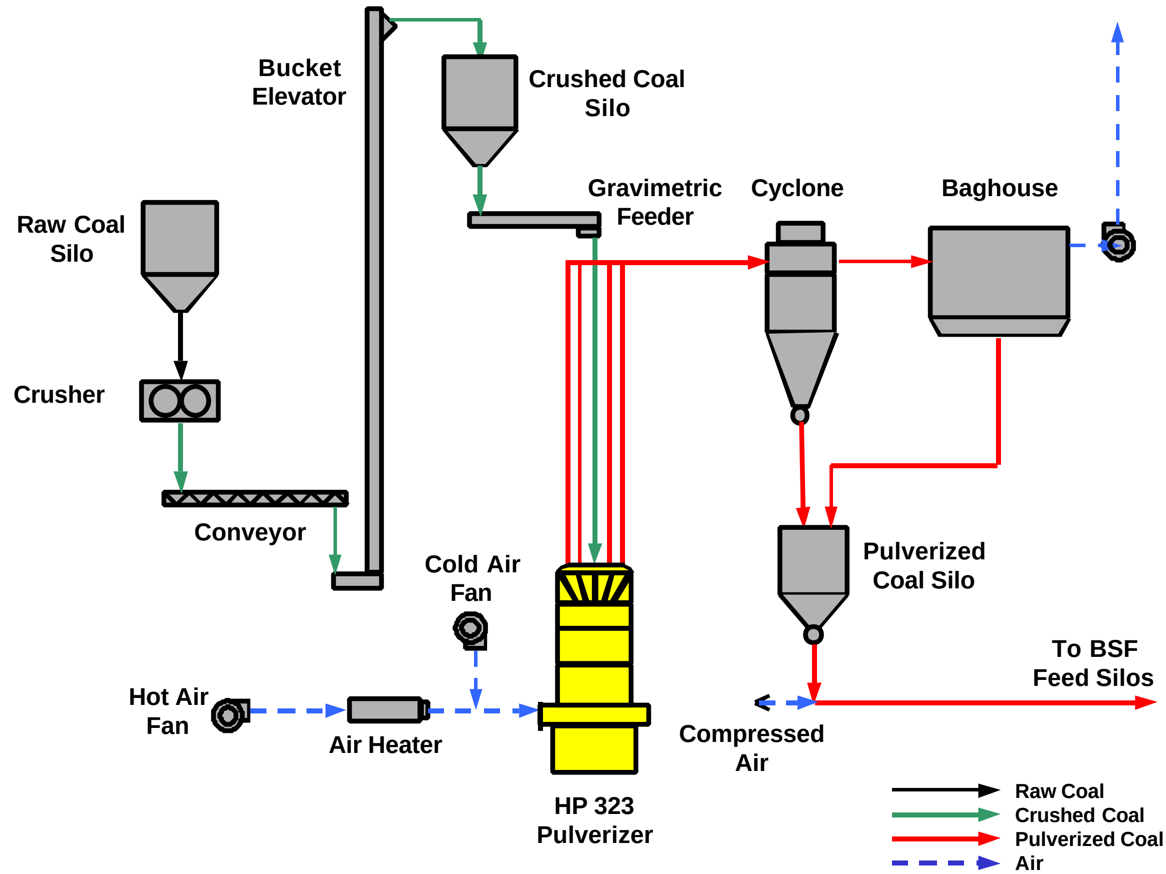

Figure 5.2-3: Pulverizer Development Facility Process Flow Diagram.

All material flows to the HP323 mill are automatically controlled. A Thayer gravimetric coal feeder (maximum capacity of 8 ton/hr) is used to feed crushed coal (nominal ¾ in x 0) to the mill. Crushed coal is supplied to the coal feeder from a 10 ton crushed coal silo. Coal is supplied to the feed silo using a combination of typical coal handling equipment (crusher, screw conveyors, bucket elevator, etc.) having a maximum transport feed rate of 6 tons per hour.

Hot air (250 to 500 °F) is supplied to the mill using a 200 HP Lamson fan with cold (ambient) tempering air being supplied by a 100 hp Lamson fan. The air is heated using a 3.5 MBtu/hr indirect fired air heater. Both airflow rate and temperature are automatically controlled to maintain the mill at constant operating conditions.

Pulverized coal product leaves the classifier section of the mill through four fuel pipes and is pneumatically conveyed to a collection cyclone where the solids are separated from the air. The cyclone discharges the product into a 20 ton storage silo from where it is pneumatically conveyed to the pulverized coal storage silos at the Boiler Simulation Facility (BSF) complex. Air from the cyclone is discharged to a baghouse where any remaining coal dust is removed and sent to the product silo prior to discharging the air to the atmosphere.

All mill operating parameters are controlled using a programmable computer based control system. Data identifying mill operating conditions, such as mill inlet/outlet temperatures, mill differential pressures, mill power consumption, etc., are continually monitored and recorded using a computer based data acquisition system. In total there are over 48 different measurements which are recorded in a format that is readily imported into an Excel spreadsheet for later data analysis.

Establishing proper coal flow rates and fineness requirements is done by performing a classifier "sweep" at rates likely to be employed for product generation. A classifier sweep consists of incrementally closing the classifier inlet vanes (in the case of the static classifiers) or incrementally increasing the speed of the classifier (in the case of the DYNAMIC™ classifier). At each classifier setting, mill performance data is recorded and a mill product sample is aspirated from the fuel lines using a cyclone collector for particle size analysis. The DYNAMIC™ classifier was used for fuel preparation for this project.

5.3 Oxidative Pyrolysis Burner

The Oxidative Pyrolysis Burner used in pilot scale testing is based on the commercial burner used in ALSTOM Power's LNCFS™-P2 Low NOx Firing System. The term "oxidative pyrolysis" refers to coal pyrolysis occurring under locally oxidizing, but globally reducing conditions. In a commercial application such as a pulverized coal boiler, some heat must be generated to drive the pyrolysis process, hence the need for some combustion to take place and the need for oxygen (air). The rationale for using an oxidative pyrolysis burner is to maximize coal devolatilization, which in turn maximizes fuel bound nitrogen release. As pointed out in Section 4.0, early release of fuel bound nitrogen in a fuel rich zone (the case in an air staged low NOx system) affords the opportunity for more of the fuel bound nitrogen to be reduced to molecular nitrogen instead of forming NOx.

Objective

To objective of this task was to design a low NOx, tangential-fired, enhanced pyrolysis burner based on the LNCFS™-P2 coal nozzle tip for use in the large pilot-scale testing task. The burner design strives to increase near field volatile matter yield, thereby increasing the formation of molecular nitrogen and reducing NOx.

Description of Commercial Burner

The commercial LNCFS™-P2 coal nozzle tip (see Figure 5.3-1) was based on ALSTOM Power's Aerotip™ coal nozzle, incorporating many of the features of this anti-distortion, long life design, while enhancing its performance from a NOx reduction standpoint.

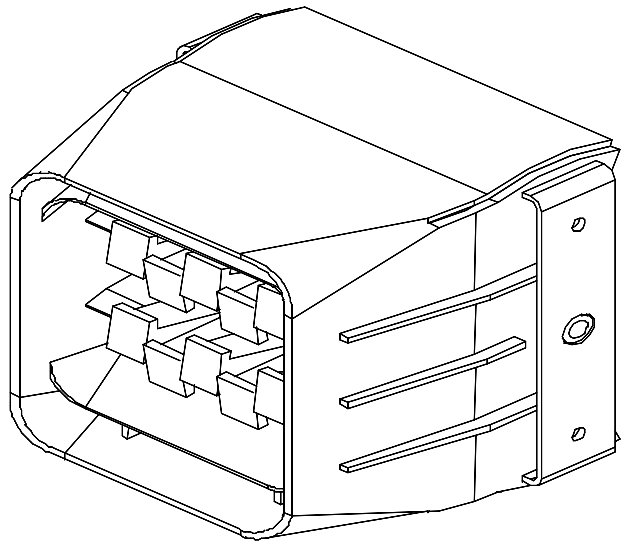

Figure 5.3-1: Commercial Version of LNCFSÔ -P2 Coal Nozzle Tip.

The features derived from the Aerotip™ nozzle include rounded corners on the inner and outer fuel air shrouds to inhibit the formation of flow stagnation regions. This reduces recirculation and deposition of coal and coke products in the fuel air section of the coal nozzle tip that could cause distortion of the burner tip. The rounded corners also reduce the high temperature hoop stresses that can occur in square corners, thereby minimizing distortion over the life of the tip. Additional Aerotip™ nozzle features incorporated into the P2 design include chamfered trailing edges of the inner fuel shroud and the nozzle tip body, and the recessing of the fuel air shroud. These features further inhibit coal/ash deposition by reducing flow separation and the surface area seeing radiation from the flame, thereby decreasing the size and bonding strength of any small deposits that might develop. To provide additional protection from radiant heating, the coal splitter plates are recessed behind the fuel shroud.

The P2 coal nozzle tip is designed to increase coal jet mixing and dispersion while simultaneously decreasing the penetration of the mixed coal and primary air jet. This configuration provides a means of controlling the near burner stoichiometry, resulting in higher peak temperatures in a reducing atmosphere. Higher peak temperatures enhance coal devolatilization and fuel bound nitrogen release resulting in a greater opportunity for the formation of molecular nitrogen, and hence reduced NOx emissions.

The desired primary air and fuel flow profile is obtained via the use of alternating wedge shaped bluff bodies with trip shear bars on the trailing edges. The location, geometry, and number of wedges can be optimized to achieve the desired flow profile for any given application. To reduce erosion, weld overlay is applied to the leading edges of the nozzle tip splitter plates and the bluff body wedge trip bar leading edges.

The P2 nozzle tip body incorporates design features to minimize uncontrolled air when tilting. Traditional coal nozzle tips allow a significant portion of fuel air to bypass the tip when in full up or down tilt positions. In some cases, this can result in tip damage due to the reduction of cooling airflow through the tip. The P2 design includes a flared back, bulbous shape to maintain consistent air gaps over the entire tilt range. Controlling the air gaps maintains the flow of fuel air into the tip as it tilts.

Description of Pilot-Scale Burner/Firing System

The scaled-down version of the LNCFS™-P2 burner designed for testing in the BSF, termed the oxidative oxidative pyrolysis burner, contained all the salient features of the P2 burner as shown in Figures 5.3-2 and 5.3-3.

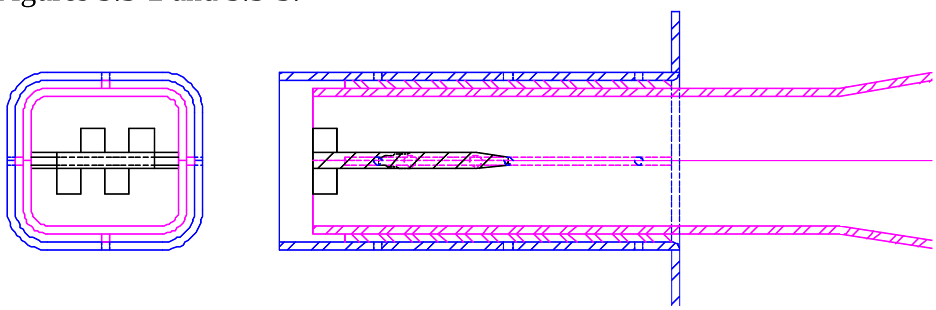

Figure 5.3-2: Drawing of the Oxidative Pyrolysis Coal Nozzle Tip.

Figure 5.3-3: Photo of the Oxidative Pyrolysis Coal Nozzle Tip Used in BSF Testing.

Unlike the commercial version, the burner used in pilot-scale testing did not need to have tilting capability. Two different sets of burners having different exit areas were built so that a constant outlet velocity (~80ft/sec) could be maintained while varying transport air to fuel mass ratio.

Concentric Firing System (CFS™) air injectors were installed above and below each of the oxidative pyrolysis burners in the Boiler Simulation Facility (BSF) as shown in Figure 5.3-4.

Main Windbox
X
X
CC OFA
Coal
CFS
Aux
CFS
Coal
CFS
Aux
CFS
Coal
Bottom
Bottom
X
X

Figure 5.3-4: BSF Main Windbox Layout.

As shown in Figure 5.3-5, the CFS™ offset air tip directs a portion of the secondary air toward the furnace walls, away from the firing angle of the primary air and coal (fuel) nozzles. Figure 5.3-5 also shows the arrangement of the main burner windbox and the lower and upper separated overfire air registers (L SOFA and U SOFA).

Under low NOx firing conditions with staged air, a reducing atmosphere could exist near the furnace walls, which can result in an increase in furnace slagging. The CFS™ system aids in the control of slagging by promoting an oxidizing atmosphere in these areas. Exact divergence angles for CFS™ air, and ratios of CFS™ air to straight air to bottom end air are adjustable and determined for each boiler based on fuels fired and furnace geometry.

An additional benefit of CFS™ air is the ability to control local, near burner stoichiometries. Since CFS™ air is directed away from the coal stream it delays air entrainment by the primary air and fuel jet, thereby reducing the combustion stoichiometry during devolatilization and the initial stages of char combustion. This results in the formation of a fuel rich primary flame, while maintaining oxidizing conditions along the furnace.

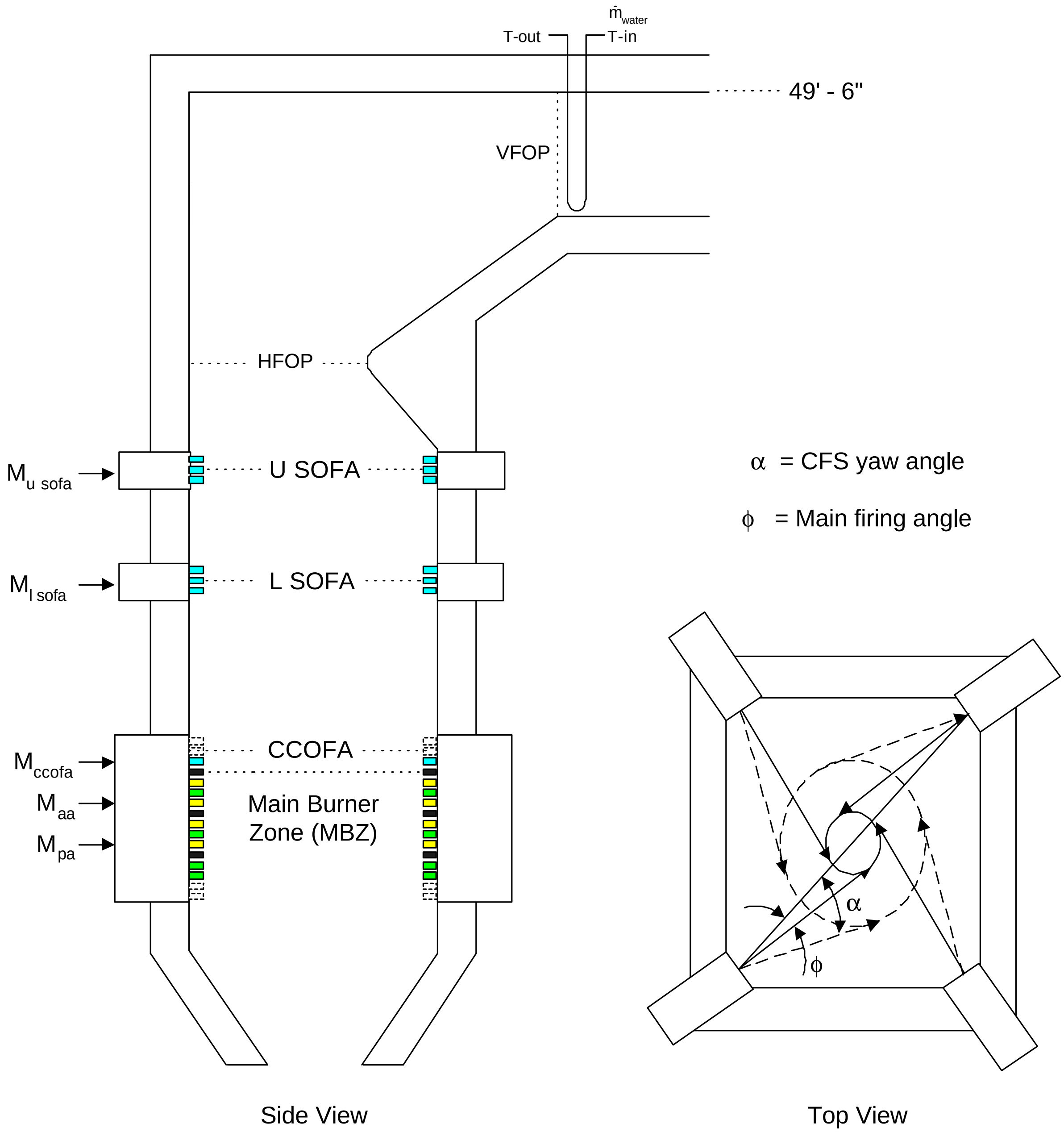

Figure 5.3-5: Elevation and Plan View of CFSÔ Air, Main Windbox and Overfire Air.

5.4 Overfire Air Injection

Introduction

Overfire air injection is a critical component of an air staged low NOx firing system. There must be sufficient residence time in the substoichiometric main burner zone to allow coal devolatilization and release of fuel bound nitrogen to proceed to reasonable levels so that molecular nitrogen can be formed, thereby reducing NOx emissions. From a combustion point of view the overfire air must be injected at a location such that sufficient residence time exists downstream of the point of SOFA injection to largely complete combustion of the coal char prior to entering the upper furnace. Given these goals, it becomes very important to mix the overfire air with the combustible gases/char particles from the main burner zone as quickly and as thoroughly as possible. An important part of this project was to evaluate various arrangements for injecting overfire air to determine which arrangement would provide the best mixedness, as will be described in this section.

Objective

The objective of this task was to utilize Computational Fluid Dynamic (CFD) modeling to identify, design and evaluate improvements to the global mixing process of tangentially-fired boiler designs in order to increase staged residence time for NOx destruction and improve overfire air mixing for improved char/unburned combustible oxidation. Improved overfire air mixing will also be evaluated as an enabling technology for reducing furnace excess air levels, reducing NOx emission while maintaining overall high carbon heat loss levels.

Modeling Test Plan

Figure 5.4-1 is a schematic of the test furnace that was modeled. The particular configuration shown represents the TFS 2000™ arrangement with a close-coupled overfire air (CCOFA) elevation and two separated overfire air (SOFA) elevations, denoted as lower (L) and upper (U) SOFAs. The main burner zone (MBZ) was modeled as a fuel rich / reducing zone with correspondingly higher stoichiometries as additional air is introduced through the OFA ports. The horizontal furnace outlet plane, right at the nose of the boiler and below the panels is used in the modeling studies as a measurement plane to assess mixedness. If proper mixing does not occur by the time the gases reach the horizontal outlet plane, gas passage through the super heat panels and platens tends to maintain any gas concentration profiles that may have existed up to that point.

Figure 5.4-2 shows relative plug flow residence times in various sections of the BSF versus those of a range commercial boilers. Specifically, residence times are shown from the center line of the CCOFA to the center line of the lower SOFA, from the center line of the lower SOFA to the center line of the upper SOFA and from the center line of the upper SOFA to the horizontal furnace outlet plane. Although on the high end, the BSF is seen to have stoichiometric / time histories representative of those in commercial units.

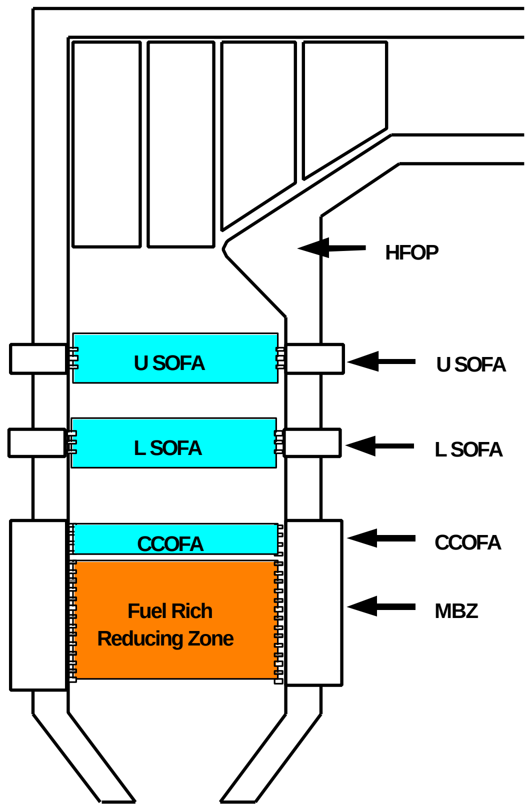

Figure 5.4-1: Schematic of BSF as Modeled with CFD.

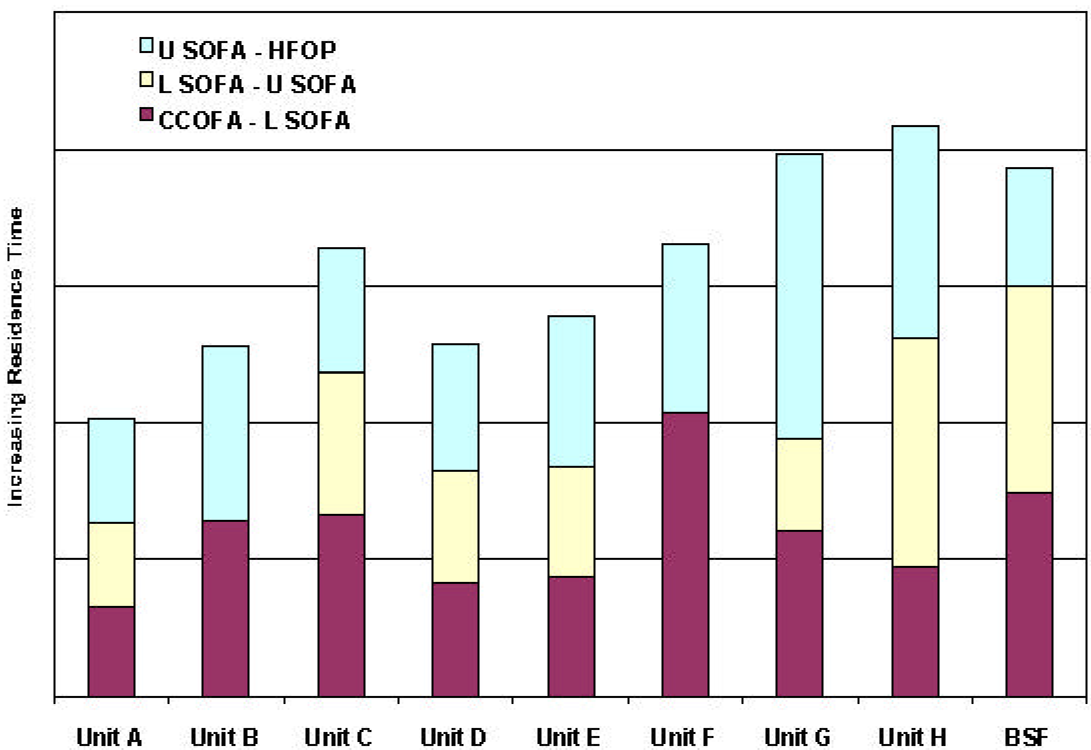

Figure 5.4-2: BSF vs. Utility Boiler Residence Times.

One important variable that was evaluated with CFD was the velocity of the overfire air. Increasing OFA velocity can improve jet penetration and mixing, resulting in lower CO emissions and decreased carbon in the fly ash. In all cases in this modeling study, the overfire air was injected into the furnace at the normal firing angle, i.e., yaw angle was kept constant.

Modeling was carried out on overfire air arrangements that can be categorized in five groups, as follows:

Group 1:

Group 1 cases have all the overfire air injected in tangential fashion, from two SOFA elevations (upper and lower). Air injection velocities were the same for upper and lower SOFAs. Velocities were varied from a baseline value up to a velocity of 5 times the baseline velocity. Air injection velocities were varied by altering the nozzle free areas, with lower free areas giving higher velocities. The five cases in Group 1 are identified as Base, Mod 1, Mod 2, Mod 3 and Mod 4. The Base case has the lowest injection velocity and the Mod 4 case has the highest injection velocity.

Group 2:

Group 2 cases have all the overfire injected in tangential fashion from two SOFA elevations (upper and lower). Unlike Group 1, the velocity for the lower SOFA was kept constant at the baseline value (X), while velocities for the upper SOFAs were varied. Velocities for the upper SOFAs were increased up to 5 times the baseline velocity. The four cases in this Group are identified as Mod 1a, Mod 2a, Mod 3a and Mod 4a, with Mod 1a representing the lowest upper SOFA velocity and Mod 4a representing the highest upper SOFA velocity.

Group 3:

Group 3 cases have all the overfire air injected in tangential fashion, but from only <u>one</u> SOFA elevation, either the upper or the lower. Specifically, three cases were evaluated wherein velocity was varied for the upper SOFAs and three cases were evaluated wherein velocities were varied for the lower SOFAs. Upper SOFA cases were represented as Mod 1b, Mod 3b and Mod 5b. Lower SOFA cases were represented as Mod 2b, Mod 4b and Mod 6b.

Group 4:

Group 4 cases have all the overfire air injected from the walls, i.e., not tangentially, for both SOFA elevations. Configurations modeled included: keeping the same number of furnace penetrations as T-injected OFA by injecting all of the air through the left, middle, or right ports, doubling the number of penetrations by using the middle and right ports, or tripling the number of penetrations by using all available inlets. Note that in all cases both the upper and lower SOFA configurations were identical.

Group 5:

Group 5 cases have overfire air injected from the walls for the upper elevation and T-injected overfire air for the lower elevation. The combinations of wall and T-injected overfire air were examined as a means to prevent channeling in the boiler that would result in fuel-rich pockets in the furnace corners and near the furnace walls.

General modeling parameters were as follows:

- SOFA Velocity
  - Baseline velocity to 5 times the baseline velocity

- SOFA Location
  - TFS 2000™ (2 elevation)
  - Single SOFA elevation
  - Corner versus wall

- Evaluated Results
  - Mixedness

5.4.1 CFD Modeling Approach

CFD simulations were made using FLUENT version 5.3.18, a commercially available computational fluid dynamics (CFD) code. FLUENT is a general-purpose computer code for modeling fluid flow, heat transfer, and combustion for a user- specified geometry. FLUENT uses a control volume-based technique to solve the differential equations governing the reacting flow problem and uses the SIMPLE (Semi-Implicit Method for Pressure-Linked Equations) algorithm to solve for the pressure-velocity coupling.

Eulerian transport equations are solved for pressure, each of the components of velocity (U, V, and W), turbulence, enthalpy, radiation (radiation is governed by a Boltzmann transport equation – it does not have a diffusion term and the integral source term is unique), and gas species. The k-e turbulence model was used for all simulations performed in this study. Conservation equations were solved for both the product and reactant species (fuel, O_2, CO, CO_2, SO_2, and H_2O), while N_2 was calculated by difference. The discrete ordinates radiation model was used.

The Lagrangian discrete phase model was used to simulate combustion of the coal particles. Rosin-Rammler distributions (10 particle sizes) were injected into the model at various input locations from each of the 12 coal nozzles. The turbulent particle dispersion was modeled using the stochastic random walk model with 20 tries per particle, resulting in a total of 4800 total particle trajectory calculations for each discrete phase iteration. A 2-step devolatilization model was used along with the kinetics/diffusion limited model for char combustion.

A generalized finite rate formulation was used to model the complex gas phase chemical reactions. A 2-step reaction mechanism was used with the gaseous fuel reacting with O_2 in the first step to form CO, which was subsequently oxidized to CO_2. For each reaction, FLUENT calculates both the Arrhenius rate and the mixing rate from the eddy breakup model of Magnussen and Hjertager. The reaction rate is assumed to be the limiting (slowest) rate, which is then used to calculate the source terms for the species and enthalpy equations.

The BSF was simulated using a grid of approximately 245,000 cells to resolve the furnace (see Figures 5.4.1-1, 5.4.1-2) from the hopper through the simulated economizer. The windbox detail in Figure 5.4.1-1 shows the various fuel and air inlets as modeled with CFD. Note that each inlet was discretized into multiple cells to more accurately simulate the flow, although the detailed geometric features of the individual fuel and air nozzles were not modeled. The simulated convective pass and economizer tube banks were modeled as anisotropic porous media for the flow calculations. Inertial resistance factors (loss coefficients per unit length) were calculated for each of the superheater tube banks as a function of tube spacing. Heat was extracted in the simulated superheater tube banks by specifying a volumetric heat extraction rate such that the total heat extraction was equal to that predicted by heat exchanger correlations and the predicted outlet gas temperature agreed with experimental measurements.

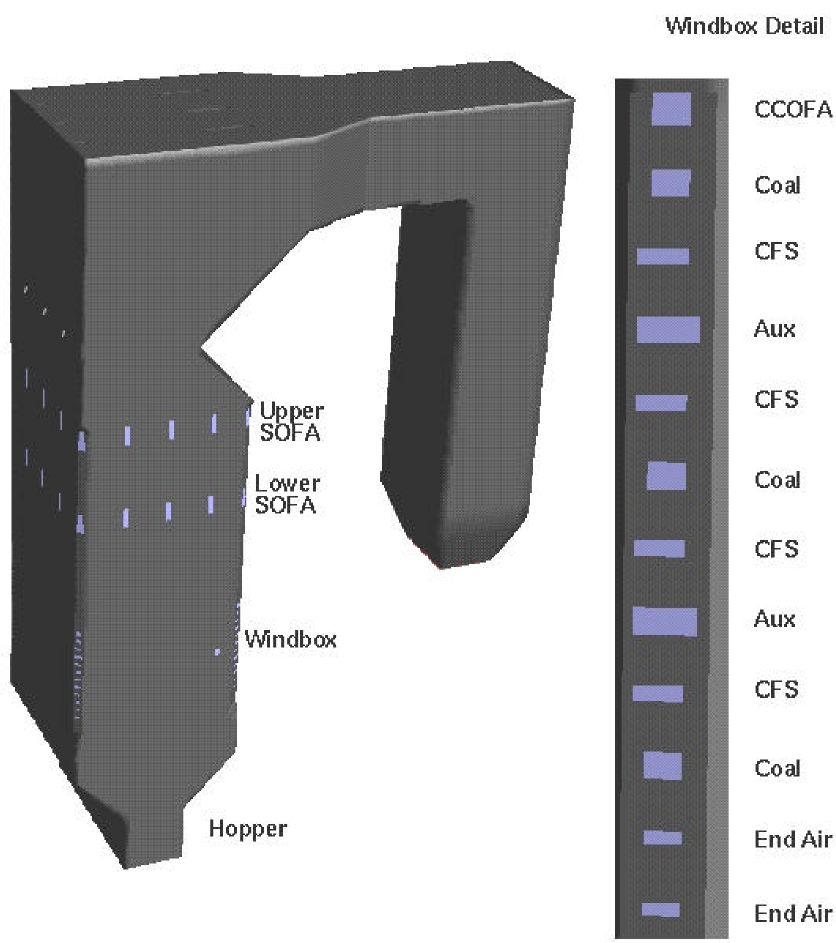

Figure 5.4.1-1: BSF Geometry as Modeled with CFD.

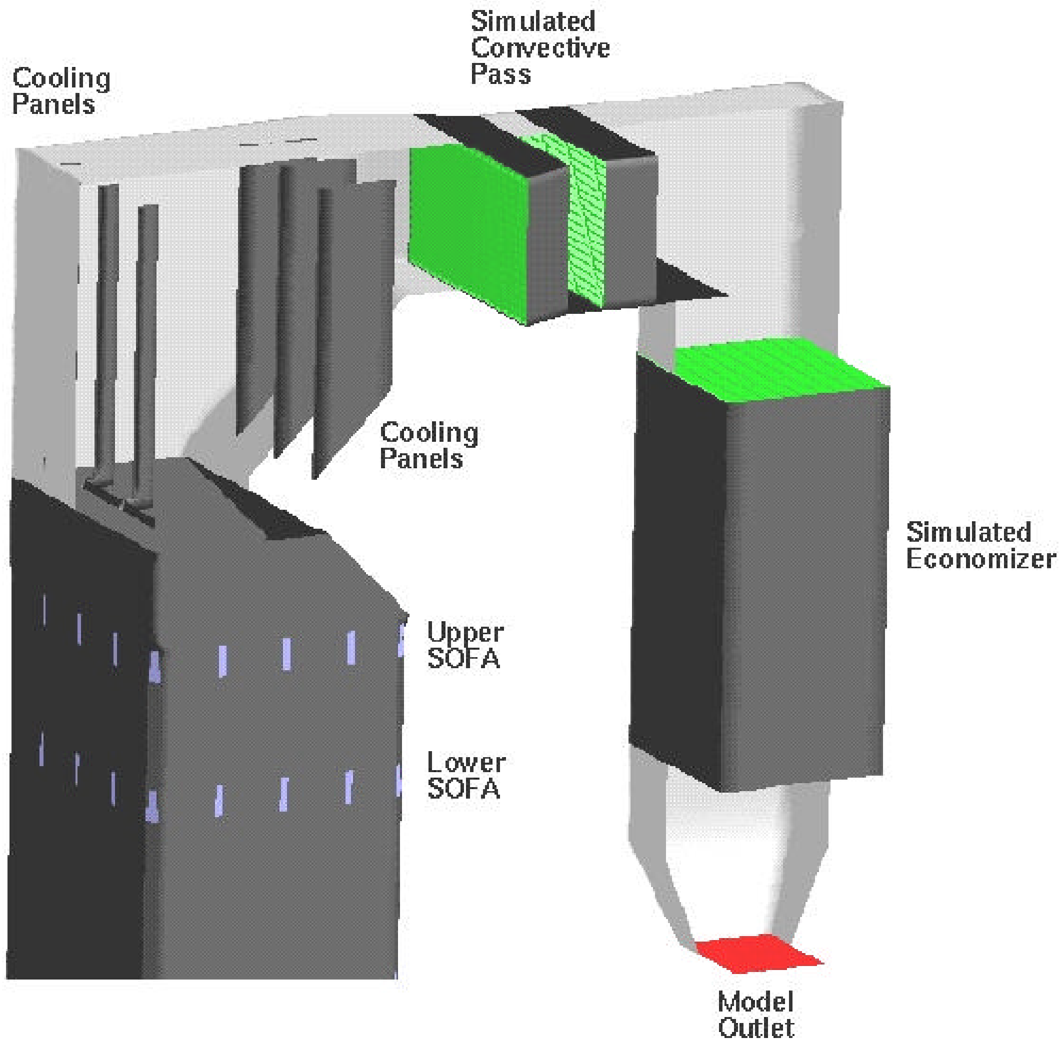

Figure 5.4.1-2: BSF Geometry as Modeled with CFD.

More detail of the overfire air inlets (as-modeled) is provided in Figure 5.4.1-3. Note that two elevations of OFA inlets were included in the grid in the corners (traditional T-fired arrangement) and at 3 locations across each of the furnace walls. Each SOFA assembly had 3 different nozzles that could be utilized. Not all of the OFA ports were utilized in each simulation as the inlets could be turned on or off for the various simulations. This grid configuration provided significant flexibility in evaluating the impact of OFA location and velocity on furnace mixing.

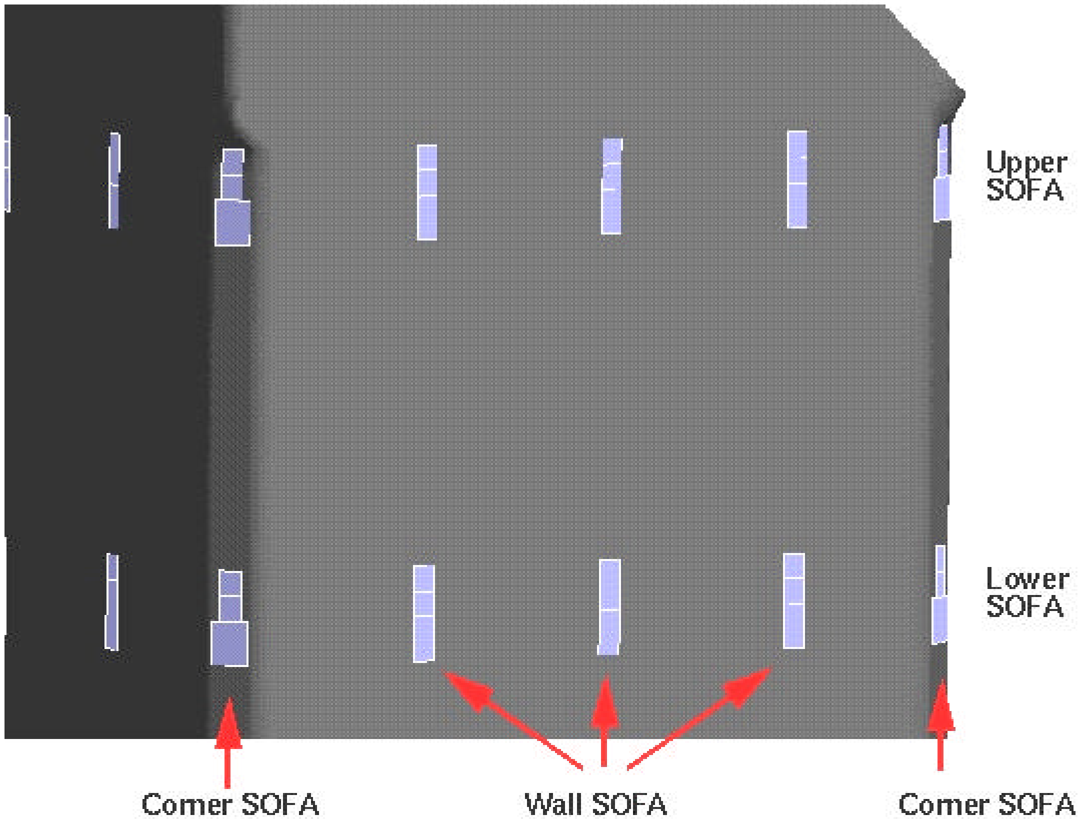

Figure 5.4.1-3: BSF Geometry – Closeup of Overfire Air Inlets.

The furnace walls were modeled with a thermal resistance boundary condition. An average waterwall fluid temperature (212 °F) was specified, as were the wall emissivity and thermal resistance. The thermal resistance was set to account for the resistance of the steel walls, the furnace refractory, and any slag that may be present on the walls. The value of the waterwall thermal resistance was adjusted to match the furnace outlet temperature predicted by the CFD model to the furnace outlet temperature as measured in previous BSF test campaigns. The thermal resistance was then fixed at that value for all subsequent simulations.

5.4.2 Parametric Evaluation of SOFA Mixing

In accordance with the cases identified in the five (5) groups above, approximately 25 parametric, computational fluid dynamic (CFD) runs were completed to examine the impact of velocity and location on the degree of separated overfire air (SOFA) mixing. Note that SOFA yaw angles were fixed at the normal firing angle and were not varied in this study.

For this work, the SOFA mixing at a given plane is defined as:

$$Mixedness = \sum_{n=1}^{n_{tot}} M_n \frac{(x_n - x_{final})}{x_{final}} \qquad \textbf{(5.4.2-1)}$$

where n is the local grid cell, n_{tot} is the total number of cells on a given horizontal plane, M_n is the normalized mass flux through cell n, X_n is the oxygen mole fraction in cell n, and x_{final} is the average oxygen mole fraction at the furnace outlet, which was 0.027 (2.7% O_2 by volume) on a wet basis for these simulations.

Group 1 Results

As previously noted, Group 1 cases represented two elevations of tangentially injected overfire air wherein the velocities in both elevations were varied in unison. Figure 5.4.2-1 shows the predicted improvement in SOFA mixing at the horizontal furnace outlet plane (boiler nose) of the BSF for four different SOFA injection velocities (increasing velocity from Mod 1 – Mod 4). As expected, the degree of SOFA mixing increases with velocity (decreasing nozzle free area), suggesting a significant improvement in mixing can be achieved through the use of higher OFA velocities for current tangentially-injected designs. It should be noted that the mass flow rate and temperature of the overfire air were held constant for each of these cases as was the main (firing zone) windbox configuration.

Figure 5.4.2-2 shows essentially the same information as the previous figure, but shows increases in mixedness as a percentage increase over the base tangentially injected configuration. Increasing velocities by 25% yields increases in mixedness of 20%, while velocity increases by a factor of 5 yields increases in mixedness of nearly 60%. For commercial application, judgments must be made between benefits gained through increased mixing versus the increases in fan power required to obtain the higher nozzle velocities.

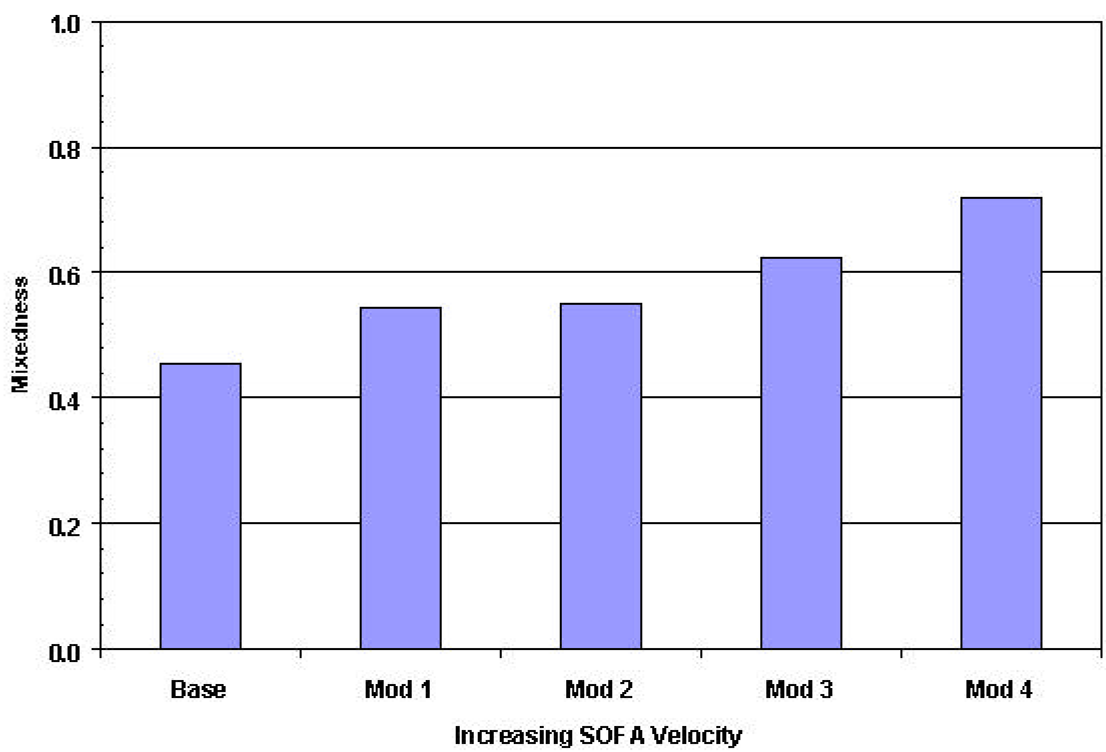

Figure 5.4.2-1: Mixedness vs. Increasing SOFA Nozzle Velocity.

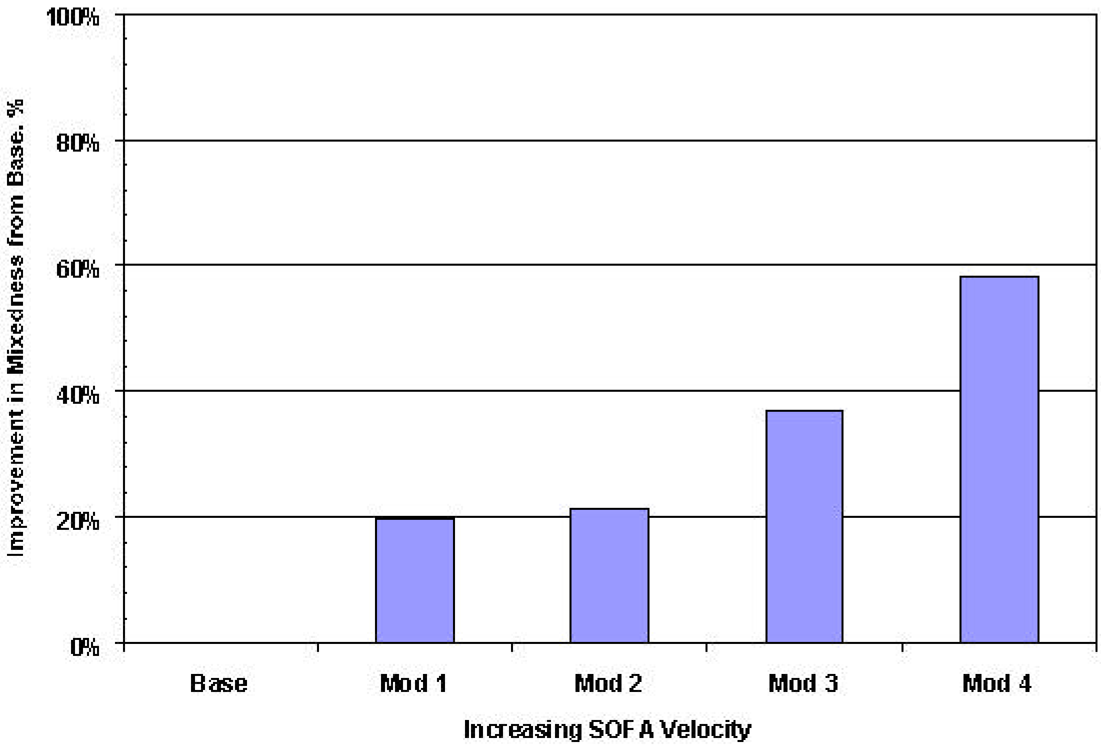

Figure 5.4.2-2: Relative Mixedness vs. Base T-Injected Nozzle Velocity.

In addition to evaluating mixedness, certain other parameters were also evaluated during the modeling study, specifically changes in carbon in ash (CIA) and CO levels. Figure 5.4.2-3 shows changes in carbon in ash and CO levels along with the changes in mixedness associated with Mod 1 through Mod 4.

It is interesting to note that the mixedness increased with velocity over the range of velocities studied, but increased mixedness did not necessarily result in improved carbon in the fly ash and CO emissions. Figure 5.4.2-4 compares the predicted oxygen distributions for the Base case and Mod 4 (highest OFA velocity). At the upper SOFA plane, the increased OFA velocity results in lower peak oxygen concentrations and better jet penetration to the center of the furnace. This results in a more uniform oxygen distribution at the horizontal furnace outlet plane (HFOP) as shown in the figure. However, there are still pockets of low oxygen concentration near the furnace walls and in the corners where the temperatures are cooler and mixing is poor. Particles that remain in these pockets of low oxygen can contribute to higher than expected levels of carbon in the fly ash and CO. Note that all of the CFD cases were run with the same, zero degree SOFA nozzle yaw, and that yaw adjustment could be potentially used to improve the overall degree of SOFA mixedness as well as the carbon in ash and CO emissions.

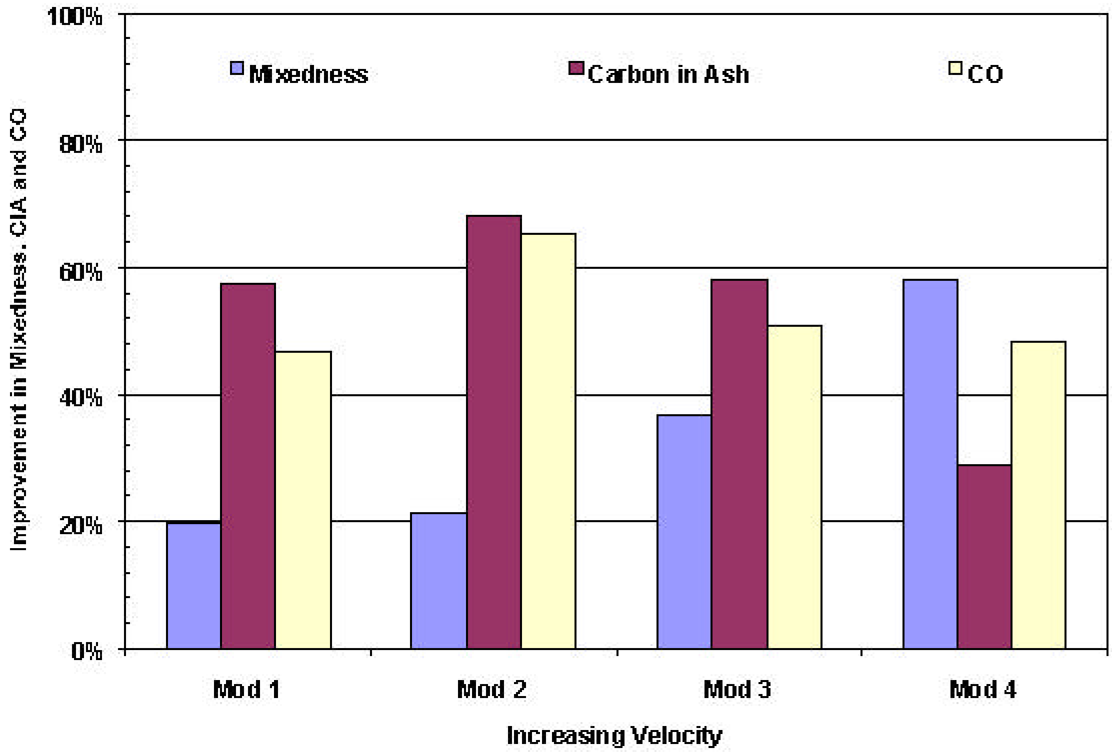

Figure 5.4.2-3: Impact of OFA Velocity on Mixedness, CIA and CO.

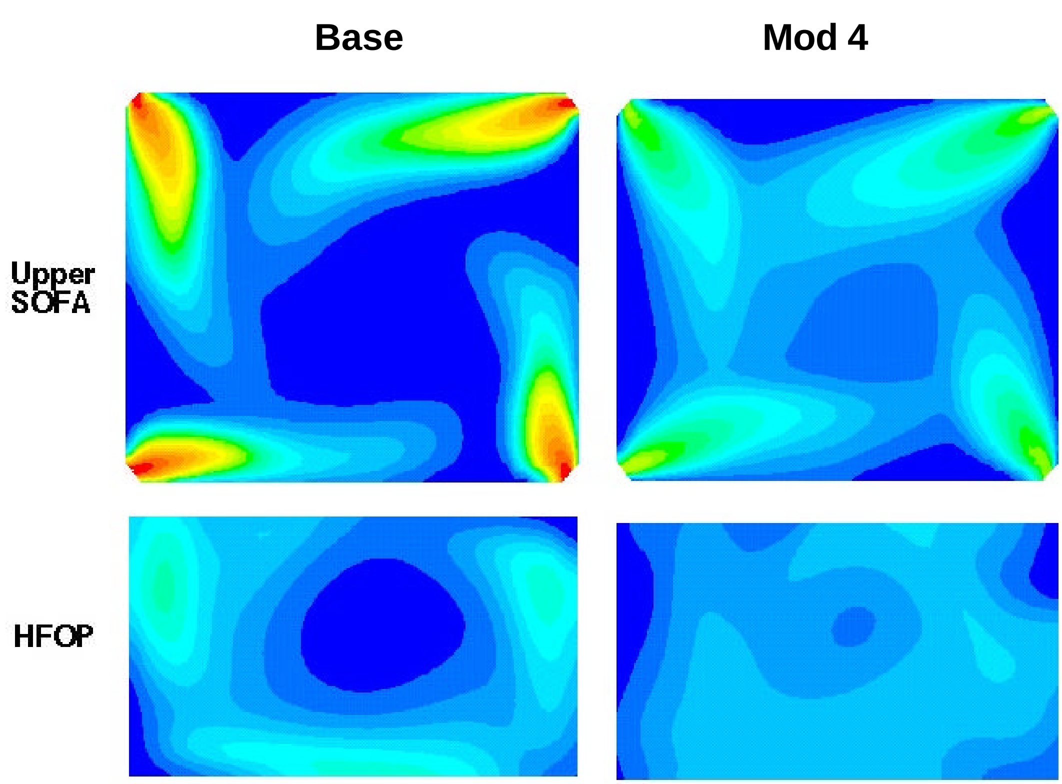

Figure 5.4.2-4: Predicted O_2 Distribution vs. SOFA Velocity.

Group 2 Results

Group 2 cases represent configurations whereby the lower SOFA velocity was kept constant (base case velocity), but the velocity in the upper SOFA nozzle was increased in cases denoted as Mod 1a through Mod 4a. The exact velocities evaluated in the upper SOFA ports were in direct correspondence with those in Group 1 cases.

The predicted mixedness, carbon in ash, and CO emissions for Group 2 cases are shown in Figure 5.4.2-5. In contrast to the Group 1 results, the model predicts improved carbon in ash and CO emissions with increasing mixedness for Group 2. The lower velocity air jets at the lower SOFA elevation tend to stay closer to the walls, while the high velocity upper SOFA jets tend to penetrate more to the center of the furnace. This combination of low and high velocity SOFA jets help prevent the channeling that occurred for the Group 1 cases when the velocities of both SOFA elevations were increased.

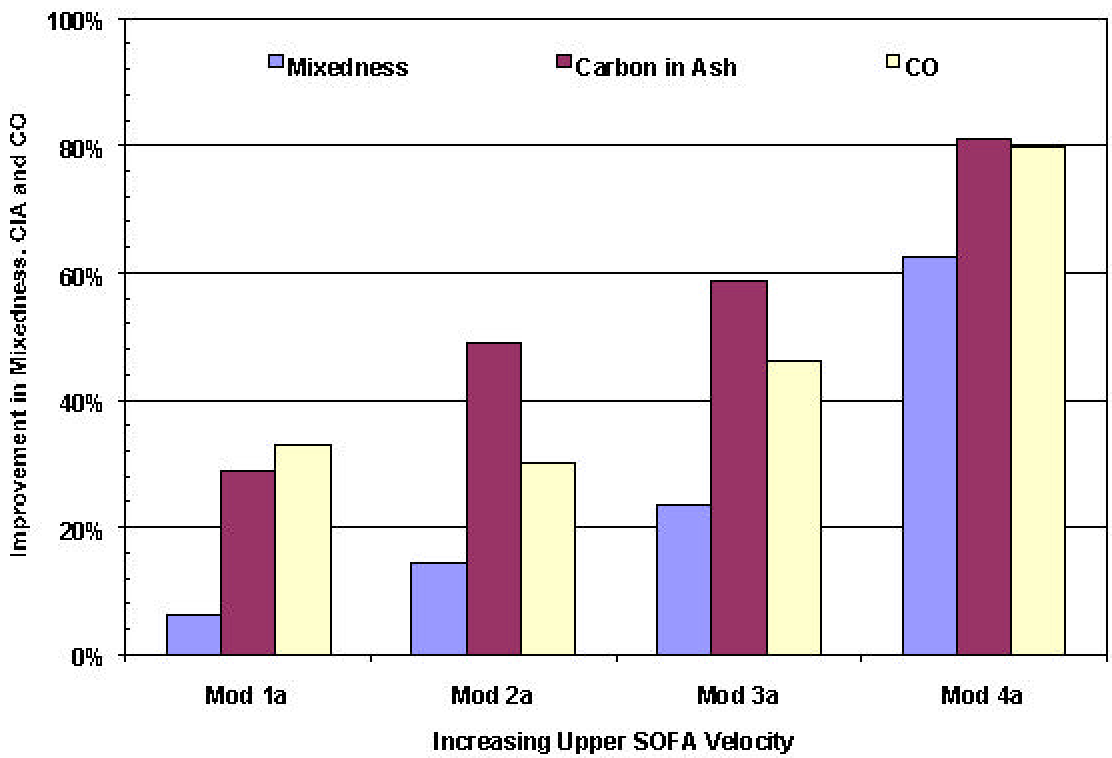

Figure 5.4.2-5: Impact of USOFA Velocity on Mixedness, CIA and CO - Lower SOFA Velocity Held Constant.

Group 3 Results

Group 3 cases represent configurations that have tangential injection of the overfire air, but from only <u>one</u> SOFA elevation. Specifically, three cases were evaluated wherein velocity was varied for the upper SOFAs and three cases were evaluated wherein velocities were varied for the lower SOFAs. Upper SOFA cases were represented as Mod 1b, Mod 3b and Mod 5b. Lower SOFA cases utilized the same velocities as the upper SOFA cases and are represented as Mod 2b, Mod 4b and Mod 6b.

The predicted mixedness, carbon in ash, and CO emissions for the upper SOFA cases are shown in Figure 5.4.2-6. Note that the baseline system (2 SOFA elevations) to which the change in mixing, carbon in ash, and CO emissions is compared, is the same for all groups. With a single upper elevation of overfire air, the predicted mixing, carbon in ash, and CO emissions are significantly worse than the baseline system. The low velocity air jets do not penetrate to the center of the furnace leaving a fuel rich core of high levels of CO and carbon in the fly ash. The simulated superheater panels/convective sections then cool the flue gas and slow the oxidation reactions before mixing with oxygen can be completed.

As the velocity is increased, overfire air penetrates to the center of the furnace and the predicted mixing and CO emissions improve to within 10% of the baseline values. However, as the oxidizing residence time decreases with a single upper SOFA elevation, the predictions show increased levels of carbon in the fly ash.

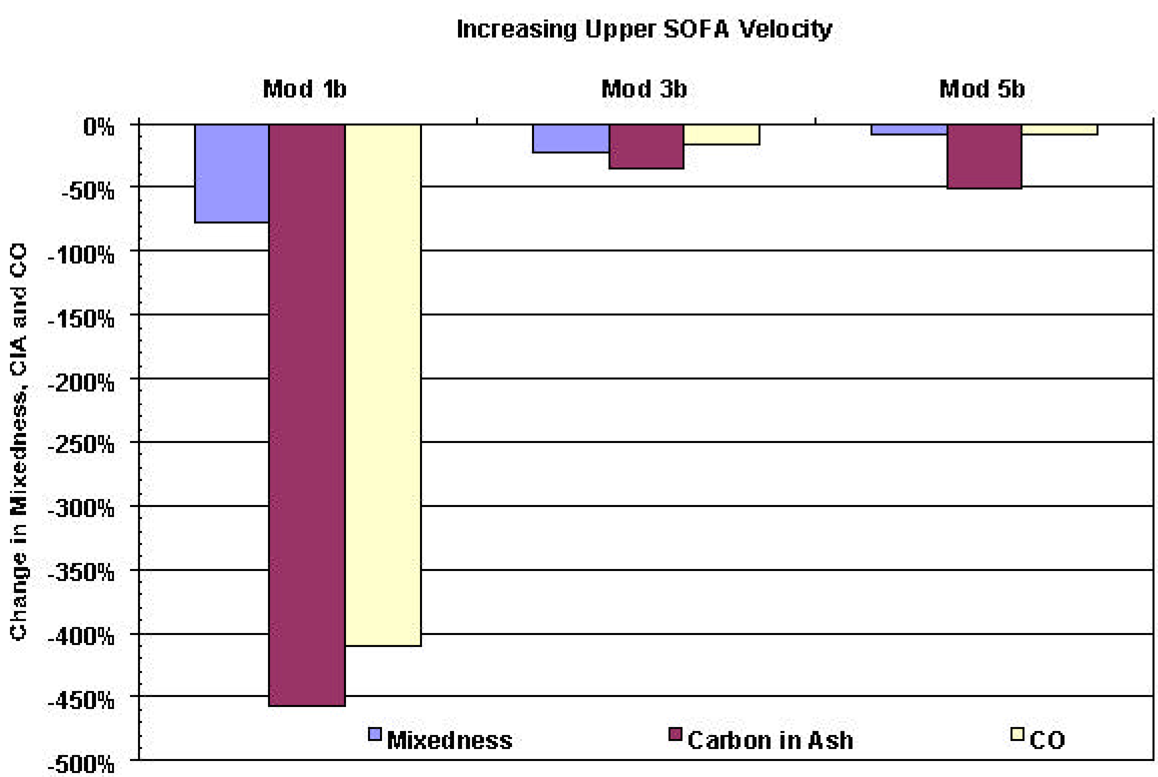

Figure 5.4.2-6: Impact of Single USOFA Velocity on Mixedness, CIA and CO.

The predictions for a single lower elevation of overfire air are shown in Figure 5.4.2-7. The low velocity case (Mod 2b) shows slightly worse mixing and CO/carbon in ash levels than the 2 SOFA elevation base case, due largely to the reduced number of injection locations.

However, with a single lower SOFA elevation, the mixing and emissions are predicted to improve as the velocity is increased (Mod 4b). As the velocity is increased further (Mod 6b), the predicted mixing and emissions do not continue to improve. At high velocities, the model shows fuel rich pockets that form near the walls and in the corners of the furnace that persist up through the HFOP. Although not modeled as part of this study, improved mixing and emissions performance may be achievable by varying the overfire air yaw.

For the single lower SOFA cases, the oxidizing residence time (residence time from the SOFA to the HFOP) is higher due and there is sufficient time for the overfire air to mix in reasonably well. Note that the increased oxidizing residence time comes at the expense of the substoichiometric or staged residence time as the total residence time in the furnace is constant. The reduced staged residence time will result in higher NOx emissions. Thus, the 2 SOFA elevation TFS 2000™ system is a good compromise that achieves low NOx emissions without sacrificing the carbon in ash and CO emissions.

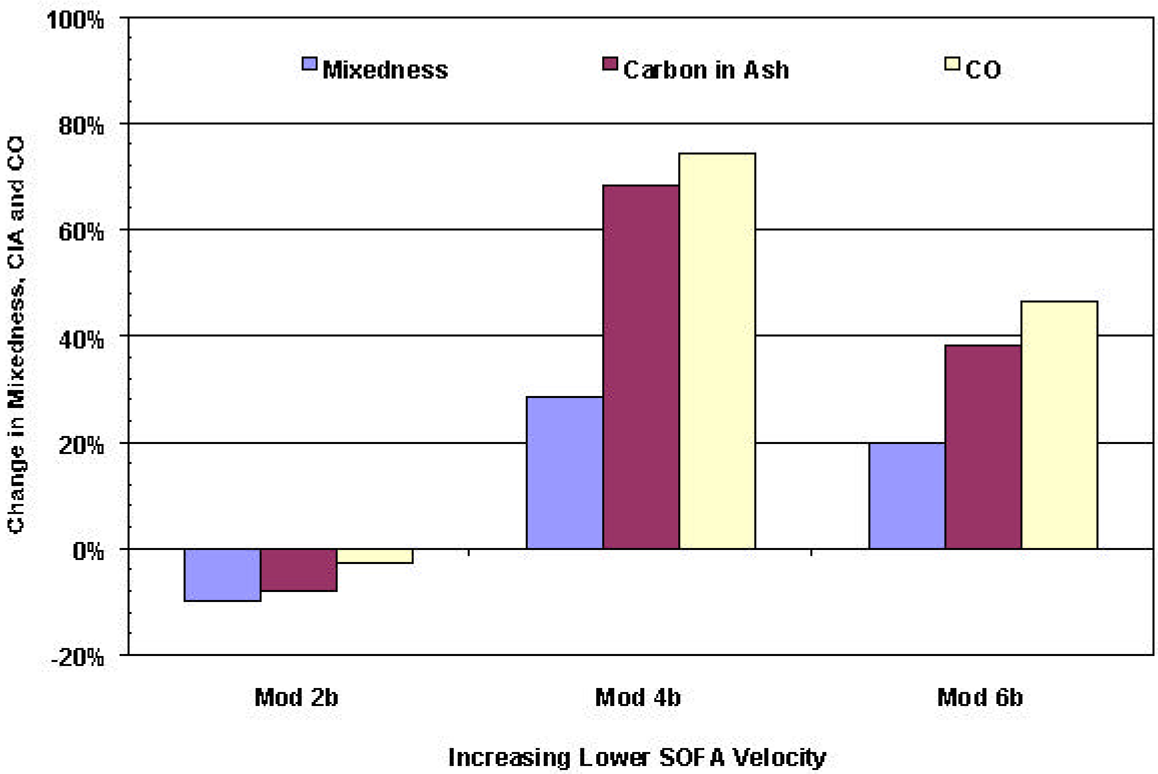

Figure 5.4.2-7: Impact of Single LSOFA Velocity on Mixedness, CIA and CO.

Group 4 Results

In addition to the tangentially-injected studies mentioned above, a series of cases were run where overfire air was injected from various locations on the furnace walls to examine the overall impact on bulk furnace mixing. The computational grid used for this study was designed with three (3), equidistant, SOFA nozzle locations on each wall as shown in Figure 5.4.2-8. The left, mid, and right designations refer to the SOFA nozzle location when viewing the inlets from outside of the boiler on a given wall. Each of the wall-injected air cases was run using one or more of the SOFA nozzles on each wall to maintain total free areas, and thus velocity, consistent with that of the tangentially-injected overfire studies.

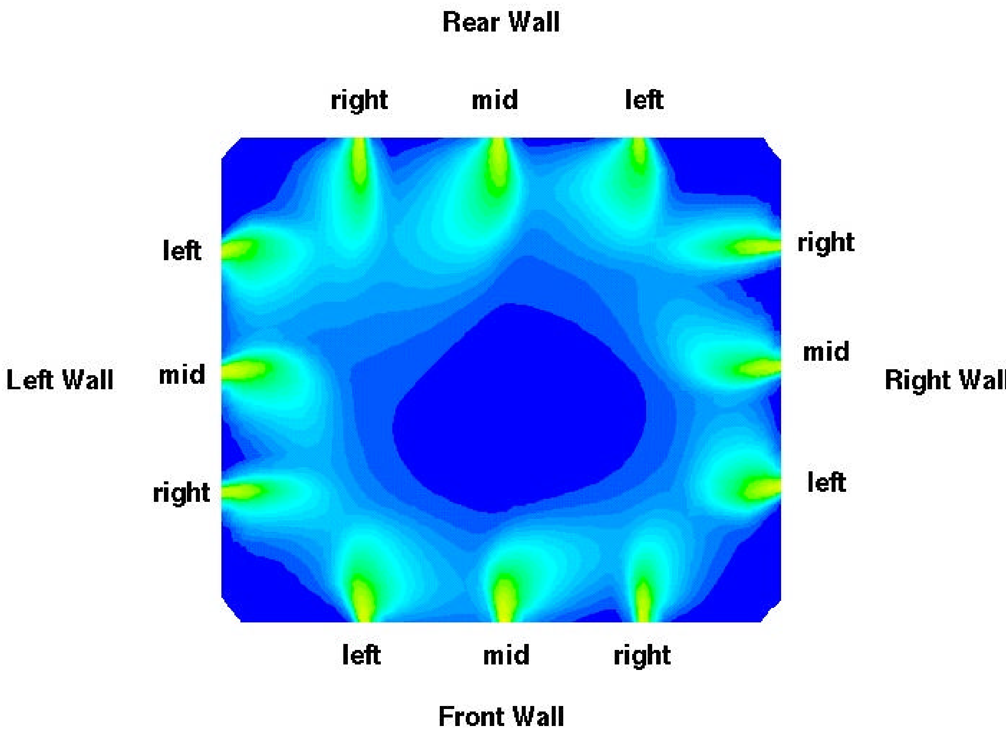

Figure 5.4.2-8: SOFA Nozzle Locations for Wall-Injected Overfire Air Study.

Figure 5.4.2-9 shows the predicted SOFA mixing relative to a standard tangentially-injected air design for several cases with SOFA nozzles at different locations on the boiler walls ("Wall Injected Overfire Air"). Configurations examined included: (1) maintaining the same number of furnace penetrations as tangentially-injected OFA by injecting all of the air through the left, middle, or right ports, (2) doubling the number of penetrations by using the middle and right ports, or (3) tripling the number of penetrations by using all available inlets. Note that in all cases both the upper and lower SOFA configurations were identical.

In all but one of the test cases (Configuration 6), the mixing for the wall injected SOFA configurations was worse than that of a tangentially-injected case with an equivalent total free area of the injector nozzles. Since Configuration 6 utilized all of the available inlet location, the slight predicted improvement in SOFA mixing likely does not justify the cost of adding the additional furnace penetrations.

In tangentially-injected SOFA configurations, air is introduced through the corners, which results in high oxygen concentrations near the walls. With sufficient residence time above the SOFA nozzles, the oxygen will mix into the center of the furnace. However, in general, the predicted oxygen concentration is higher near the walls and lower in the center of the furnace. In contrast, air jets from the wall-injected SOFA configurations penetrated further to the center of the furnace, but often resulted in pockets of high CO in the corners and near the furnace walls.

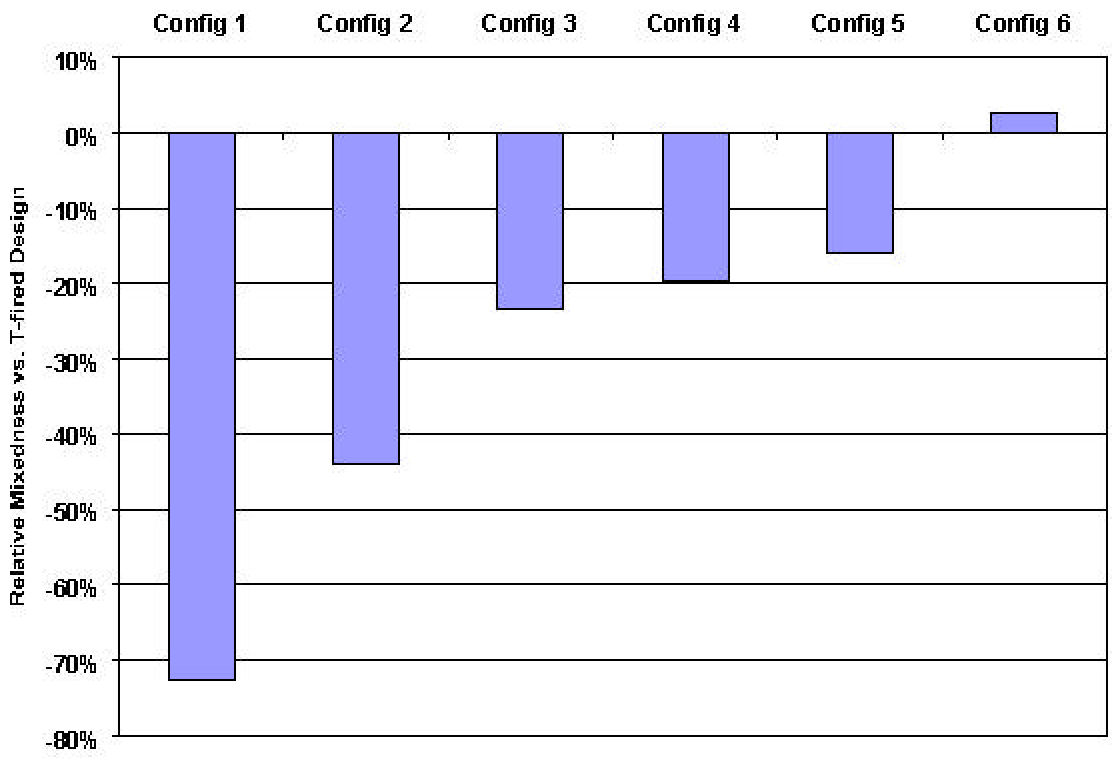

Figure 5.4.2-9: Predicted SOFA Mixing for Various Wall-Injected Configurations (2 Elevations of SOFA).

Group 5 Results

To address the pockets of high CO that occurred with the wall-injected overfire air cases (Group 4), a series of cases were run with combined wall- and T-injected overfire air. Group 5 cases have overfire air injected from the walls for the upper elevation and T-injected overfire air for the lower elevation. Having T-injected overfire air at the bottom elevation was examined as a means to prevent channeling in the furnace that would result in fuel-rich pockets forming in the corners.

Figure 5.4.2-10 presents the predictions for various combinations of T- and wall-injected overfire air. The best results (Configuration 6a) were obtained when the wall-injected overfire air (upper elevation) was introduced through the middle and right ports, resulting in a 28% improvement over the base T-injected arrangement. Although not shown, the improved mixing for Configuration 6a resulted in a less than 5% improvement in the predicted CO and carbon in ash levels. These modest improvements in performance do not provide strong evidence for adding the additional wall-injector ports.

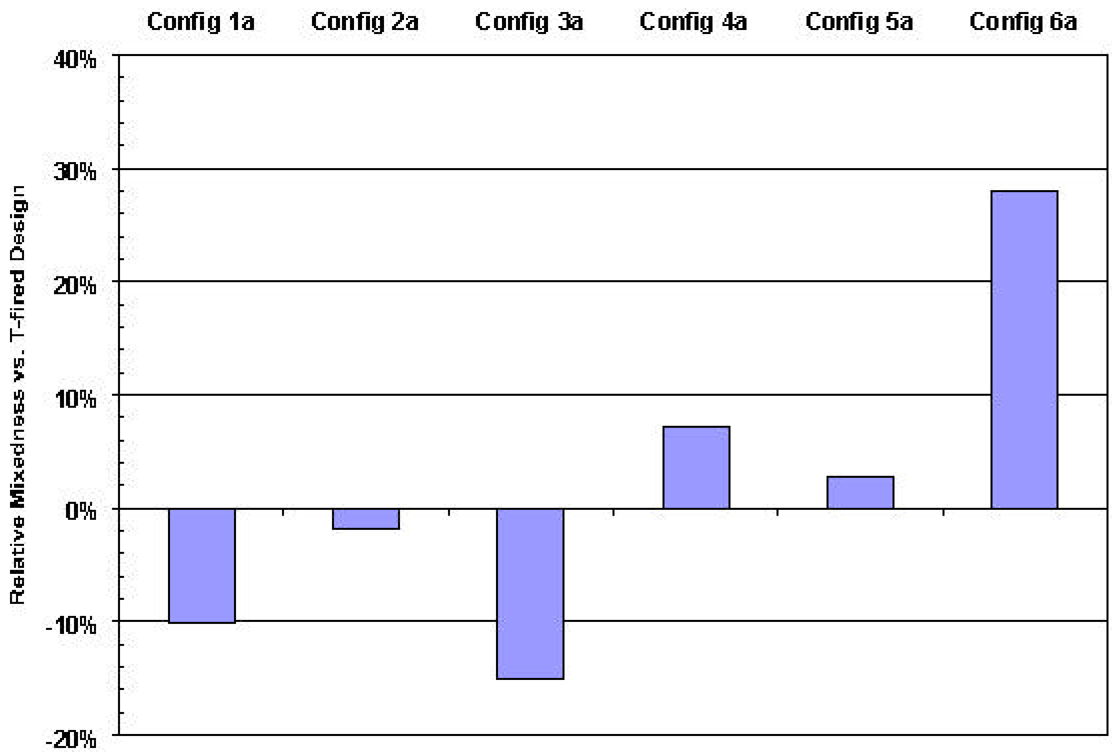

Figure 5.4.2-10: Predicted SOFA Mixing in the BSF for Various Configurations with Wall-Injected for Upper SOFA Elevation and T-Injected for the Lower SOFA Elevation.

Summary

Approximately 25 CFD simulations of the BSF were performed to evaluate various overfire air injection scenarios. For a TFS 2000™ firing system with two elevations of overfire air injected from the corners in a T-injected arrangement, increasing the overfire air velocity improved the oxygen mixing at the horizontal furnace outlet plane. However, at the highest velocities, overfire air penetrates to the center of the furnace leaving more fuel rich pockets near the furnace walls. Injecting the lower SOFA elevation at the baseline "low" velocity improves the predicted furnace performance since the lower SOFA jets do not have as much momentum and tend to increase the oxygen concentration near the furnace walls.

Given a choice between higher oxygen concentrations near the furnace walls with correspondingly lower oxygen concentrations near the center of the furnace, versus the reverse condition, the advantage would go to the former condition. The rationale for this choice is that oxygen deficiencies near the wall combine two potentially adverse conditions as far as carbon and CO burnout are concerned. First the oxygen deficiency would aggravate burnout, and secondly the lower temperatures near the walls would further adversely affect burnout. Conversely, there is a greater opportunity, with time, to rectify oxygen deficiencies in the center of the furnace. Additionally, gas temperatures will remain higher in the center of the furnace so that when oxygen does become available, combustibles will still be at a sufficiently high temperature to burn. A third advantage can be cited for coals having high iron contents in their ash, namely avoiding lower melting temperatures due to reducing conditions. Having higher oxygen concentrations near the wall will work toward maintaining higher melting temperatures by avoiding the reduced forms of iron.

For cases with a single elevation of overfire air, the results were mixed. For cases with a single lower elevation of overfire air, mixedness, CO and carbon in the fly ash were similar to the 2-elevation TFS 2000™ system. Cases with a single upper elevation of overfire air performed significantly worse than the base 2-elevation TFS 2000™ system for mixedness, CO and carbon in the fly ash. However, with increased upper SOFA velocity, the predicted performance approaches that of the TFS 2000™ firing system.

The mixedness and predicted performance of the wall-injected overfire air cases were generally not as good as the T-injected systems. Increasing the number of furnace penetrations will increase the predicted performance, but the best case with 3 penetrations on each furnace wall was only marginally better than the baseline T-injected system.

Hybrid systems, where the lower SOFA elevation was T-injected and the upper SOFA elevation was injected from the wall, showed performance similar to the TFS 2000™ system. The hybrid configurations help prevent fuel-rich pockets that formed in the corners for the wall-injected SOFA configurations. They may also be useful for boilers with mechanical or pressure part interferences, which may prevent T-injected overfire air at both elevations.

5.4.3 CFD Simulation of BSF Test Conditions

A series of CFD simulations were run of experimental conditions that were tested in the BSF with the PRB coal. The aim of this task was to benchmark the CFD model against actual data to verify that CFD was predicting the appropriate trends. This section briefly describes the cases that were run and compares some of the predictions to available experimental trends.

The CFD modeling approach for this task was the same as described previously in Section 5.4.1. However, as there were significant differences between the original BSF model and the actual as-tested BSF configuration (e.g., the windbox design and the elevation of the lower overfire air assembly) it was necessary to generate a new CFD grid. As only a small number of cases were modeled in this task, a larger grid of approximately 490,000 cells was generated. The grid was refined near the nozzle inlets in an attempt to increase the quantitative accuracy of the jet penetration and mixing. A portion of the new grid is illustrated in Figure 5.4.3-1. The figure illustrates the as modeled arrangement of the 3 nozzles of the lower SOFA assembly.

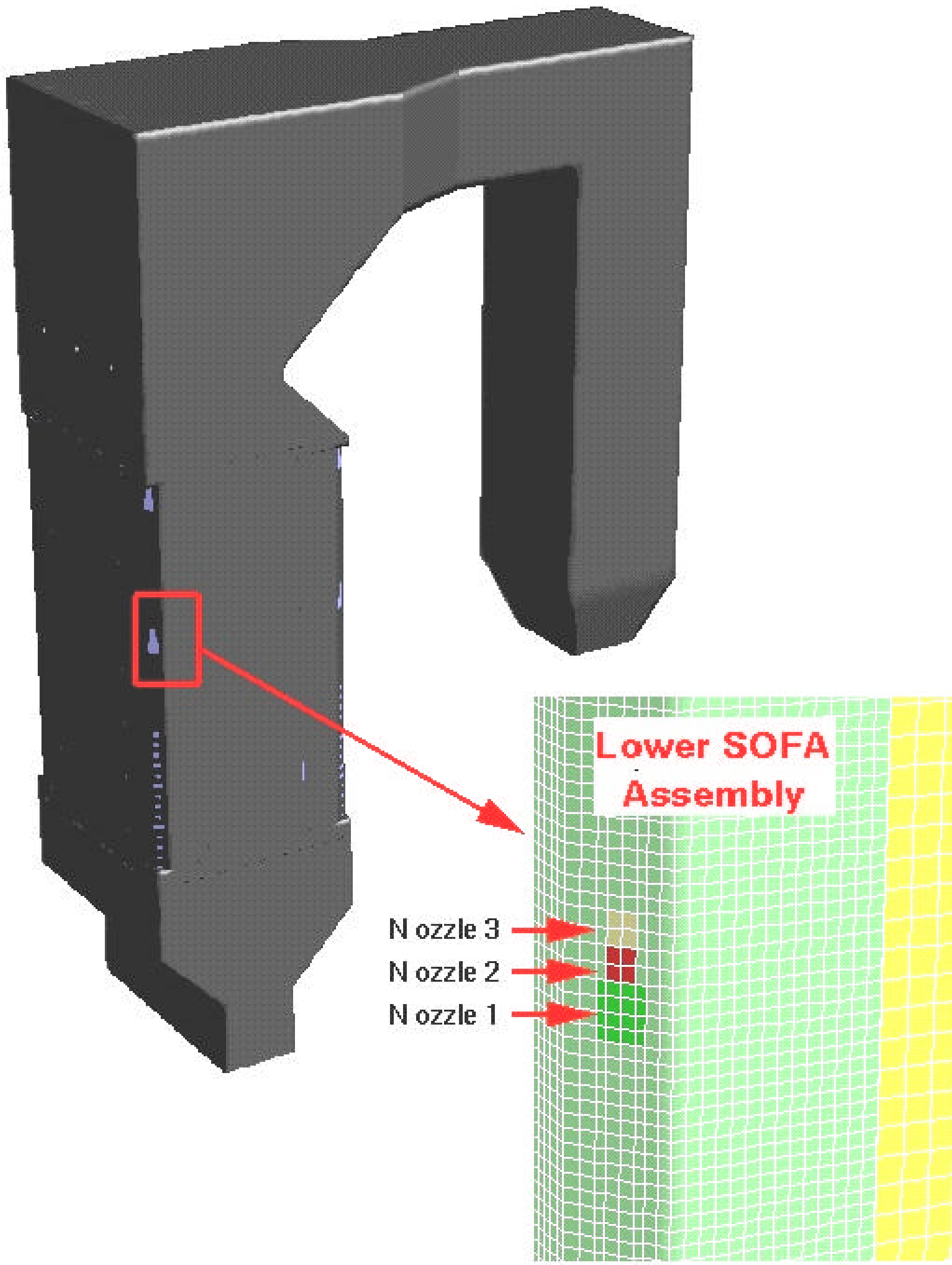

Figure 5.4.3-1: CFD Grid Used to Simulate BSF Test Conditions.

Figures 5.4.3-2 – 5.4.3-4 show contours of the predicted gas temperature, oxygen, and CO distributions for a TFS-2000™ test configuration. The outlet oxygen concentration was nominally 3 % on a dry basis. The peak gas temperature predicted by CFD was approximately 3000 °F, while the maximum CO level in the lower furnace approached 8% by volume.

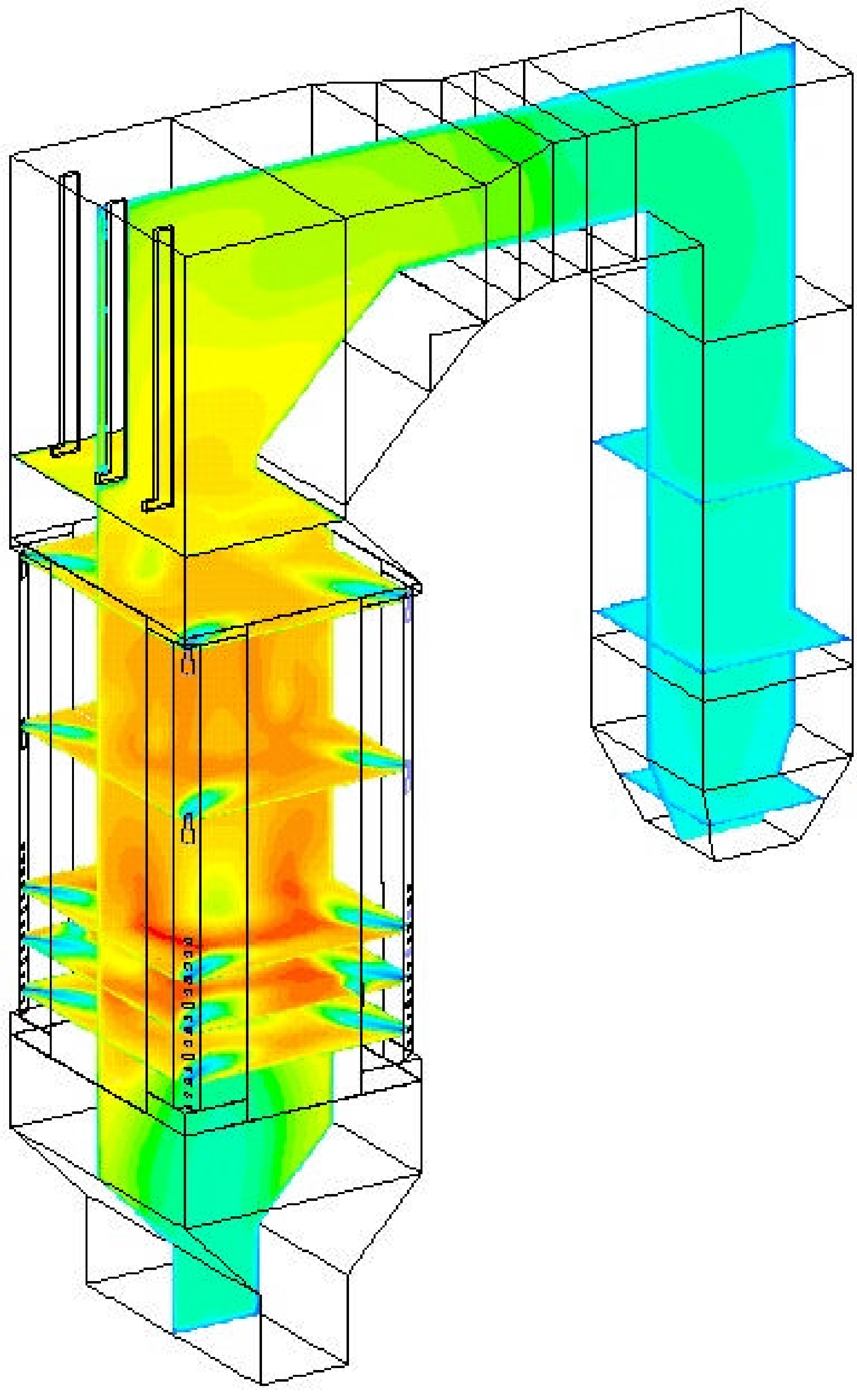

Figure 5.4.3-2: CFD Predictions of Gas Temperature – TFS 2000Ô.

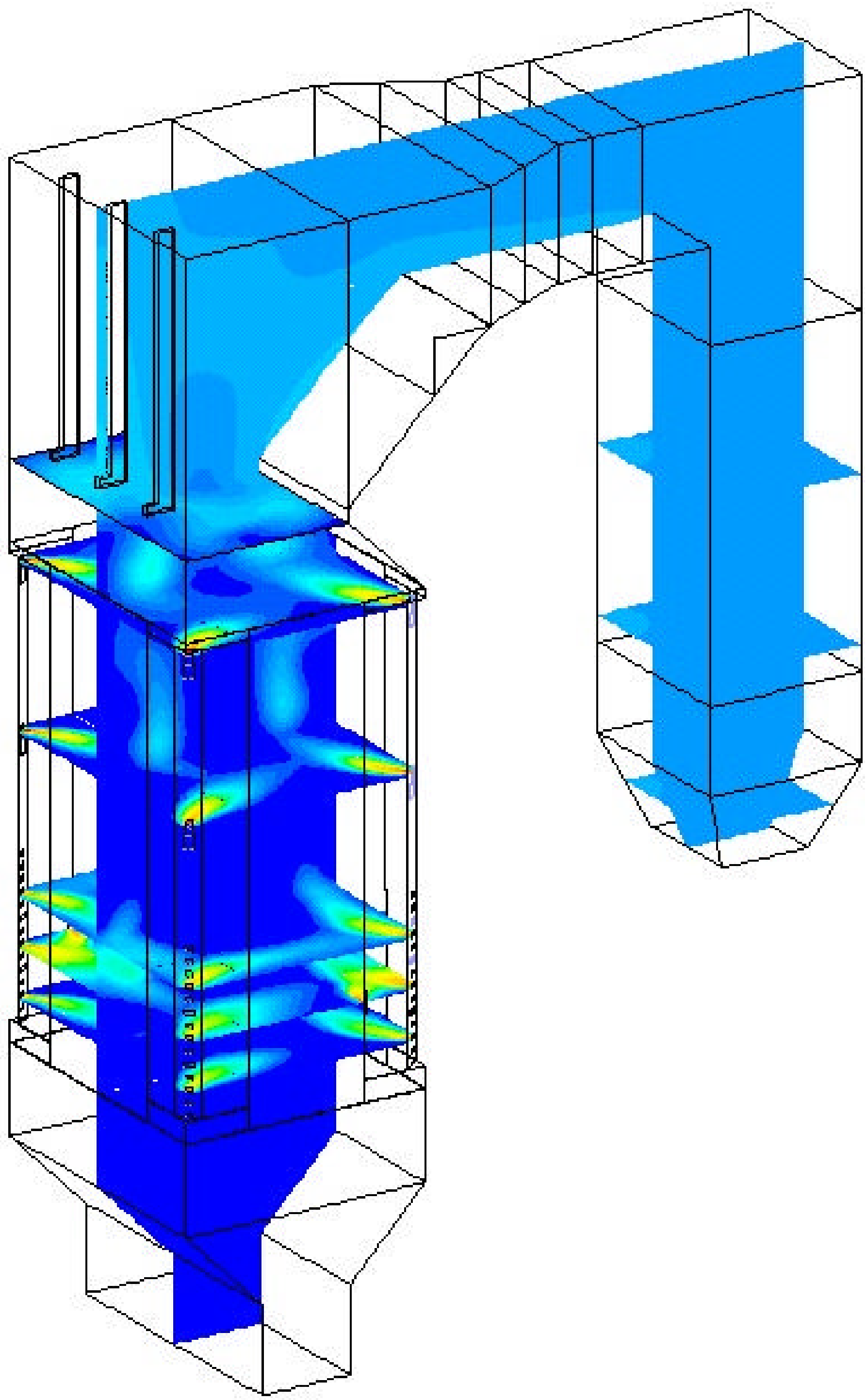

Figure 5.4.3-3: CFD Predictions of Oxygen Mole Fraction – TFS 2000Ô

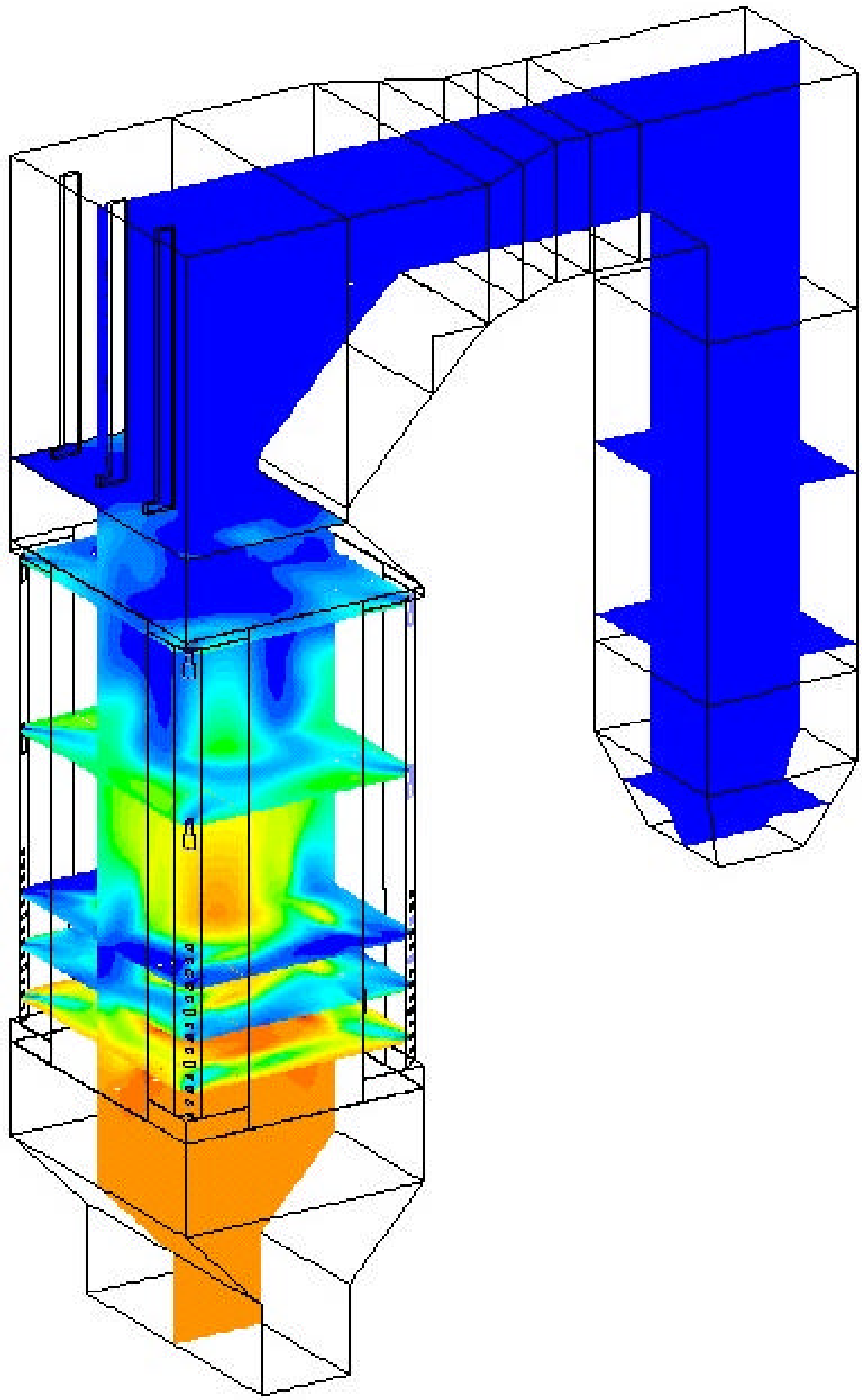

Figure 5.4.3-4: CFD Predictions of CO Mole Fraction – TFS 2000Ô .

A series of BSF test conditions looking at the impact of main burner zone stoichiometry (MBZ) with the PRB coal was simulated with the CFD model. A "Baseline" condition with a small quantity of close coupled overfire air and no separated overfire air (MBZ = 1.08) was run first. The thermal resistance of the wall was adjusted in order to approximately match the predicted furnace outlet temperature (FOT) to the measured value. The fraction of nitrogen in the char was also varied in the model in order to obtain reasonable agreement between the measurements and predictions of NOx. All of the model parameters and wall boundary conditions were then held constant for all of the remaining runs where the MBZ stoichiometry was varied.

Figure 5.4.3-5 compares predicted and measured gas temperatures at the horizontal furnace outlet plane (boiler arch) and at the model outlet (after the economizer). The predictions are generally in good agreement with the measurements, although the model overpredicts the increase in the furnace outlet temperature at low stoichiometries. This discrepancy between modeling and experimental results at low main burner zone stoichiometries is due, in part, to the fact that the impact of soot on the local absorption coefficient was not accounted for in the radiation model. Increased soot levels at low stoichiometries cause the local absorption coefficients to increase, augmenting the waterwall heat absorption and lowering the furnace outlet temperature.

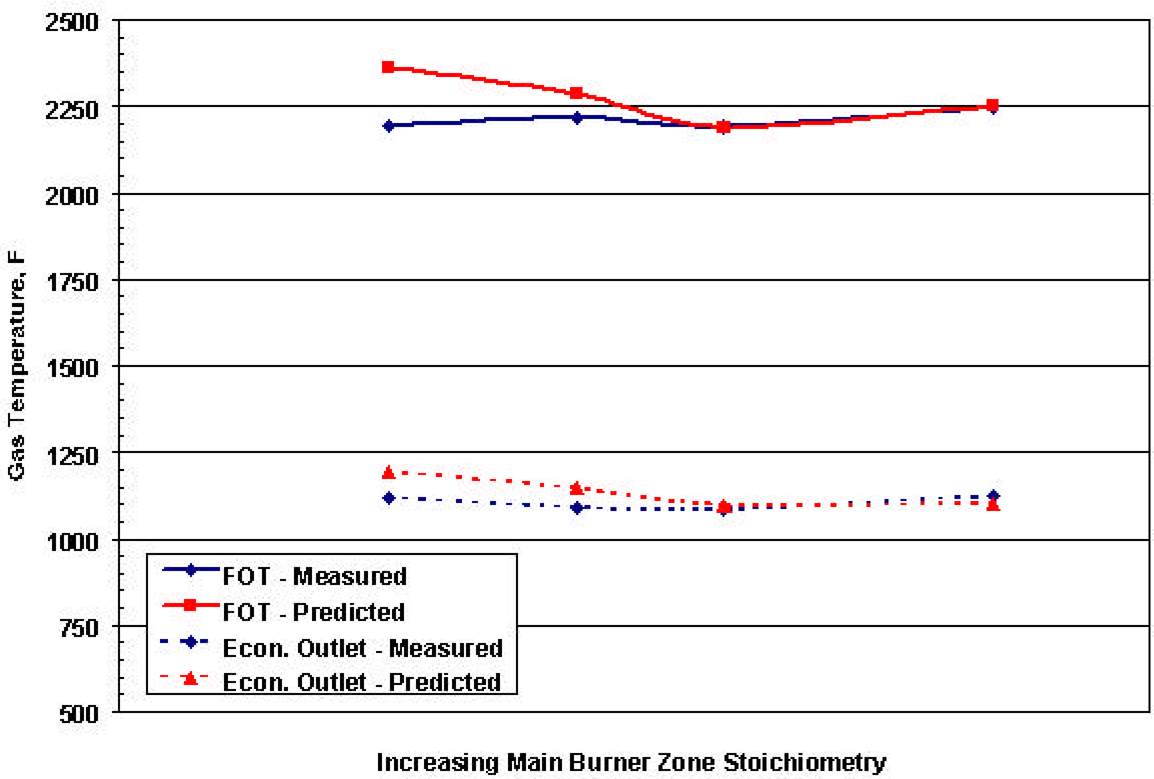

Figure 5.4.3-5: Predicted and Measured Gas Temperatures vs. Main Burner Zone Stoichiometry.

The predicted CO emissions are compared to measurements in Figure 5.4.3-6. The CO results are presented as normalized values to simplify the plotting as the predicted values tended to be higher (max of approximately 85 ppm) as compared to CO measurements of less than 5 ppm. The difference between the model predictions of CO and the measurements is largely due to the fact that the CFD model outlet did not correspond to the location where the experimental gas measurements were made. There is an outlet duct of significant length after the economizer that adds over 1 second of additional residence time to the gas before the sampling point. As the gas temperatures are on the order of 1100 °F coming out of the economizer, additional oxidation of the CO can occur. The additional outlet duct was not modeled in order to reduce the size of the grid. In the future, the gas sampling location in the BSF should be moved closer to the economizer outlet for more representative CO measurements.

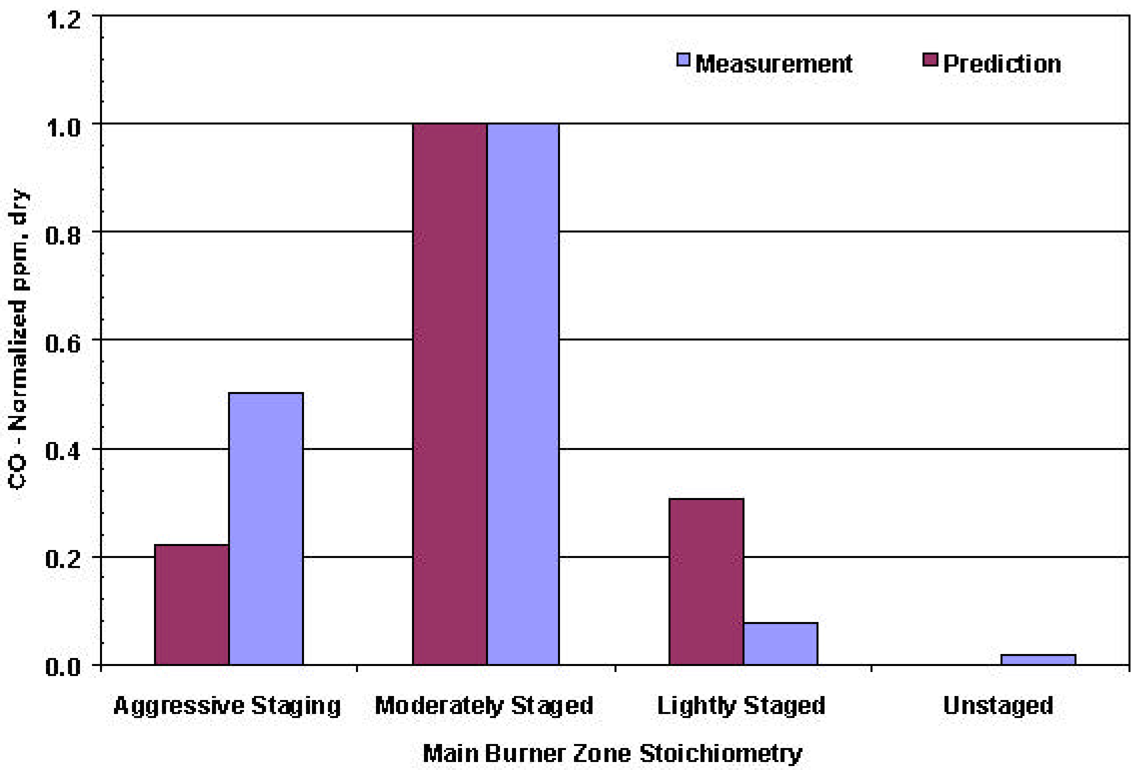

Figure 5.4.3-6: Predicted and Measured CO Emissions (normalized) vs. Main Burner Zone Stoichiometry.

Figure 5.4.3-7 compares the predicted and measured NOx emissions as a function of main burner zone stoichiometry. Note that the model predicts the general trend of decreasing NOx emissions with increasing levels of overfire air, but does not quantitatively predict the impact of overfire air on NOx emissions due to the simplicity of the NOx model. Only thermal and fuel NOx were calculated, with corrections for local fluctuations in temperature due to turbulence. No NOx reduction mechanisms, such as reburn reactions, were included in this study.

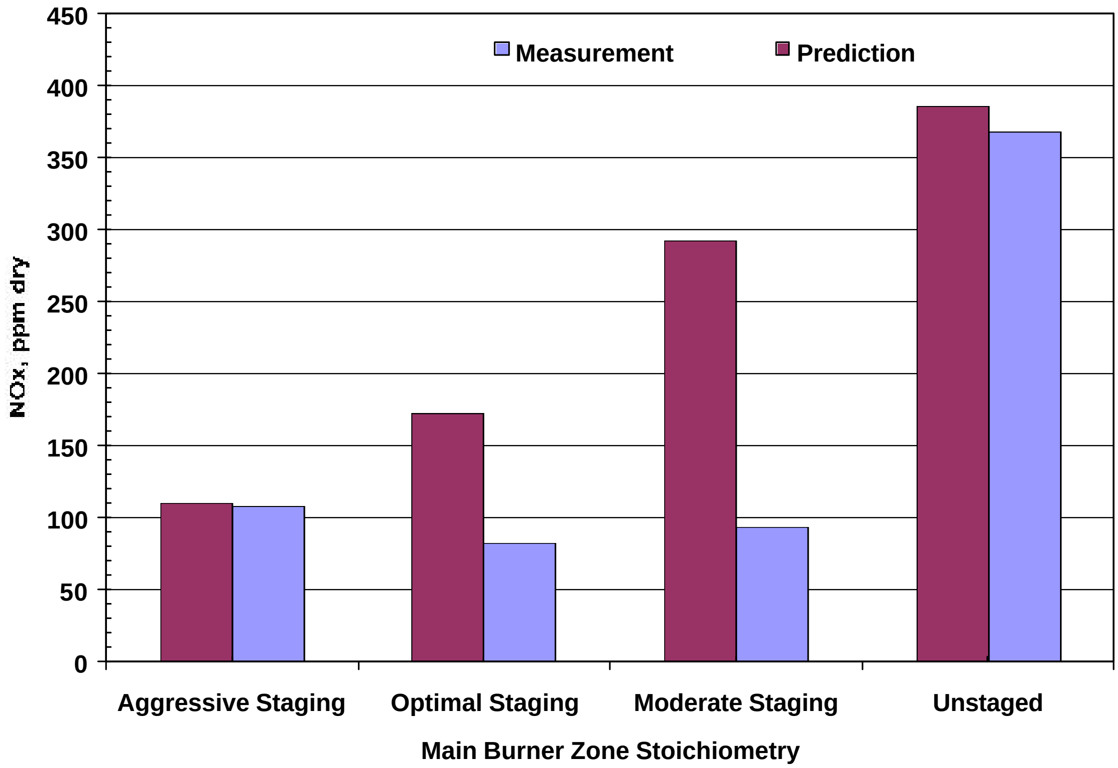

Figure 5.4.3-7: Predicted and Measured NOx Emissions vs. Main Burner Zone Stoichiometry.

In summary, CFD predictions were made for a series of BSF test conditions with the PRB fuel looking at the impact of main burner zone stoichiometry. The reasonable agreement between the CFD model predictions and BSF experiments suggests that the CFD model is sufficiently accurate to predict trends in boiler performance.

5.5 High Temperature SNCR Evaluation

Chemical reaction kinetics modeling was performed to evaluate potential reductions in NOx emissions by "High Temperature SNCR." Instead of injecting the amine NOx reduction reagent (ammonia or urea) in the traditional fuel-lean combustion products (1700-2100 °F), in high temperature SNCR the reagent is injected into a fuel-rich region in the boiler at significantly higher combustion temperatures.

<u>Objective</u>

The objective of this task was to examine the impact of flue gas temperature, residence time, NH_3 quantity, and oxygen concentration on predicted NOx emissions using detailed chemical reaction kinetics modeling. The results generated from the modeling study would guide the design and implementation of the NH_3 injection system for testing in the BSF.

Modeling Approach

A CHEMKIN software utility, specifically the SENKIN code (SENKIN User's Manual, 1999), was used to parametrically investigate the impact of ammonia on NO reduction in a fuel-rich, post-flame zone. SENKIN is a program that predicts the time-dependent chemical kinetics behavior of a homogeneous gas mixture. It was used in the present study to simulate plug-flow reactor characteristics (without species transport effects) in order to simulate SNCR/NO chemistry in a fuel-rich environment.

For this work, the kinetic mechanism of Glarborg was utilized (Glarborg, *et al.*, 1998). The detailed mechanism consists of approximately 66 species and 440 elementary steps and contains both reburn and NO/NH_3 chemistry. The adequacy of the mechanism was confirmed (in a limited sense) by comparison of the SENKIN calculations with the experimental $He/O_2/NO/NH_3$ plug-flow data of Lyon and Hardy (Lyon and Hardy 1986, Jesse *et al.*, 1993) as shown in Figure 5.5-1.

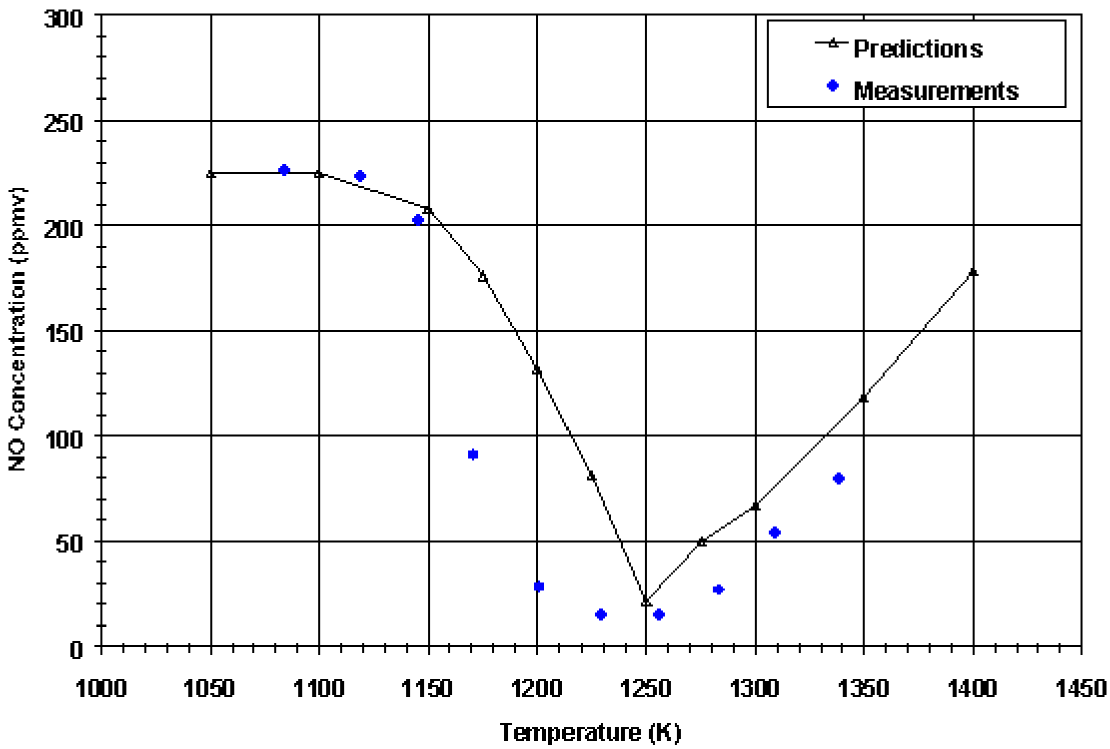

Figure 5.5-1: Comparison of SENKIN Calculations with Experimental $He/O_2/NO/NH_3$ Plug-Flow Data of Lyon and Hardy (1986).

The gaseous composition of a post-flame, fuel-rich zone with a stoichiometry of 0.7 was approximated by computing the corresponding adiabatic, equilibrium compositions of mixtures of coal (medium volatile bituminous) and air. An in-house derivative of the CREE equilibrium code (CREE,1976) was used for the equilibrium calculations. The computed fuel-rich equilibrium composition (see Table 5.5-1 for major species) served as the baseline mixture, to which various amounts of NO, NH_3, and O_2 were added parametrically to form the final feed stream composition that was input to the SENKIN code. Each SENKIN case was run at a prescribed, constant temperature and residence time to assess the impact of the NO, NH_3, and O_2 additives, as well as temperature, on NO reduction. While it is conceded that the true equilibrium composition of the baseline mixture would change somewhat as the temperature is varied, the application of a single equilibrium mixture (at a given stoichiometry) over the prescribed temperature range was deemed adequate for present purposes. The range of variables examined in the study is shown in Table 5.5-2.

Table 5.5-1: Major Species Equilibrium Concentrations – Input to SENKIN.

Species	Volume Fraction
CO_2	0.089
CO	0.131
H_2	0.022
H_2O	0.079
N_2	0.679
O_2	1.25E-05

Table 5.5-2: Variables Examined in CHEMKIN Modeling.

Variable	Low	High	Units
Initial NO	75	150	ppm
Initial O2	0	2	% by volume
NH_3/NO	0	4	Moles/moles
Temperature	1700	3140	Degrees F

<u>Modeling Results</u>

The fact that NO will be reduced to molecular nitrogen in a fuel-rich environment is the basis for air staging in a pulverized coal fired utility boiler. Figure 5.5-2 illustrates the impact of temperature and residence time on the NO reduction reactions for an initial NO concentration of 75 ppm with no NH_3 injection. At a gas temperature of 1700 °F, the NOx reduction reactions are sufficiently slow that the reduction in NO concentration is less than 7% even at a residence time of 2 seconds. Note that staged residence times in pulverized coal-fired utility boilers are generally much shorter than 2 seconds. However, when the gas temperature was increased to 2780 °F, the theoretical NOx reduction for the same residence time was much greater (> 70% reduction).

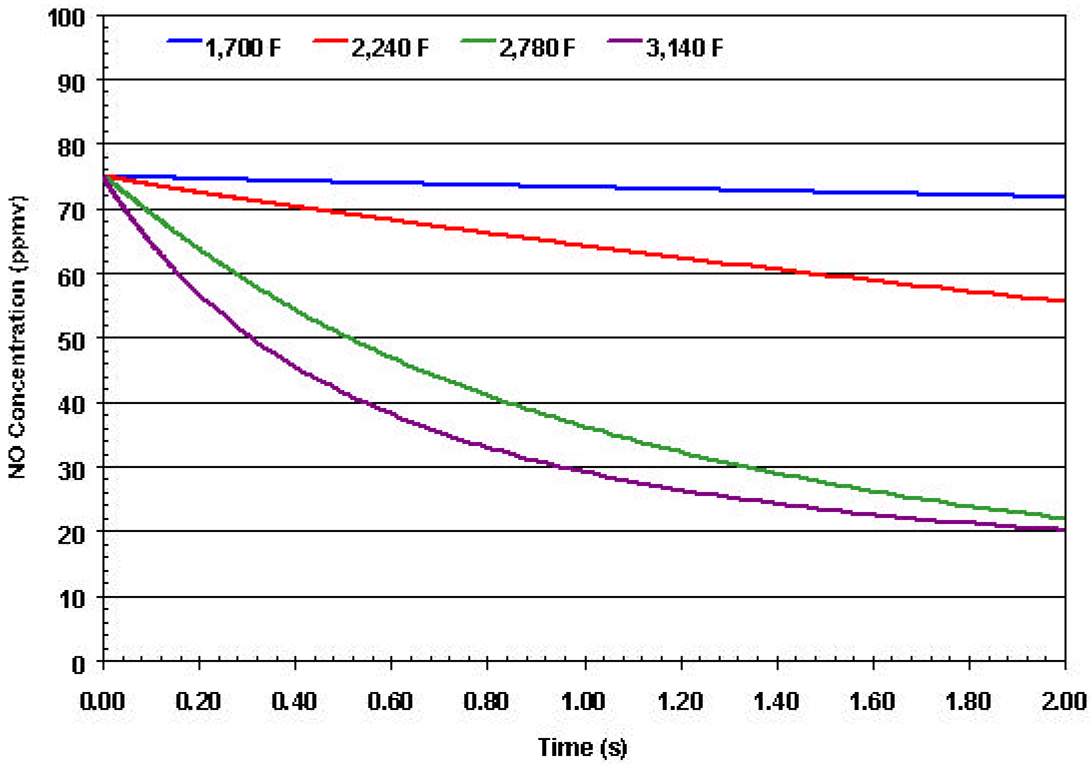

Figure 5.5-2: NOx as a Function of Time and Temperature – NH_3/NO = 0.

Predictions with NH_3 injection at molar ratios of NH_3/NO = 2 and NH_3/NO = 4 are presented in Figures 5.5-3 and 5.5-4, respectively. As shown in the figures, adding ammonia will speed up the NOx reduction process at gas temperatures 2780 °F or less. At a gas temperature of 3140 °F, the NO emissions actually increase initially as part of the NH_3 is oxidized by the available oxygen. For most cases, the overall NOx reduction at 2 seconds residence time is not increased with NH_3 additions. However, the rate of reduction increases significantly with NH_3 addition such that increased NO reductions can occur within the shorter staged residence times typically available in utility boilers.

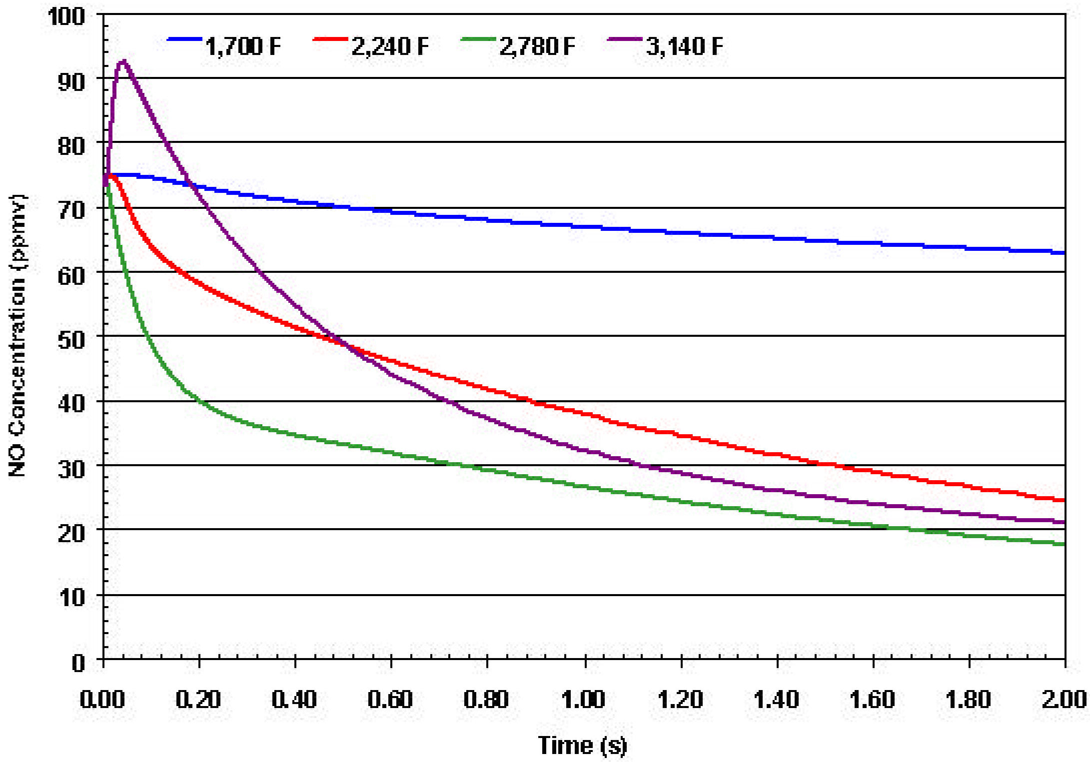

Figure 5.5-3: NOx Concentration vs. Time and Temperature – NH_3/NO = 2.

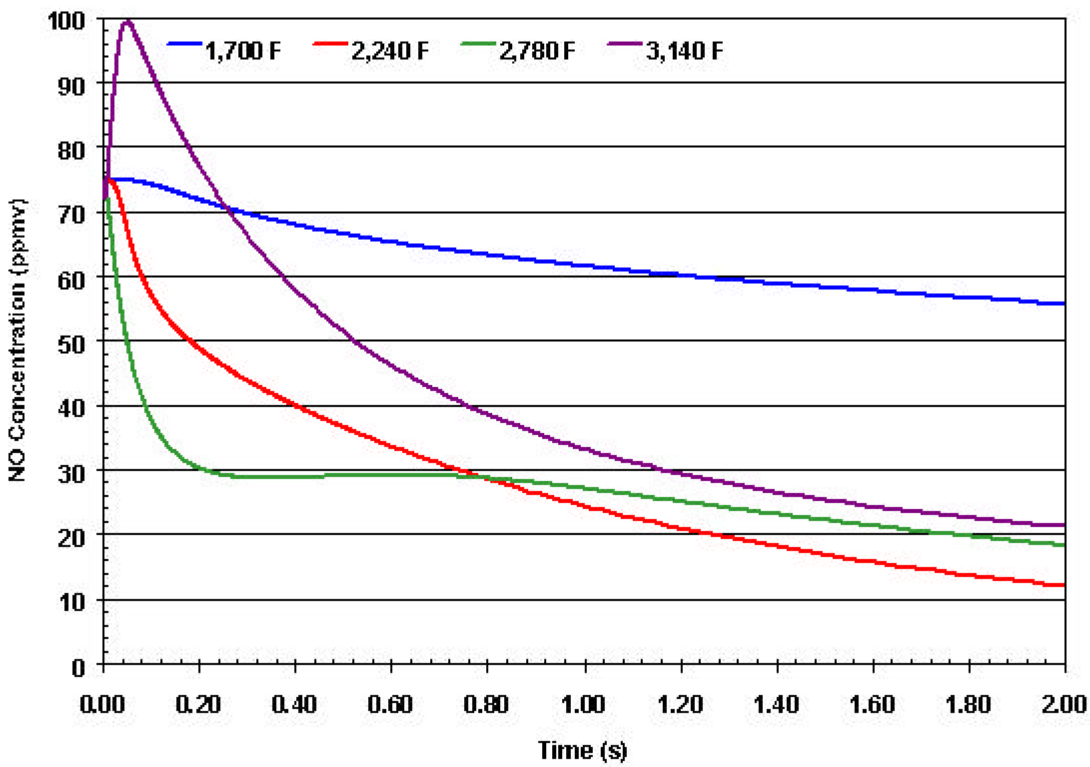

Figure 5.5-4: NOx Concentration vs. Time and Temperature – NH_3/NO = 4.

The predicted NH_3 concentrations as a function of residence time and temperature for the NH_3/NO = 4 case are shown in Figure 5.5-5. At the highest temperature (3140 °F), the NH_3 is oxidized / decomposed in approximately 50 msec. The NH_3 is also oxidized / decomposed at a gas temperature of 2780 °F, although at a significantly slower rate than was predicted at 3140 °F. At a gas temperature of 2240 °F, the NH_3 is not oxidized or decomposed and whatever concentration of NH_3 is not utilized in the NO reduction reactions will remain at the reactor outlet.

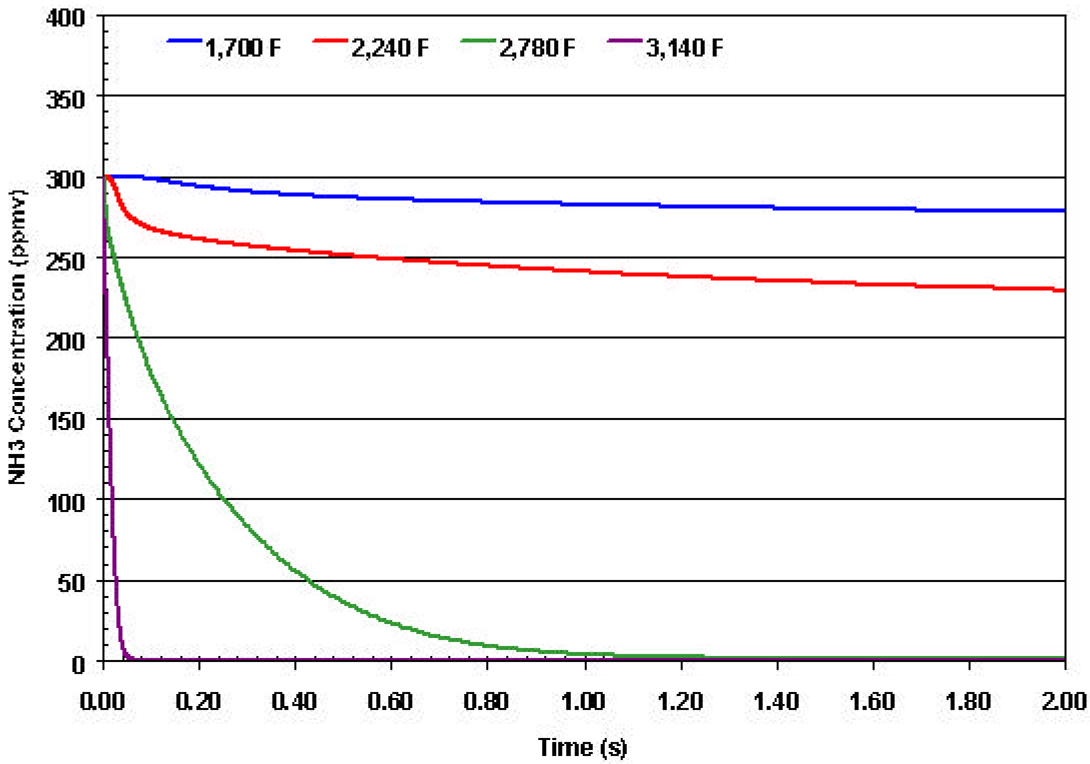

Figure 5.5-5: NH_3 Concentration vs. Time and Temperature – NH_3/NO = 4.

SENKIN runs were performed while increasing the oxygen concentration by 1-2% without changing the composition of the major species predicted by equilibrium at a stoichiometry of 0.7. These cases were run to simulate the local mixing of pockets of fuel-rich combustion products with oxygen-rich pockets of air. As shown in Figure 5.5-6 for a gas temperature of 2780 °F, the presence of additional oxygen causes rapid oxidation of the available NH_3 to NO. These results suggest that high temperature NH_3 injection should be done in a location with no oxygen to be effective at reducing NOx.

An additional series of cases were run with an initial NO concentration of 150 ppm as compared to 75 ppm for the previously shown results. Figure 5.5-7 presents the predicted NO concentrations as a function of time and temperature for initial NO of 150 ppm (compare to Figure 5.5-2 for 75 ppm initial NO). The predicted trends are essentially the same. It is interesting to note that the predicted equilibrium NO values as the residence time approaches 2.0 sec. for the higher temperature cases is not a function of the initial NO concentration. Thus, the predicted NO reduction will be greater for a higher initial NO value.

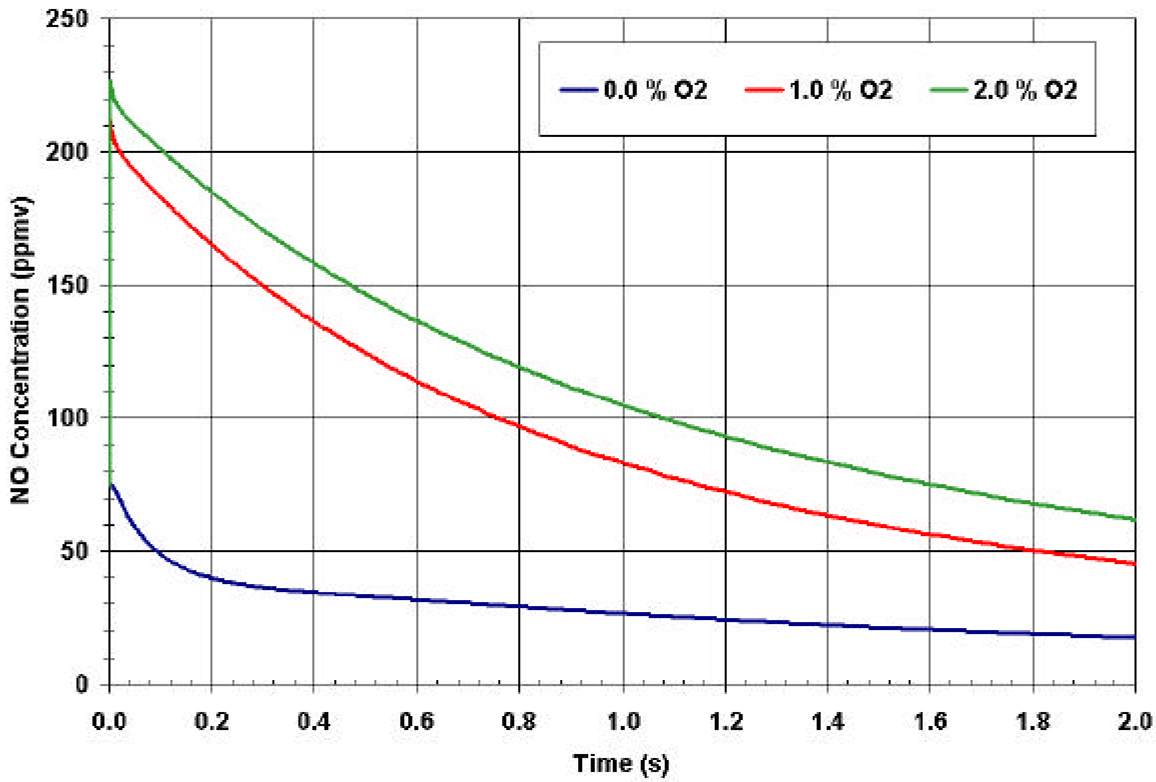

Figure 5.5-6: NH_3 Concentration vs. Time and Oxygen % (T = 2870 °F).

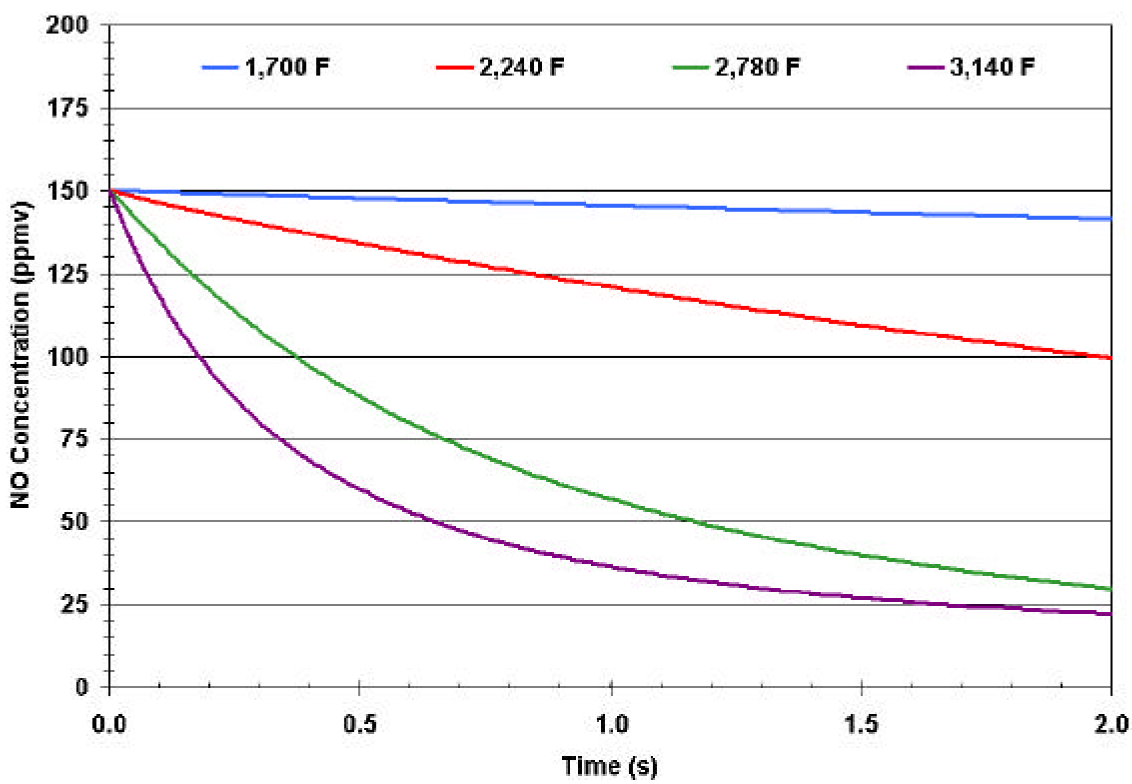

Figure 5.5-7: NOx Concentration as a Function of Time and Temperature – NH_3/NO = 0, Initial NO = 150 ppm.

Predicted NO reductions for staged residence times spanning the range of typical utility boiler retrofits are shown in Figure 5.5-8. These results were generated at a stoichiometric ratio of 0.7 with no added oxygen. These results suggest that NO reductions of up to 40% may be possible with high temperature NH_3 injection with ideal mixing. These results assume that the NH_3 is injected in regions of very low oxygen concentration. Note that the measured NO reduction with high temperature NH_3 injection will generally be less than predicted by the simplified modeling approach used in this study. The gas phase model predictions do not account for NO formed from oxidation of the char bound nitrogen in fuel-lean regions of the boiler which can account for a significant fraction of the NO formed in a utility boiler. Also, additional NO may be formed from the gas-phase reactions as the overfire air is injected into the boiler. However, NOx reductions of 15-20% are anticipated with high temperature NH_3 injection.

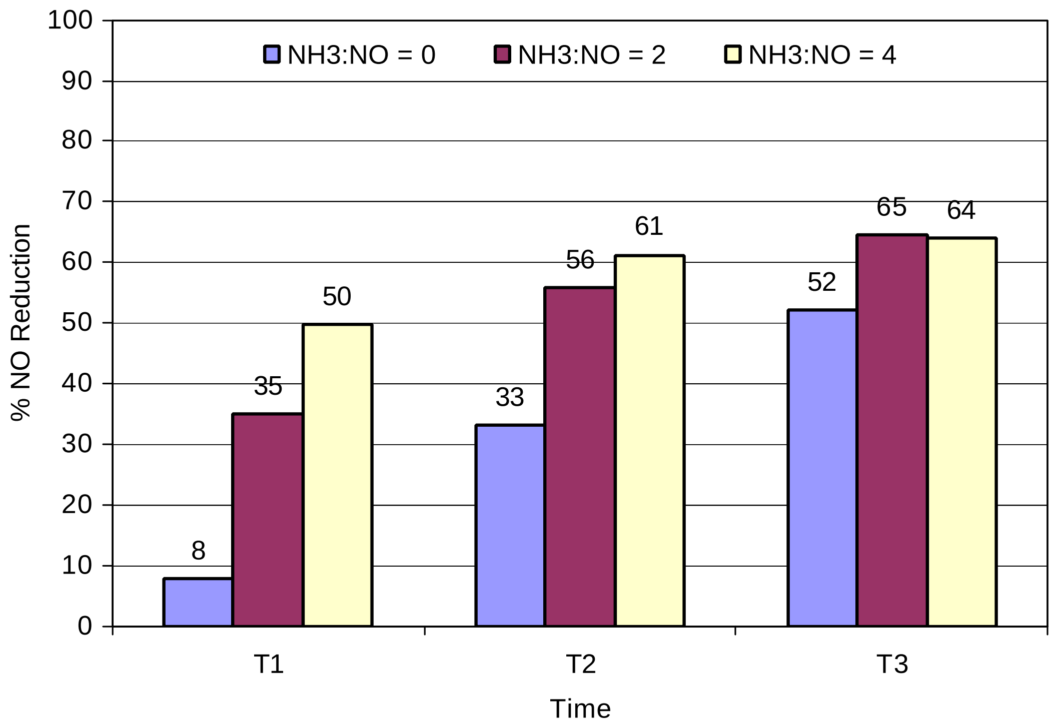

Figure 5.5-8: Predicted NO Reduction as a Function of Residence Time and NH_3 Concentration.

<u>Summary</u>

Chemical reaction kinetics modeling was performed to evaluate potential reductions in NOx emissions by "High Temperature SNCR" using CHEMKIN. Predictions were made to examine the impact of flue gas temperature, residence time, NH_3 quantity, and oxygen concentration on predicted NOx emissions. The modeling results suggest that for high temperature SNCR to be effective, the NH_3 must be injected in the absence of oxygen / away from combustion air sources. This information was used, along with in-furnace species concentration data from previously performed BSF testing, to identify appropriate locations for ammonia injection in the large pilot-scale BSF testing.

5.6 Advanced Control System and Sensor Development

One key component within the Low NOx Subsystems was the development of new control system concepts that would integrate existing boiler control strategies with dynamic control methods. Part of this advanced control system design included the evaluation of "new to market" and developmental sensors.

A key capability of the advanced boiler control system is that optimal boiler performance with regard to NOx and the other control targets would be achieved at <u>all</u> boiler operating conditions. Rather than meeting operating targets at the single “guaranteed” setpoint, the advanced control system would produce optimized boiler operation under all conditions. This optimization would include periods of changing plant operational conditions, such as load changes and ramps.

The following section (5.6.1) provides more information on the conceptual ALSTOM Power advanced control system development effort that was continued as part of this project. Despite the realistic behavior of the Boiler Simulation facility (BSF), from a boiler controls perspective, it provides information only on the fire-side of the overall boiler. This is a significant limitation in terms of developing an optimized overall boiler control system. Also, the amount of data that would have to be collected, and the tuning that would be required to support an optimized control modeling effort are significantly beyond what could have been accomplished during two weeks of actual testing.

It was, therefore, decided that the advanced boiler control system development effort would go forward but would focus on eventual installation in a commercial boiler. This decision did not impact the range and depth of boiler control system development, which was accomplished, but rather prevented the advanced control system concepts from being implemented and tested on the BSF during pilot-scale testing.

The advanced boiler control system concept presented in following sections covers three areas:

- Dynamic Optimization of Overall Boiler Performance
- Fuel Balancing to Achieve Uniform Burner Firing Rates at all Locations
- Individual Burner Performance Optimization

The boiler control concept presented includes the latest methods for optimization using dynamic predictive models, linear and non-linear multiple input neural processing and fuzzy logic methods. Taken as a complete boiler control strategy, a fully developed advanced boiler control system, together with existing low NOx hardware, could provide optimized boiler operation with respect to plant performance targets for both steady state and transient boiler operation.

In addition to developing an advanced boiler control system concept, new sensor technologies were evaluated during the two one-week testing periods. The two areas evaluated were on-line coal flow measurement and advanced flame scanner signal processing.

The on-line coal flow measurement is a relatively new sensing system, which is essential to the goal of controlling the firing rate of individual furnace burners. A balanced firing system would avoid local hot spots, typical of firing imbalance, and reduce the generation of thermal NOx. A balanced firing system will also decrease zones that are excessively fuel rich which cause high levels of unburned carbon in the fly ash or CO. Reductions in unburned carbon and CO may allow the furnace excess air to be reduced, which should result in decreased NOx emissions. The impact of burner fuel balancing for ALSTOM Power tangential fired furnaces could be established by using an on-line fuel measurement system. Section 5.6.2 presents results from the coal flow measurement effort.

The informational content of burner flame scanner signals has been a source of much speculation. The requirement of one flame scanner per burner for the Boiler Management System (BMS) has always raised the intriguing possibility of using these sensors to provide more information than simply a burner "off/on" condition.

In particular, information regarding near-burner conditions (local stochiometry, flame temperature, flame attachment point) would be needed as inputs to an individual burner optimization control strategy. Although new video measurement systems are being considered as a means of obtaining near-burner information, the high cost of such systems makes evaluating the use of presently available burner flame scanners economically prudent. During the BSF testing portion of this project, commercially available flame scanners were evaluated to determine if there were any relationships between scanner signal information and local burner combustion conditions. The goal, relative to scanner information, was to determine if the necessary advanced burner control inputs could be acquired by extending the analysis of the existing flame scanner signal. Section 5.6.3 provides more detail on this activity.

Objective

The objective of this task was to identify, evaluate, and develop advanced control system components to enhance NOx reduction/destruction and dynamically compensate for system disturbances to improve and maintain optimal system performance. Selected advanced control system components will be evaluated as part of the testing in the BSF. Components which were determined to be effective and necessary to achieve the stated objective have been incorporated into a conceptual design for utility applications.

5.6.1 Conceptual Design of a Neuro-Fuzzy Low NOx Boiler Control System

Introduction

The Neuro-Fuzzy Low NOx Boiler Control system is a fully integrated, balanced performance control system concept designed to obtain the lowest possible NOx emissions from a large, aggressively staged pulverized coal fired utility boiler. This control system concept integrates all the conventional Digital Control System (DCS)-based boiler control systems with neural net optimization and advanced dynamic model predictive control of key control parameters such as plant heat rate, emissions (NOx) and reheat and superheat steam temperatures. Also included is neuro-fuzzy control of selected local, multivariable control loops. These specific multivariable fuzzy controls will be used to control the balancing of fuel, air and local burner conditions to provide optimal main firing zone conditions.

The primary purpose of this control concept is to maintain boiler performance at optimal levels throughout the operating range of the boiler. This includes the ultra minimization of boiler emissions, in particular NOx along with minimizing plant heat rate, maximizing combustion efficiency, and maintaining unburned carbon at levels such that the fly ash is a salable byproduct rather than a waste disposal problem. The methodology is to use advanced controls and the latest low NOx pulverized coal-firing hardware to achieve environmental emissions compliance and minimum cost of electricity. It is believed possible to achieve environmental compliance for many coals without requiring expensive back end cleanup equipment such as selective catalytic reactors.

Description

The Neuro-Fuzzy Low NOx Boiler Control system concept is depicted diagrammatically in Figure 5.6.1-1. The control system uses inputs from existing boiler control system components, specifically the plant DCS standard boiler sensors such as furnace pressure, differential pressure (furnace vs. ambient), temperature and flow sensors, pulverizers and feeders, as well as input from the continuous emissions monitoring system (CEMS). Connections between conventional boiler sensors and control actuators and the advanced control system would be made through the DCS.

The conventional boiler control system would continue to perform burner management and standard boiler control system functions such as boiler load, steam pressure, feedwater flow, drum level, total fuel and airflow control. In addition to these conventional controls the following advanced control and optimization systems would be added:

1. Supervisory control: neural net steady state optimizer with advanced hybrid model predictive dynamic controllers (nonlinear).

2. Neuro-fuzzy stoichiometry profile / residence time controller.

3. Advanced neuro-fuzzy elevation/burner/corner fuel balancing controllers using advanced optical burner sensors, pulverized coal flow sensors and advanced dynamic pulverized coal splitters.

4. Advanced neuro-fuzzy elevation/burner/corner air balancing controllers using advanced optical burner sensors, airflow monitoring and airflow dampers.

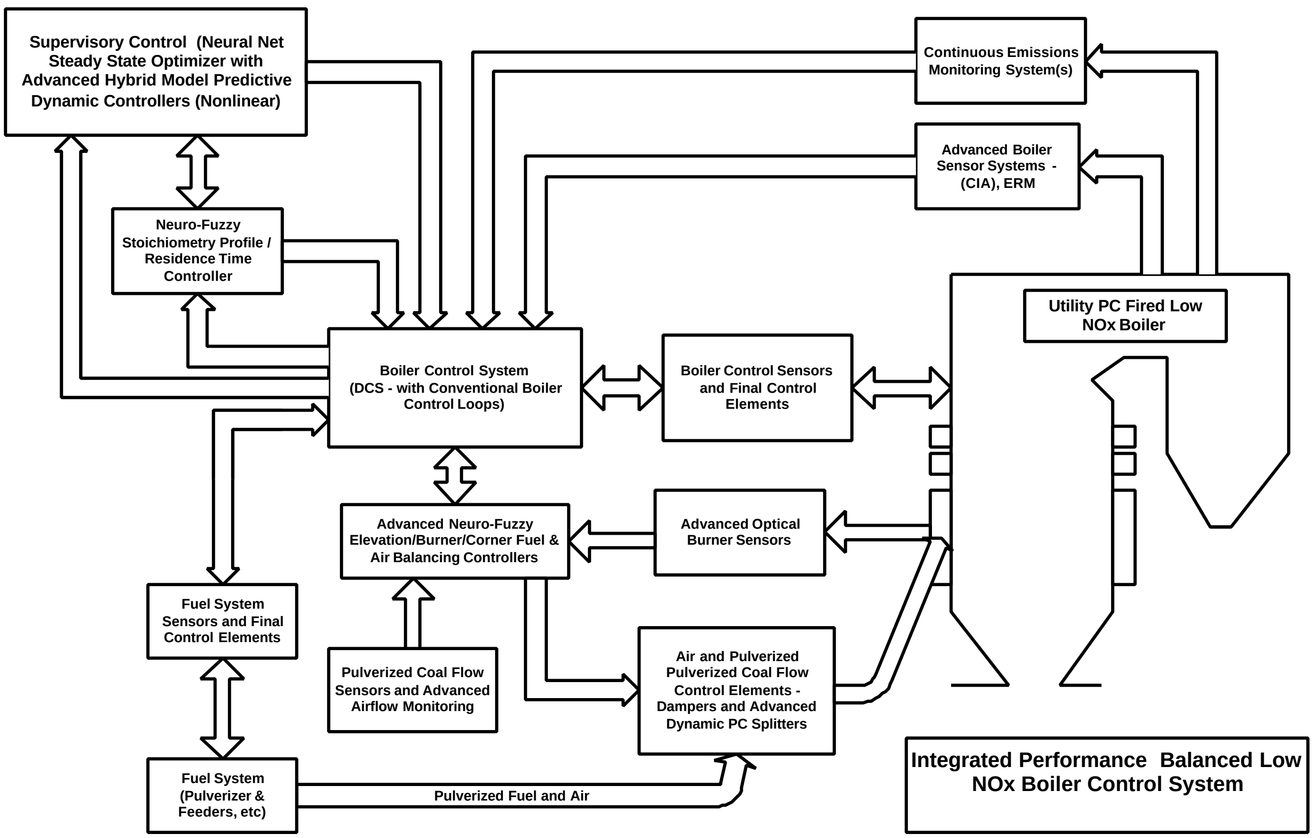

Figure 5.6.1-1: Diagram of Neuro-Fuzzy Low NOx Boiler Control System Concept.

The Supervisory control, neural net steady state optimizer and advanced hybrid model predictive dynamic controllers (nonlinear) are shown in some detail by Figure 5.6.1-2, “MIMO Control Algorithm Structure NOx Boiler Control System". (MIMO refers to Multiple Input and Multiple Output).

Necessary sensor inputs include:

- Conventional boiler sensors and control actuator positioners such as wind box to furnace differential pressure

- Furnace pressure
- Steam and feedwater flows
- Air flows
- Oxygen concentration
- Mill and feeder control states
- Air, water and steam temperatures
- Damper positions
- Fuel flows
- Burner and overfire air tilt positions.

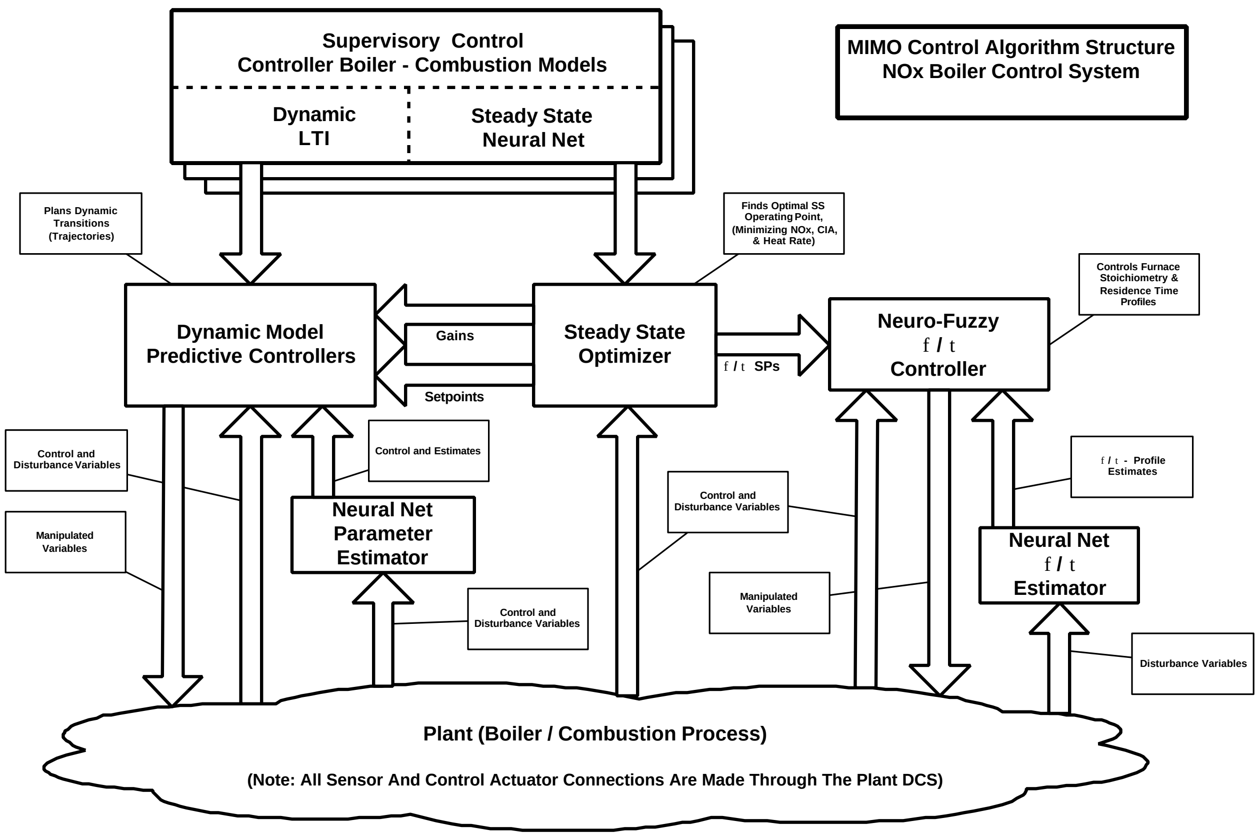

Figure 5.6.1-2: MIMO Control Algorithm Structure NOx Boiler Control System.

Control and disturbance parameters not directly measured are estimated from conventional sensor readings using both math calculation and neural network models as parameter estimators. These parameters include emissions, heat rate and other boiler performance calculations and unburned carbon in the fly ash. The steady state optimizer provides setpoints as well as controller gains for manipulated variables to the dynamic model predictive controllers.

The steady state optimizer solves the differential equations describing combustion models in a back propagation calculation to minimize a cost function based on the current optimization targets. These targets are the minimization of NOx, the maximization of boiler combustion efficiency, the minimization of plant heat rate, and the cost optimization for a close tolerance steam temperature control system.

The dynamic Model Predictive Controllers (MPC) use a hybrid neural net- linearized math model(s) based on predictive control to achieve the optimization goals in a continuous dynamic environment even during rapid load swings. Manipulated variable control trajectories are computed for 50-100 time steps in the future. Many of the MPC manipulated variables are setpoints for control variables in the conventional DCS based boiler control system. Examples include windbox to furnace differential pressure and excess air.

The neuro-fuzzy controller is an advanced neural fuzzy MIMO controller for stoichiometry profile/staged residence time control. This controller exploits functional relationships between NOx production in an aggressively air staged pulverized coal fired boiler, the stoichiometry profiles and staged residence times. Neuro-fuzzy controllers and fuzzy estimators, as shown in Figure 5.6.1-3, can approximate these functional relationships. A controller of this type can utilize both ALSTOM Power combustion expertise and pilot-scale test results to effect optimal control of the combustion air staging process in order to minimize NOx.

The neuro-fuzzy elevation/burner/corner fuel and air-balancing controllers also use the controller architecture as depicted in Figure 5.6.1-3. Sensor signals and calculated parameters are retrieved from the process either by direct connection to the Neuro-Fuzzy controller or through the DCS. The signals are scaled (normalized) and then fuzzified using an over lapping triangular system. The sensor inputs are used in the fuzzy rule-based inference engine based on overlapping triangular shaped rules feeding a centroidal defuzzifier to position the control actuators. The exact shape of the rule patches used to approximate the desired functional relationships between the sensors and the control variables are constructed by a combination of neural network based empirical training of the fuzzy rules from test data and the manual tuning of rules by ALSTOM Power combustion experts.

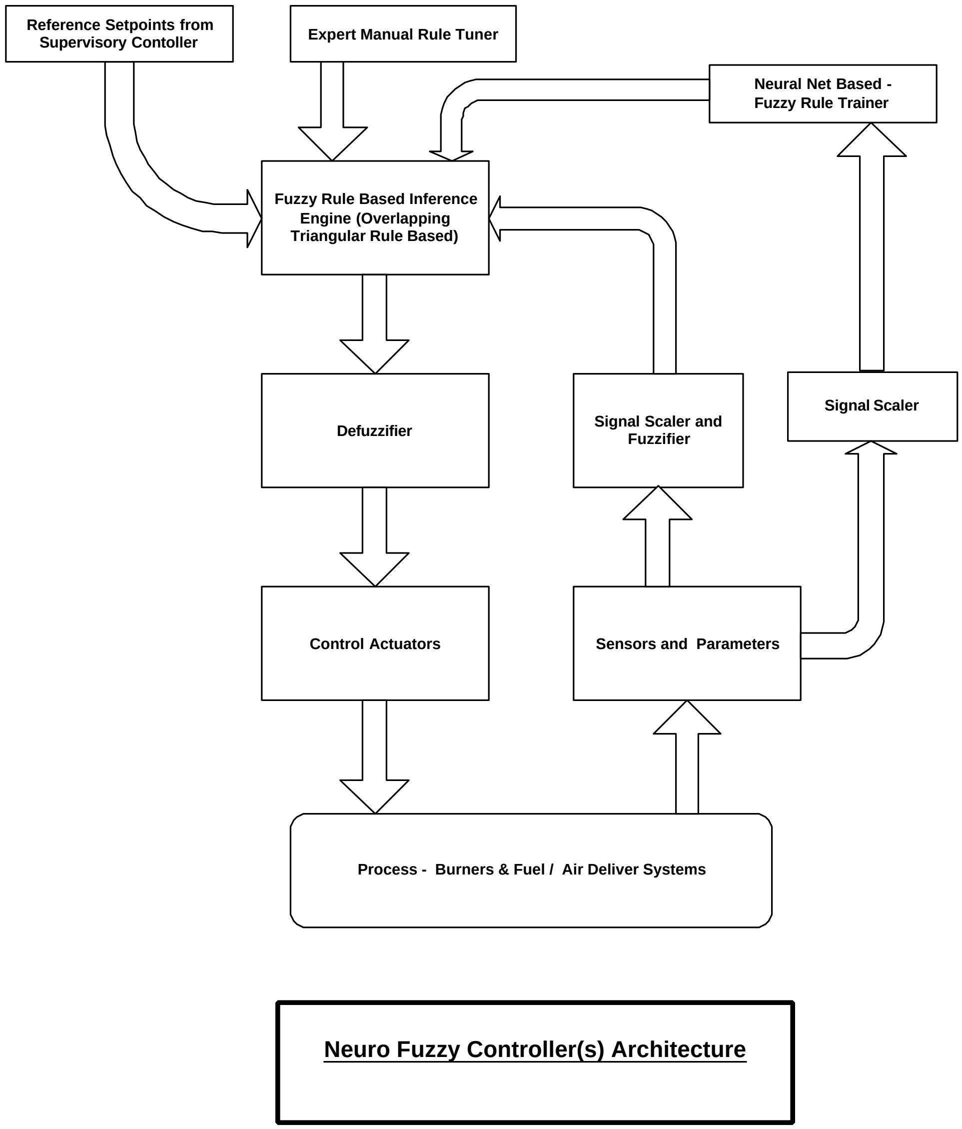

Figure 5.6.1-3: Neuro-Fuzzy Fuel and Air Balancing Controller Architecture.

Figure 5.6.1-4 shows the “Fuel Balancing Control Systems.” Inputs to these control systems are generated by pulverized fuel flow sensors, which are now commercially available from a number of sources. Each fuel source (mill) is provided with its own fuel-balancing controller, based on the neuro-fuzzy controls. These systems effect dynamic fuel balancing using adjustable pulverized coal splitters. Having the ability to adjust coal splitters and balance fuel flows will insure burner firing rate balance, thus preventing furnace hot spots which can result in excessive thermal NOx generation.

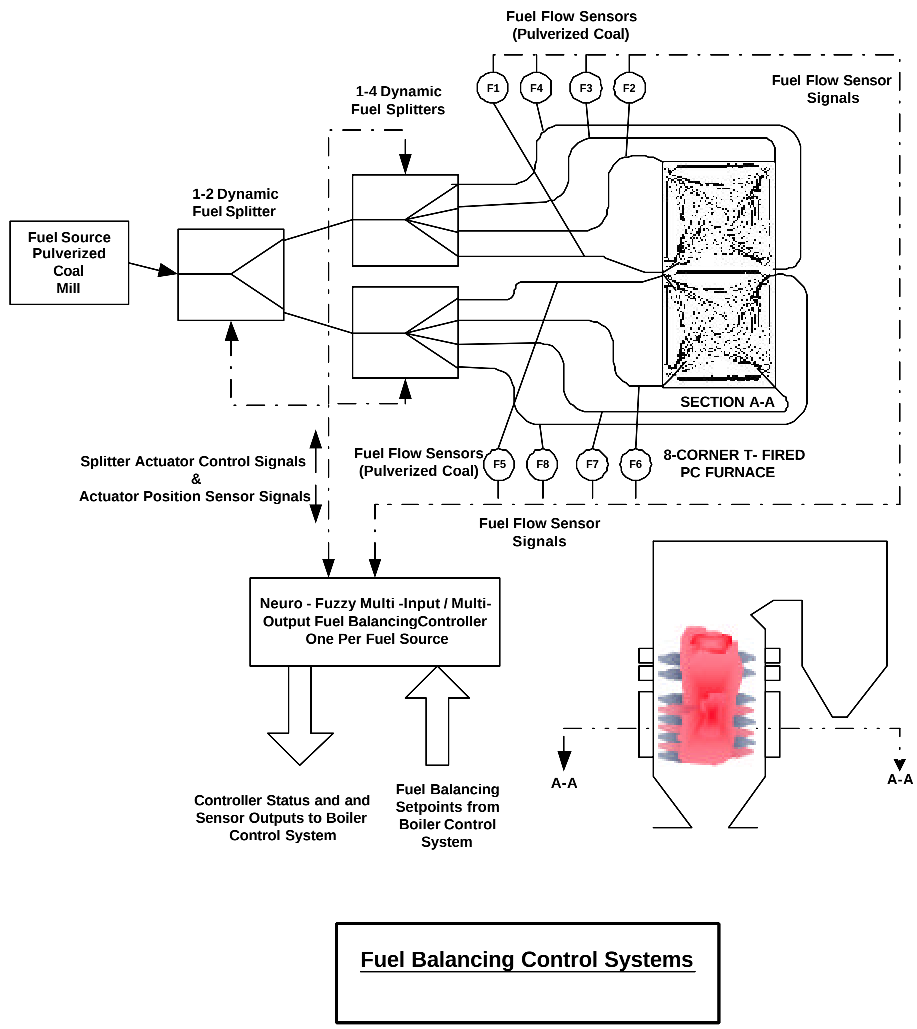

Figure 5.6.1-4: Schematic of Fuel Balancing Control System.

Figure 5.6.1-5 schematically presents the "Near Burner Flame Field Control System", a controller per burner/corner system, which adjusts the characteristics of the near burner flame field to minimize local NOx production and unburned carbon in ash. Advanced optical burner sensors are used to sense the local burner conditions; burner flame quality parameters such as local stoichiometry, temperature and flame shape are then predicted and used as inputs by the control system. Finally, burner actuators (for fuel flow control) and airflow dampers are used as control elements of the burner control system.

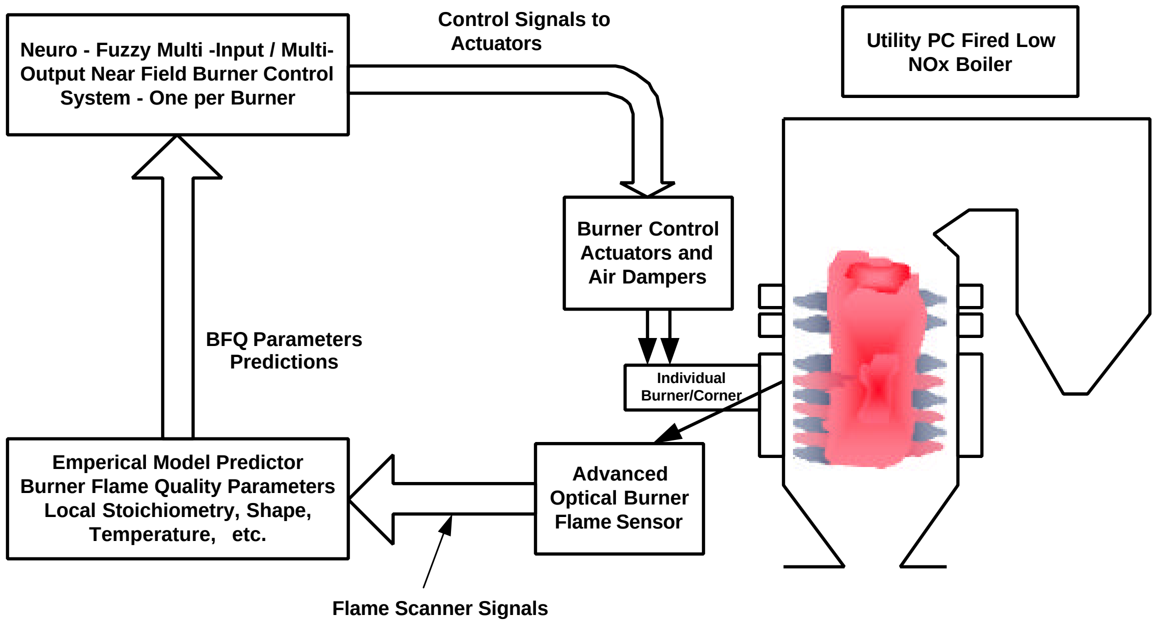

Figure 5.6.1-5: Schematic of Near Burner Flame Field Control System.

5.6.2 Coal Flow Measurement

In an effort to better understand the effect of fuel feed balancing on the quality of coal combustion, and also to determine whether coal balancing was beneficial to ultra Low NOx operation, the Boiler Simulation Facility (BSF) was equipped with twelve (12) on line coal flow meters, one for each burner.

The coal transport line feeding each corner burner, at all three elevations, was equipped with a coal flowmeter. The meters were mounted in vertical sections of the coal feed line within 10' of the burner.

The meters were to be utilized to monitor the amount of pulverized coal being delivered to each BSF burner. Use of measurements from the flow meters could occur during both normal balanced flow and biased fuel flow testing. These measurements would enable a series of experiments to be conducted that would show the impact of varying fuel distribution on NOx and other combustion characteristics.

<u>Coal Flow Meter Description</u>

The coal flow meters selected were manufactured by ABB Automation. The meters, remote field preamplifiers, and analysis and display computer are collectively known as the ABB pfMaster. Each meter consists of a sensor that is placed in the coal flow piping, a remote electronic signal conditioning module and a computer based signal processing channel. In Figure 5.6.2-1 the meter and the remote electronics can be seen as installed on the BSF.

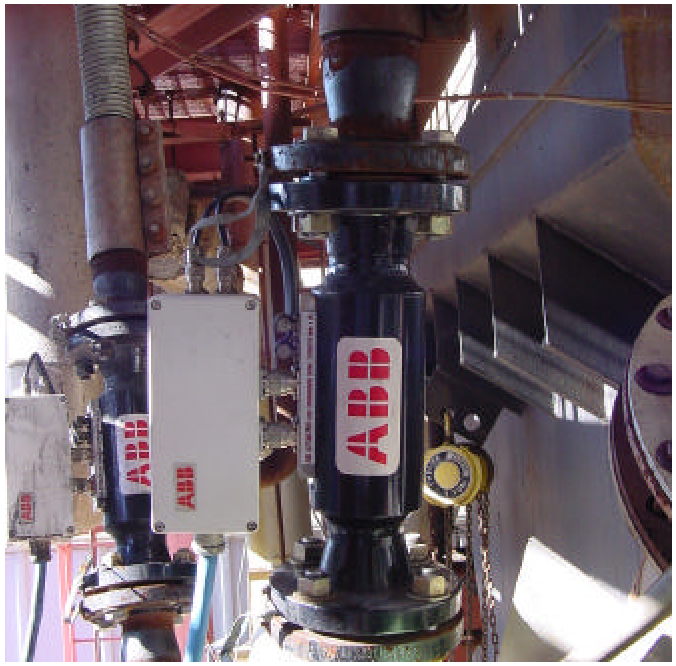

Figure 5.6.2-1: A pfMaster Sensor and Remote Electronics Box as Installed on the BSF.

The meters were installed with a flanged connection to the existing coal transport piping. The specific meters used (Model D50; 50 mm ID) were accommodated in the BSF piping, which is 2 1/2" (63mm), through a pair of reducing flanges that ABB supplied with the meters. Signals from the electronics boxes from all twelve meters were cabled back to the central coal flow processing computer.

The pfMaster analysis computer is a rack-mounted industrial computer, with individual signal conditioning capability. It receives signals from the twelve remote sensors (each having their own power supply) and calculates the coal flow rate per burner from the coal flow sensor data. Standard computer peripherals exist for outputting the calculated coal flow values for each burner to a remote plant DCS using 4-20 mA current loop outputs as well as provision for remote data monitoring using a dial-in modem.

In the pfMaster analysis computer the relative coal distribution is computed and displayed (Figure 5.6.2-2). While the meters provide only relative coal flow values, knowledge of the total coal flow (which is known) allows individual coal mass flow rates (lb./hr) to be computed and displayed. During BSF testing total coal flow was determined with a Thayer coal feeder employing a calibrated weight sensor output, which provided an actual coal flow rate (pounds per hour value) as an input to the pfMaster.

The coal flow data from each coal sensor was integrated into the BSF Advant DCS using the twelve 4-20 mA current loop outputs.

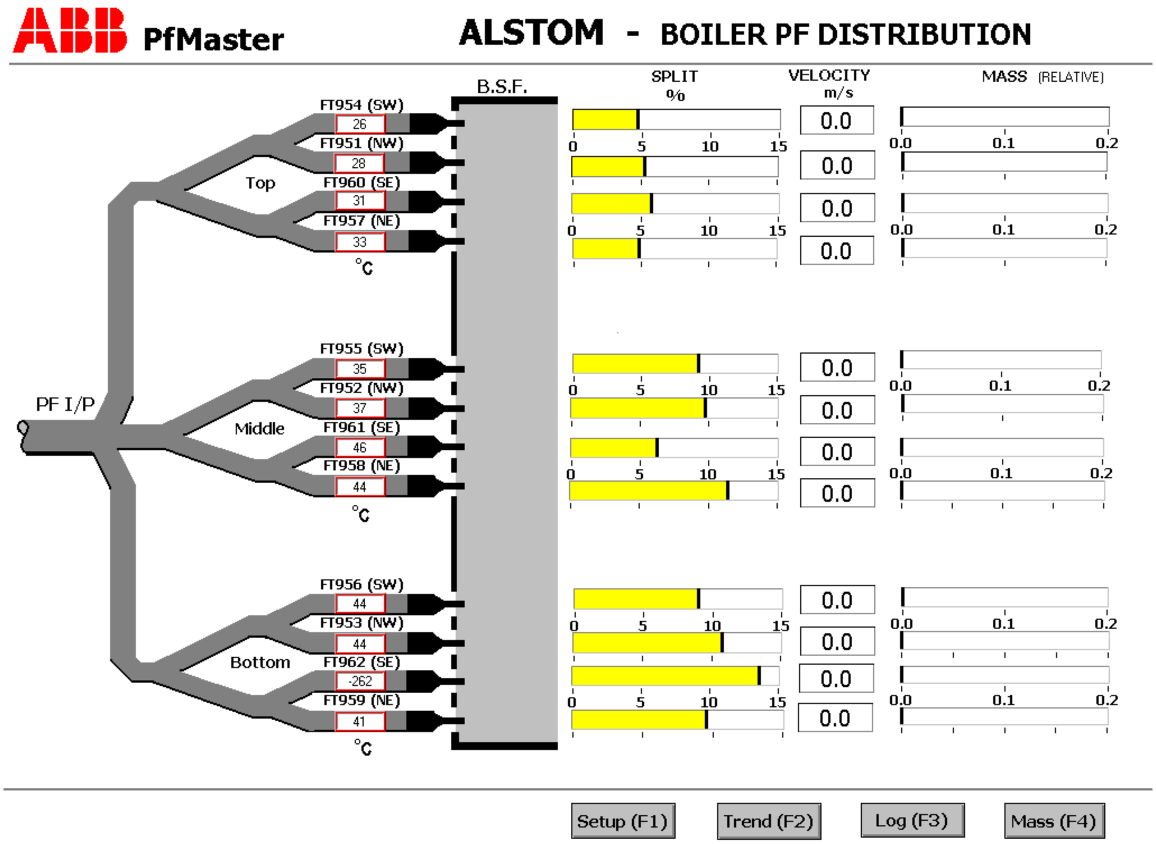

Figure 5.6.2-2: BSF Test Facility Twelve Sensor pfMaster Coal Flow Display.

pfMaster Operational Principle

The pfMaster sensor has three sensing rings per meter. Each ring is electrically isolated from the metallic body of the meter. The rings are flush with the normal ID of the meter and hence do not cause any coal flow obstructions or create a possible area for erosion to occur.

The coal quantity measurement ring is the broadest, largest length segment, of the three rings. The relative coal flow measurement is obtained by making use of the static electric charge created by pulverized coal as it is transported through a pipe. As this static charge passes through the measurement ring a current is induced in the ring which is sensed and amplified by the remote electronics.

While the intensity of the static charge is sensitive to environmental conditions, humidity, as well as coal particle size distribution, the instantaneous sensed current is proportional to the amount of coal passing through each sensor. A wide dynamic range of signal processing permits accommodation of daily changes in the absolute charge level measured.

The other sensor rings are narrow and are placed on either side of the charge-sensing ring at a precise separation distance. The signals from these two sensors are cross-correlated to determine the coal velocity within the pipes.

Charge magnitude and particle velocity signals are both processed in the central analysis computer to develop relative coal flows, and hence a coal flow distribution ratio for the twelve BSF meters. The relative coal distribution was then scaled by the BSF total coal flow reading to an absolute pounds/hour coal flow rate. This coal flow rate was displayed locally as well as transmitted to the BSF DSC for control room display and logging.

Installation and Operational Performance

The coal flow measurement system including the twelve sensors, remote electronics and the analysis computer were ordered with an initial delivery date prior to shakedown of the BSF. Due to production problems with the vendor the equipment was delivered and installed immediately prior to actual testing. ABB automation personnel provided installation and commissioning engineering support immediately before and during the first week of testing.

Mechanical installation of the sensors was performed per the ABB installation instructions and utilized the reducing flanges provided by ABB. Technicians from ALSTOM Power's Power Plant Laboratories did the electrical wiring. ABB performed the equipment inter connection. Early in the commissioning process there was concern about the magnitude of the sensed signal. The ABB field engineer made a field adjustment to each of the remote electronics boxes to raise the signal gain.

The pfMaster system was connected to the BSF Advant system and encountered computer reliability problems throughout the first phase of testing. Between the first and second test periods the pfMaster analysis computer was replaced and ABB Automation personnel again returned to install the computer and upgrade the coal flow analysis software.

During the second phase of testing the greater-than-expected variability of the pfMaster measurements was cause for concern. Although gross sensor response was observed to correspond with the throttling of the coal line valve, the large variability in measurement point readings, in concert with little or no response when changing an upstream splitter setting, raised questions regarding the ability of the sensors to provide reliable coal flow data.

It was decided that based on large deviations between expected and actual pfMaster measured values a post test, "bucket and stop watch" test would be performed.

Coal Flow Meter Calibration

A series of tests were performed to establish the system accuracy of the complete twelve-channel pfMaster system installed on the BSF. The test program utilized the same coal feeder system and transport piping as was used during the BSF testing phase of the project. No piping changes were made until 10' beyond the location of the pfMaster sensors being tested. Instead of routing the coal to the burners the coal was transported to storage drums (buckets) with appropriate dust control filters.

The drums were tare weighted and then connected to the individual pfMaster sensor outputs. The tests were run at firing rates representative of the test rates, 3000 - 5000 lbs/hour. Repeat tests were performed to insure the reliability/reproduceability of the transport system. During the test period the pfMaster analysis computer was storing the instantaneous coal flow rate at three-second intervals. Over the duration of the test (15-20 minutes) pfMaster readings exhibited coal flow rate variations which were not consistent with average air flow measurement readings recorded by a manometer.

At the conclusion of the test period the barrels were weighed and the pfMaster data was integrated. The total quantity of coal transported, calculated from the sum of the barrel weights, was in close agreement with the weight computed from the Thayer coal feeder.

However, large discrepancies were observed between the drum weight data and the pfMaster system results. Figure 5.6.2-3 is a bar chart of the 3000 lb/hour results.

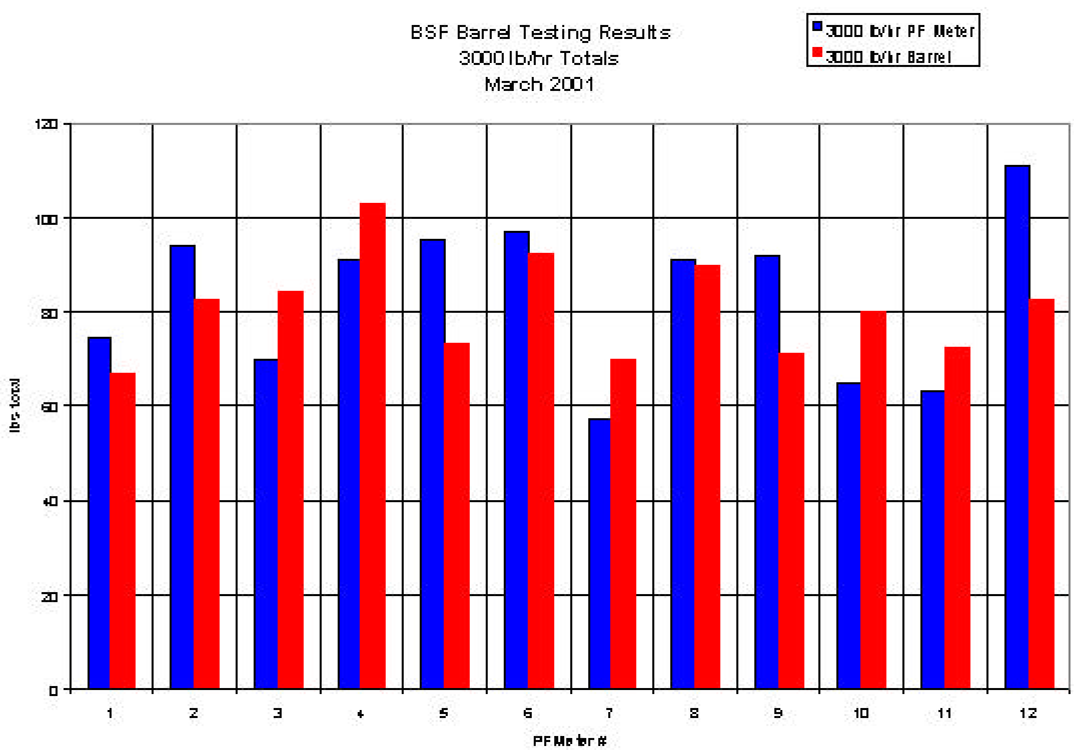

Figure 5.6.2-3: Results of the 3000 lb./hr Drum Weight Test.

The large deviations in the actual versus measured values were even more disconcerting when the ratio of pfMaster measured values to actual drum weights was found to be inconsistent from test to test.

After completion of the drum testing a decision was made to dismiss any use of the pfMaster system data in the BSF test results analysis.

Coal Flow Meter Discussion

After reviewing the coal flow rate data from the pfMaster system versus that obtained from the drum weight tests ALSTOM Power personnel concluded that there was something fundamentally wrong. Arrangements were made to return one pfMaster sensor together with the upstream and downstream piping to ABB Automation for their root cause analysis.

ABB Automation, which has a number of pfMaster installations in commercial service, had confidence in the design of the basic meter and the correlation-based measurement analysis. A problem that the ABB field engineer had noted during system commissioning and subsequent support trips to Windsor, CT was that both the magnitude and shape of the computed signal correlation obtained at the BSF were different from that measured at other locations. Figure 5.6.2-4 compares the BSF correlation functions with a typical pfMaster correlation. At the ABB test laboratory a set of tests was performed to first verify if the BSF problem could be reproduced and then to determine if the condition could be improved.

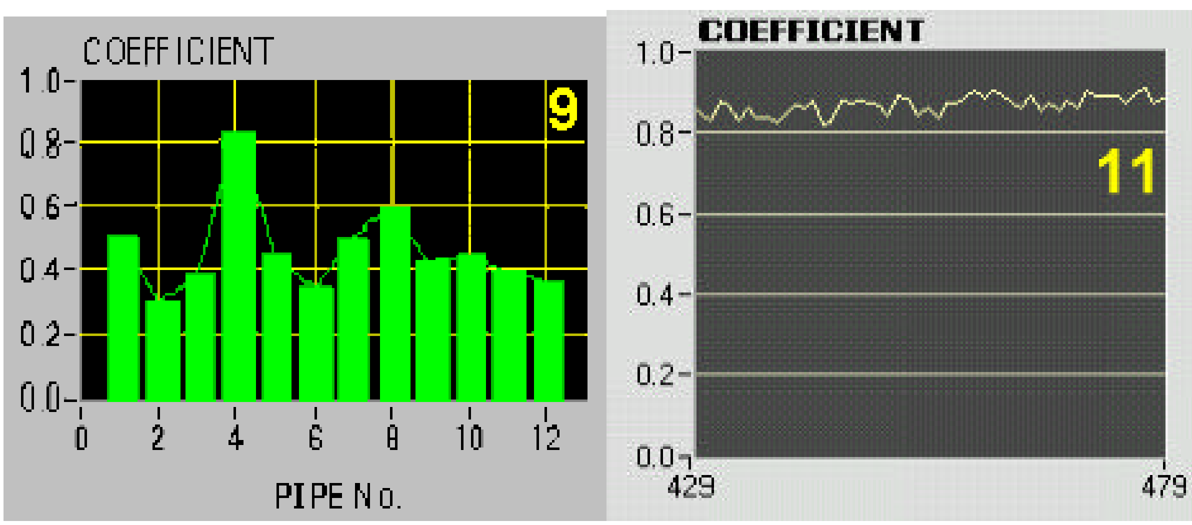

Figure 5.6.2-4: Comparison of pfMaster Velocity Correlation Functions: ALSTOM Power's BSF (left) and ABB Test Laboratory Results (right).

The first set of tests employed the pfMaster sensor exactly as it was installed at the BSF. Figure 5.6.2-5 is a photograph of the BSF installation arrangement and resulting velocity correlation function. It was concluded that the ABB installation accurately produced the variant correlation that was identified during the BSF operation.

The focus of the investigation then turned to the manner in which the coal feed piping diameter was reduced from 2 1/2" (63mm) down to the 2" diameter (50mm) to accommodate the pfMaster sensor. The original ABB mockup replicated the BSF installation wherein the transition was made immediately before and after the sensor body (see Figure 5.6.2-5). In the test facility ABB introduced the transitions at 10 pipe diameters before and after the pfMaster sensor. Figure 5.6.2-6 documents both the physical arrangement and the resulting velocity correlation function.

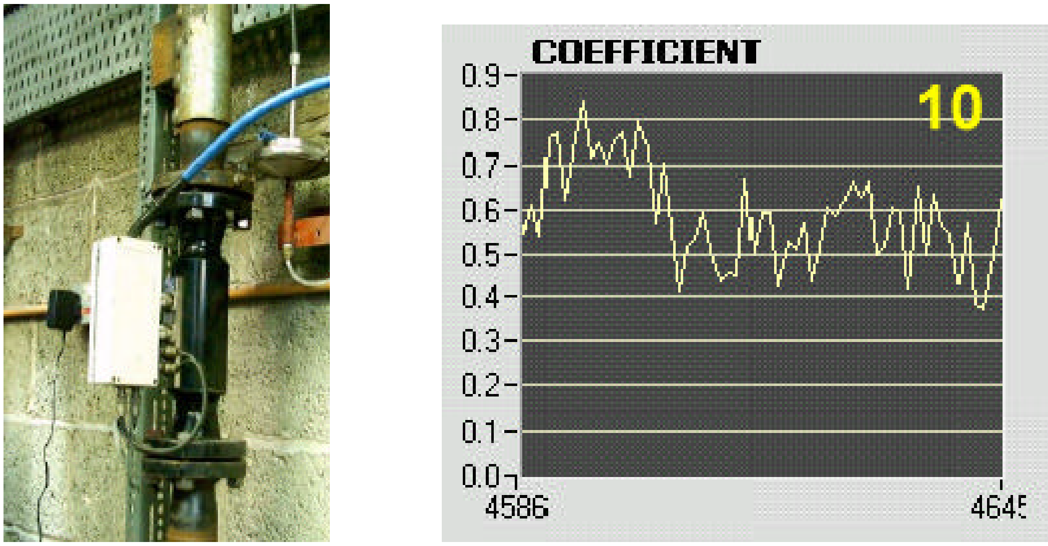

Figure 5.6.2-5: ABB Test Installation of ALSTOM Power's BSF Configuration and Associated Velocity Correlation Function.

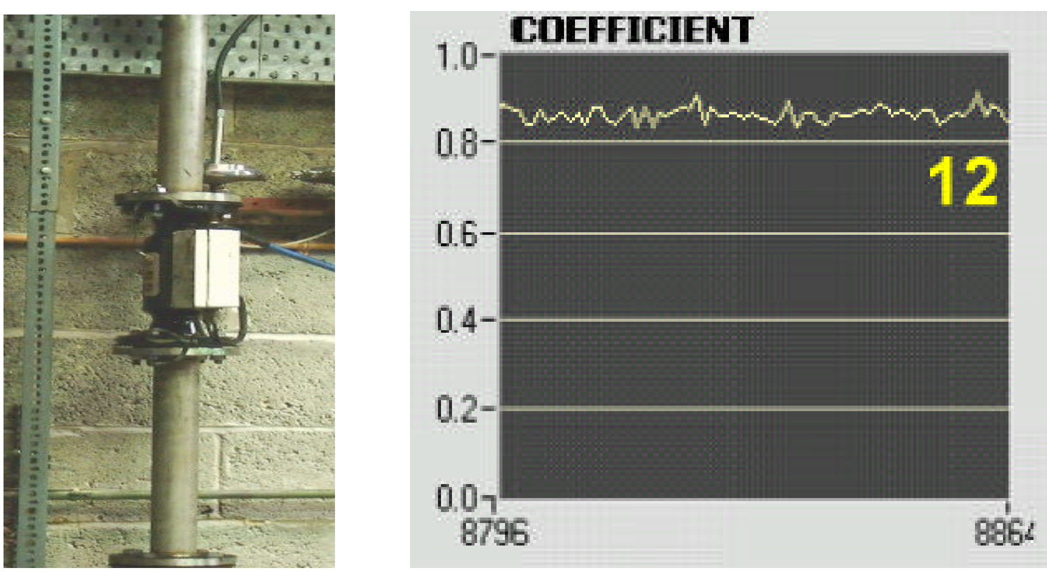

Figure 5.6.2-6: ABB Test Installation Placing the pfMaster Sensor 10 Pipe Diameters Upstream and Downstream from Transition Sections and Associated Velocity Correlation Function.

The ABB experimental results indicate that the close proximity between the coal pipe reducers and the pfMaster sensor had a significant negative impact on the quality of the pfMaster sensor's velocity correlation function. It should be noted that although the velocity correlation function with the BSF configuration was not as good as obtained in the subsequent, modified ABB test setup, the actual velocity measurements were about the same in both cases. What is unclear is the relationship between velocity function and mass flow rate measurements.

ALSTOM Power personnel followed the ABB Automation installation instructions in the BSF installation and used the vendor-supplied close reducer flanges. It is apparent that the vendor was not adequately aware of the potential impact of pipe reducer induced turbulence on the performance of the pfMaster. Additional sensor calibration and testing would be required to determine if the accuracy of the coal flow measurements could be sufficiently improved to balance the coal flow rates to the individual burners.

Conclusions and Recommendations

The performance of the ABB Automation pfMaster Coal Flow meter system during BSF testing was disappointing. One important element in the overall test matrix was determining the impact of burner coal balancing on the overall NOx/combustion performance. A reliable, accurate coal flow meter was a requirement for the success of these tests. ABB Automation, despite being the only vendor willing to undertake sensor manufacture for the "small pipe diameter" BSF facility, did not provide a coal flow measurement system that was sufficiently accurate to achieve the goal of balancing coal flow.

Failure to obtain coal flow data has had two impacts on this project: (1) inability to accurately quantify the effect of coal flow balancing on NOx and/or combustion performance, i.e., carbon loss and CO levels, and (2) inability to verify the use of individual coal flow measurement devices as a key component in an advanced boiler control system for achieving performance optimization.

5.6.3 Flame Scanner Development

Introduction

In principle, combustion stability as well as other combustion-related consequences (e.g. NOx emissions, carbon loss, CO levels, etc.) are affected by the mixing, reaction rates, temperature, species and concentration distributions that define the flame. The extent to which combustion-related variables affect flame properties can be sensed in the flame radiation data. Sensing flame radiation, therefore, can provide information on the combustion conditions. Hence, sensing flame radiation has great potential use for combustion diagnosis and optimization and, when properly instrumented and analyzed, can be used in a control fashion.

The radiation signal, that is obtained using a single detector measurement flame scanner, is a stochastic time series, which consists of a DC component and AC components. It is expected that flame feature quantities can be defined through statistical analysis in the time-domain and frequency-domain.

The flame scanner, used during BSF testing, has been widely used in power plants to provide on/off indication for a single burner flame. The objective in this project is to extract information from the flame scanner signals and use it for on-line monitoring and control, specifically associated with achieving ultra low NOx performance. Relevant information was obtained during testing in the BSF.

Subtopics within this section cover the following: (1) a generic methodology is presented for flame signal processing and correlation analysis; (2) data collection and analysis methods are described; (3) statistical moments are computed and their correlations with main burner zone stoichiometry as well as the NOx measurements are carried out; (4) frequency domain analysis is used to provide further insight into the flame signal characteristics; (5) a flame feature vector was formed, and fuzzy inference method analysis performed, and (6) conclusions and recommendations are presented.

Flame Signal Processing Methodology

The following is a summary of the method used to process the single point flame scanner time series signals:

- Collect test data under typical test conditions, and examine the reliability of the measurements
- Perform analysis in both time domain and frequency domain to compute the basic quantities of the flame signals
- Perform correlation analysis using these individual quantities and the combustion process variables
- Use the relative quantities to form a preliminary feature vector, and perform dimension reduction operation (if necessary) using correlation analysis, PCA, etc.
- Define the mapping relationship between the final feature vector and the selected process variables

Data Acquisition

Figure 5.6.3-1 shows a schematic representation of the data acquisition process. During the BSF operation, two flame scanners (one IR and the other UV) were installed in the West Side view ports. The UV scanner monitored the main burner flame in northwest corner while the IR flame scanner monitored the southwest corner. The UV scanner being used is a line-of-sight (LOS), type one with integral electronics. For the UV scanner head, an optical lens in the flame scanner head assembly transfers the UV energy emitted by the flame to a silicon photodiode (see Figure 5.6.3-2). The IR scanner uses a fiber optic cable (FOC) to direct the flame energy back to signal conditioning electronics. The photodiode in each flame scanner generates an electrical current (at the level μA) which is proportional to the radiant flux it receives from the flame radiation. The current value is then converted into a voltage value through a logarithmic amplifier.

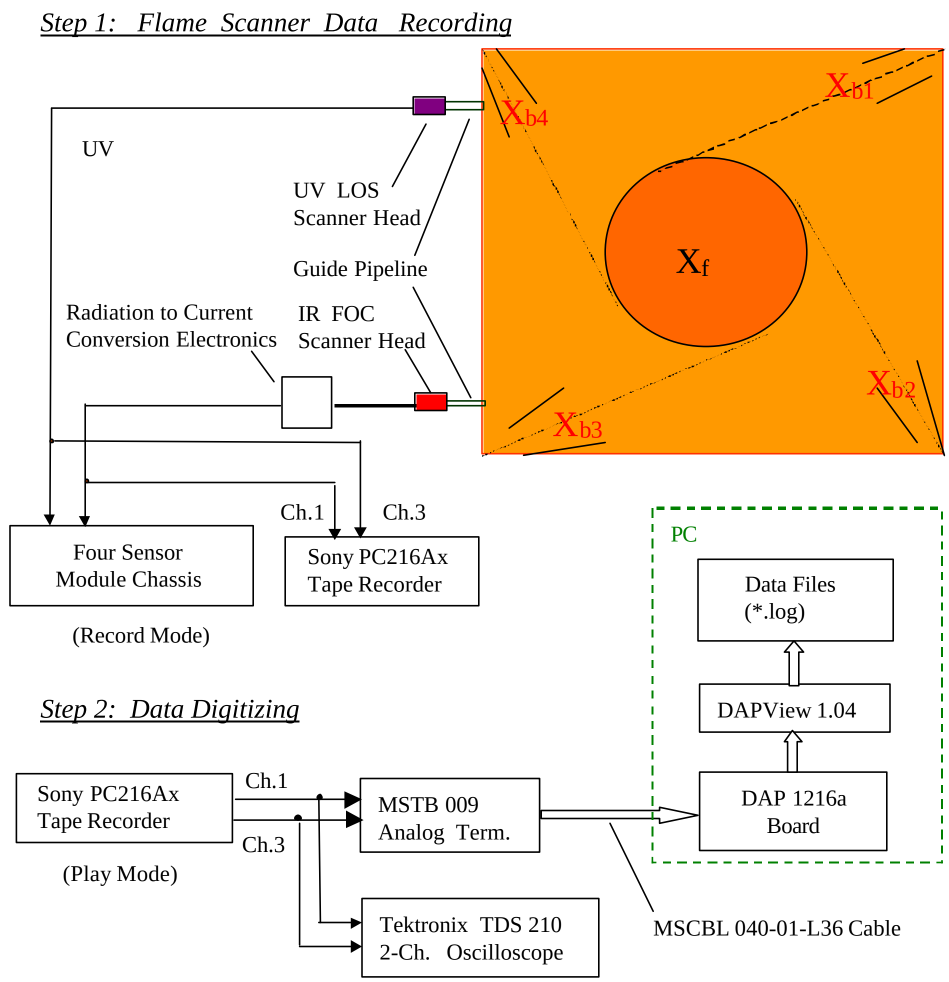

Figure 5.6.3-1: Schematic of the Flame Scanner Data Acquisition Process.

The scanner voltage was recorded using a DAT recorder. The DAT taped data was later replayed off line and digitized using a conventional, successive approximation 12- bit A/D converter system. Digitized signals were saved as data files for each test condition. Observation of the flame scanner signal in the frequency domain revealed that the signal bandwidth was naturally limited to 250Hz. Therefore, a data sampling rate of 500 Hz was selected.

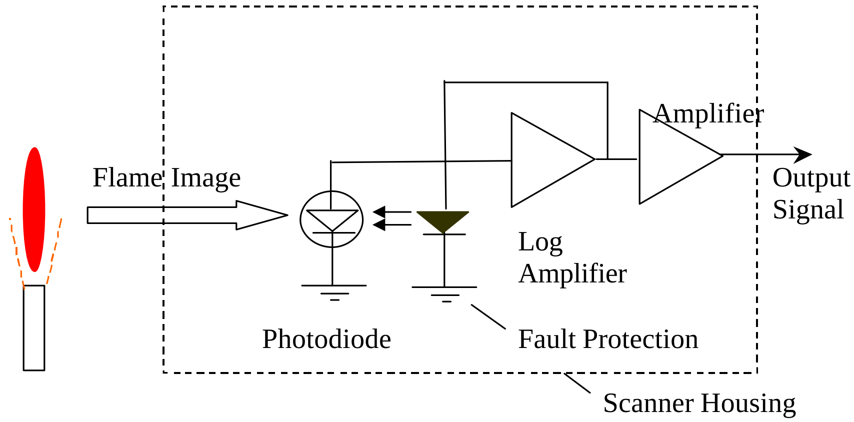

Figure 5.6.3-2: A Simplified Block Diagram of the Scanner Head Electronics.

Using the method described above, 31 sets of data were built, among which there are 28 sets corresponding to the BSF NOx test numbers. Two other data sets were recorded during the gas fired transient conditions, and one set was sampled for the electrical noises in the A/D process. Each set of data has 50,000 points for both IR and UV spectrums, at a sampling rate of 500 samples/second. Later, nine (9) data sets were collected for test No.75 and No. 103a to test the statistical stationary nature of the flame scanner signals.

Data Validation

To examine the reliability of the test data as acquired using the above system, statistical analysis has been performed to check the consistency of the measurement within the same test conditions (specifically Test No. 103a and Test No. 75 were used). For each of these two test conditions, the statistics, up to the fourth order (mean, standard deviation, skewness and kurtosis), were computed for each of the nine (9) sub interval data sets. The central moment and variation for these four quantities were estimated by calculating their mean values and standard deviations. The results are listed in Table 5.6.3-1 and Table 5.6.3-2. Observation of the data in these two tables shows that the individual test conditions were from a stationary process.

Table 5.6.3-1: Computing Results for Test No. 75.

	Q1 (Mean)	*Q2 (Std)*	*Q3 (Skewness)*	*Q4 (Kurtosis)*
IR (Average)	2071.55	45.54	-0.302	9.966
IR (Std)	4.99	0.61	0.0731	0.496
UV (Average)	2358.57	154.14	0.3	3.102
UV (Std)	27.04	5.12	0.073	0.137

Table 5.6.3-2: Computing Results for Test No. 103a.

	Q1 (Mean)	*Q2 (Std)*	*Q3 (Skewness)*	*Q4 (Kurtosis)*
IR (Average)	1654.48	69.29	-0.09666	9.13
IR (Std)	6.8	1.83	0.083	0.59
UV (Average)	1833.44	176.01	-0.0933	3.59
UV (Std)	9.03	3.22	0.044	0.07

Statistical Analysis of the Flame Signals

The flame signal output provides a direct reflection of the combustion conditions, which are influenced by the deterministic controls such as the firing rate and air-fuel-ratio as well as unknown disturbances and noise. To extract features from the flame signal time series the statistical moments (mean value, standard deviation, skewness, and kurtosis) have been computed for both IR and UV flame scanner signals under the 28 different test conditions. To conduct a correlation study between the flame statistics and main burner zone stoichiometry and NOx, values for these two variables were obtained from the official test log spread sheet for the particular BSF test.

In contrast to the small signal variation measured within an experiment, as shown in Tables 5.6.3-1 and 5.6.3-2, Table 5.6.3-3 presents the variation observed from the statistical moments for all of the test points. The conclusion is that statistically the moments are sensitive to some operational changes within the BSF test matrix.

Table 5.6.3-3: Variations of the Four Features.

STD		*Q1 (Mean)*	*Q2 (Std)*	*Q3 (Skewness)*	*Q4 (Kurtosis)*
IR	***103a***	6.8	1.83	0.083	0.59
	75	4.99	0.61	0.0731	0.496
	All(28)	**236**	**23.88**	**0.219**	**5.04**
UV	***103a***	9.03	3.22	0.044	0.07
	75	27.04	5.12	0.073	0.137
	All(28)	**290.6**	**31.43**	**0.286**	**0.461**

Correlation coefficients were computed for relationships between each of the four statistical features (both IR and UV) and the main burner zone stoichiometry and the NOx measurements recorded during the test program. Correlations between these four statistical features and boiler parameters covered all of the test conditions recorded.

Table 5.6.3-4: Correlation Statistical Features (Converted Data) with MBZ and NOx.

		Q1(Mean)	Q2 (Std)	Q3(Skewness)	Q4(Kurtosis)
IR	Cr. Stoi.	0.2927	-0.2712	**0.6625**	**0.9091**
	Cr. NOx	0.3061	0.0006	**0.4719**	**0.7312**
UV	Cr. Stoi.	**0.7141**	**0.6557**	-0.1062	-0.2115
	Cr. NOx	**0.8716**	**0.8708**	0.1417	0.1527

It can be seen that for both main burner zone (MBZ) stoichiometry and the NOx measurements the IR detector kurtosis values and the UV mean values are highly correlated. Figure 5.6.3-3 presents the functional relationship between IR Kurtosis and MBZ Stochiometry.

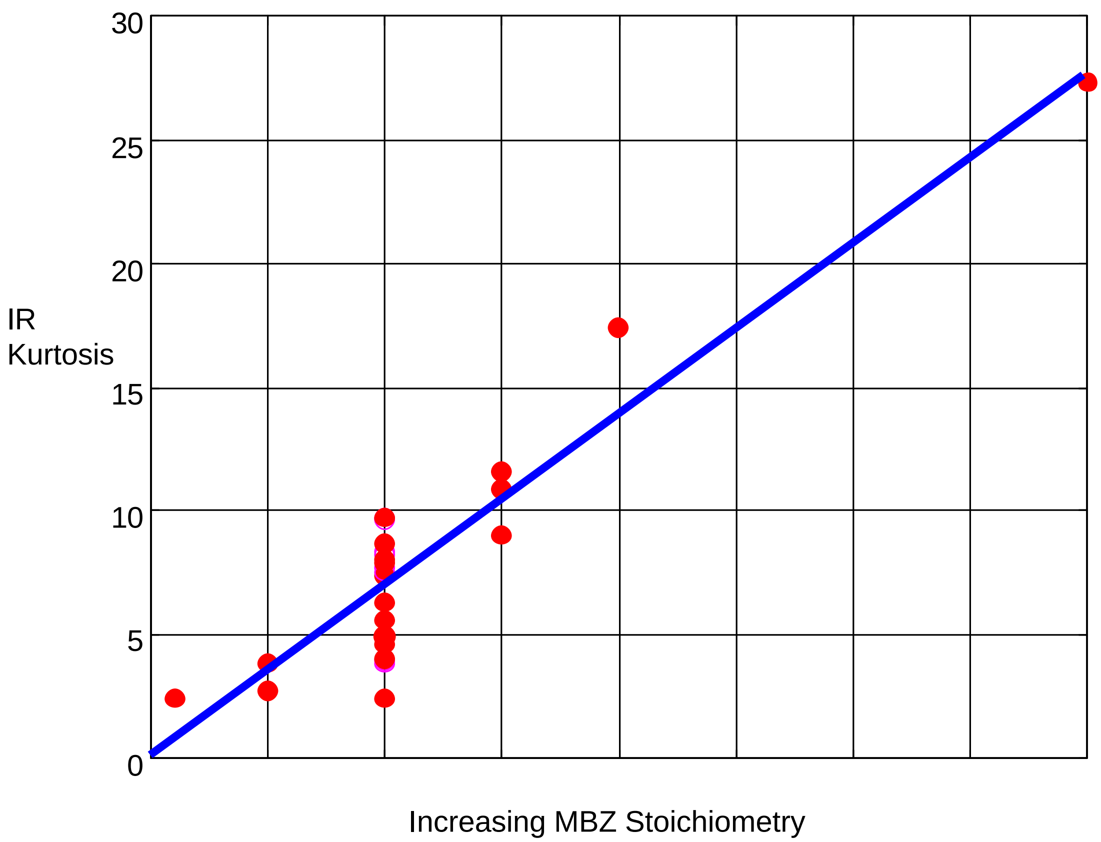

Figure 5.6.3-3: Correlation between IR Kurtosis and MBZ Stoichiometry.

Based on the analysis results reported in Table 5.6.3-4, a preliminary feature vector can be formed to use in the model for predicting MBZ stochiometry:

Kurtosis for IR signal:	Kurt_IR_After	(V1)
Skewness for IR Signals:	Skew_IR_After	(V2)
Mean for UV Signals:	Mean_UV_After	(V3)
Standard Deviation for UV Signals :	Std_UV_After	(V4)
Standard Deviation for IR Signals:	Std_IR_Before	(V5)

To further reduce the dimensionality of the feature vector, correlation analysis was performed. This was done to determine if each of the preliminary vector components was independent or whether it was a function of another feature. Table 5.6.3-5 presents the results of using feature correlation to refine the feature vector to form a "minimum basis vector set" for predicting MBZ stochiometry.

Table 5.6.3-5: Correlation Among the Selected Feature Variables.

	V1	***V2***	***V3***	***V4***	***V5***
V1	1	**0.8183**	0.3762	0.3525	-0.4533
V2	**0.8183**	1	0.5694	0.5497	-0.5625
V3	0.3762	0.5694	1	**0.973**	-0.1889
V4	0.3525	0.5497	**0.973**	1	-0.1445
V5	-0.4533	-0.5625	-0.1889	-0.1445	1

Based on Table 5.6.3-5 it was concluded that preliminary feature vectors (V2 and V3) were sufficiently highly correlated to be redundant. These features were dropped and the signal statistic's feature vector had the following form:

$$V_f = [Kurt\_IR\_After,\ Mean\_UV\_After,\ Std\_IR\_Before] \qquad (E5.6.3\text{-}1)$$

Using the three inputs and the MBZ stoichiometry as the output, rules were drawn up from observations made. For ease of illustration, two fuzzy logic scales were defined for each input, namely high and low. A rule can be inferred from the previous observations:

Rule 1: If:

Kurt_IR_After	IS	high	AND
Std_IR_Before	IS	high	AND
Mean_UV_After	IS	high	

Then:

MBZ Stoichiometry IS high

In a later section it will be shown how fuzzy logic will be used to construct the fuzzy rules for different combinations of the inputs (which will be fuzzified with membership functions.)

Frequency Domain Analysis

It was anticipated that the spectral content of the flame scanner signal might provide correlated content with MBZ stochiometry. To test this hypothesis DFT (Discrete Fourier Transform) was performed on the flame scanner data sets. Variations in spectra were observed among the 28 different test data sets. While these spectral variations provide a qualitative measure of signal difference, tracking individual frequency changes is unwieldy. In order to use the spectral information, but eliminate the excessive single frequency variability, a computed spectral parameter, a characteristic frequency (Equation 2) is defined as a "weighted spectral average frequency" over the frequency range 0-250Hz.

$$Fav = \frac{\sum_{i=1}^{250} y_i f_i}{\sum_{i=1}^{250} y_i} = \frac{\sum_{i=1}^{250} y_i (i-1)_i}{\sum_{i=1}^{250} y_i} \qquad \text{(E5.6.3-2)}$$

F_{av} is the weighted average frequency; yi refers to the amplitude corresponding to the i-th frequency f_i.

In order to evaluate normal F_{av} variations within the same test condition an evaluation similar to that used with the statistical moments was performed. Again, using Test No. 75 and 103a, the 50,000 data points from each test condition were divided into 100 groups of 500 points each. Then the average frequency value was calculated using the 100 spectral averages. This spectral averaged "Characteristic Frequency" is then used as the frequency domain feature quantity.

The overall average frequency for IR is 105.64HZ and that for UV is 53.18 HZ. The overall variations among the 28 test conditions are 6.78Hz (STD) and 4.55Hz (STD) for IR and UV, respectively. For the gas only tests (data collected during the last period when the BSF is shutting down, gas only), it is significantly different (127Hz, 124 HZ). Table 5.6.3-6 provides a comparison for these numbers:

Table 5.6.3-6: Comparison of the Variations in Characteristic Frequency.

	IR	UV
All (28)	**6.78**	**4.55**
Test 103a	0.75	0.79
Test 75	0.49	0.63

In the same manner as with the comparison of the variance in the statistical moments, the variation in the characteristic spectral frequency far exceeds the variance from a single test condition. This variation now needs to be checked to establish the level of correlation between the characteristic frequency and MBZ stochiometry.

In the same fashion as was performed on the preliminary feature vector statistical components, a correlation with the UV and IR characteristic frequency and MBZ and NOx was performed. Correlation coefficients were calculated between the characteristic frequencies and the MBZ stoichiometry as well as NOx measurements. The results are listed in Table 5.6.3-7.

Table 5.6.3-7: Correlation Between the Characteristic Frequencyand MBZ and NOx.

Char_Freq	IR	UV
MBZ St.	**0.5199**	0.0809
NOx	0.2248	-0.173

From this correlation analysis it was concluded that only the IR characteristic frequency parameter was significantly correlated with MBZ stochiometry.

Thus, one more feature may be added to the feature vector defined by equation (3). Further analysis reveals the IR Characteristic Frequency is well correlated with the kurtosis of the converted IR scanner signals (65.11%). This may indicate that the frequency also reflects the reaction turbulence. Its correlation with the IR feature quantities (before and after conversion) is given in Table 5.6.3-8.

Table 5.6.3-8: Correlation between Characteristic Frequency and the Q1-Q4 for IR Signal Statistics.

	Q1(Mean)	***Q2(Std)***	***Q3(Skewness)***	***Q4(Kurtosis)***
IR CH Freq -vs- IR Moments	***-0.4133***	*-0.8644*	*0.7448*	*0.6511*

The final feature vector is thus selected as:

$$V_f = [Kurt\_IR\_After, Mean\_UV\_After, Std\_IR\_Before, IR\_Ch\_Freq] \qquad \text{(E5.6.3-3)}$$

Fuzzy Inference System

In this section, the ANFIS (Adaptive Neuro-Fuzzy Inference System) is used to learn the rules/knowledge from the feature data sets that have been prepared using statistical and frequency domain analysis in the previous sections.

The fuzzy inference system has a network structure similar to that of a neural network. It is a model that maps inputs through input membership functions and associated parameters, and then through output membership functions and associated parameters to outputs. In many applications, membership functions are considered fixed, and the rule structure (as previously illustrated) is determined by the user.

The inference system for the subject application is constructed as a Sugeno-type inference system with four inputs (the four elements of the feature vector in equation (3)) and one output (the MBZ stoichiometry). The output membership function is a constant (zero order).

For the feature vector to MBZ stochiometry predictive model, the training quickly converges. Figure 5.6.3-4 shows the comparison between the real data and the predicted output using the trained model; Figure 5.6.3-4 also gives the prediction error.

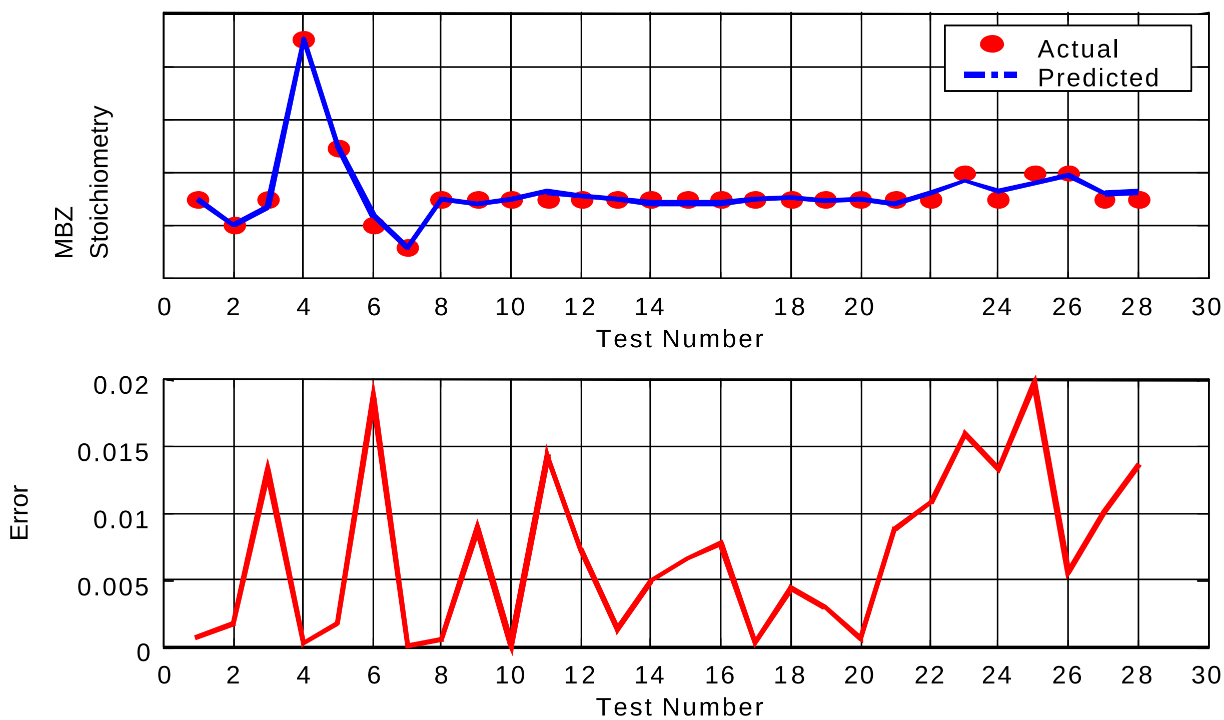

Figure 5.6.3-4: Fuzzy Logic Predictive Model Performance (Flame Scanner Features Prediction of MBZ Stochiometry).

Conclusions

The following conclusions were reached from the advanced flame scanner development task:

- The time series statistics as well as the characteristic frequency of both the UV and IR flame scanner time series data have significant correlation with the MBZ stoichiometry. This knowledge can be expanded to include the prediction of local burner NOx (under the condition that the OFA is also known.) This predictive capability can provide important information for real-time estimation and control of local NOx emissions.

- Based on this work a flame scanner feature vector has been constructed for combustion condition estimation; vector order reduction using correlation analysis has been performed and a minimum set of features has been identified.

- An Adaptive fuzzy inference model has been constructed and used to learn the rules based on the feature vector. The trained model's performance was verified using data from the BSF flame scanner tests. The model's performance using the tested range of operating conditions is very encouraging.

Recommendations

The following recommendations are suggested for the advanced flame scanner development work:

- More flame scanner tests should be conducted with a wider range of combustion conditions.

- Multiple flame scanners should be used to monitor several individual burner flames on the BSF or at an operating utility.

- A larger range of MBZ stoichiometries should be tested.

5.7 Bubbling Bed Char Oxidizer

A low velocity bubbling bed process, developed by Progress Materials, Inc., is among the Low NOx Subsystems that ALSTOM Power has considered in this project. No experimental work has been done in association with this process; rather its use has been assessed under “Economic Systems Analysis and Economics” in Section 7.0.

Progress Materials Inc. refers to their process as Carbon Burn Out™ (CBO™) wherein fly ash containing higher carbon contents than desired (nominally above 6%) can be burned in their low velocity fluidized bed to reduce unburned carbon to values, typically below 3%. Maintaining carbon levels below 3% can result in a marketable fly ash that can be used in concrete production.

The rationale for considering the use of CBO™ was that aggressive air staged low NOx systems could cause an increase in carbon content of the fly ash. Processing the fly ash through the CBO™ could make the difference between paying to landfill fly ash versus selling it for use in cement making. Application of the CBO™ process might also enable an additional degree of freedom for NOx control. The main burner zone could be more deeply staged without concern over carbon loss, since high carbon concentrations in the ash can be reduced to low levels in the backend bubbling bed system.

Objective

The objective of considering this technology was to determine the economic feasibility of using the Carbon Burn Out™ char oxidizer as part of an integrated, ultra low NOx system in order to remove a barrier to low NOx operation for low reactivity coals. As noted above, assumptions based on the use of this technology, will be used in the economic analysis and covered in Section 7.0.

Process Description

The CBO™ process combusts residual carbon in the fly ash carbon using a bubbling bed, with a 4 ft. deep fly ash bed at a typical operating temperature of 1350^{o}F, and at fluidizing velocities around 1 ft/sec. The bed temperature is operated below 1500^{o}F to avoid formation of agglomerates. A unique feature of this process is the ability to fluidize fly ash at velocities well above the particle terminal velocity, yet still maintain an active bed. These relatively high fluidizing velocities greatly reduce the required plan area for the combustor. The CBO™ process uses a hot cyclone to return elutriated particles back to the bed. The process recycles cooled product ash from a downstream particulate collector to control bed temperature. The final product is low-carbon fly ash exiting the bubbling bed combined with the relatively small amount of fly ash not collected by the high-efficiency hot cyclone.

Progress Materials has built a 1 ton/hr pilot plant (8 ft x 2.5 ft cross-sectional area), under EPRI's sponsorship. Fly ashes from over 20 different power plants have been successfully processed to carbon contents below 2%. Figure 5.7-1 shows pilot plant results with fly ashes from 5 power plants, with initial carbon concentrations up to 16%. The Gainesville fly ash, for example, had carbon content reduced from 15.6% to 0.5% when it was combusted at 1275F. Progress Materials has shown that Carbon Burn Out™ can control the product carbon content to a very close tolerance through variations in fly ash feed rate, operating temperature, and fluidizing velocity. Figure 5.7-2 also shows a consistent relationship between product ash carbon concentration and bed operating temperature.

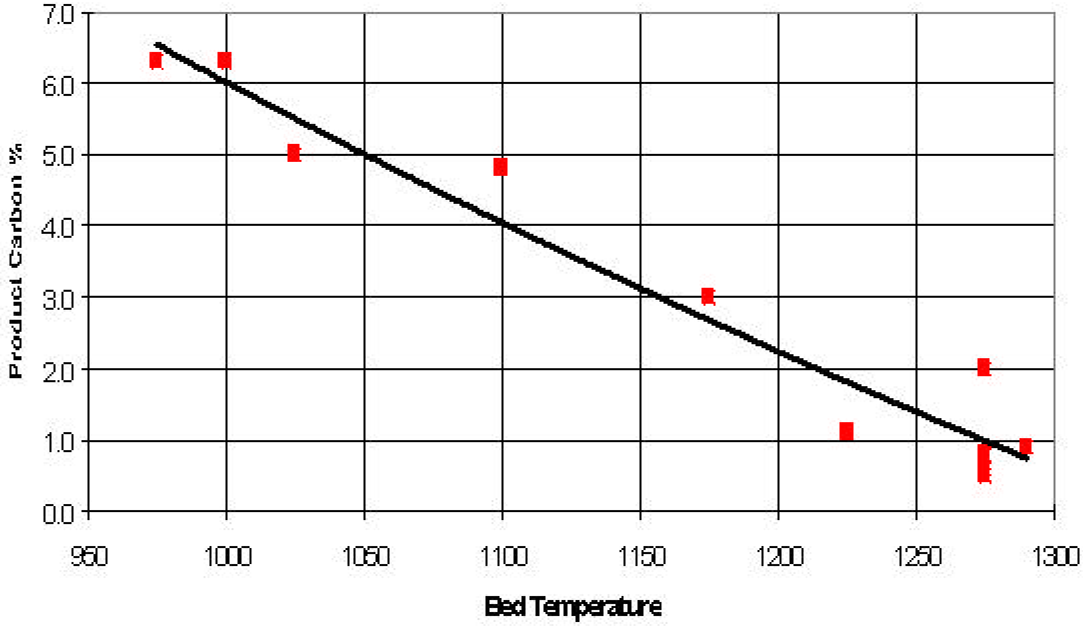

Figure 5.7-1: Product Carbon vs. Bed Temperature (Provided by Progress Materials, Inc.).

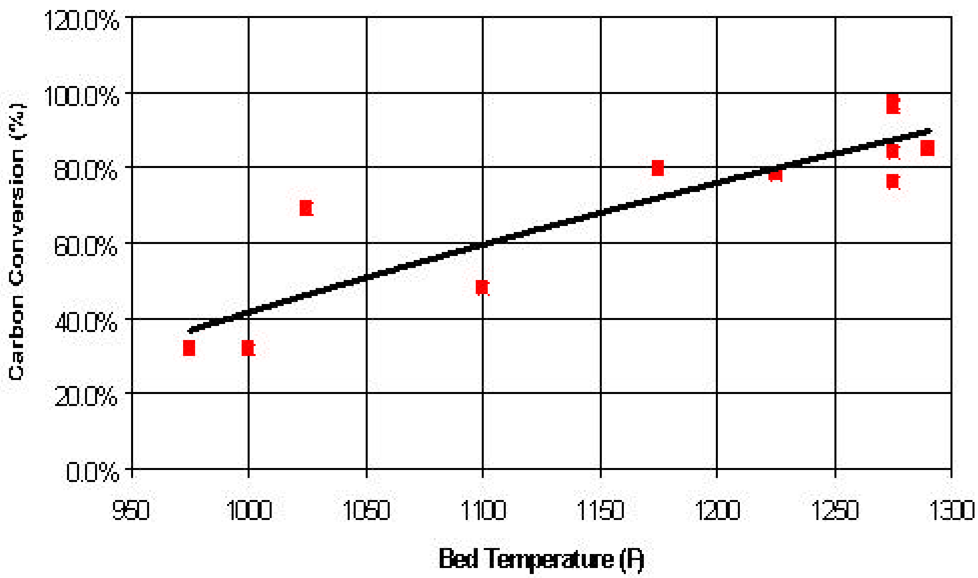

Figure 5.7-2 Carbon Conversion vs. Bed Temperature (Provided by Progress Materials, Inc.).

6.0 LARGE PILOT-SCALE COMBUSTION TESTING

Pilot-scale combustion testing represented a key activity in this project. Test results have provided quantitative indications of how the various components and process operating conditions have affected NOx, as well as other combustion performance parameters. A staged combustion system can be viewed as consisting of two sequential processes: (1) the fuel rich zone wherein fuel nitrogen is released and converted to molecular nitrogen, and (2) the overfire air zone wherein the remaining combustibles from the fuel-rich zone are burned.

Presentation of test results from pilot-scale testing has been organized to first discuss the variables and their effects on performance in the fuel-rich zone, followed by a discussion of variables and their effects on performance in the burnout zone. Among the key variables were main burner zone stoichiometry, staged residence time, fuel fineness and specific windbox compartment arrangements in the fuel-rich zone. In the burnout zone, overfire air location and velocity were among the important variables. High temperature SNCR through direct ammonia injection was briefly evaluated, both in the lower furnace and above the windbox for possible additional NOx reduction. Finally, very limited testing was done as a function of excess air and boiler load. Testing was performed on 3 coals; an Eastern medium volatile bituminous (MVB), a Powder River Basin subbituminous (PRB) and a Midwestern high volatile bituminous (HVB) coal.

6.1 Objective

The objective of this task was to quantify individual component and integrated system design and operating parameters versus performance, utilizing ALSTOM Power's 15 MW_t Boiler Simulation Facility (BSF). Results of this work will provide a means to optimize system and component operation and to generate data at a scale suitable to support scale-up to commercial installations.

6.2 Boiler Simulation Facility

Facility Overview

The Boiler Simulation Facility (BSF) is a water-cooled, atmospheric pressure, balanced draft, combustion test facility designed to replicate the time - temperature - stoichiometry history of a typical utility boiler. Configurable in tangential or wall fired modes, the BSF replicates all major attributes of a utility boiler including a "V" hopper, an arch, and appropriate (simulated) superheater, reheater, and economizer surface. For pulverized coal firing the BSF is nominally rated at 50 million Btu/hr (15 MW_t), but is capable of being fired at up to 90 MMBtu for oil or natural gas fired combustion testing. A photo of the BSF is shown in Figure 6.2-1.

Figure 6.2-1: Boiler Simulation Facility.

Test Procedure

Combustion testing in the BSF commonly proceeds as follows: after a cold facility start-up, several hours are allowed for the BSF to reach desired load and the refractory lining to reach operating temperatures/thermal equilibrium. Then, test conditions (firing system configuration, furnace stoichiometry history, firing rate, excess air level, etc.) are set to the desired level based on the test matrix specification. Relevant mass flow and emissions data will then be observed by the test engineer for several minutes to verify that the conditions are correct and acceptably steady. The flue duct gas sample point is maintained at a slightly positive pressure to avoid dilution of relevant flue emissions through air in-leakage.

The BSF DCS is continually monitoring system variables and the desired data (over 200 system variables) are logged at 1 minute intervals with a Labview data acquisition system. The data for a particular matrix test point is then extracted from the continuous data log from the actual start and stop times of the test point. Some of the variables logged for each data point include the global air and fuel input mass flow information, associated temperature data, main burner region windbox air flow rates and total separated overfire air (SOFA) flow rates, which allows for on-line calculation and control of bulk furnace stoichiometry history. Additional, pertinent operational data such as individual windbox compartment flows and main windbox and SOFA windbox damper positions are manually recorded as test board data.

Acquisition of data for each matrix test point typically consists of 30 minutes of steady state furnace operation, for which configuration and operational variables are monitored and held constant. For tests where collection of fly ash samples were not required, 10-15 minute tests were performed. For detailed, characterization testing (if applicable), steady state operation is maintained for extended periods on an as-needed basis. At the end of a test point, furnace operation and/or configuration are modified and, after the necessary time for conditions to equilibrate has elapsed, the process is started again.

The BSF utilizes a continuous sampling Gas Analysis System (GAS) to measure the gaseous species concentrations in the furnace effluent gas stream, prior to the post-combustion, flue gas conditioning equipment. The GAS system utilizes gas species analyzers meeting the requirements of 40 CFR methods 7E, 6C, 3A, 10, 25A, and 3A for NO/NOx, SO_2, CO_2, CO, THC, and O_2, respectively. This system is calibrated against certified bottled gas standards at least every twelve hours when taking test matrix data.

In furnace sampling is accomplished with water-cooled sample probes being inserted through more than 100 lower and upper furnace access ports. When recorded, in-furnace information may include, but is not limited to: total and incident heat flux, extractive solid samples, gaseous species concentrations, gas temperature, and gas and particle velocity information. A water cooled, suction pyrometer with a single Type B thermocouple can be utilized to measure in-furnace gas temperatures (horizontal furnace outlet plane temperature, etc.) and a steam heated, water cooled sampling probe is used to obtain gas samples for constituent analysis. Particulate samples, for determining the extent of combustion/devolatilization achieved at various locations in the furnace, can be obtained via a ceramic filter attached to the end of a water-cooled sample probe. All in-furnace sampling is done with the furnace operating at slightly positive pressure at the sampling port to eliminate air leakage into the furnace, and subsequent data inaccuracies.

Carbon loss data is obtained through isokinetic sampling of fly ash with an electrically heated, water-cooled sampling probe (consistent with U.S. EPA method 5), which is inserted in the furnace gas duct downstream of the economizer outlet. Additionally, a high-volume, cyclone equipped sampling probe can be used to extract particulate samples from the lower furnace hopper to quantify bottom ash carbon content.

6.3 Facility Preparation

Preparation of the Boiler Simulation Facility involved detailed inspection of all relevant equipment/hardware to ascertain its status, subsequent need for repair/replacement. In addition to the general facility preparation, certain components were replaced with those of modified design. Specifically, all original coal nozzles were replaced with new ones that were patterned after the commercial LNCFS™-P2 based low NOx pyrolysis burner design (see Figure 6.3-1). As discussed in greater detail in Section 5.3, the newly designed coal nozzle contains a bluff body to create greater recirculation and mixing in the coal nozzle to enhance devolatilization, hence the name oxidative pyrolysis burner.

Figure 6.3-1: Photo of Coal Nozzle Tip Used During BSF Testing.

Also, as part of the preparation of components within the burner zone, all required CFS™ air nozzles were set to a consistent offset angle. Additionally, two new CFS™ air nozzles were designed to provide optical access for testing of alternate flame scanner/flame front control feedback system components (See Figure 6.3-2). Allowance was also made for the installation of coal mass flow meters. Flexible coal piping was installed to facilitate movement of coal nozzles within the windbox; this would be important in conducting tests where a “compressed windbox” arrangement was tested, wherein the coal nozzles were grouped more closely to allow a greater staged residence time.

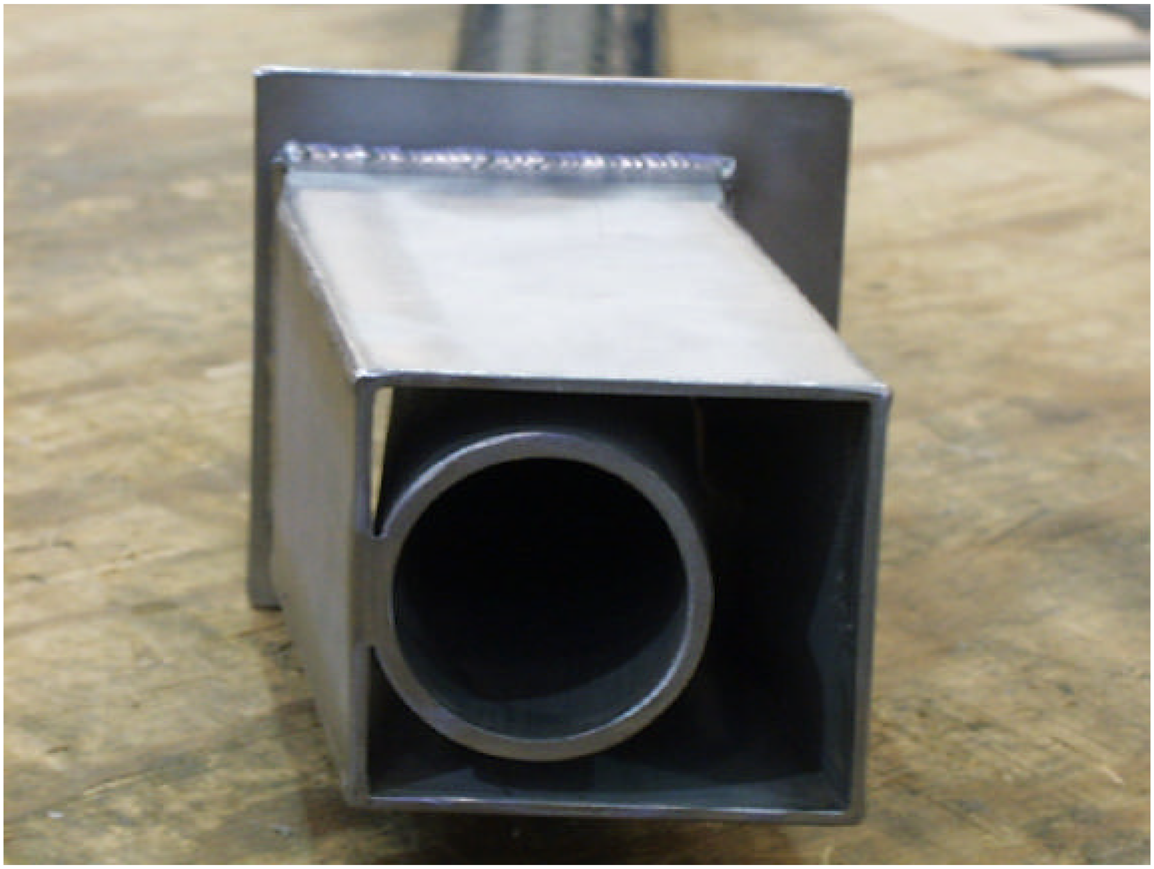

Figure 6.3-2: Photo of CFSÔ Air Nozzle Tip Modified for Optical Access.

The separated overfire air (SOFA) nozzles were also modified. For the subject testing, a new, larger air compartment was added to the bottom of each (upper and lower) SOFA assembly in order to increase the range of air velocities and mass flow rates/stoichiometries that could be tested in the BSF. The addition of the larger air compartments in each of the SOFA assemblies allowed more flexibility in studying and understanding the impact of jet velocity on the penetration and mixing of overfire air, with respect to unburned carbon and CO oxidation. Specifically, enlargement (greater free area) of the bottom compartment of both the upper and lower SOFA assemblies would allow a greater quantity of combustion air to be injected at lower velocities, in better correspondence (equivalent to commercial units) with the vertical velocities within the BSF. Figure 6.3-3 is a photo of the modified SOFA assembly that was used during BSF testing.

Figure 6.3-3: Photo of Modified SOFA Assemblies Used During BSF Testing.

Figure 6.3-4 shows the installed firing system components in the BSF, namely the lower SOFA assembly and a coal nozzle with the associated auxiliary air compartements.

Figure 6.3-5 is a photo of the entire north wall, taken inside the BSF. This photo provides a good perspective of the correspondence between the burner zone (fuel and air nozzles) and the overfire air nozzles (lower and upper SOFA assemblies).

Figure 6.3-4: Photo of Installed Firing System Components.

Figure 6.3-5: Inside View of the North Wall of the BSF.

Figure 6.3-6 is a photo of the BSF in operation. While the BSF is operating, steam is released from the atmospheric water jacket that cools the simulated water walls. The size of the BSF can be put in perspective by observing a member of the test crew taking data on the 3rd deck.

Figure 6.3-6: The BSF in Operation During Testing of the MVB Coal.

6.4 Combustion Testing

6.4.1 As-Fired Fuel Analysis

Table 6.4.1-1 shows the as-fired fuel analysis (after pulverization) for the three coals tested in the BSF. The analyses shown here are in reasonable agreement with those shown earlier in Table 4.3-1 when compared on an equivalent basis.

Table 6.4.1-1: As-Fired Pulverized Coal Analyses.

	PRB Coal	HVB Coal	MVB Coal
Proximate			
VM	35.6	37.7	22.5
FC	39.6	51.4	63.1
FC/VM	1.1	1.4	2.8
VM, DAF	47.3	42.6	26.3
Ultimate			
Moisture	18.9	4.3	0.9
Hydrogen	3.7	4.9	4.0
Carbon	56.4	71.6	74.7
Sulfur	0.4	2.5	1.4
Nitrogen	0.9	1.5	1.3
Oxygen	13.8	7.9	4.2
Ash	5.9	7.2	13.6
Total	100	100	100
HHV, BTU/lb	9,890	13,088	13,109
O/N	15.3	5.3	3.2
lb N/MMBTU	0.91	1.15	0.99
lb S/MMBTU	0.40	1.91	1.04
lb Ash/MMBTU	6.0	5.5	10.3

6.4.2 Test Matrix Development

As noted in Section 4.0, under Test Coal Selection (Subsection 4.2), three different coals were chosen for testing, namely an Eastern medium volatile bituminous (MVB), a Powder River Basin subbituminous (PRB) and a Midwestern high volatile bituminous (HVB) coal. The testing sequence started with the MVB coal, followed by the PRB and HVB coals. Approximately 80 tests were conducted on each of the MVB and PRB coals (total of 160 tests), and about 35 tests were conducted on the HVB coal. Many of the test variables were the same for each of the coals. Table 6.4.2-1 shows all of the test variables evaluated and for which coal(s) that particular variable was explored.

Table 6.4.2-1: Pilot Scale Combustion Test Variables.

TEST VARIABLE	MVB COAL	HVB COAL	PRB COAL
MBZ Stoichiometry	X	X	X
Staged Residence Time	X	X	X
Transport Air/Fuel Ratio	X	X	X
Transport Air/Fuel Flow Balancing	X	X	X
Coal Ballistics		X	X
Bottom End Air		X	X
Near Field Stoichiometry Control		X	X
Compressed Windbox		X	X
Coal Fineness	X		X
SOFA Elevation			X
SOFA Velocity	X		X
Excess Air			X
High Temp. SNCR	X		
Boiler Load			X

Main burner zone (MBZ) stoichiometry and staged residence time are significant, key variables, relative to NOx control, and have been evaluated for each of the three coals. Transport air to fuel ratio was varied for the MVB and PRB coals, the rationale being that lesser amounts of transport air might have a favorable thermal effect (greater fuel bound nitrogen release) and/or a favorable aerodynamic effect (higher concentration of particles in the near-burner zone). Transport air and fuel flow balancing involved the uniformity of fuel and transport air flow rates from each of the twelve (12) coal nozzles, and possible effects of non-uniformity on NOx.

Coal ballistics, tested for the HVB and PRB coals, involved the angle at which the lower elevation of coal was being injected. Specifically, the bottom elevation of coal could be varied in both yaw and tilt, relative to the other coal streams, which had a fixed orientation. Figure 6.4.2-1 shows the standard windbox compared to the configuration employed with the “Coal Ballistics” test case.

	Standard Windbox	Coal Ballistics	Compressed Windbox
(Top) 16	CCOFA	CCOFA	CCOFA
15	CCOFA	CCOFA	CCOFA
14	CCOFA	CCOFA	CCOFA
13	Straight Coal	Straight Coal	CFS
12	CFS	CFS	CFS
11	Aux	Aux	Straight Coal
10	CFS	CFS	Aux
9	Straight Coal	Straight Coal	CFS
8	CFS	CFS	Straight Coal
7	Aux	Aux	Aux
6	CFS	CFS	CFS
5	Straight Coal	Offset Coal	Straight Coal
4	Bottom End	Bottom End	Bottom End
3	Bottom End	Bottom End	Bottom End
2	Bottom End	Bottom End	Bottom End
(Bottom) 1	Bottom End	Bottom End	Bottom End

Figure 6.4.2-1: BSF Windbox Configurations.

The compressed windbox case, also shown in Figure 6.4.2-1, represents an arrangement whereby the three elevations of coal are injected at an overall lower elevation than the standard windbox setup. The rationale was to increase the substoichiometric residence time between the top coal elevation and separated overfire air (SOFA) injection. The "Coal Bias" case was similar in concept to the compressed windbox case in that coal flow to the top elevation was decreased, with additional coal being injected in the first two elevations to maintain a constant overall coal flow.

Coal fineness was varied for two of the three coals, namely the MVB and PRB coals. Because of the low volatile content in the case of the MVB coal, two different coal grinds were tested: a microfine grind wherein the coal was ground to a fineness of 96% less than 325 mesh, and a fine grind of 85% less than 200 mesh. The microfine grind was prepared off site at ALSTOM Power's Air Preheater Company (Raymond Operation) in a ball tube mill and shipped to the Windsor, CT site in 55-gallon drums. The fine grind was prepared in the

ALSTOM Power's Power Plant Laboratories (PPL), in Windsor, CT. In the case of PRB coal, the coal was ground to two different levels, namely 65% through 200 mesh and 85% through 200 mesh, both of which were produced at PPL.

The test variable identified as "Near Field Stoichiometry Control" refers to the location of air (within the firing zone) relative to the coal nozzles. Another variable within the firing zone involves air entering the furnace beneath the first coal elevation, termed "bottom end" air (see Figure 6.4.2-1). Both quantity and location of the bottom end air were tested using the 4 available bottom end air compartments.

Another key variable explored during pilot-scale testing was the injection of overfire air. Overfire air was injected in three areas: (1) close coupled overfire air (CCOFA) located immediately above the top coal elevation, (2) lower separated overfire air (LSOFA) located at some distance above the top coal elevation and (3) the upper separated overfire air (USOFA) located even further above from the top coal elevation. Variation in overfire air included location, quantity, and velocity of air injection. Within each of the two SOFA assemblies (one lower and one upper assembly) there are three compartments. As noted in Subsection 6.3, one of the modifications made to the BSF was to increase the free area of the lower compartment in each of the two SOFA assemblies. Having three compartments within each SOFA assembly provided a means to vary the SOFA air velocity, by shutting off some of the compartments and putting all the air through fewer compartments, which necessarily increased velocity.

Finally, "Excess Air" was varied, in the case of PRB coal, to determine its effect on NOx, CO and carbon in ash.

As an additional method of reducing NOx, high temperature SNCR, including direct injection of ammonia through the coal piping was briefly explored for the MVB coal.

Very limited testing was carried out wherein boiler load was varied for the PRB coal to determine effects of firing rate on NOx.

It should be noted that periodically throughout the pilot-scale testing the standard TFS 2000™ configuration was re-tested to determine if changes in conditions, such as ash deposit buildup, changed the NOx values. This was considered important since NOx values and other performance data (unburned carbon, CO, etc.) taken during new test configurations/ conditions was always compared to those values obtained with the standard TFS 2000™ configuration. In other words, the differential between TFS 2000™ values and values obtained during new test conditions was considered significant. Figure 6.4.2-2 shows the reproducibility of baseline (Standard TFS 2000™) configuration results for tests that were conducted periodically throughout execution of the test matrix. Figure 6.4.2-2 shows results for the PRB coal, which is typical of reproducibility results for the other two coals.

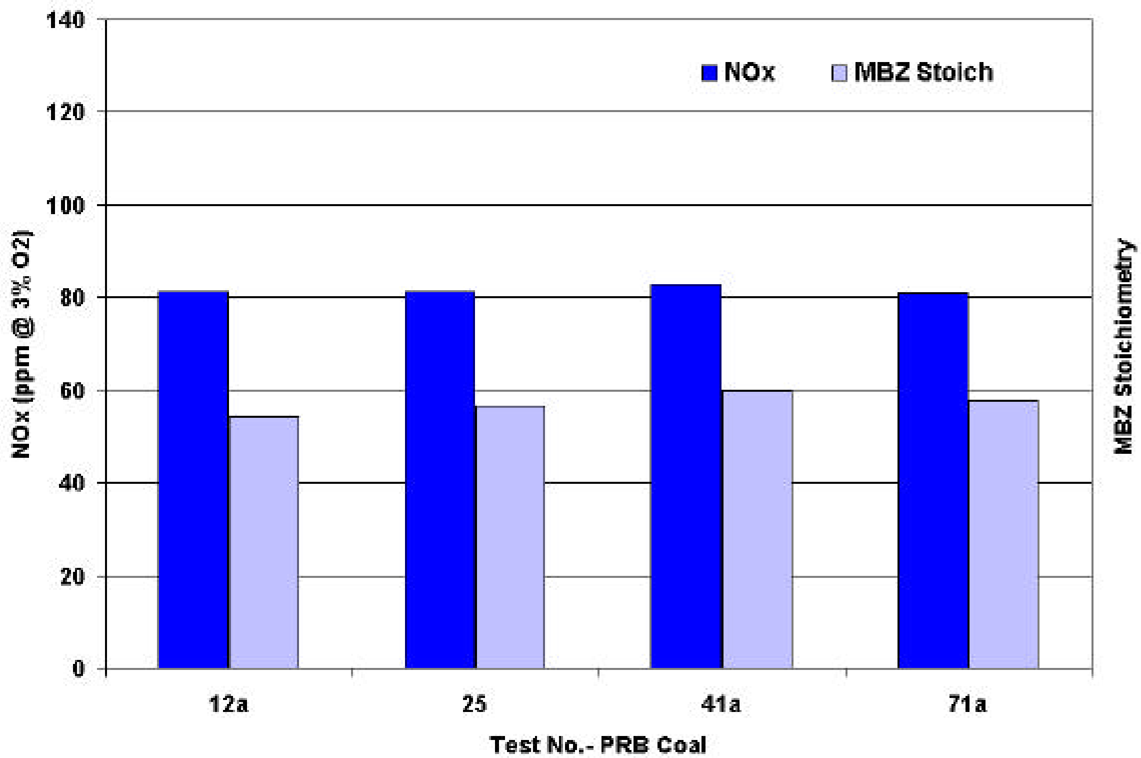

Figure 6.4.2-2: NOx Repeatability Tests for PRB Coal.

6.4.3 Pilot-Scale Test Results

Main Burner Zone Stoichiometry

Main burner zone (MBZ) stoichiometry is one of the key variables in a staged air, low NOx firing system. In addition to reducing NOx, lower MBZ stoichiometries can also affect combustion performance parameters of carbon in ash (CIA) and carbon monoxide (CO). Figure 6.4.3-1 shows NOx as a function of MBZ stoichiometry for the three coals tested. Interestingly, but not surprisingly, the optimum stoichiometry, from a NOx point of view, is different for the three coals.

One way to explain the differences in optimum stoichiometry for the various coals is to first realize that the MBZ stoichiometry is based on the theoretical amount of air to burn all the combustible in the coal. In reality the atmosphere (reducing versus oxidizing) that actually exists in the MBZ depends on the reactivity of the fuel. A more reactive fuel burns more quickly and consumes more oxygen in a given amount of time. Hence for a given stoichiometry, the more reactive fuel consumes more oxygen, which means there is less oxygen available for producing nitrogen oxides. For the same stoichiometry a less reactive fuel consumes less oxygen in a given amount of time, hence more oxygen is available for producing oxides of nitrogen.

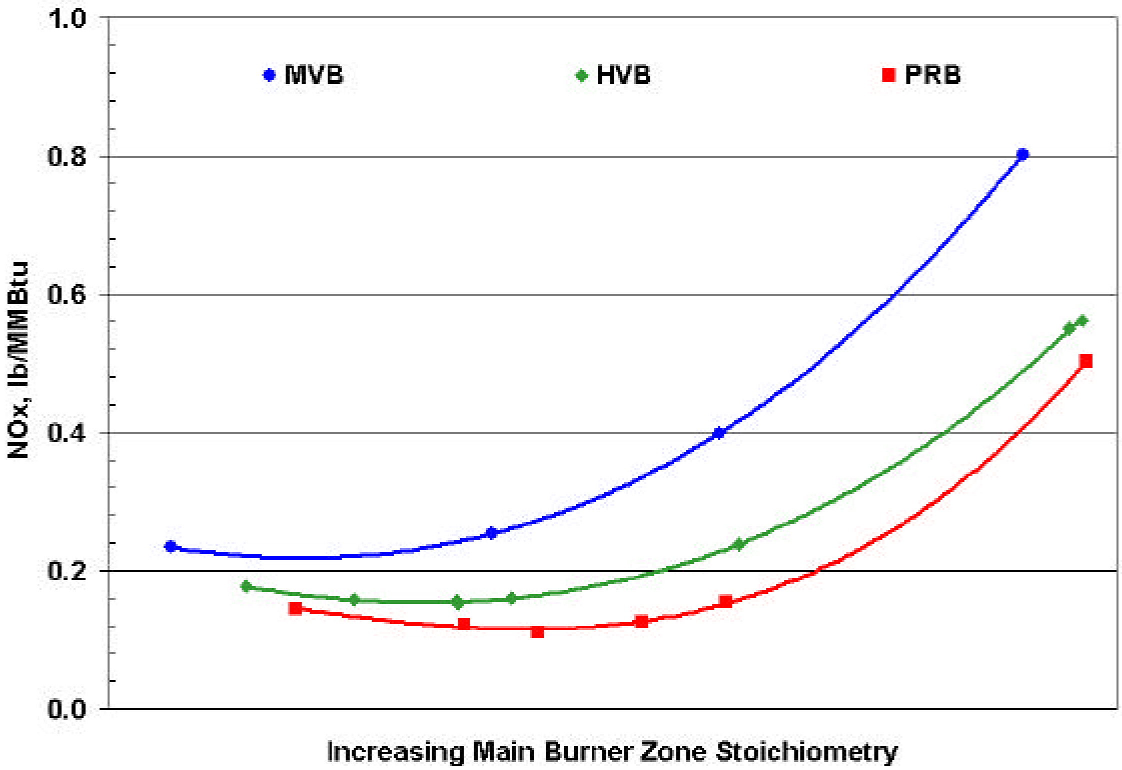

Figure 6.4.3-1: NOx versus Main Burner Zone Stoichiometry.

As was noted in Section 4.0 (Test Fuels Characterization) the MVB coal was the least reactive of the three coals tested. Furthermore fuel bound nitrogen conversion to nitrogen-bound gas species was considerably lower for the MVB coal, compared to the HVB and PRB coals. This simply means that there was less fuel nitrogen being released in the MBZ for conversion to molecular nitrogen. As noted in Section 4.0 fuel bound nitrogen that is not released in the MBZ is much more likely to produce nitrogen oxides as it is released downstream of the MBZ. The combination, then, of these two fuel properties, i.e., lower reactivity and lower amounts of fuel bound nitrogen being released in the MBZ, both serve to explain the higher NOx emissions for the MVB coal.

As previously mentioned above, obtaining lower NOx through an air staging process normally comes with some impact to carbon in ash and carbon monoxide, albeit to different degrees, depending on the coal properties. Figure 6.4.3-2 shows the relationship between carbon in ash (CIA) as a function of MBZ stoichiometry for the three test coals.

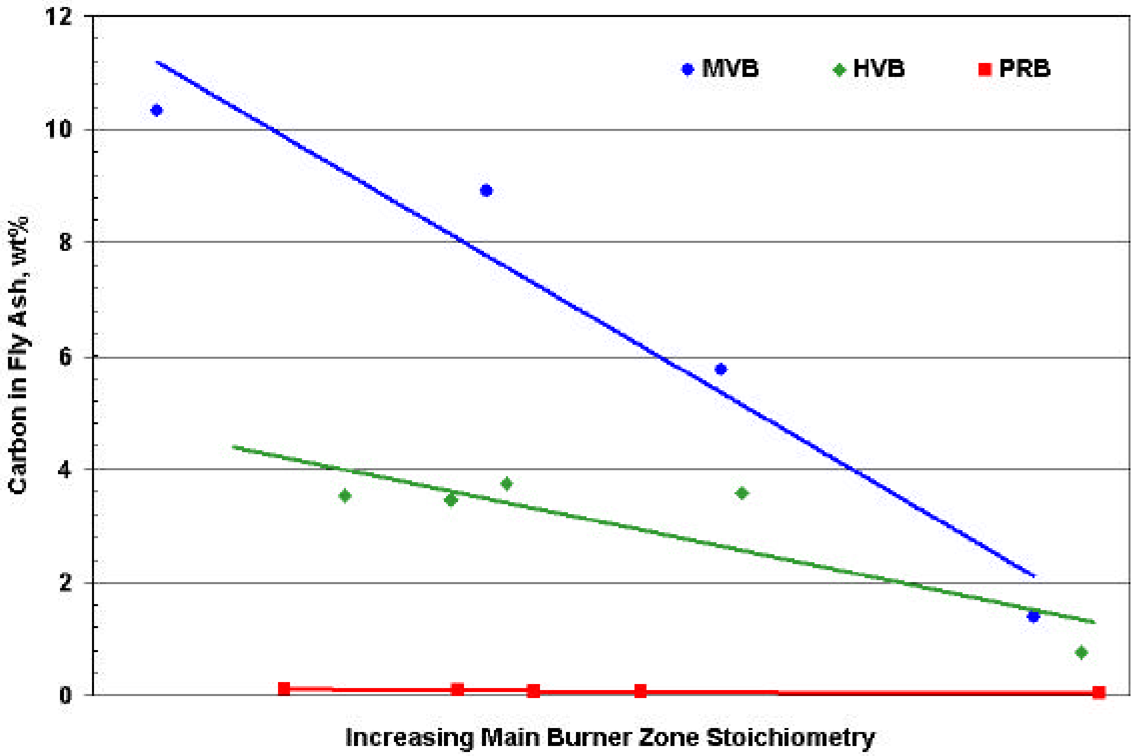

Figure 6.4.3-2: Carbon in Ash vs. MBZ Stoichiometry.

As expected, based on bench-scale laboratory data, the MVB coal shows the greatest increase in carbon loss as MBZ stoichiometry decreases. The PRB coal, by contrast, shows very little impact of decreasing stoichiometry on CIA; showing practically no carbon in ash over the range of stoichiometries tested. The plot for the HVB coal falls about midway between the other two coals, consistent with BET surface area and TGA reactivity results. A comparison of field data and BSF data (when the same MVB coal is burned) shows quite good agreement for both NOx and CIA values at similar stoichiometries (see Figure 6.4.3-3).

In addition to carbon in ash carbon monoxide was also monitored. Carbon monoxide values are shown as a function of MBZ stoichiometry in Figure 6.4.3-4. For the most part the CO levels mirror the unburned carbon levels in the fly ash for each of the three test coals. Carbon monoxide levels were the highest for the MVB coal and lowest for the PRB coal. In all cases the CO emissions were less than 20 ppm.

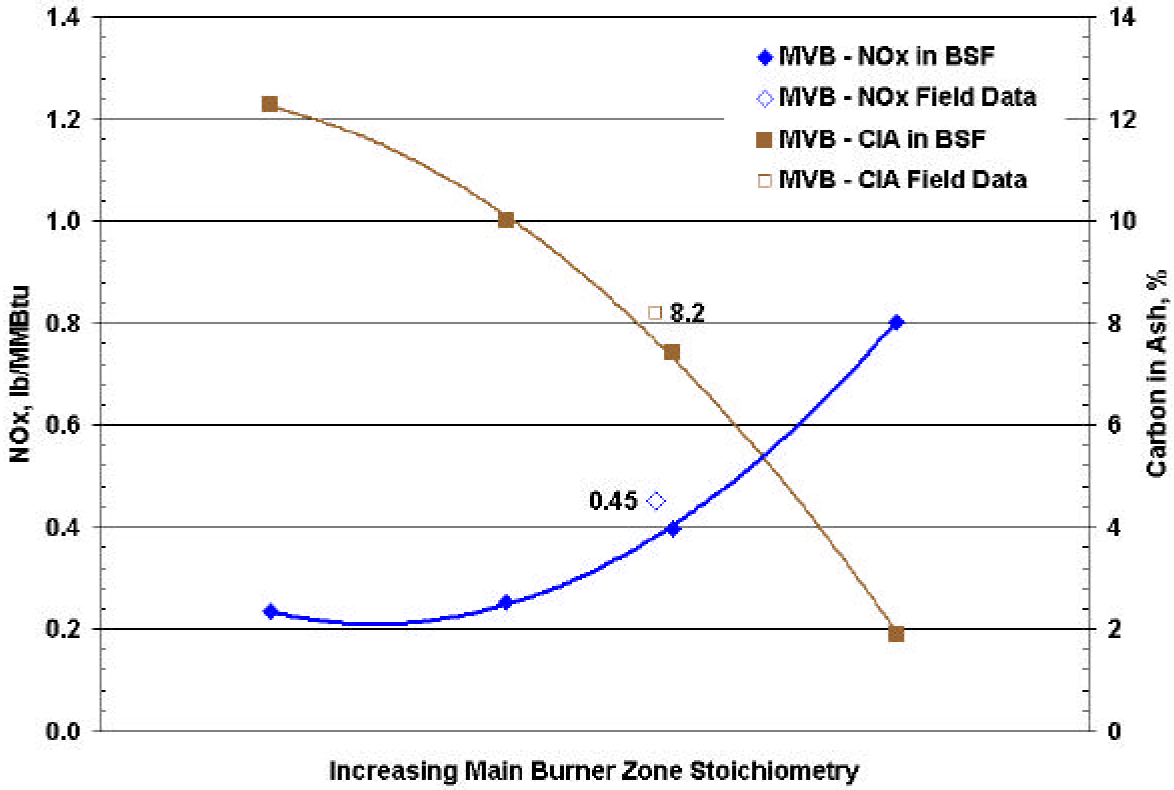

Figure 6.4.3-3: NOx and CIA vs. Stoichiometry from BSF and Field Data.

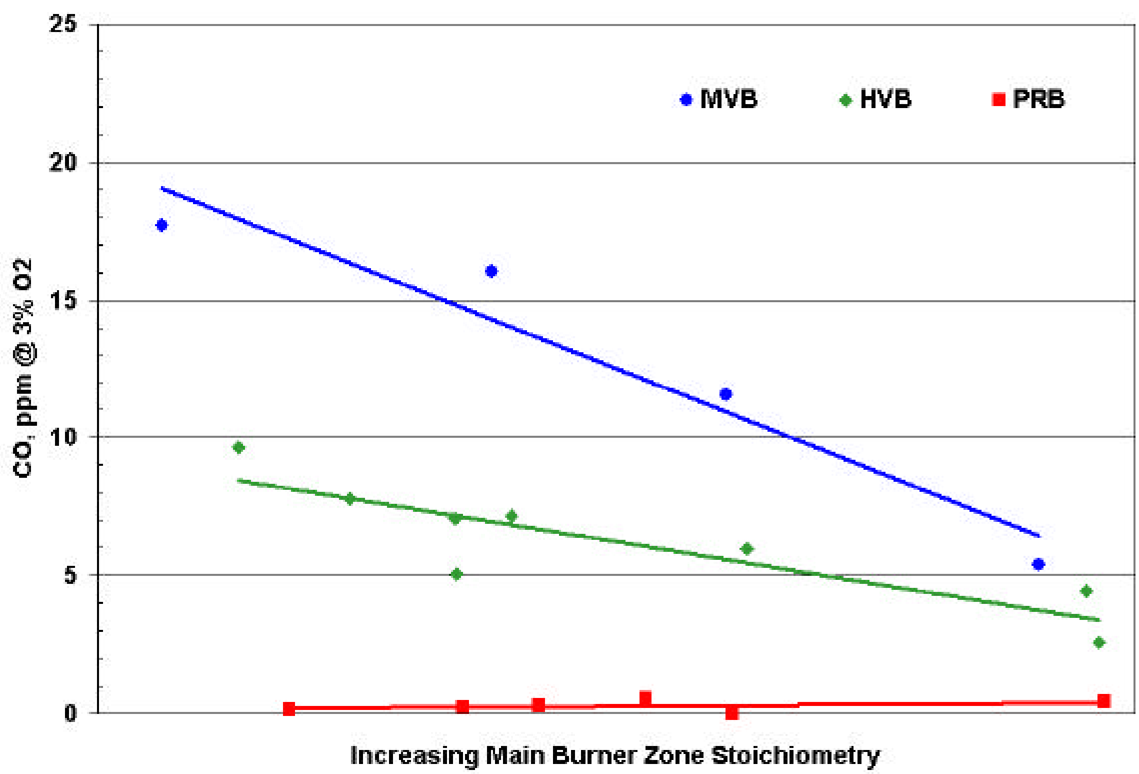

Figure 6.4.3-4: CO vs. MBZ Stoichiometry.

Gas temperatures were measured in various locations within the BSF to determine if there were any significant deviations caused by the air staging process. Figure 6.4.3-5 shows gas temperatures at the horizontal furnace outlet plane, at the economizer inlet and economizer outlet for the HVB coal. The horizontal furnace outlet temperature was measured with a line-of-sight acoustic pyrometer, while the inlet and outlet economizer gas temperatures were measured with a single thermocouple. As the line of sight of the acoustic pyrometer passed through the BSF water jacket, the absolute measurements were low by 250-300 °F as compared to suction pyrometer measurements. The measured trends in HFOT with operating conditions for the acoustic and suction pyrometers, however, were in good agreement. It is acknowledged that these temperatures may not be exactly representative of their respective locations, but they did serve a purpose in identifying any significant deviation that might have occurred due to air staging.

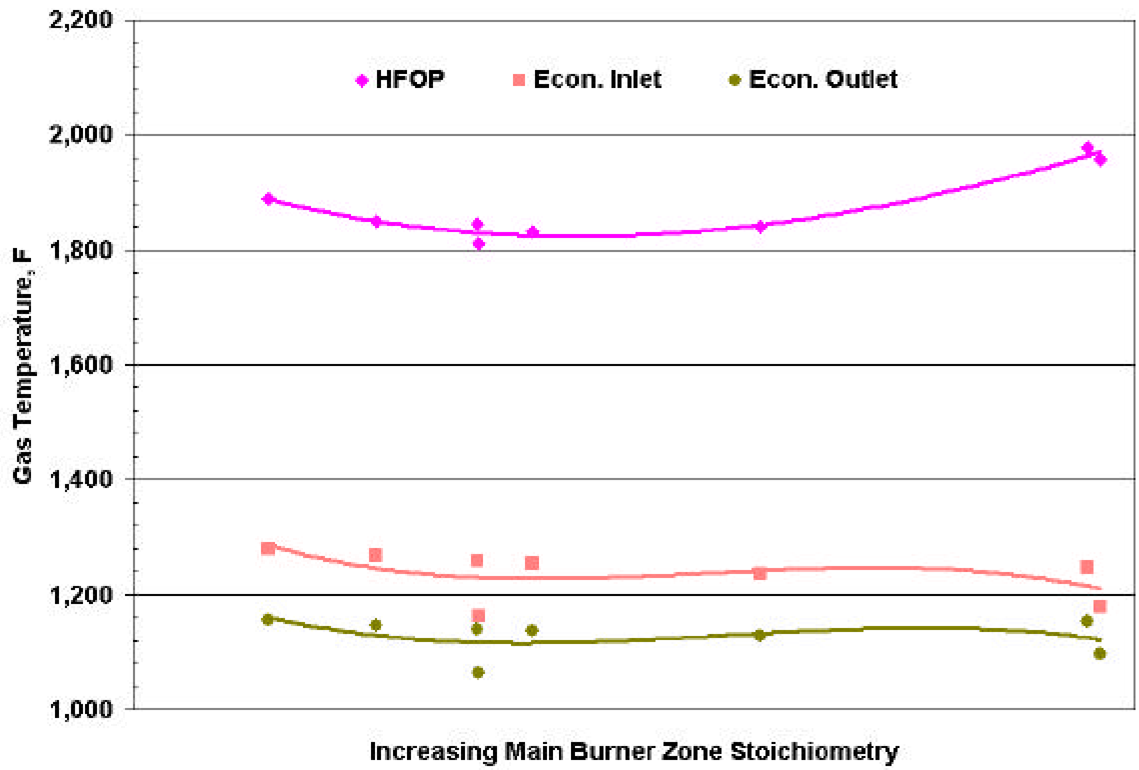

Figure 6.4.3-5: Gas Temperatures for HVB Coal vs. MBZ Stoichiometry.

Varying MBZ stoichiometry did not have a significant effect on gas temperatures in the BSF, which is typical of field experience with staged air firing systems. The plots shown in Figure 6.4.3-5 are typical of what was observed for the other two test coals.

Staged Residence Time

Along with main zone burner stoichiometry, staged residence time is an important parameter for achieving low NOx in an air-staged system. Figure 6.4.3-6 shows NOx as a function of staged residence time. The MBZ stoichiometries chosen for these test points were close to the optimum found for each of the coals, as shown in previous Figure 6.4.3-1. For example the optimum stoichiometry for the MVB coal was found to be lower than the optimum stoichiometry for the PRB coal. Also it should be noted that "staged residence time" was calculated as a plug flow residence time from the top coal nozzle to the first elevation where additional air was introduced. The test points shown with the lowest staged residence time were achieved by admitting air through the CCOFA compartments, i.e., closest to the top coal nozzle. The intermediate test points were achieved by having additional air admitted through the lower SOFA compartment and the test points with the greatest staged residence time were achieved by admitting air through the upper SOFA compartments.

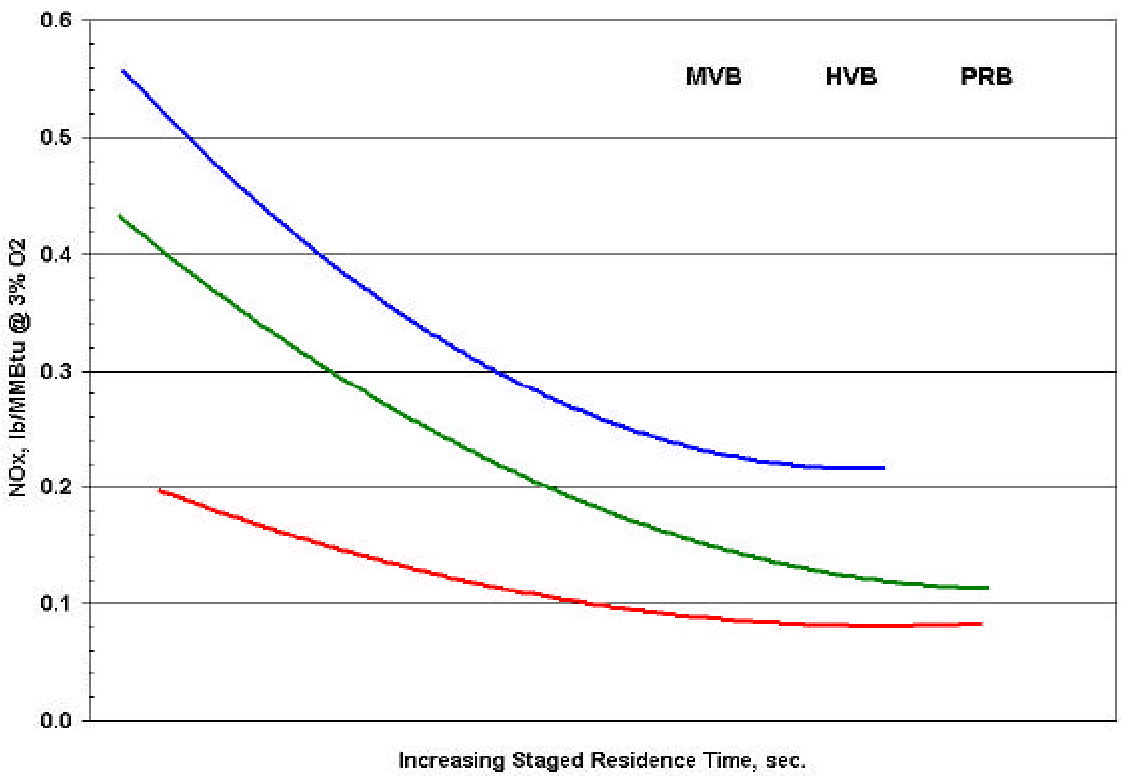

Figure 6.4.3-6: NOx as a Function of Staged Residence Time.

Nitrogen oxides for the three test coals, as plotted in Figure 6.4.3-6, are in the same order as shown in previous plots, i.e., the PRB coal showing the lowest NOx and the MVB coal showing the highest NOx. For each of the coals, initial increases in staged residence time have a greater effect on NOx reduction rate, with this effect being most pronounced in the MVB and HVB coals. In the case of each coal the rate of NOx reduction tapers off with increasing staged residence time.

As can be anticipated, as staged residence time increases, less time becomes available for burnout of combustibles, both CIA and CO. Figure 6.4.3-7 shows the relationship between CIA and staged residence time.

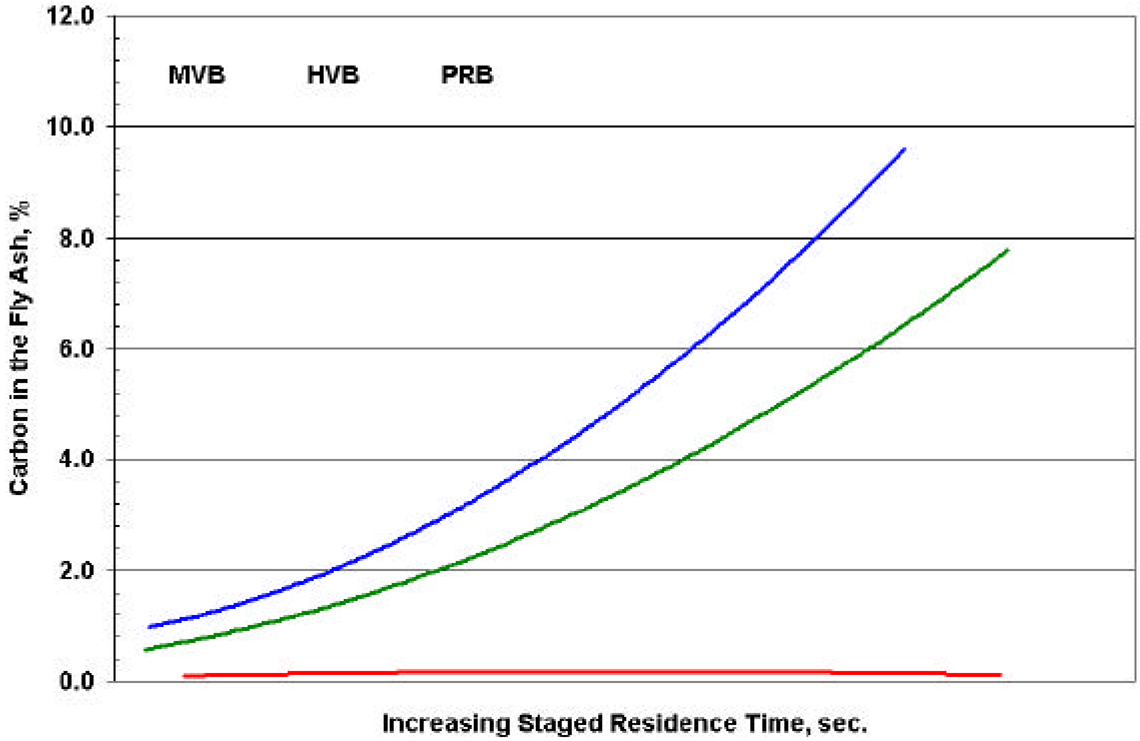

Figure 6.4.3-7: CIA as a Function of Staged Residence Time.

Because of the very high reactivity of the PRB coal there is little consequence of increasing staged residence time on CIA. However, for both the MVB and HVB coals increasing staged residence time does have a significant effect on CIA. The good news is that staged residence times that can give acceptably low CIA values (<4%) can also produce appreciable NOx reduction for even the MVB and HVB coals.

Figure 6.4.3-8 shows the relationship between CO and staged residence time. As in the case with CIA, the PRB coal showed no measurable increase in CO with increasing staged residence times. Though there was measurable CO with both the MVB and HVB coals, as a function of increasing staged residence time in the BSF, the level of CO was acceptably low.

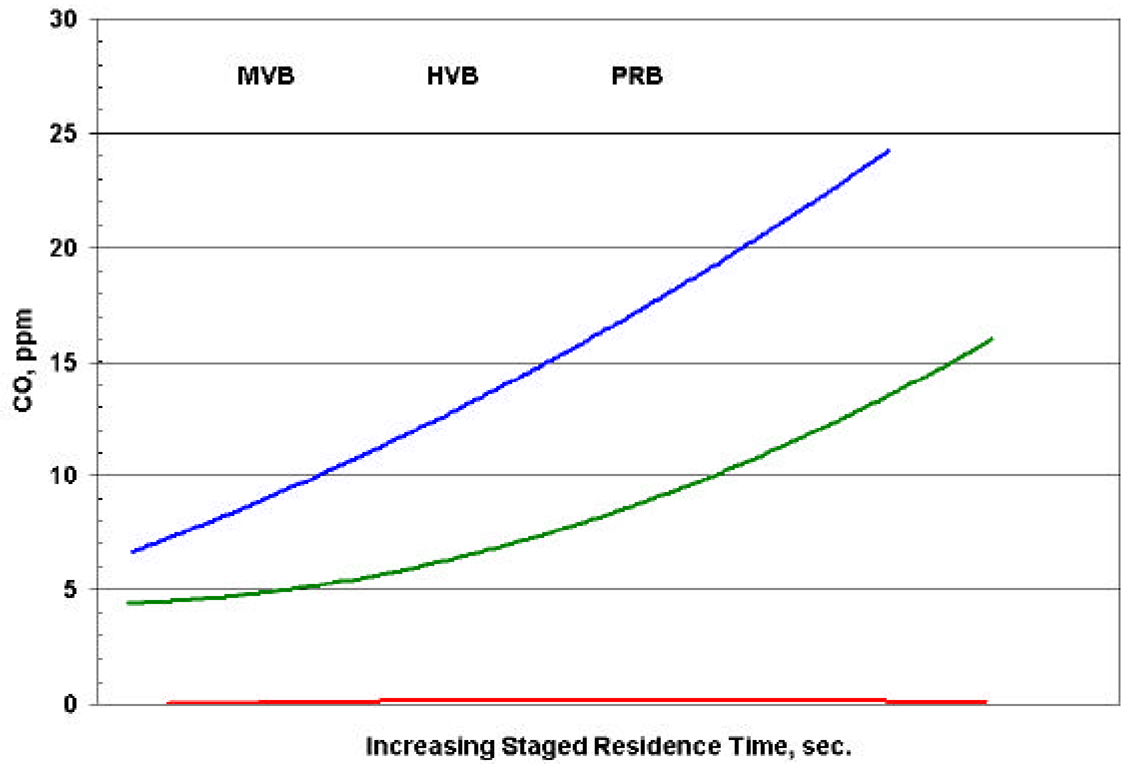

Figure 6.4.3-8: CO as a Function of Staged Residence Time.

Transport Air/Fuel Ratio

The transport air/fuel ratio was varied for the MVB and PRB coals. The idea was to determine if there might be some optimum near-burner stoichiometry that could enhance fuel bound nitrogen release. Coal ignition and initial burning are primarily influenced by volatile matter release and subsequent combustion. As such, the stoichiometries discussed in this instance are based on combustion of ASTM-determined volatile matter only. Ideally, high local (near-burner) temperatures are desirable from the standpoint of maximizing the release of fuel bound nitrogen. Additionally, the local stoichiometry should be slightly substoichiometric to inhibit the formation of nitrogen oxides. This combination of desirable conditions suggests that some optimum stoichiometry might do two things: (1) maximize the release of fuel bound nitrogen, and (2) minimize the formation of nitrogen oxides, or conversely maximize the formation of molecular nitrogen.

Stoichiometry in the near-burner zone is controlled by two air sources: (1) the air which transports the pulverized coal, appropriately called transport air, and (2) the air immediately surrounding the coal nozzle, called fuel air. Figure 6.4.3-9 shows the relationship between the transport air/fuel mass ratio (lb air/lb of fuel) versus the near burner stoichiometry (based on the transport air) for the MVB coal. As noted in Figure 6.4.3-9, the near-burner stoichiometry varied from 0.61 to 0.96 as calculated from the transport air and coal volatile matter.

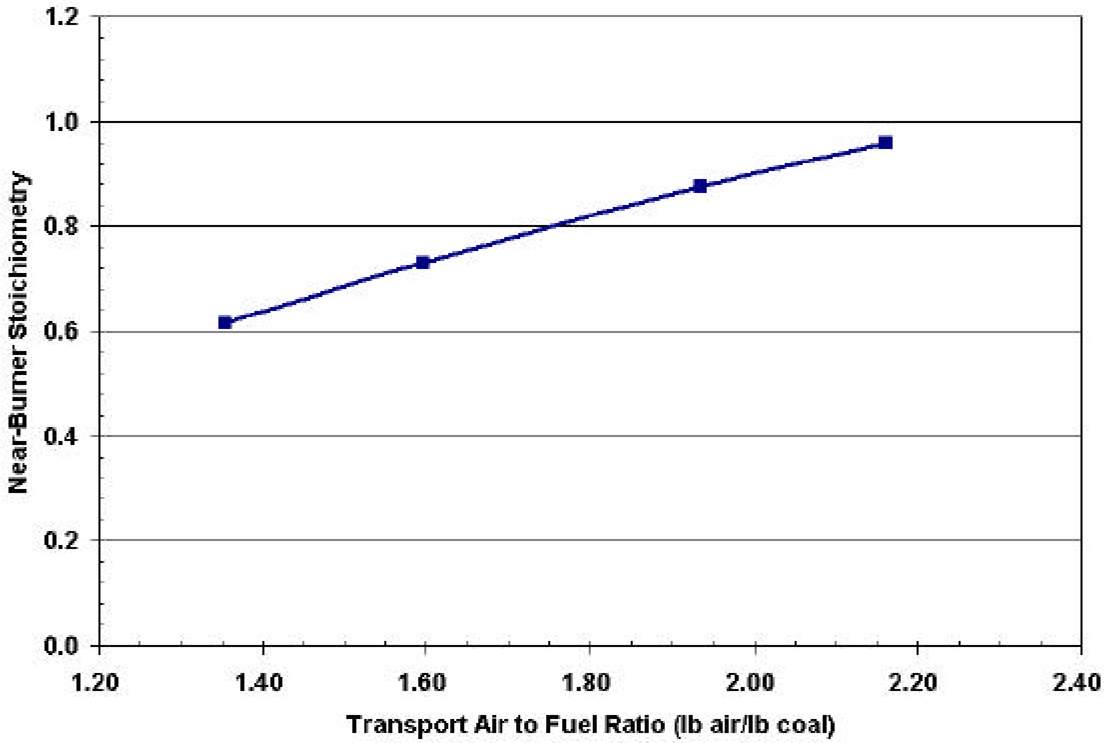

Figure 6.4.3-9: Near-Burner Stoichiometry vs. TA/Coal Ratio for the MVB Coal.

Figure 6.4.3-10 shows that, at least for the MVB coal, variation of near-burner stoichiometry had no measurable effect on NOx. While there was some variation in carbon-in-ash there was no clear-cut trend with variation in transport air to fuel ratio. A possible explanation for this result could be the relatively low quantity of fuel bound nitrogen that is available for release in the MVB coal, as discussed in Section 4.0. When similar testing was conducted on the PRB coal there was a slight decrease in NOx with increasing near-burner stoichiometry, for the range tested (see Figure 6.4.3-11).

Carbon monoxide emissions were relatively unchanged by variations in near-burner stoichiometry. As previously noted the near-burner stoichiometry was calculated on the basis of transport air plus fuel air, and based on the theoretical amount of air required for the combustion of ASTM volatile matter. Unlike the MVB coal, the PRB coal showed that a high percentage of fuel-bound nitrogen was released during high temperature pyrolysis testing (presented in Section 4.0). Therefore, it might be argued that evolution of fuel-bound nitrogen would be more likely to vary with changes in near-burner stoichiometry (temperature) in the case of PRB coal than with MVB coal.

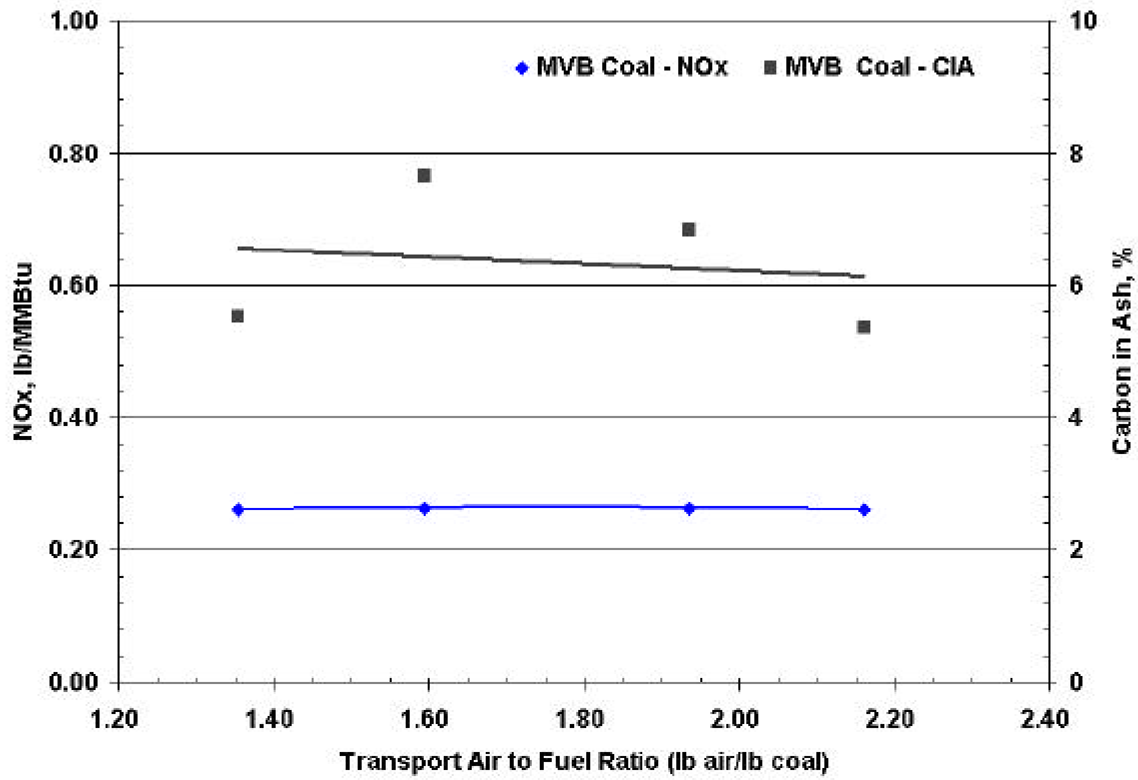

Figure 6.4.3-10: NOx and CIA as a Function of TA/Fuel Ratio for MVB Coal.

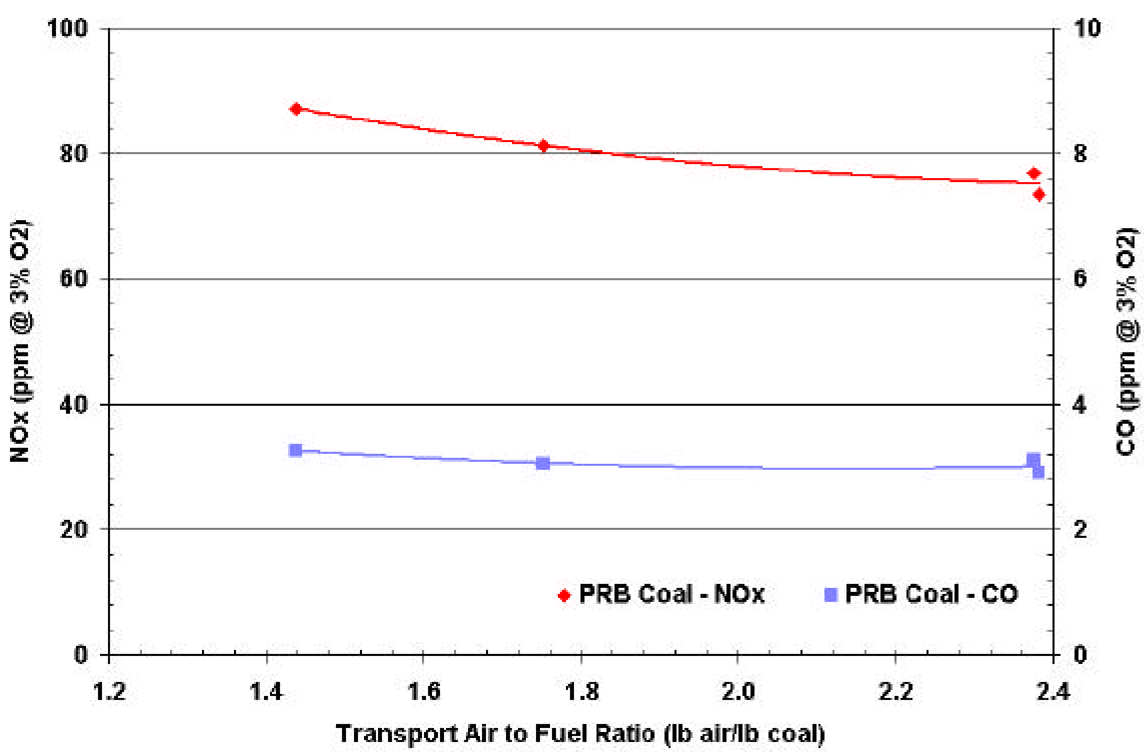

Figure 6.4.3-11: NOx and CO as a Function of Near-Burner Stoichiometry.

Transport Air/Fuel Flow Balancing

Coal flow balancing was investigated in the BSF testing as a means to achieve additional NOx reduction. Since the as installed ABB Kent Taylor coal flow meters were not found to be sufficiently accurate to measure and improve the coal flow balance (as reported in Section 5.6), BSF testing utilized increasing levels of imbalance, achieved by restricting the coal and air flow to selected coal nozzles. The transport air and coal flow restrictions were achieved by partially closing ball valves that were in each of the 12 coal transport lines, just before the coal nozzles.

Figure 6.4.3-12 illustrates the deviation in transport air flow as a function of ball valve position, as measured by orifice plates in each of the 12 coal transport lines. Specifically, ball valves at the bottom elevation (left/front corner), mid elevation (right/front corner), bottom elevation (right /rear corner) and top elevation (left/rear corner) were modulated.

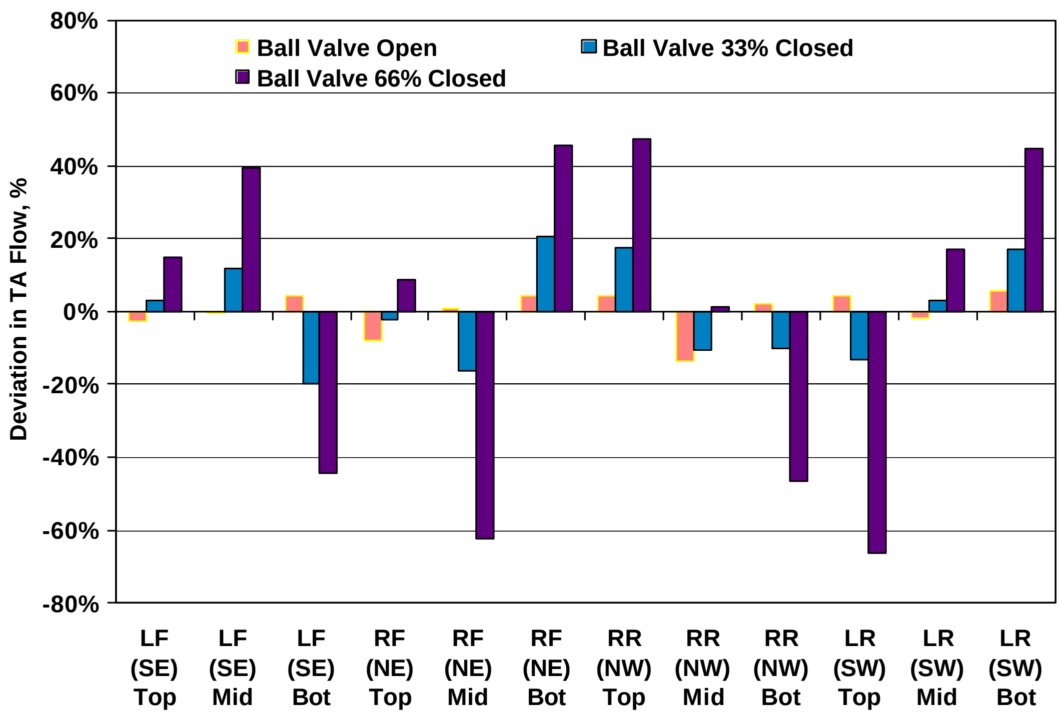

Figure 6.4.3-12: Modulation of TA Flow vs. Coal Imbalance.

The baseline condition with all of the ball valves open had an average transport air flow deviation of 6% (14% max). Closing four (4) of the ball valves 33% increased the average transport air flow deviation to 14% (20% max) while 66% closure increased the transport air flow deviation to 46% (66% max). Previous barrel testing of the coal flow transport system suggested that the coal flow rates decreased as the transport air decreased, but not linearly. Therefore, the conditions tested resulted in increasing levels of imbalance in the coal and transport air flow.

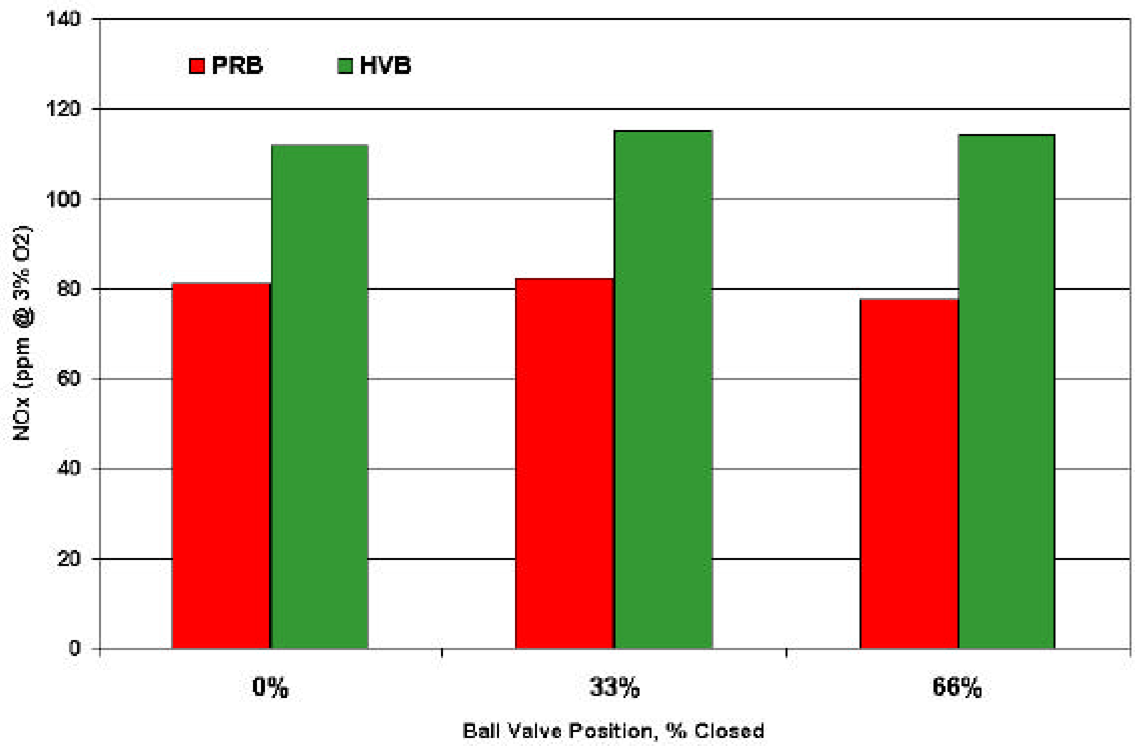

Figure 6.4.3-13: NOx Emissions vs. Coal Flow Imbalance.

For both the PRB and HVB coals there was no significant variation in NOx emissions with increasing coal flow imbalance as shown in Figure 6.4.3-13. As might be expected, there was a small increase in carbon in the fly ash for the HVB coal as shown in Figure 6.4.3-14, but little impact on carbon in ash for the PRB coal. Although not shown, there was little impact on CO emission levels, which were less than 10 ppm in all cases.

The BSF results suggest that rigorous coal and air flow balancing may not significantly improve the performance of a deeply staged, tangentially fired boiler. However, the modest gains in the carbon in fly ash achieved by improving balancing may allow for reductions in excess air, which in turn may result in slight improvements in NOx emissions and boiler efficiency. Note that the impact of fuel and air balancing on CO and carbon in the fly ash may be underestimated in the BSF due to differences in the configuration of the BSF and a utility boiler (e.g., refractory lined walls, location of sampling system, etc.). Additional field validation of the impact of coal flow balancing on deeply staged, tangentially fired boilers would be desirable.

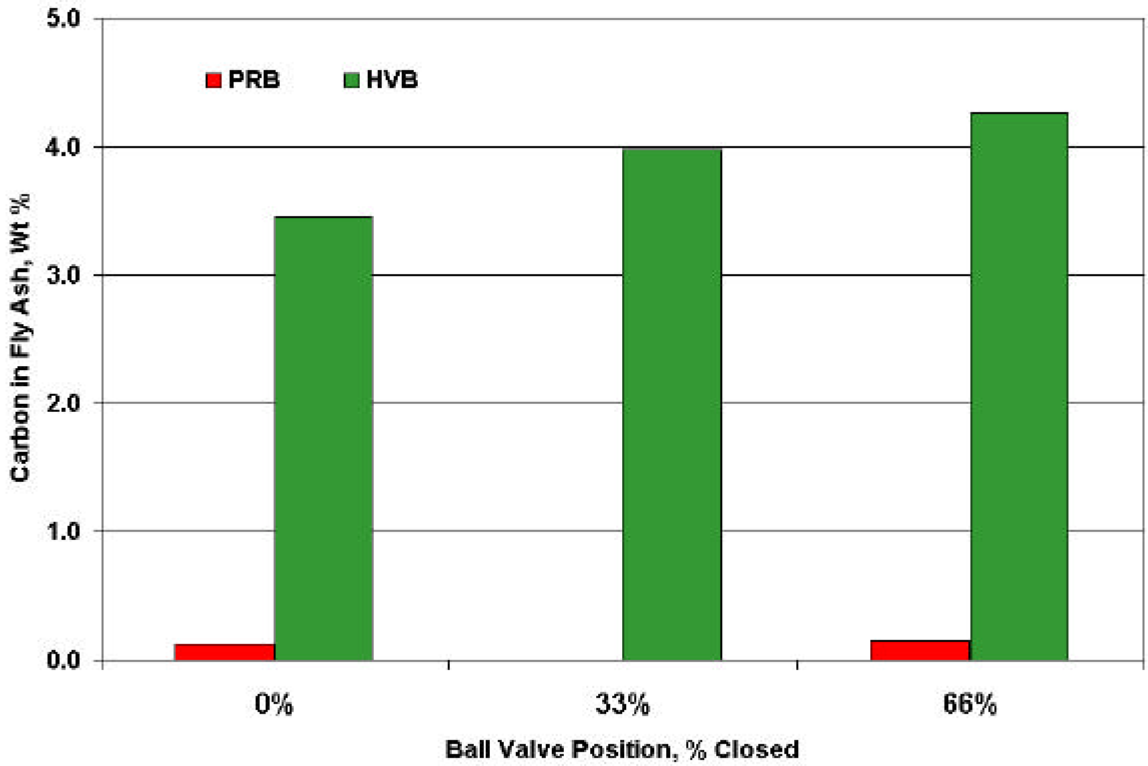

Figure 6.4.3-14: Carbon in Ash vs. Coal Imbalance.

Coal Ballistics

As noted above in Subsection 6.4.2, specifically as shown in Figure 6.4.2-1, "Coal Ballistics" refers to the various angles at which the bottom elevation coal stream could be injected. The bottom elevation of coal nozzles were configured such that in a horizontal position, i.e., no upward or downward tilt, the coal stream was injected at a 15^o angle from the normal firing angle. Furthermore this particular coal nozzle could be rotated such that the coal stream could either be injected 15^o greater than or less than the normal firing angle. Also if the nozzle were to be rotated in a vertical up or down position, the coal stream would be injected at the normal firing angle, but at a 15^o up tilt or 15^o down tilt, or various positions in between, depending on the degree of rotation.

Figure 6.4.3-15 is a plot of the HVB and PRB coals showing how NOx varied as a function of the position of the bottom elevation coal nozzle. Interestingly, for both coals there was an optimum coal nozzle orientation that provided a significant NOx reduction. Additional work would be required to fully understand the physical mechanism governing the observed reduction in NOx emissions.

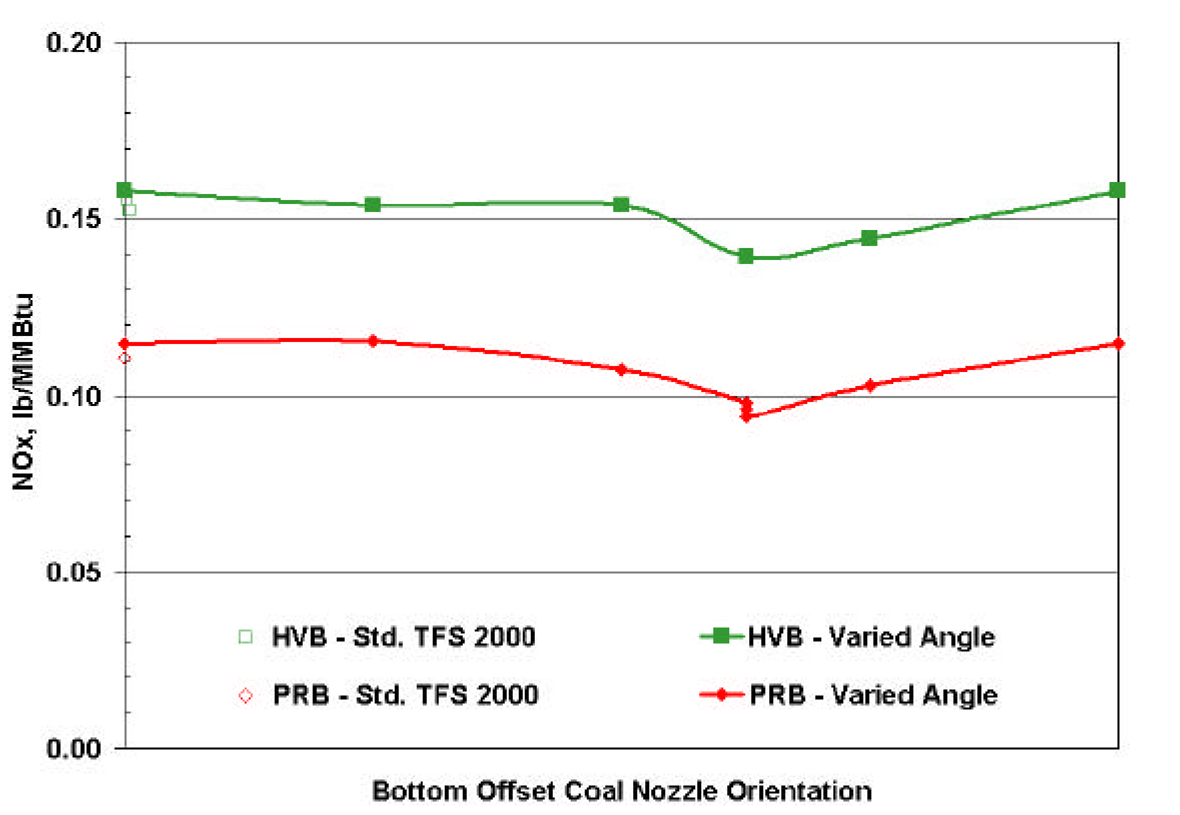

Figure 6.4.3-15: NOx vs. Bottom Offset Coal Nozzle Orientation.

Compressed Windbox

The compressed windbox configuration represents a way to exaggerate staged residence time by moving the coal nozzles down in a more "compressed" arrangement. As shown in Figure 6.4.2-1 in Subsection 6.4.2 the "compressed windbox" is achieved by moving the mid-elevation coal nozzles down one compartment (by removing the CFS™ air below the coal nozzle), and by moving the top coal nozzle down two compartments (by removing one CFS™ air and one AUX air compartment). Additionally, for the compressed windbox tests, CFS™ air was injected in the compartment directly above the top coal elevation and no more "overfire" air was injected until the upper SOFA. This arrangement maximized the staged residence time.

Figure 6.4.3-16 shows NOx versus MBZ stoichiometry for the standard and compressed windbox arrangements for HVB and PRB coals, the compressed windbox points being shown with open symbols. The compressed windbox arrangement did not significantly change the NOx values (for a given MBZ stoichiometry) for the HVB coal. For the PRB coal there was some further slight NOx reduction (at the optimum stoichiometry) with the compressed windbox case.

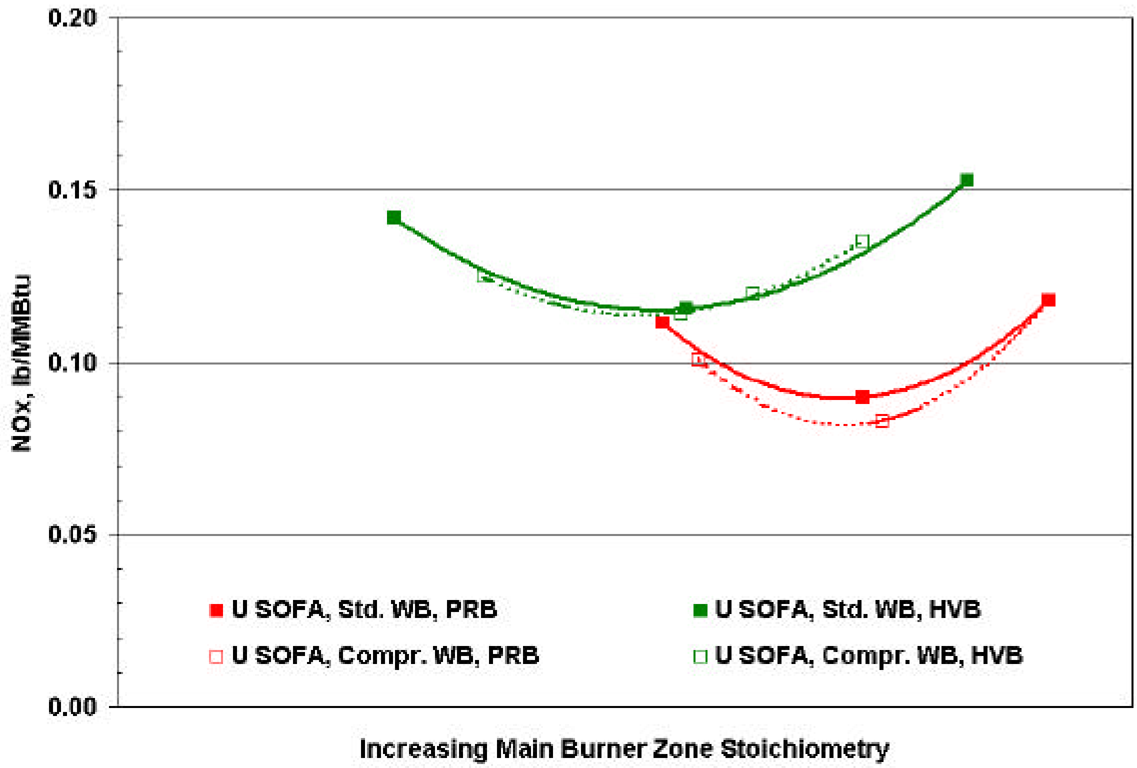

Figure 6.4.3-16: NOx vs. MBZ Stoichiometry for Standard & Compressed Windbox.

Coal Fineness

Coal fineness is an obvious parameter regarding its impact on carbon in ash and CO emissions: finer coal particles will decrease CIA and CO emissions. Not as obvious is the impact of coal fineness on NOx. The assumption is that finer coal particles burn more rapidly, create higher temperatures in the near-burner region, which in turn drive off more fuel bound nitrogen in a substoichiometric environment (under staged firing conditions) thereby promoting molecular nitrogen in place of NOx formation. It is also possible that firing coal with a finer particle size may indirectly reduce NOx by allowing deeper staging or longer staged residence times to be employed without adversely impacting carbon in ash or CO emissions.

All three test coals were ground to various levels of fineness. Specifically, the MVB coal, being the least reactive, was fired at 85% and 99.9 % -200 mesh and the PRB and HVB coals were each fired at 65% and 85% -200 mesh. Achieving 85% through 200 mesh was possible in the Power Plant Laboratory’s mill equipped with a dynamic classifier. The micro fine size was produced by ALSTOM Power’s off-site facility at their Raymond Division.

Figure 6.4.3-17 shows NOx and CIA as a function of MBZ stoichiometry for the fine grind and micro-fine grind MVB coals. The NOx values are slightly better with the micro-fine coal while the CIA is significantly improved for the micro-fine coal at a given MBZ stoichiometry. Clearly the potential benefit for fine grinding in the case of the MVB coal is that it would allow more aggressive MBZ stoichiometries to be employed without exceeding the limits of CIA levels. In the case of the BSF, for example, the optimum stoichiometry could be employed while still maintaining a CIA level of about 3%. Of course it must be noted that relationships between NOx, CIA and stoichiometry for a given coal grind are boiler specific.

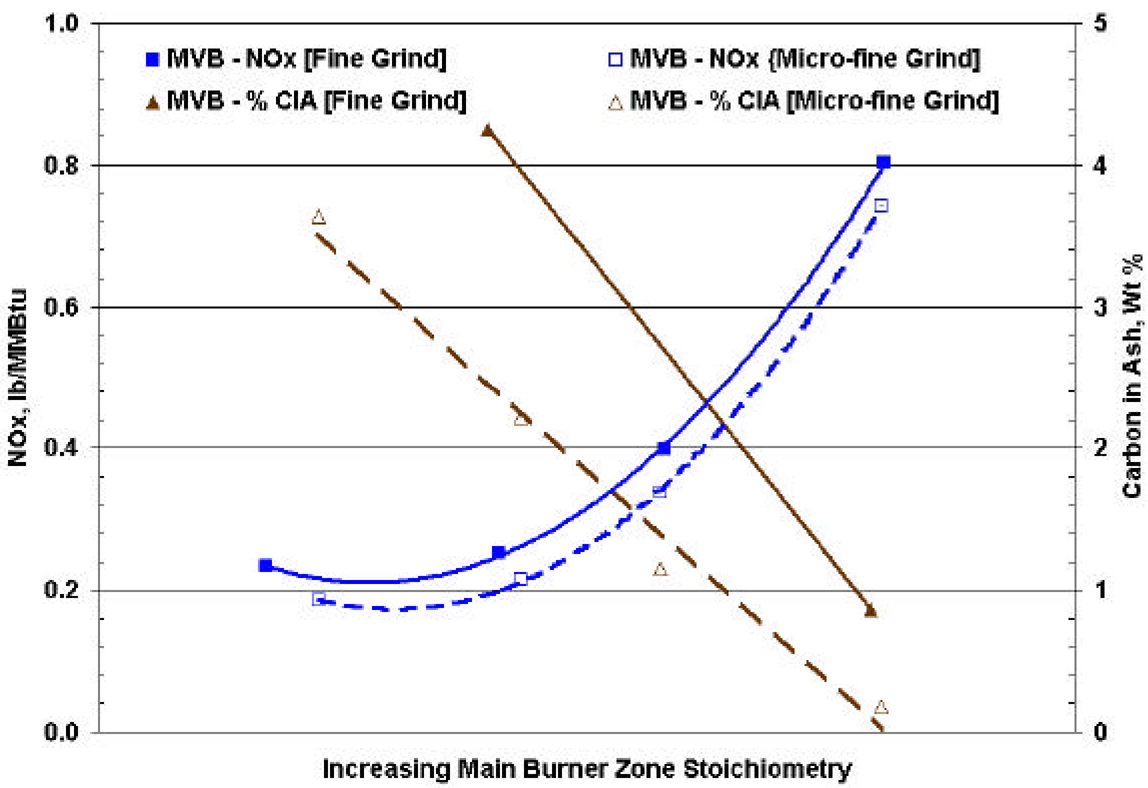

Figure 6.4.3-17: NOx and CIA vs. MBZ Stoichiometry an Coal Particle Size.

Figure 6.4.3-18 shows NOx versus MBZ stoichiometry for two different particle sizes for PRB coal. The finer particle size (85% - 200 mesh) gives slightly lower NOx than the coarser particle size (65% - 200 mesh). Also, the stoichiometry to achieve the lowest NOx is higher for the finer particle size.

A summary of the NOx emissions from the 3 coals fired in the BSF (with coal fineness as a focal point) is shown in Figure 6.4.3-19; carbon in ash for the same cases is shown in Figure 6.4.3-20. For each coal, a post-NSPS baseline (no OFA, CCOFA only), TFS 2000™, and minimum NOx test condition case are shown. Note that in the case of the MVB and HVB coals the three test conditions were run at a coal fineness of 85% -200 mesh, achievable with the DYNAMIC™ classifier. Hence, the test baseline numbers may not be representative of the actual baseline NOx and carbon in ash values that might be seen in the field. See Table 6.4.3-1 for the test conditions for each coal.

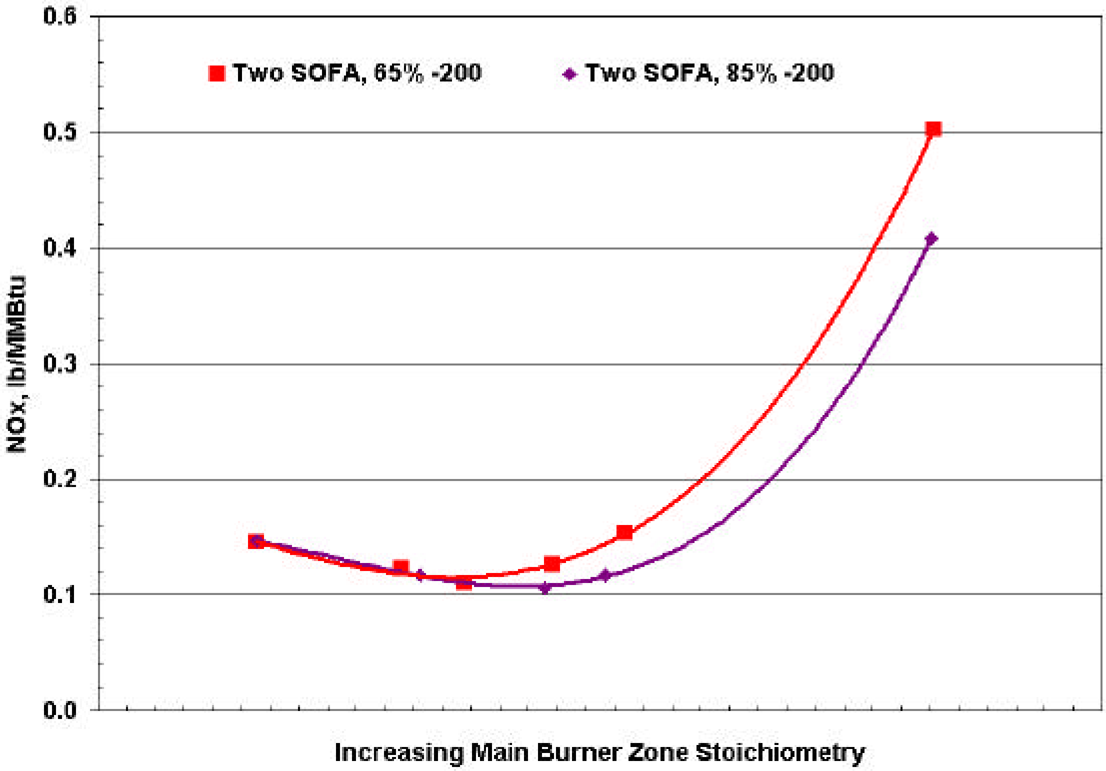

Figure 6.4.3-18: NOx vs. MZB Stoichiometry for 2 PRB Coal Particle Sizes.

As illustrated in Figure 6.4.3-19, a decrease in the NOx emissions is seen as a function of decreasing coal rank and firing system configuration. A reduction of 65-75% over the baseline number was achieved with a TFS 2000™ firing system at the optimum main burner stoichiometry. Additional NOx reduction was achieved for each of the coals through optimized combinations of the test variables as previously shown in Table 6.4.2-1.

However, as illustrated in Figure 6.4.3-20, carbon in ash increased due to the firing system modifications made to decrease NOx emissions for the HVB and MVB coals. As expected, the PRB coal showed little carbon in the fly ash under any test condition. However, it should be noted that "baseline" conditions would not have normally included finer grinding, but as a matter of practicality the DYNAMIC™ classifier grind (85% -200 mesh) was also used for the baseline tests. What this means is that the carbon in ash for the baseline case is lower than it would normally be, which in turn has exaggerated the differences between CIA values for the baseline case versus TFS 2000 and "minimum NOx" cases.

Results are also shown in Figures 6.4.3-19 and 6.4.3-20 for a microfine grind of the MVB coal. The additional coal particle size reduction allowed the carbon in ash level to be decreased to the TFS 2000™ level with the added benefit of additional NOx reduction. The smaller particle sizes burn more rapidly, releasing more of the fuel bound nitrogen in the reducing zone of the furnace, which resulted in lower NOx and carbon in fly ash levels.

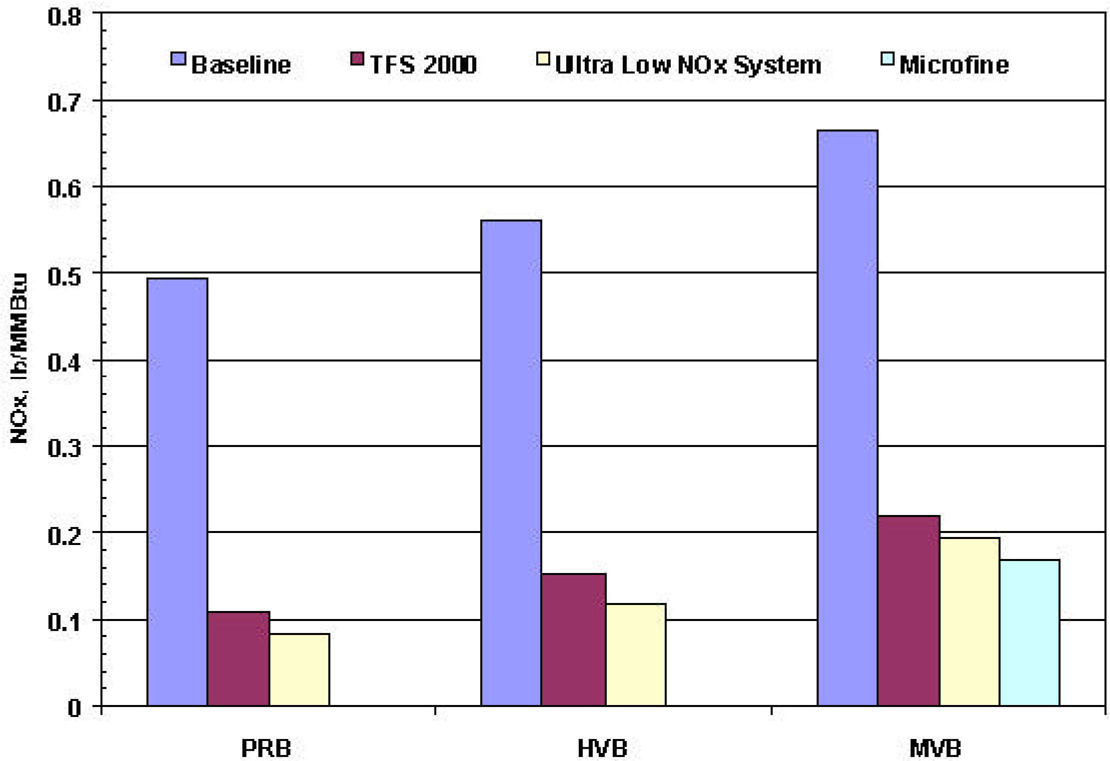

Figure 6.4.3-19: NOx Emissions from BSF Combustion Testing.

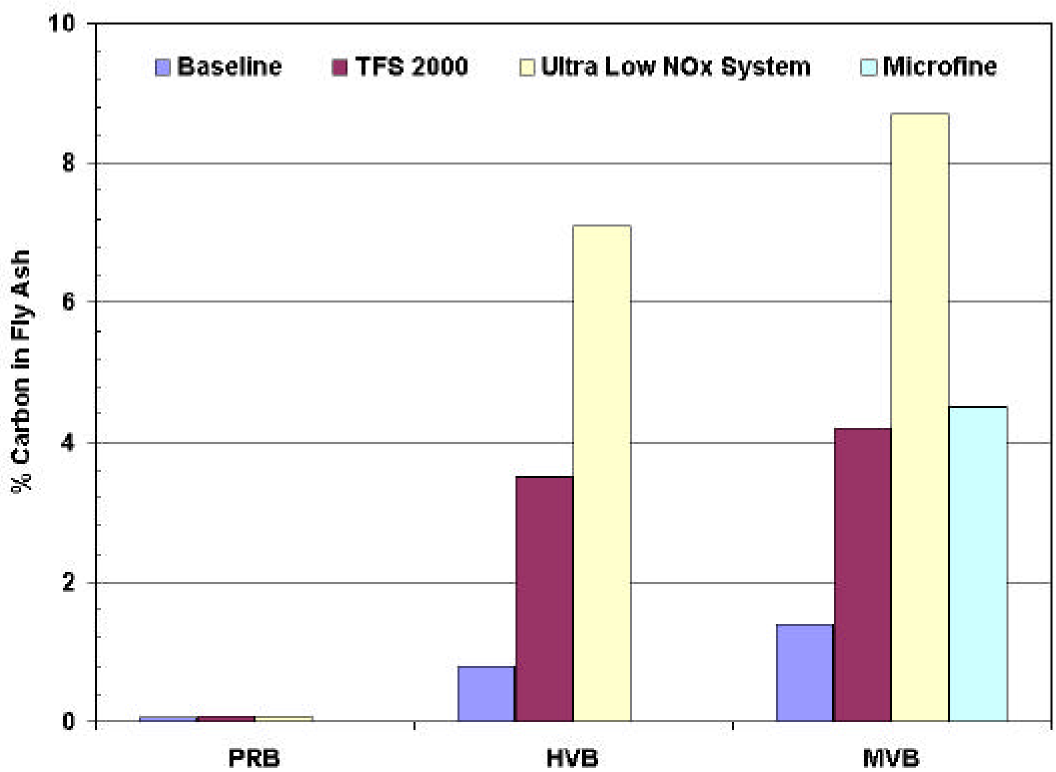

Figure 6.4.3-20: Carbon in Ash from BSF Combustion Testing.

Table 6.4.3-1: Test Conditions for Cases Shown in Figures 6.4.3-19 & 20.

	Coal	Firing Rate [MMBtu/hr]	Grind [% -200 Mesh]
Baseline	MVB	50	85
TFS 2000	MVB	50	85
Ultra Low NOx	MVB	50	85
Microfine	MVB	60	99.8
Baseline	HVB	50	85
TFS 2000	HVB	50	85
Ultra Low NOx	HVB	50	85
Baseline	PRB	50	65
TFS 2000	PRB	50	65
Ultra Low NOx	PRB	50	65

Note that the microfine coal was fired at 60 MMBtu/hr, while the other test cases shown in Figures 6.4.3-19-20 were fired at 50 MMBtu/hr. As shown in Figure 6.4.3-21, there was a small increase in both NOx and carbon in fly ash with load for the MVB coal (85% - 200 mesh). The increase in NOx emissions with load is likely due to increased gas temperatures and decreased staged residence time in the boiler. The small increase in the carbon in fly ash is probably not significant, but illustrates the tradeoff between the higher gas temperatures (increased char reaction rates) and the decreased residence time due to the increased gas velocities. These results suggest that even lower NOx numbers may have been achieved with the microfine coal grind if it had been fired at 50 MMBtu/hr.

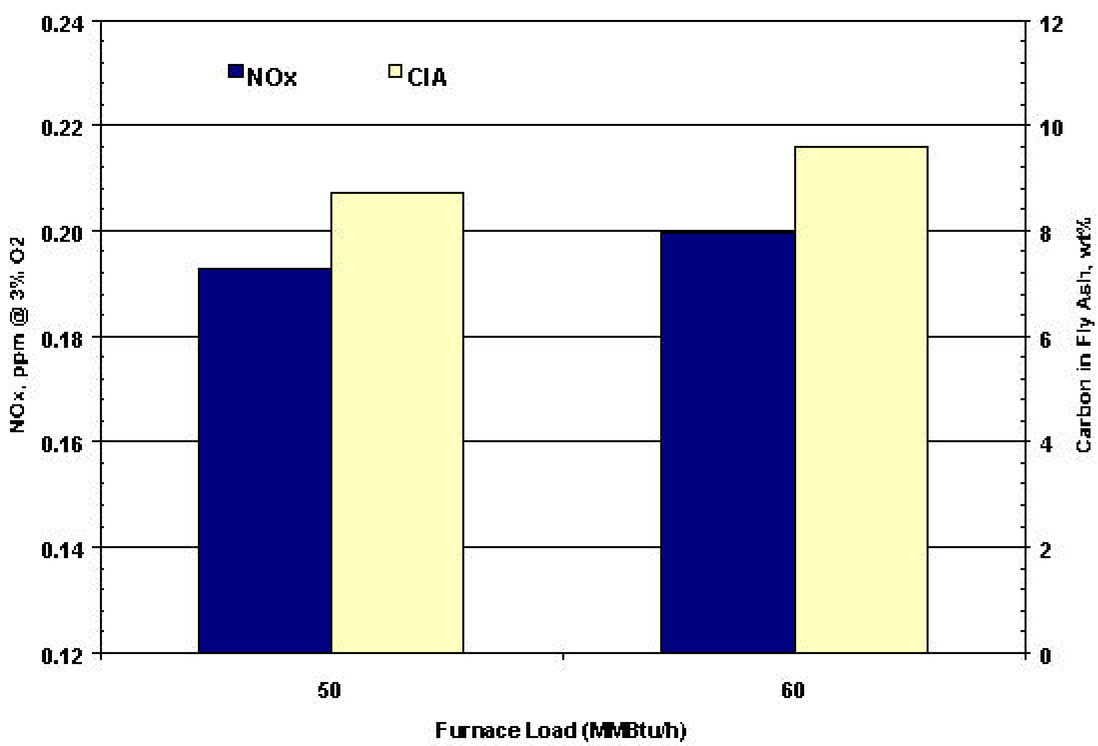

Figure 6.4.3-21: NOx and CIA vs load for MVB coal, 85% -200 mesh.

Near Field Stoichiometry Control

As previously noted, near field stoichiometry control refers to the location of air injection relative to the coal nozzle within the firing zone. Table 6.4.3-2 shows the 3 windbox arrangements that were tested. Figure 6.4.3-22 shows NOx levels for the three test coals as a function of windbox auxiliary air arrangement. A small, but consistent, NOx reduction of 0.01-0.02 lb/MMBtu was seen with windbox arrangement 3 for all coals tested.

Table 6.4.3-2: Windbox Arrangements for Near Field Stoichiometry Control.

Arr. 1	Arr. 2	Arr. 3
USOFA	USOFA	USOFA
USOFA	USOFA	USOFA
USOFA	USOFA	USOFA
LSOFA	LSOFA	LSOFA
LSOFA	LSOFA	LSOFA
LSOFA	LSOFA	LSOFA
X	X	X
X	X	X
CCOFA	CCOFA	CCOFA
COAL	COAL	COAL
CFS	CFS	X
Aux	X	Aux
CFS	CFS	X
COAL	COAL	COAL
CFS	CFS	X
Aux	X	Aux
CFS	CFS	X
COAL	COAL	COAL
Bottom End	Bottom End	Bottom End
Bottom End	Bottom End	Bottom End
X	X	X
X	X	X

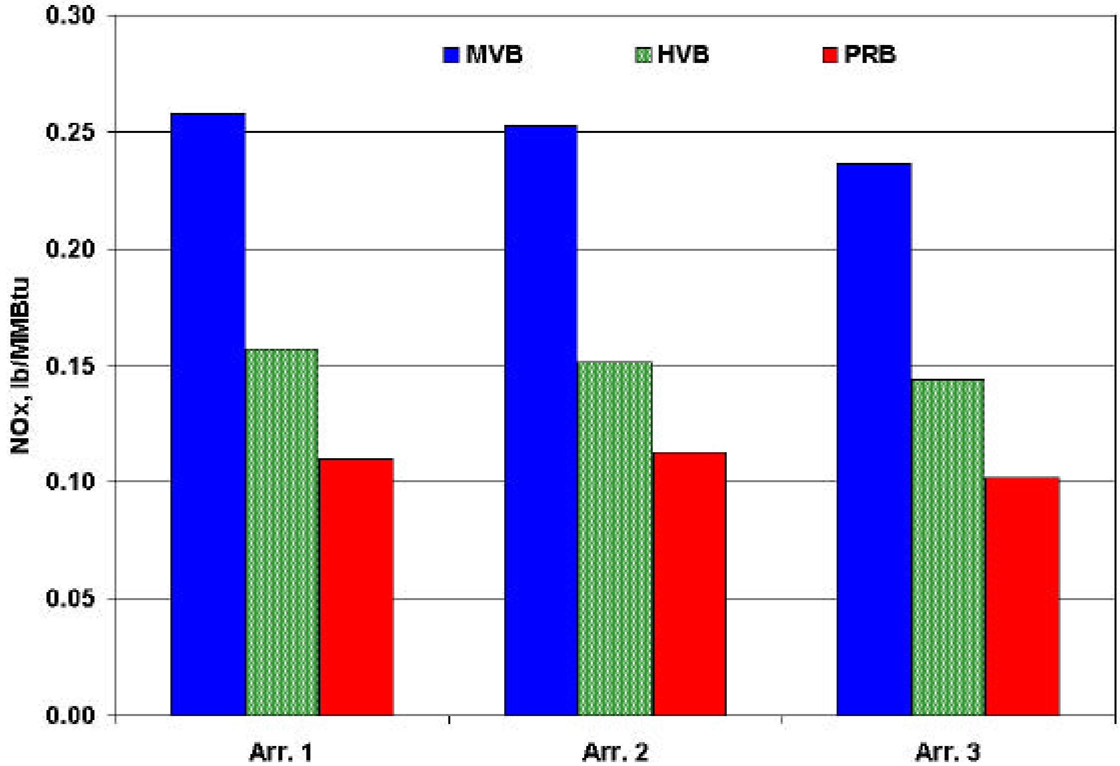

Figure 6.4.3-22: NOx vs. Windbox Arrangement for the Three Test Coals.

A look at CO and CIA levels for the HVB and PRB coals (Figures 6.4.3-23 and 6.4.3-24) shows arrangement 2 to generally give the lowest CIA and CO values. However, the CO and carbon in ash levels were low in all cases. These data (Figures 6.4.3-22 – 6.4.3-24) show that controlled admixing of the fuel and auxiliary air (near field stoichiometry control) can result in reductions in NOx emissions. Windbox arrangement 3 should provide a modest improvement in NOx emissions with only a small impact on combustion efficiency.

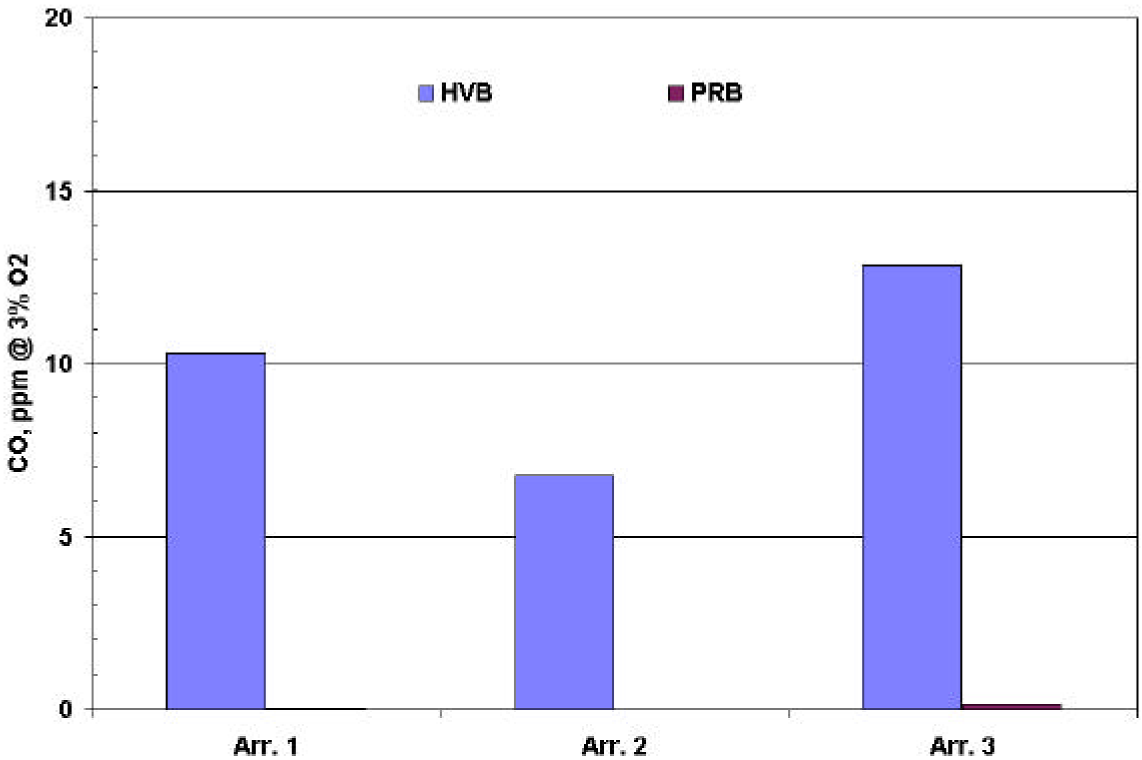

Figure 6.4.3-23: CO vs. Windbox Configuration for HVB and PRB Coals.

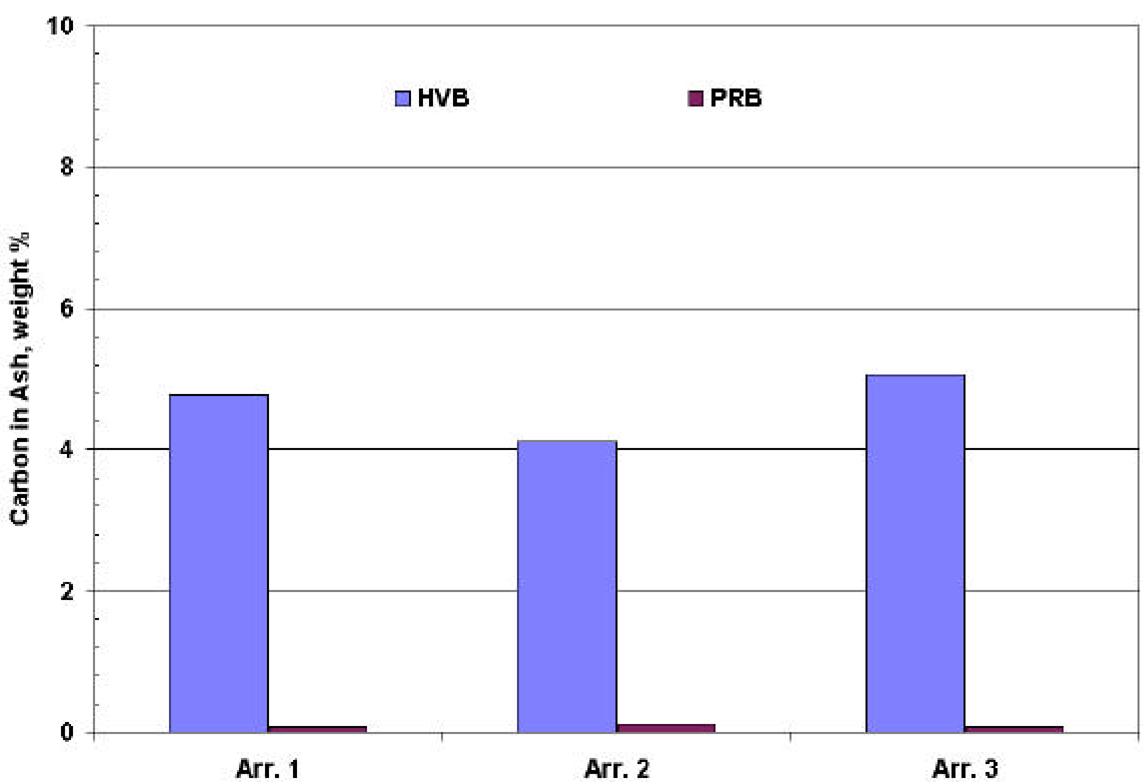

Figure 6.4.3-24: CIA vs. Windbox Configuration for HVB and PRB Coals.

Bottom End Air

As previously shown in Figure 6.4.2-1, bottom end air can be injected through four compartments beneath the bottom coal nozzle. Tests were conducted with various firing zone/OFA arrangements whereby bottom end air quantity was varied.

Figure 6.4.3-25 shows NOx versus the percent of total air entering as "bottom air" for four (4) different firing zone/OFA arrangements. The PRB coal was tested in the standard TFS 2000™ arrangement and with the upper elevation of SOFA only. The HVB coal was tested with the standard TFS 2000™ arrangement. For the PRB coal there was essentially no change in NOx with increasing amounts of bottom end air. The HVB coal showed a slight increase in NOx with increasing amounts of bottom end air.

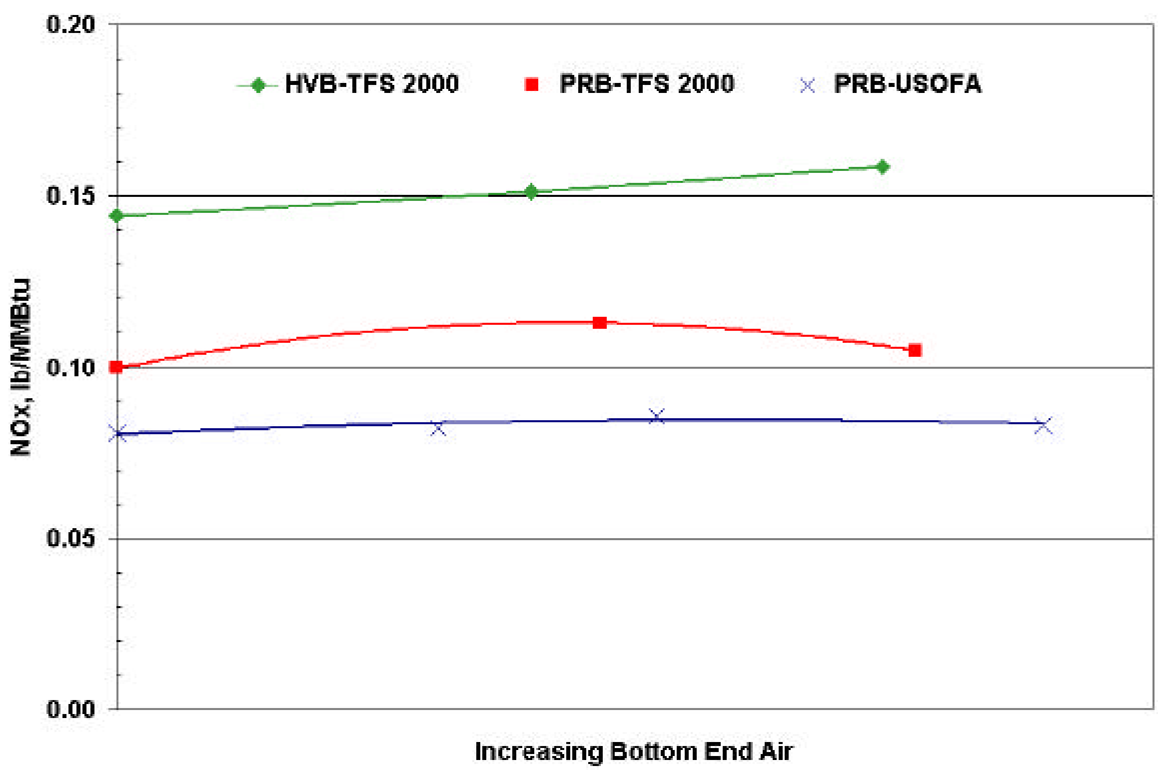

Figure 6.4.3-25: NOx vs. Percent Bottom Air for Various Firing Arrangements.

SOFA Elevation

How and where the overfire air is introduced in an air staged low NOx system can have significant effects on NOx, CO and carbon in ash, among other things. A separate task was devoted to this aspect of the air-staged process, namely CFD modeling, which was previously discussed in Subsection 5.4. Ideally, as has been shown, it is desirable to increase staged residence time from a NOx reduction point of view, but not to adversely affect CIA and CO to the point where they become unacceptably high. Rapid mixing of overfire air is seen as a key objective in this regard.

A number of tests were carried out in the BSF wherein the location of the overfire air was varied to ascertain its effect on NOx, as well as on CIA and CO. Figure 6.4.3-26 shows the effect of SOFA location on NOx emissions. The point where 50% of the overfire air is shown going through lower and upper SOFA elevations represents the TFS 2000™ configuration. As the fraction of air to the upper SOFA increases, NOx decreases due to the increased residence time at reducing conditions. It should be noted, however, that pushing all of the overfire air to the upper SOFA elevation will reduce the oxidizing residence time, which may result in higher unburned carbon and CO emissions and may impact steam temperature control.

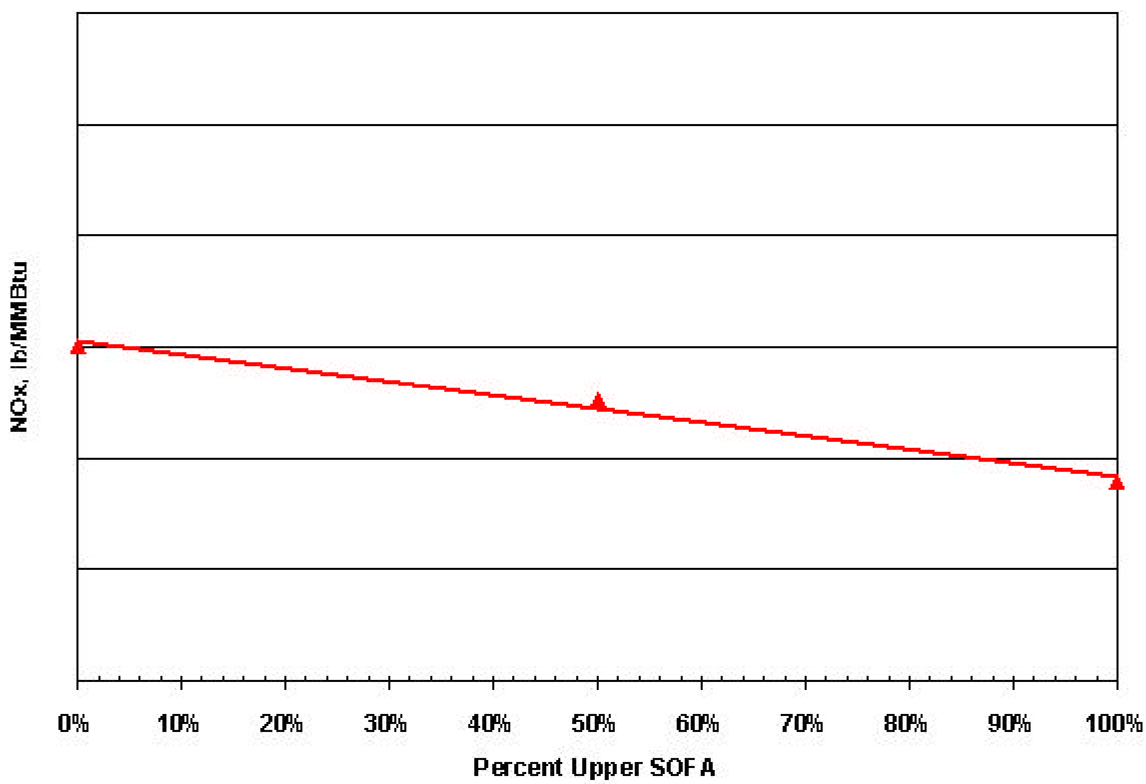

Figure 6.4.3-26: NOx vs. SOFA Splits at Three MBZ Stoichiometries for PRB Coal.

Figures 6.4.3-27, 6.4.3-28 and 6.4.3-29 show NOx and CIA for each of the three test coals for the three SOFA arrangements described above, namely all the air through the upper SOFA, all the air through the lower SOFA and the air being split 50/50 through both upper and lower SOFAs. The NOx values reported in the bar charts (Figures 6.4.3-27 through 6.4.3-29) represent the lowest NOx values achievable with the particular SOFA arrangement at the optimum MBZ stoichiometry.

The PRB coal (Figure 6.4.3-27), as previously indicated, gives the highest NOx when only the lower SOFA is in service and the lowest NOx when only the upper SOFA is in service. Carbon in ash runs opposite to the NOx values with highest levels occurring with the upper SOFA in service and lowest levels with the lower SOFA in service. Having both SOFAs in service (the TFS 2000™ arrangement) shows NOx and CIA values, which are intermediate to those for the other two cases. Similar trends are shown for both the HVB and MVB coals (Figures 6.4.3-28 and 6.4.3-29, respectively). Although not shown, CO emissions for all cases trended with carbon in ash levels.

For the HVB and MVB coals, NOx for the single upper SOFA case is better than the TFS 2000™ case while the increase in CIA is significantly higher than the TFS 2000™ case. Keeping both NOx and CIA in mind the TFS 2000™ arrangement may be the better choice for less reactive coals. Note that these are pilot-scale data and that field results may vary. In a utility boiler, pushing all of the overfire air to the upper SOFA elevation may impact steam temperature control, fouling of convective surfaces, etc.

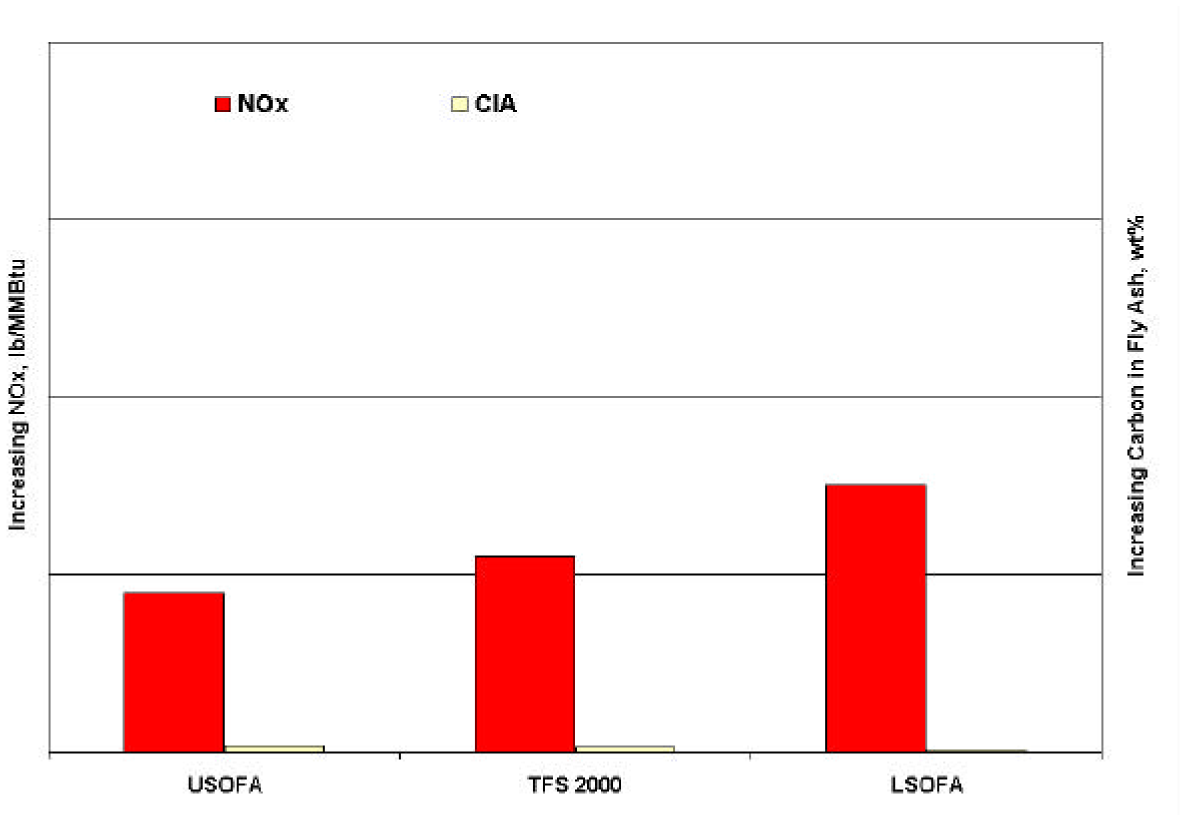

Figure 6.4.3-27: NOx and CIA for Various SOFA Configurations - Firing PRB Coal.

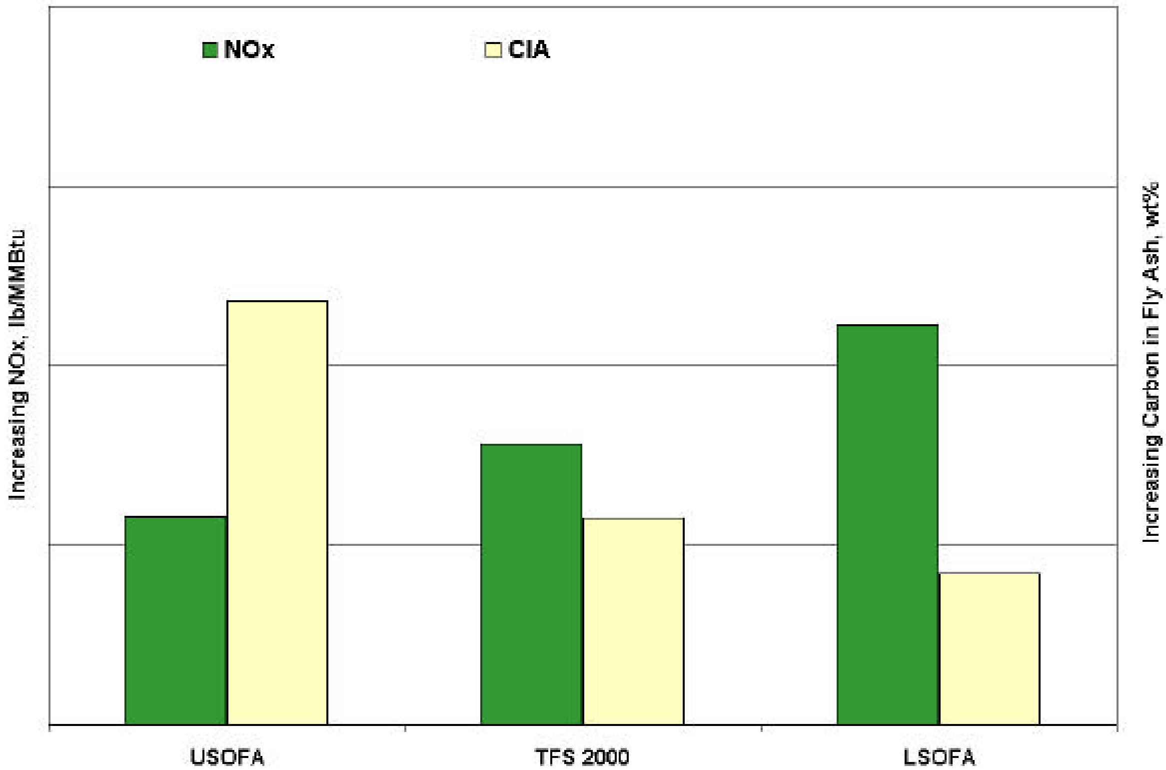

Figure 6.4.3-28: NOx and CIA for Various SOFA Configurations - Firing HVB Coal.

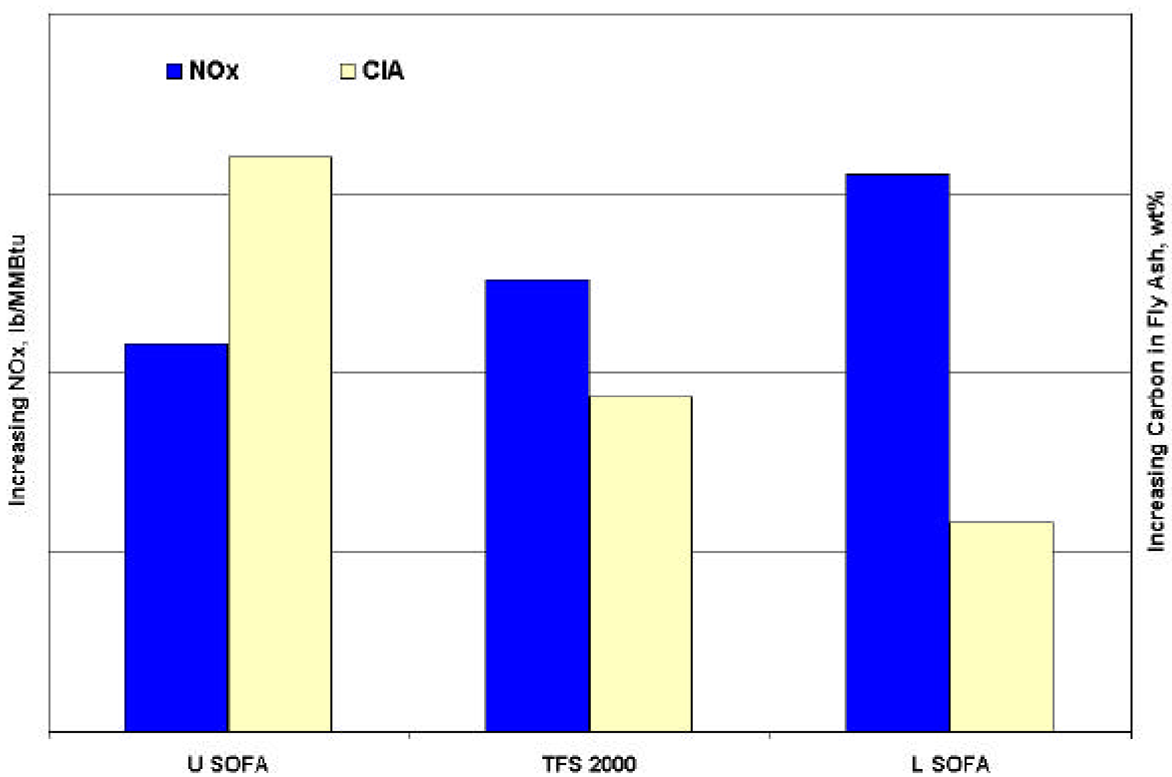

Figure 6.4.3-29: NOx and CIA for Various SOFA Configurations - Firing MVB Coal.

SOFA Velocity

Tests were also conducted wherein the velocity of air through the SOFA compartments was varied. Air injection velocity was varied by changing the number of SOFA compartments utilized. Figure 6.4.3-30 shows how NOx, CIA and CO varied with SOFA velocity for the MVB coal. In this particular case, both upper and lower SOFAs were used. The lowest velocity was achieved by having all six compartments open (three in each of the upper and lower SOFAs), while the highest velocity was achieved by having only two compartments open (one in each of the upper and lower SOFAs).

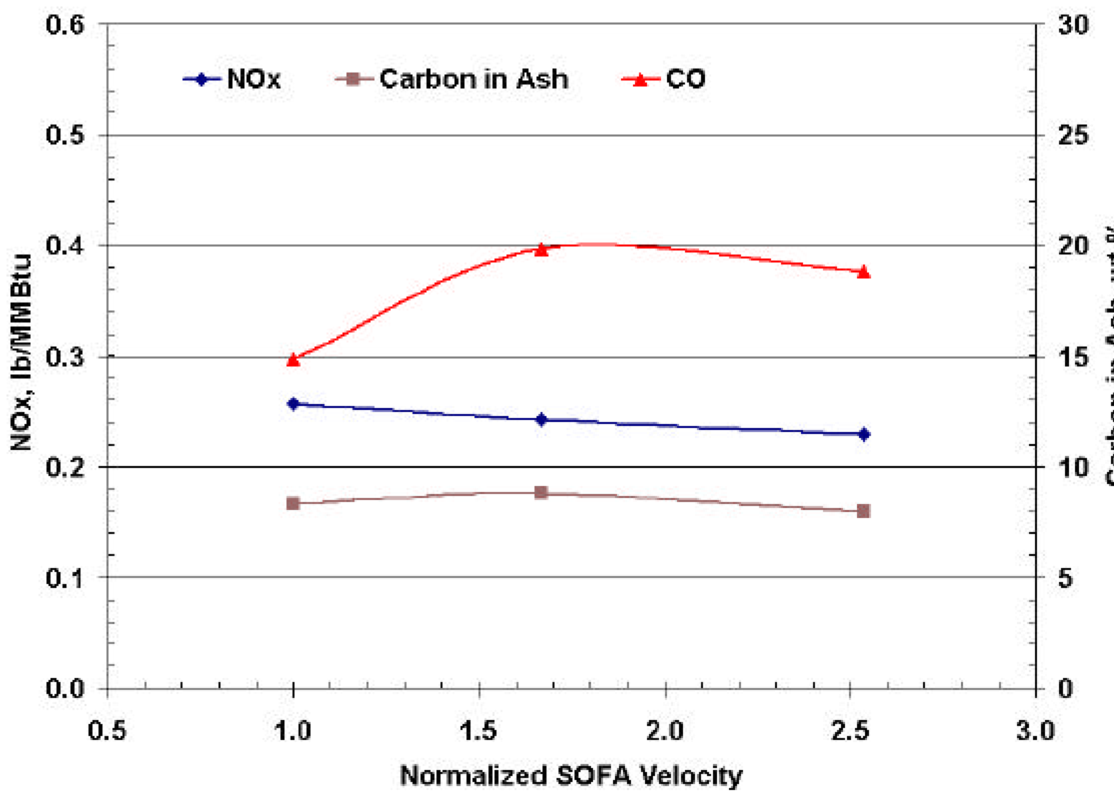

Figure 6.4.3-30: NOx, CIA and CO as a Function of SOFA Velocity (Employing 2 SOFA Elevations) - Firing MVB Coal.

A modest decrease in NOx emissions was seen with increasing SOFA velocity. It is hypothesized that the higher velocity mix more rapidly with the flue gas, thus decreasing the local oxygen concentration and minimizing thermal NOx formation in the upper furnace. Another perceived benefit of increasing SOFA air velocity would be to decrease CIA and CO through the more rapid mixing. However, test results did not show any significant differences in CIA or CO values as a function of SOFA air velocity when testing was carried out with two (2) SOFAs in operation. It should be noted, however, that the pilot-scale facility (BSF) may underestimate the impact of SOFA velocity on CO and carbon in ash as compared to a full-scale utility boiler.

Excess Air

Limited testing was conducted on the PRB coal wherein excess air was varied (measured as final O_2) to determine its effect of NOx and CO. More specifically, the goal was to determine at what point CO and/or NOx began to show significant variation. Figure 6.4.3-31 shows NOx and CO versus final O_2 in the flue gas.

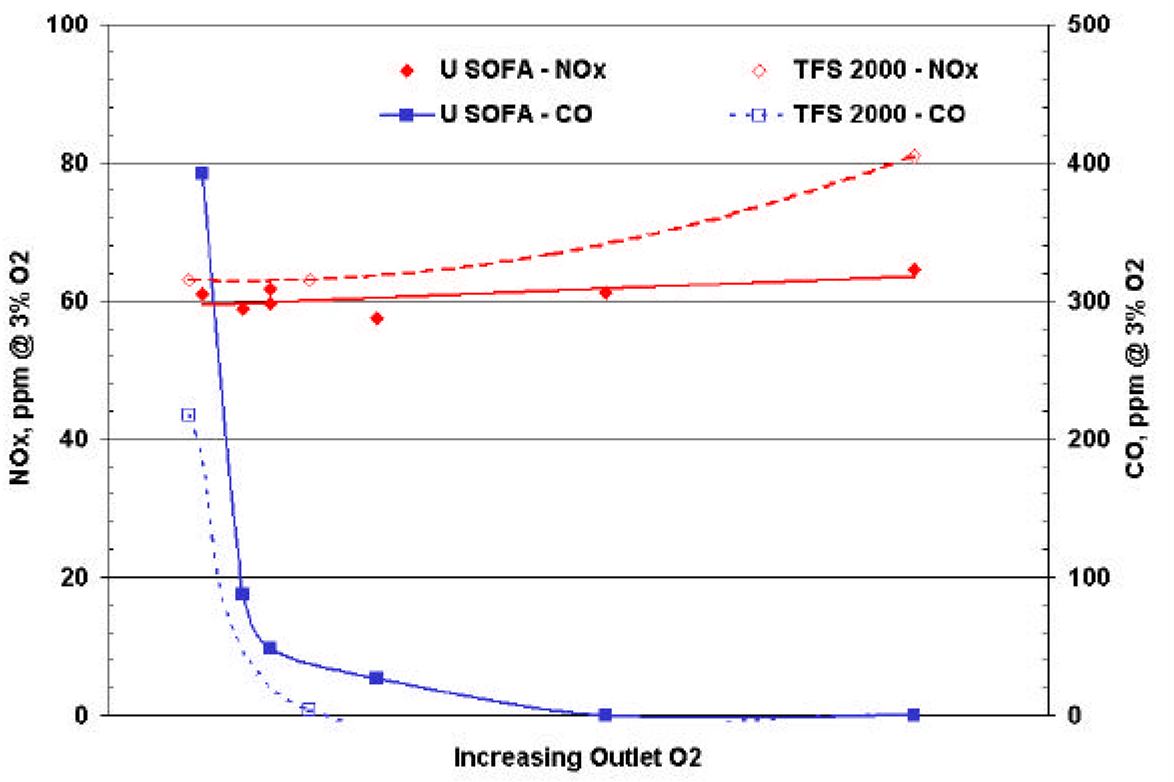

Figure 6.4.3-31: NOx and CO vs. Final O_2 Content in Flue Gas for PRB Coal.

Being a reactive coal, the PRB coal does not begin to show any significant increase in CO until the final O_2 goes below about 1.5% with the upper SOFA only in service. When the TFS 2000™ arrangement is used the CO does not begin to show a significant increase until the final O_2 goes below 1.0%. NOx does not show a significant increase with increasing final O_2 when the single upper SOFA is employed. When the TFS 2000™ arrangement is employed NOx increases with increasing excess air. However, it should be noted that excess air is normally dictated by CIA or CO levels. Therefore, NOx values would necessarily be taken at lowest final O_2 values commensurate with acceptable CIA and/or CO levels.

<u>Ammonia Injection</u>

Ammonia injection was tested as a possible way of further reducing NOx on the MVB coal. Two methods were tested: (1) ammonia was injected directly through the coal pipe, and (2) ammonia was injected directly into the furnace. Ammonia was injected in dosages equivalent to a 1 to 4 molar ratio (NH_3/NOx). In the case of ammonia injection in the coal pipe various arrangements were used, i.e., ammonia was injected through all (three) coal elevations or some combination of less than three elevations. The basic TFS 2000™ arrangement was used for these tests, i.e., with both lower and upper SOFAs in service.

Figure 6.4.3-32 shows differentials in NOx concentration (from the standard TFS 2000™ case) for various tests where ammonia was injected through the coal pipe. Results show that NOx differentials from the TFS 2000™ case are essentially within the error band for this kind of measurement. Even the purge case, where no ammonia was injected, shows a 5 ppm reduction from the base case. Within the framework of testing carried out there was no significant NOx reduction due to injection of ammonia through coal pipes in the BSF.

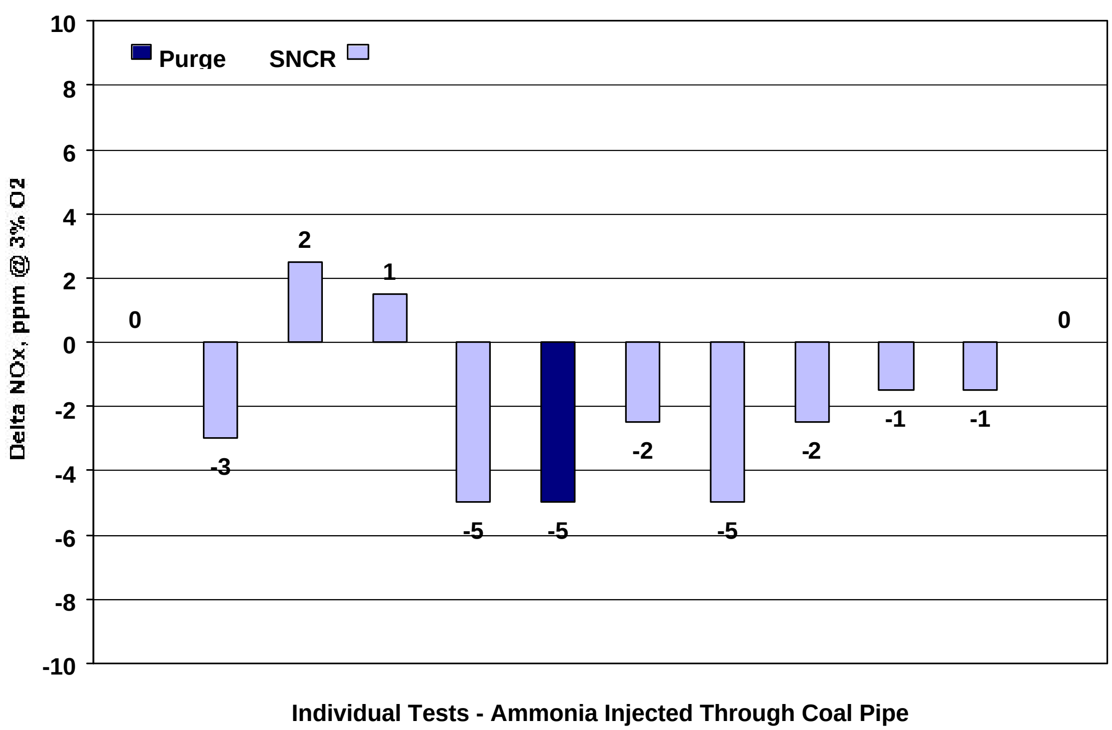

Figure 6.4.3-32: NOx Differentials - Ammonia Injected Through Coal Pipes versus Standard TFS 2000Ô Case.

In the case of ammonia injection directly into the furnace, the ammonia was injected through a water-cooled probe using bottled nitrogen as a carrier gas to provide more momentum/mixing of the ammonia. The injection probes were located upstream of (below) the lower SOFA elevation and, significantly, the lower SOFAs were not operational. The rationale was to inject the ammonia into a location where oxygen concentrations were relatively low to prevent direct oxidation of ammonia to produce NOx.

Figure 6.4.3-33 shows differentials in NOx concentration (from the standard TFS 2000™ case) for various tests where ammonia was injected directly into the furnace. As was the case with ammonia being injected through the coal pipe the differentials in NOx from the TFS 2000™ case were essentially in the error band. During purge periods NOx differentials fluctuated almost as much as when ammonia was being injected. Within the framework of testing carried out, there was no significant NOx reduction when ammonia was directly injected into the BSF furnace.

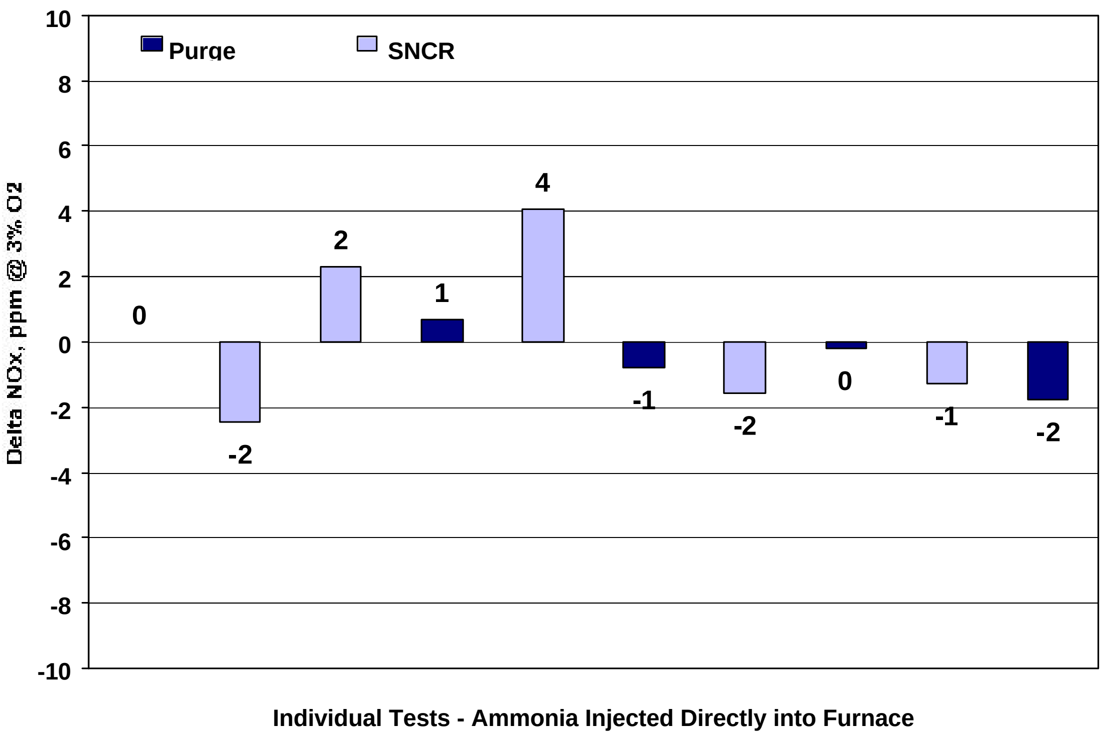

Figure 6.4.3-33: NOx Differentials – Ammonia Injected into Furnace versus Standard TFS 2000Ô Case.

Boiler Load

Very limited testing was carried out with respect to boiler load variation and its effect on NOx. Figure 6.4.3-34 shows NOx versus load variation for the PRB coal where the standard TFS 2000™ arrangement was employed. Though there was a very slight (about 5ppm) decrease in NOx from about 55 MMBtu/hr down to about 48MMBtu/ hr, further load decreases did not show additional NOx reduction.

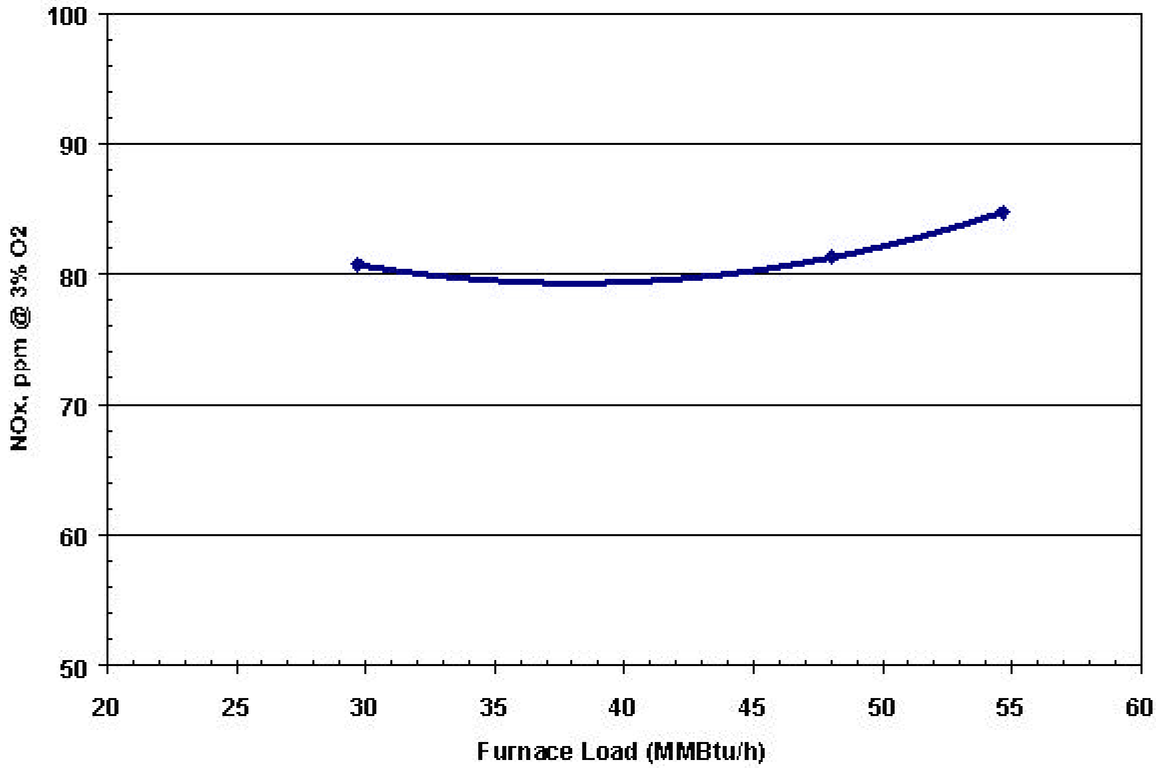

Figure 6.4.3-34: NOx as a Function of Boiler Load for PRB Coal.

6.5 Conclusions

Pilot-scale test results have fallen in line with predictions from bench-scale testing as far as differences in coals are concerned. Of the three coals evaluated under staged firing conditions, the most reactive coal (PRB) showed the greatest reduction in NOx followed by the moderately reactive HVB and least reactive MVB coals. Under staged firing conditions two properties are of paramount importance, as far as NOx reduction and combustion performance are concerned. First the fuel bound nitrogen must be readily released in the near burner zone to allow the nitrogen to form molecular nitrogen. Secondly, the char must be sufficiently reactive to permit reasonably complete combustion in the burnout zone. In the case of the three coals evaluated, the PRB coal showed the highest percentage of fuel bound nitrogen being released in the near-burner zone and the most reactive char having to be burned in the burnout zone. Conversely, the least reactive coal (MVB) showed the lowest percentage of fuel bound nitrogen being released in the near-burner zone, and the least reactive char having to be burned in the burnout zone. More reactive coals also allow more aggressive conditions to be specified for the staged combustion conditions, i.e., lower stoichiometries and/or greater staged residence times.

From the above, it then follows that higher reactivity coals are more amenable to NOx reduction, with acceptable combustion performance, under staged combustion conditions.

When both NOx and combustion performance (CIA and CO) were equally weighed, the standard TFS 2000™ set of operating conditions/system components gave the best results for the HVB and MVB coals. Absolute minimum NOx values, for example, were usually within 0.03 lb/MMBtu of what was achievable with the standard TFS 2000™ system. However, the carbon in ash values associated with absolute minimum NOx were on the order of double of what was achieved with the standard TFS 2000™ system.

Specific, key findings from the pilot-scale testing were as follows:

- NOx decreases with decreasing main burner zone stoichiometry. The PRB coal gave lower NOx (at optimum stoichiometry) than the HVB and MVB coals. The optimum stoichiometries (for lowest NOx) were higher for the PRB coal and lower for the HVB and MVB coals.

- Carbon in ash and CO are inversely related to stoichiometry. The HVB and MVB coals showed a greater dependence on stoichiometry (steeper slope) than the PRB coal.

- NOx decreases with increasing staged residence time. The HVB and MVB coals showed a greater dependence on residence time throughout the range tested. The PRB coal showed a smaller dependence on residence time throughout the range tested.

- Carbon in ash and CO levels increased with increasing staged residence time (which translates to decreasing burnout zone time). The HVB and MVB coals showed a greater dependency on staged residence time while the PRB coal showed very small values of CIA and CO for the range of staged residence times tested.

- Variation of the transport/coal mass ratio had virtually no effect on NOx and very little effect on CIA for the MVB coal, over the range tested.

- Non-uniformity of transport air/coal flows at various locations within the BSF had little effect on NOx or CIA for the PRB and HVB coals over the range tested. Further research is required to quantify the impact of coal and air flow balancing on carbon in ash and CO on a utility scale.

- Micro-fine coal grinding measurably improved NOx reduction for the MVB coal, but significantly decreased CIA. Micro-fine grinding represents a technique to enable operation at optimum stoichiometries, for low NOx purposes, while still allowing acceptable CIA values to be achieved.

- Operation with a single upper SOFA when firing a high reactivity coal (PRB) showed a an improvement in NOx emissions as compared to the standard TFS 2000™ system with little impact on CIA. Operation with a single upper SOFA for the HVB and MVB coals also showed an improvement in NOx emissions as compared to the standard TFS 2000™ arrangement, but at the expense of significantly higher CIA values.

- Injection of ammonia either directly into the furnace or through the coal pipes did not significantly affect the NOx values when compared to baseline (no injection) NOx values.

It should be noted that absolute NOx and carbon in ash emissions levels are also a function of the boiler design, including furnace height, furnace cross sectional area, firing zone heat release rates, etc. The Boiler Simulation Facility is a large pilot-scale test facility that was designed to span the available range of time-temperature histories of commercial utility boilers. As such, the design and typical operating conditions of the BSF result in NOx and carbon in ash levels, which are typically lower than which can be obtained in the majority of commercial utility boilers. As such, absolute results in the BSF are transferable only to utility boilers of similar overall furnace time-temperature history and design characteristics. However, relative results of the BSF are broadly applicable and illustrate the effectiveness of firing system modification, including those achieved with the commercial TFS 2000™ system in lowering NOx emissions and suggest that additional NOx reduction over the commercially available firing system is possible.

7.0 ENGINEERING SYSTEMS ANALYSIS AND ECONOMICS

An engineering systems analysis and economic evaluation was performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). The various NOx reduction options were evaluated as retrofit options for 3 tangential-fired utility boilers in the U.S.: (1) a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, (2) a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and (3) a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). The units selected are representative of a large number of the pulverized coal-fired utility boilers in the U.S.

This section briefly describes the methodology used to design and cost the various NOx reduction options. The major assumptions utilized in the ALSTOM Power economic model are also documented. The results of the economic analysis are then presented for each of the three (3) utility boilers examined in this study.

7.1 Objectives

The objective of the Engineering Systems Analysis and Economics Task is to evaluate the cost of various NOx reduction options. The economic analysis is provided as a means to compare the relative costs and predicted performance of the various NOx reduction options. However, it is recognized that the optimum NOx reduction strategy is unit, site, coal, and system specific. A utility NOx reduction strategy must account for current and anticipated local and national emissions regulations, potential of NOx credit trading, utility deregulation, etc.

7.2 Engineering Evaluation

An engineering analysis was performed for the three tangential-fired utility boilers described above to determine the extent of the hardware modifications required for the different low NOx firing system retrofits and fuel switches. Table 7.2-1 presents the different NOx reduction cases that were considered for each of the three utility boilers. The following conditions were common to all boilers: (1) purchase NOx credits, (2) the TFS 2000™ firing system, (3) the Ultra Low NOx Integrated System, and (4) the use of SCR. Fuel switching to a PRB coal was also considered along with low NOx firing system modifications for the two units firing bituminous coals. Note that the Ultra Low NOx Integrated System does not necessarily represent a specific hardware configuration, but rather a series of modifications that are unit and fuel specific. These modifications include improvements to the windbox design, changes to the overfire air system, improved in coal fineness, etc. that will result in improved NOx performance based on results from the experimental testing performed in the BSF (Section 6).

Table 7.2-1: Cases Evaluated in the Engineering and Economic Analysis.

NOx Reduction Option	Eastern Bit.	Mid-West. Bit.	PRB
Purchase NOx Credits	X	X	X
TFS 2000™	X	X	X
Ultra Low NOx Integrated System	X	X	X
Ultra Low NOx Int. System + CBO™	X		
TFS 2000™ + PRB	X	X	
Ultra Low NOx Int. System + PRB	X	X	
SCR	X	X	X
TFS 2000™ + SCR	X	X	

A case including the Carbon Burn Out™ device (CBO™), a bubbling bed combustor supplied by Progress Materials, Inc., was also examined for the unit firing an Eastern bituminous coal. Figure 7.2-1 illustrates a field installation of the CBO™ device. The CBO™ device is utilized to reduce the unburned carbon in the fly ash to less than 1% to permit the fly ash to be sold to the concrete industry and to recover the heat from the uncombusted fuel. Note that a rigorous engineering evaluation of the CBO™ device was not performed as part of this study. Progress Materials, Inc. provided cost information, both capital and operating costs, for the application of the device at utility-scale as well as the predicted performance. The cost and performance information was utilized in the boiler performance modeling as well as the economic analysis in order to determine the feasibility of utilizing the CBO™ device as part of the Ultra Low NOx Integrated System.

Figure 7.2-1: Carbon Burn OutÔ Installation

For each of the TFS 2000™ and Ultra Low NOx Integrated System retrofits, the ALSTOM Power firing systems engineering group (Performance Projects, Utility Boiler Business) specified an engineering design utilizing current company design standards. All windbox modifications were specified including new coal nozzle tips and auxiliary air compartments. The overfire air systems were also specified using current design standards for sizing, etc.

The impact of each of the firing system modifications, including fuel switching, on boiler operation was determined utilizing an ALSTOM Power proprietary boiler performance code. The boiler performance modeling was used to quantify the potential impact of the modifications on the net plant heat rate, the net electric output, etc. The boiler performance modeling was also used to quantify the extent of convective surface changes that may be needed to maintain boiler output when fuel switching from a bituminous coal to a PRB coal.

The scope of the firing system modifications, convective surface modifications, and mill modifications were determined for each of the NOx reduction strategies. Budgetary pricing of the material and installation costs for the various low NOx retrofit scenarios was then developed by ALSTOM Power utilizing the same price models currently used for commercial jobs.

Note that no engineering designs were developed for the SCR systems. The SCR systems for each of the three units were assumed to have an installed cost of $100 / kW. No attempt was made to account for unit specific issues that may impact both the design and the cost of the SCR systems.

Baseline NOx and carbon in fly ash numbers were taken from plant data and are consistent with current operation. The ALSTOM Power firing systems engineering group provided predictions of NOx and carbon in fly ash for each of the low NOx firing system modifications. The emissions performance predictions were made using boiler geometry, operating conditions, and fuel composition information using commercial prediction methodologies.

7.3 Economic Model

Budgetary pricing of the hardware modifications for each of the NOx reduction cases was fed, along with unit and case specific operating costs, to an ALSTOM Power proprietary economic model. The ALSTOM Power economic model is similar to the EPRI TAG™ methodology [REF - TAG™ Technical Assessment Guide, Volume 3 Rev 6: Fundamentals and Methods – Electricity Supply, EPRI TF-100281, Dec. 1991] and calculates the cost of electricity and the net present value of the project.

The cost of electricity calculation includes the following components: financial, fuel, fixed operation O&M, and variable O&M. The financial component includes all of the engineering, procurement, and construction (EPC) costs, financing fees, and interest accrued during construction and operation. Fuel costs are calculated based on the fuel price, net plant heat rate, degradation factor, and plant availability. The fixed O&M component represents costs incurred regardless of whether the unit is in operation or not. The variable O&M represents incremental costs, which occur when the unit is in operation.

Some of the main economic assumptions are shown in Table 7.3-1. The financial inputs (e.g., interest rates, tax rates, etc.) were held constant for all units and cases. Other unit and case specific variables (e.g., net electric output, net plant heat rate, fuel costs, etc.) were calculated for each case from the boiler performance modeling. The results of the economic analysis are provided in Section 7.4.

Table 7.3-1: Major Economic Assumptions.

Parameter	Value	Units
Depreciable Life	15	Years
Equity	50	%
Interest Rate	9	%
Cash Discount Rate	7	%
Tax Rate	38	%
Escalation	3	%
Capacity Factor	70	%
Ash Disposal Cost	10	$/ton
Ash Value	5	$/ton
NO_x Limit	0.15	lb/10^6 Btu
SO_2 Credits	150	$/ton
NO_x Credits	1500	$/ton
SCR Efficiency	80	%
SCR Installed Cost	100	$/kw

The fuel costs for the 3 utility boilers in this study are shown in Table 7.3-2. The baseline fuel costs for the 3 units are the actual average delivered fuel costs from 4/01/2000 through 3/31/2001. The price of the PRB delivered to the Eastern and Midwestern units is an estimate from one of the major coal companies marketing PRB fuels and not an actual delivered price quotation.

Table 7.3-2: Fuel Costs Utilized in Economic Analysis.

Unit	Fuel	$/MMBtu
East Coast Unit	Eastern Bit.	1.83
	PRB	2.10
Midwestern Unit	Mid-Western Bit.	0.88
	PRB	1.10
Western Unit	PRB	0.50

7.4 Engineering/Economic Analysis Results

An engineering systems analysis and economic evaluation were performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). The various NOx reduction options were evaluated as retrofit options for 3 tangential-fired utility boilers in the U.S., a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). The results of the engineering and economic analysis are presented for each of the 3 units in the following sections.

7.4.1 Unit Designed for Eastern Bituminous Coal

The unit designed for Eastern bituminous coal is a 400 MW boiler on the East coast. The unit typically fires low sulfur, bituminous coals from central Appalachian. The baseline NOx and carbon in ash levels for this unit are 0.45 lb/MMBtu and 7.9% by weight, respectively (see Figure 7.4.1-1). Note that this unit is a post-NSPS unit with close coupled overfire air. With a TFS 2000™ retrofit, NOx emissions are predicted to drop to 0.22 lb/MMBtu while carbon in ash drops slightly to 7.5% due to the use of DYNAMIC™ classifiers for improved coal fineness. A modest further drop in NOx (0.01 lb/MMBtu) was predicted for the Ultra Low NOx Integrated System at the expense of unburned carbon (10.0%). The Carbon Burn Out™ device was assumed to drop the unburned carbon to 0.1% by weight. NOx emissions of 0.15 lb/MMBtu were predicted for a TFS 2000™ retrofit accompanied by a fuel switch to a PRB coal. Again, a 0.01 lb/MMBtu drop in NOx was predicted for the Ultra Low NOx Integrated System as compared to TFS 2000™. Carbon in ash was predicted to be less than 1.0% for both systems firing a PRB coal. The SCR was assumed to drop NOx emissions by 80% over the baseline value for the SCR case and by 80% over the TFS 2000™ value for the SCR + TFS 2000™ case.

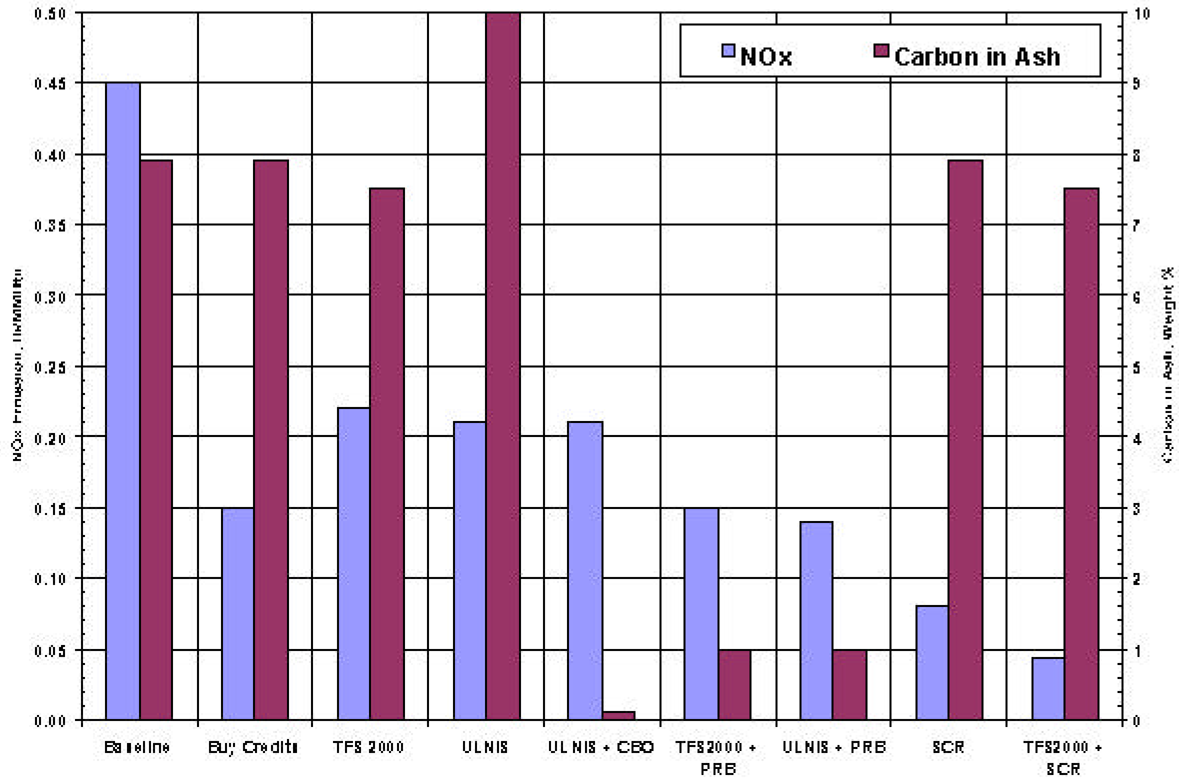

Figure 7.4.1-1: Predicted NOx and Carbon in Ash for NOx Retrofit Options: East Coast 400 MW Unit.

The capital costs of the various NOx reduction options for the unit firing the Eastern bituminous coal is shown in Figure 7.4.1-2. Obviously, there is no capital cost associated with buying NOx credits. The lowest cost retrofit option is the TFS 2000™ firing system at 8.5 $MUSD, with the Ultra Low NOx Integrated System retrofit slightly more expensive at 8.7 $MUSD. Adding the Carbon Burn Out™ device increases the capital cost to 13.0 $MUSD. A number of additional modifications must be made for the fuel switch to a PRB coal including fuel handling modifications, duct heaters, and heat transfer surface modifications. These modifications result in a capital cost approximately twice that of the retrofits without a fuel switch. However, in all cases the capital cost of the retrofits is less than half the cost of an SCR.

The impact of the various NOx reduction options on the levelized cost of electricity is shown in Figure 7.4.1-3. Three different scenarios involving buying and selling of NOx credits are shown in the figure. The blue (solid) bars represent the case where NOx credits are purchased at $1500/ton to achieve 0.15 lb/MMBtu when the firing system modifications alone can not achieve that level. NOx credits are also sold at the same price ($1500/ton) when the modifications achieve NOx emissions levels less than 0.15 lb/MMBtu. The hatched bars represent the case where NOx credits can be purchased if the unit doesn't comply with the 0.15 lb/MMBtu standard, but there is no local market to sell NOx credits from strategies that over comply. The yellow (open) bar represents the case where NOx credits cannot be bought or sold. Note that the cases marked with an asterisk are NOx compliant by performance alone (i.e., no NOx credit purchases are needed to achieve 0.15 lb/MMBtu).

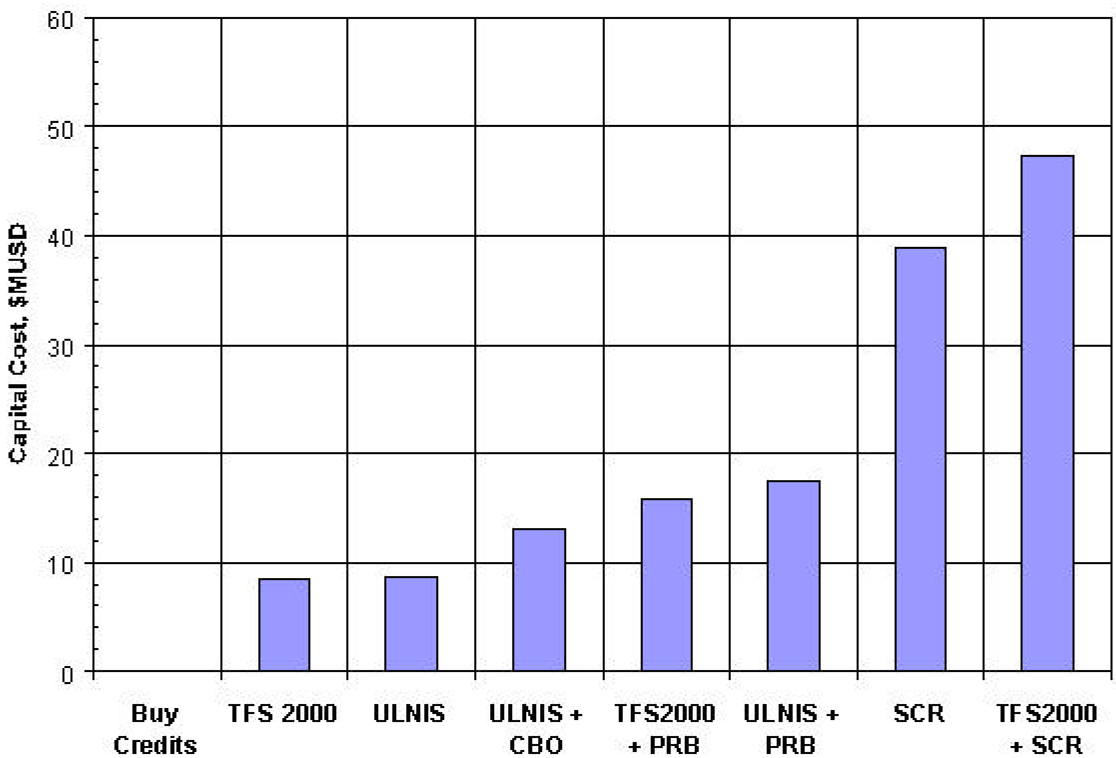

Figure 7.4.1-2: Capital Cost for NOx Retrofit Options: East Coast 400 MW Unit.

At the assumed price of $1500/ton, buying NOx credits is one of the more costly options as it increases the cost of electricity (COE) by 2.32 mills/kWh. The TFS 2000™ option (buying NOx credits to make up the difference) is the most cost effective option at a 0.85 mills/kWh increase in the COE. Note that the TFS 2000™ retrofit costs account for less than 40% of the 0.85 mills/kWh increase. The cases with the fuel switch to a PRB are the most expensive with a predicted increase of 3.4 mills/kWh in COE. The SCR cases are competitive for the Eastern unit with a predicted increase approximately 1.04 mill/kWh if NOx credits can be sold. If there is no market for the excess NOx emissions, the increase in COE would be closer to 1.6 mill/kWh. Note that these cases were prepared to allow comparison between the various NOx reduction options for a particular unit. In reality, the economic optimization of the NOx reduction strategy will be done on a system wide basis and will account for bubbling of emissions where permitted by local and federal regulations.

As shown in Figure 7.4.1-3, adding the Carbon Burn Out™ device to the Ultra Low NOx Integrated system had no impact on the cost of electricity. The additional capital and operating costs were offset as the carbon content in the fly ash was decreased to a level where the ash could be sold instead of landfilled. Note that the economics of the Carbon

Burn Out™ device depend on the local market for fly ash and landfill costs. Also, in this study the device was evaluated for use with a single utility boiler and there may be some economies of scale that improve the economics for sites containing multiple units.

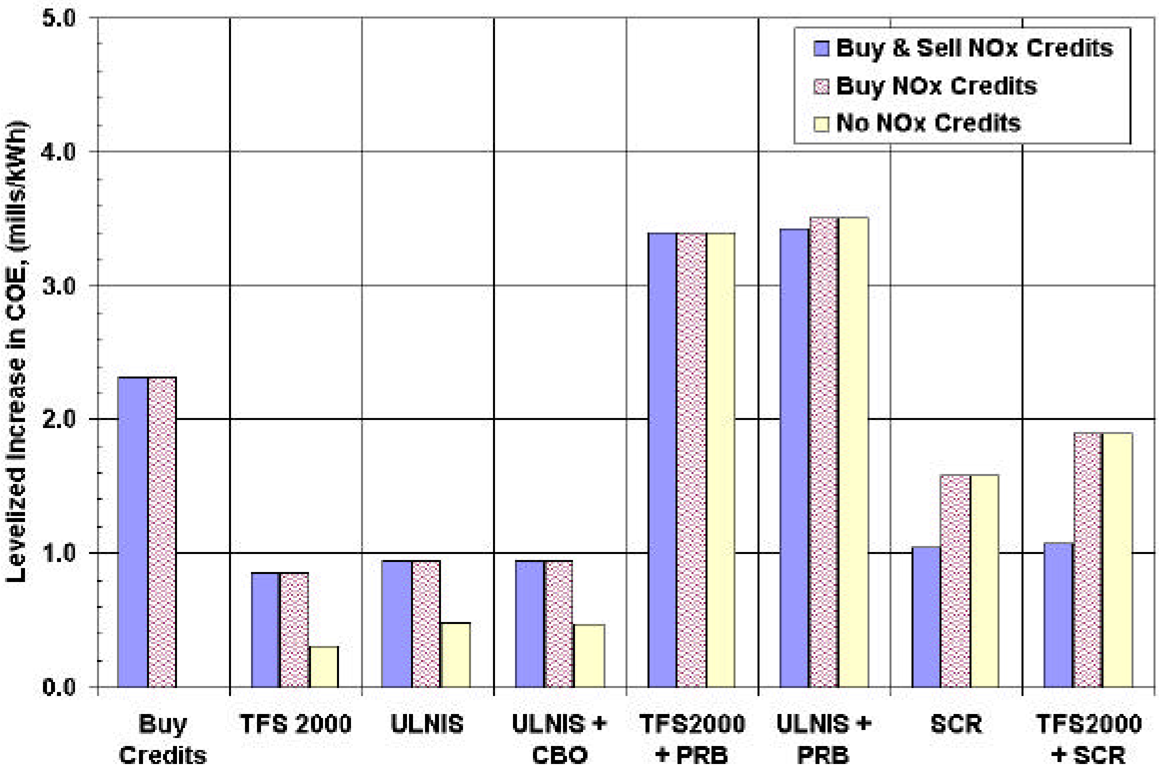

Figure 7.4.1-3: Increase in Cost of Electricity (mills/kWh) for NOx Retrofit Options: East Coast 400 MW Unit

As modeled, the economic predictions are very sensitive to the projected NOx credit price. Figure 7.4.1-4 illustrates the impact of the NOx credit price (ranging from 1000-3000 $/kWh) on the cost of electricity for the scenario where NOx credits can be bought and sold (blue bar in Figure 7.4.1-2). As expected, increasing NOx credit price makes options that rely on purchasing NOx credits more costly, while benefiting the options that over comply and sell extra NOx credits. The only case not shown to be affected by the price of NOx credits is the TFS 2000 with the fuel switch to PRB as this case was predicted to achieve exactly 0.15 lb/MMBtu.

As might be expected the cost of electricity, in cases with a fuel switch to a PRB coal, are very sensitive to the delivered fuel costs. Figure 7.4.1-5 compares the predicted costs with a fuel price of 2.1 $/MMBtu to the case where the PRB coal can be obtained at the same delivered price as the Eastern bituminous coal (1.83 $/MMBtu). This decrease in PRB fuel cost (less than 15%) results in a dramatic decrease in the predicted cost of electricity such that the fuel switching cases become the most attractive. The high degree of sensitivity to fuel costs is due to the fact that fuel costs for this unit are more than 75% of the total costs.

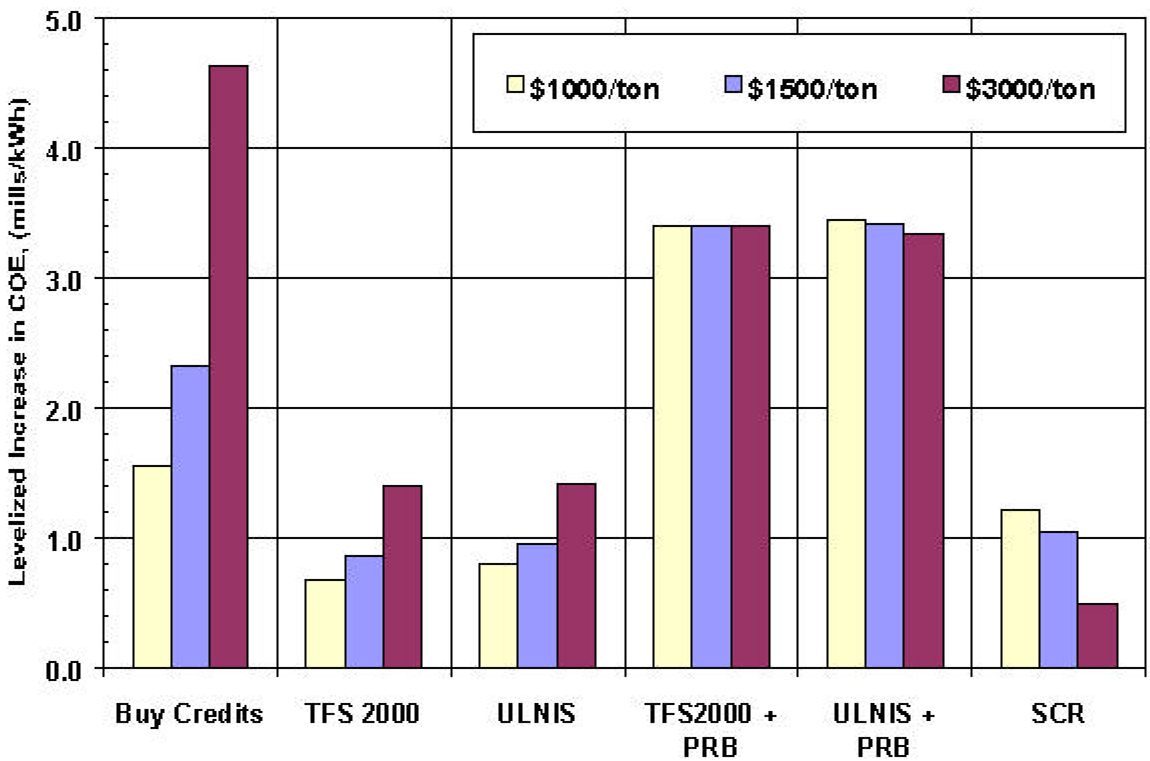

Figure 7.4.1-4: Impact of NOx Credit Price on Cost of Electricity (mills/kWh) : East Coast 400 MW Unit.

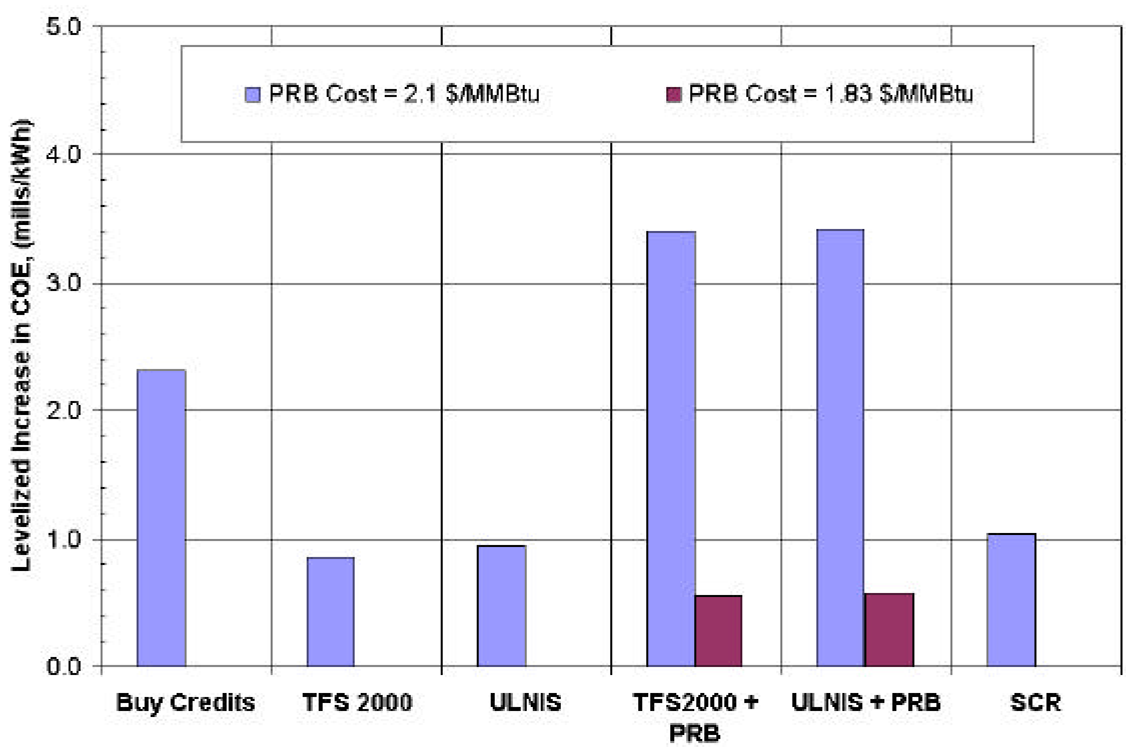

Figure 7.4.1-5: Impact of PRB Fuel Price on Cost of Electricity (mills/kWh) : East Coast 400 MW Unit.

7.4.2 Unit Designed for Midwestern Bituminous Coal

A 500 MW utility boiler located in the Midwestern U.S. was selected for the engineering and economic analysis. The tangential-fired unit fires a local high volatile bituminous coal with 2.5% sulfur by weight. The baseline NOx and carbon in ash levels for this unit are 0.38 lb/MMBtu and 3.0% by weight, respectively as shown in Figure 7.4.2-1. This unit is also a post-NSPS unit with close coupled overfire air. With a TFS 2000™ retrofit, NOx emissions were predicted to drop to 0.20 lb/MMBtu while carbon in the fly ash increased to 6%. The increase in carbon in the fly ash with TFS 2000™ for this unit is due to the fact that DYNAMIC™ classifiers were not included in the scope of modifications. An additional decrease in NOx emissions (0.18 lb/MMBtu) and corresponding increase in carbon in ash (8%) are predicted for the Ultra Low NOx Integrated System. NOx emissions less than 0.15 lb/MMBtu can be achieved with a PRB fuel switch or with SCR as shown in the figure.

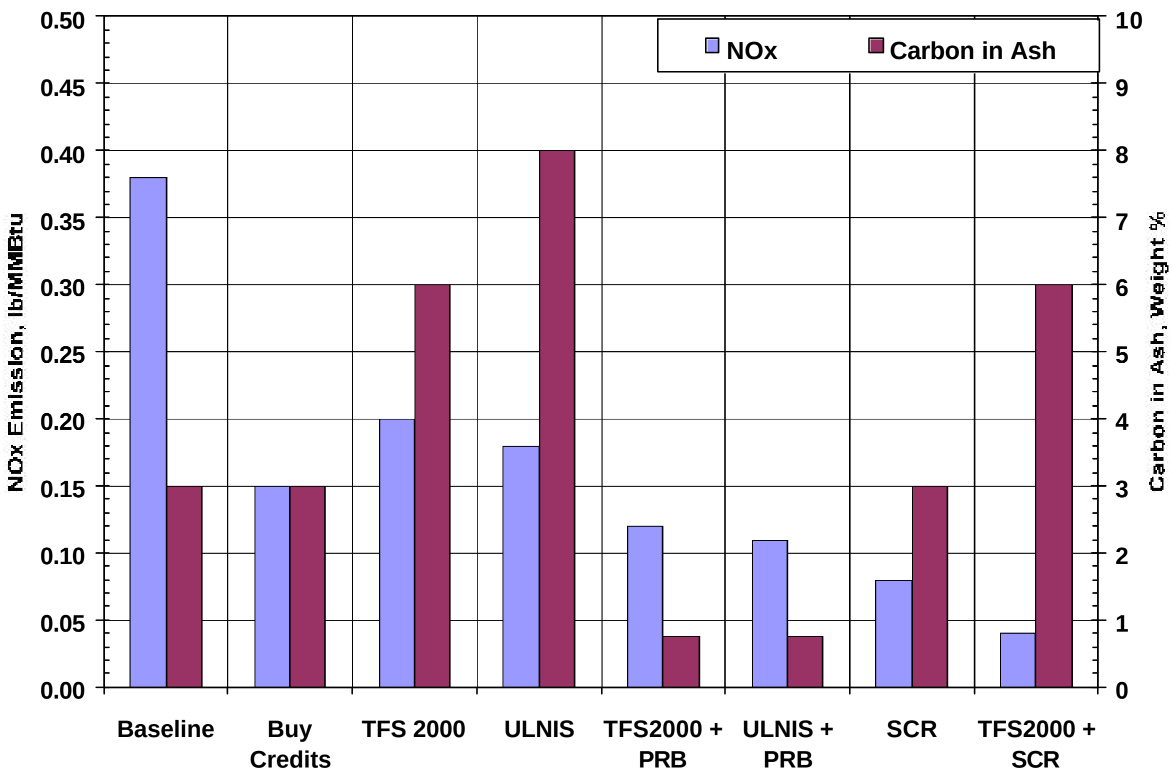

Figure 7.4.2-1: Predicted NOx and Carbon in Ash for NOx Retrofit Options: Midwestern 500 MW Unit.

The capital costs of the various NOx reduction options for the Midwestern unit are shown in Figure 7.4.2-2. The lowest cost retrofit option is the TFS 2000™ firing system at 6.6 $MUSD, with the Ultra Low NOx Integrated System retrofit somewhat more expensive at 7.6 $MUSD. Due to the generous size of this unit, the number of mills, etc. no additional boiler modifications are required for the fuel switch to a PRB coal. Note that no additional fuel handling or fire suppression equipment was included in the costs of the PRB conversion.

As a result, the capital cost of the SCR conversion is over 5 times that of the other low NOx firing system options.

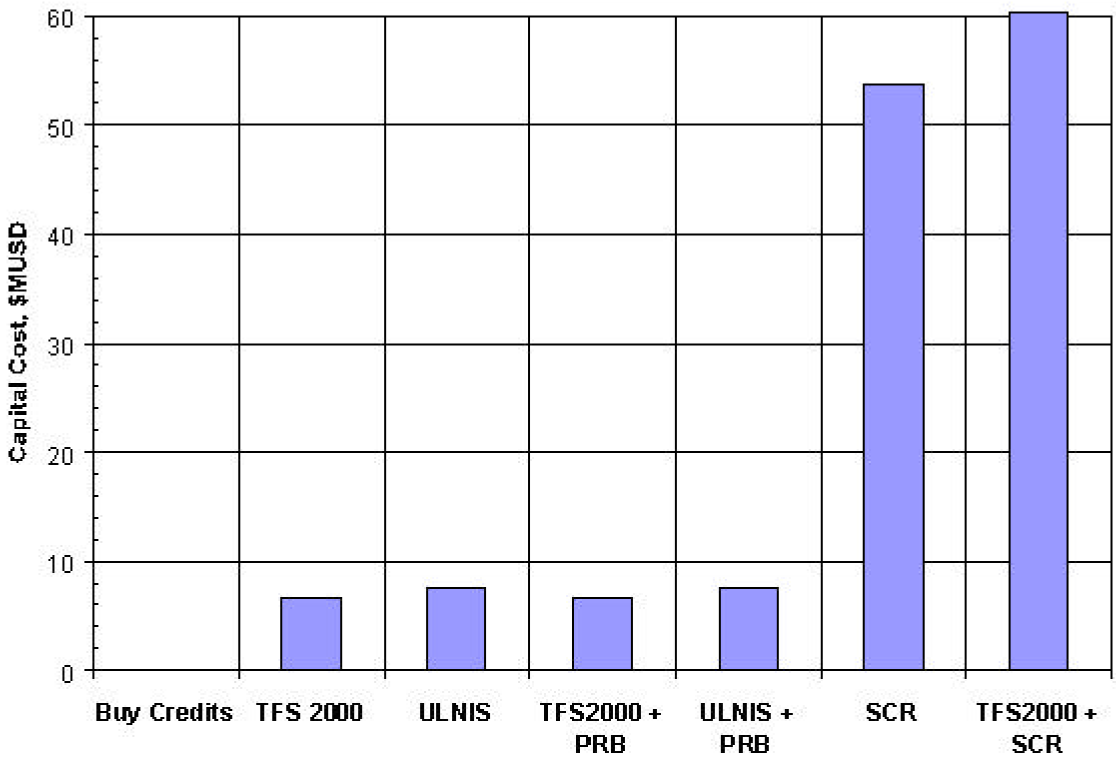

Figure 7.4.2-2: Capital Cost for NOx Retrofit Options: Midwestern 500 MW Unit.

The impact of the various NOx reduction options on the levelized cost of electricity is shown in Figure 7.4.2-3 for the 3 different scenarios involving buying and selling of NOx credits. At the assumed price of $1500/ton, buying NOx credits is one of the more costly options as it increases the cost of electricity (COE) by 1.78 mills/kWh. The Ultra Low NOx Integrated System option (buying NOx credits to make up the difference) is the most cost effective option without a fuel switch at a 0.86 mills/kWh increase in the COE. The cases with a fuel switch to PRB actually show a decrease in the cost of electricity due to the decreased sulfur content of the fuel. It was assumed that the unit did not have a scrubber and that SO_2 credits were purchased at 150 $/ton. The SCR cases are competitive for the Midwestern unit with a predicted increase approximately 1.0 mill/kWh if NOx credits can be sold. If there is no market for the excess NOx emissions, the increase in COE would be 1.54 mill/kWh. From this analysis, the most attractive NOx compliance strategy would be the Ultra Low NOx Integrated System coupled with a fuel switch to a PRB fuel.

As modeled, the economic predictions are very sensitive to the projected NOx credit price. Figure 7.4.2-4 illustrates the impact of the NOx credit price (ranging from 1000-3000 $/kWh) on the cost of electricity for the scenario where NOx credits can be bought and sold (blue bar in Figure 7.4.2-2). As expected, increasing NOx credit price makes options that rely on purchasing NOx credits more costly, while benefiting the options that over comply and sell extra NOx credits.

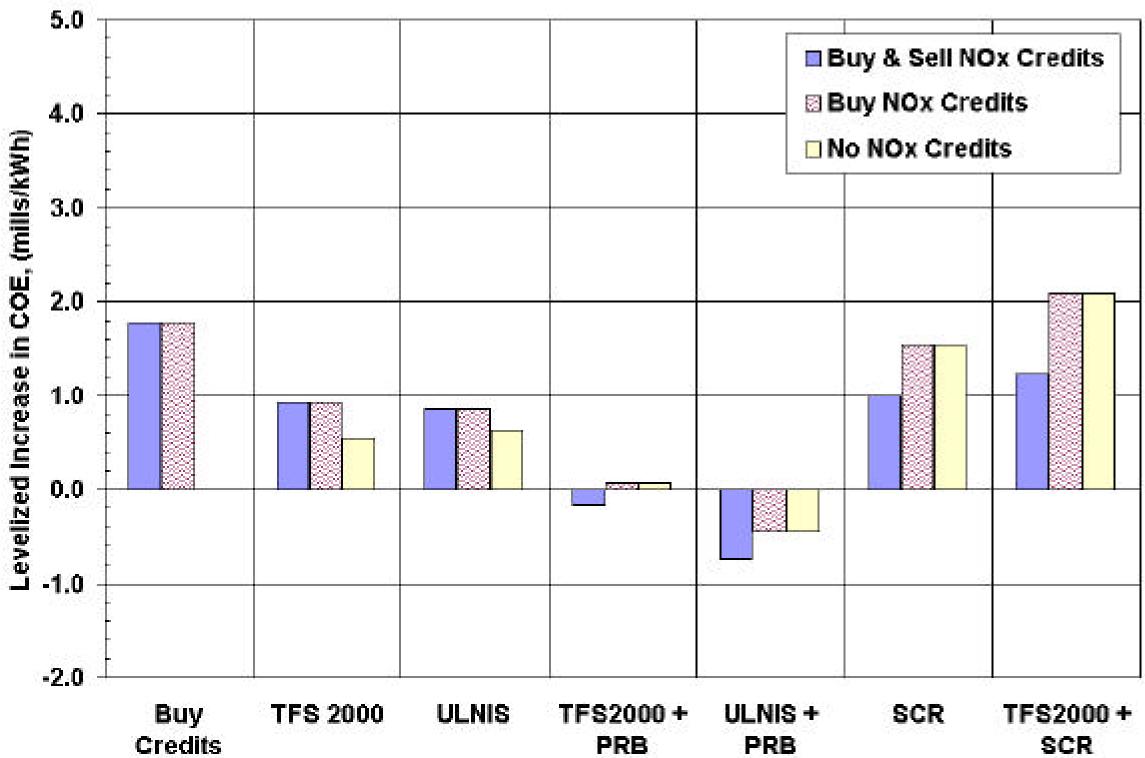

Figure 7.4.2-3: Increase in Cost of Electricity (mills/kWh) for NOx Retrofit Options: Midwestern 500 MW Unit.

As might be expected the cost of electricity, in cases with a fuel switch to a PRB coal, are sensitive to the delivered fuel costs. Figure 7.4.2-5 compares the predicted costs with a fuel price of 1.1 $/MMBtu to the case where the PRB coal can be obtained at the same delivered price as the Midwestern bituminous coal (0.88 $/MMBtu), and to a case with a 20% increase in PRB fuel cost. While still sensitive to fuel price, the impact of fuel cost is less for the Midwestern unit as fuel costs are 55-60% of the total costs as compared to over 75% of the total cost for the unit firing the Eastern coal.

As might be expected the cost of electricity, in cases with a fuel switch to a PRB coal, is very sensitive to the delivered fuel costs. Figure 7.4.2-5 compares the predicted costs with a fuel price of 2.1 $/MMBtu to the case where the PRB coal can be obtained at the same delivered price as the Eastern bituminous coal (1.83 $/MMBtu). This decrease in PRB fuel cost (less than 15%) results in a dramatic decrease in the predicted cost of electricity such that the fuel switching cases become the most attractive. The high degree of sensitivity to fuel costs is due to the fact that fuel costs for this unit are more than 75% of the total costs.

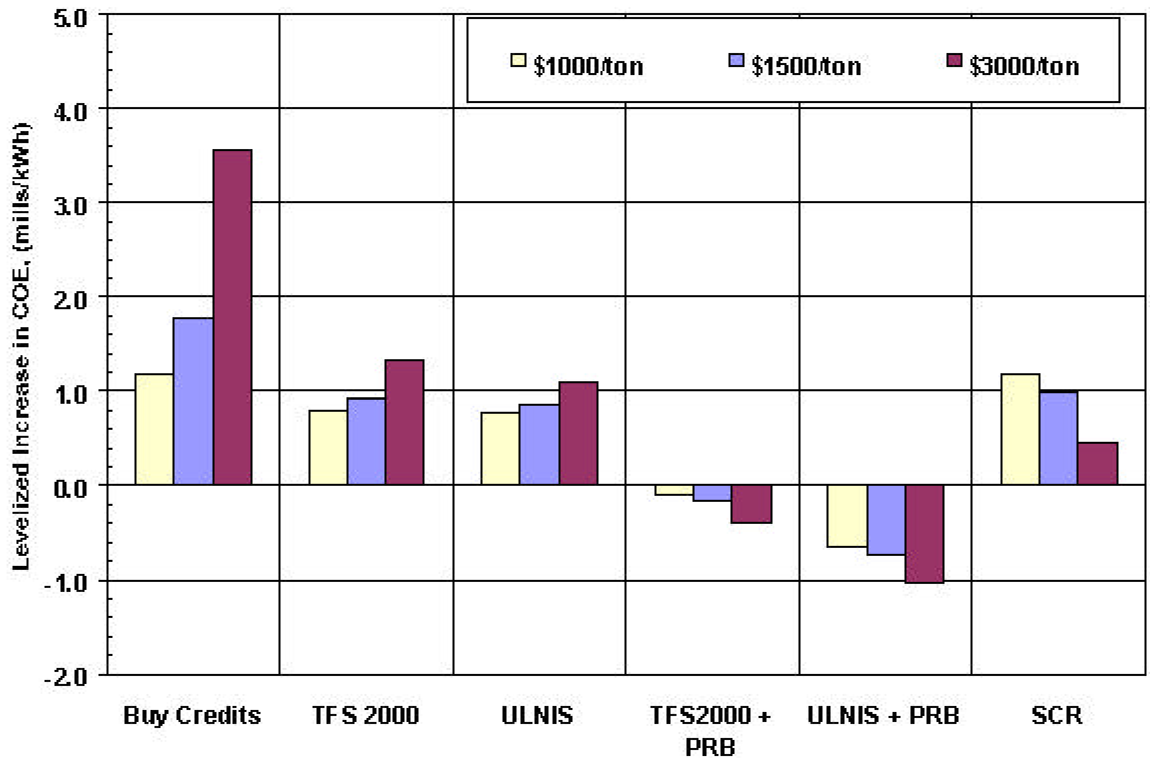

Figure 7.4.2-4: Impact of NOx Credit Price on Cost of Electricity (mills/kWh): Midwestern 500 MW Unit.

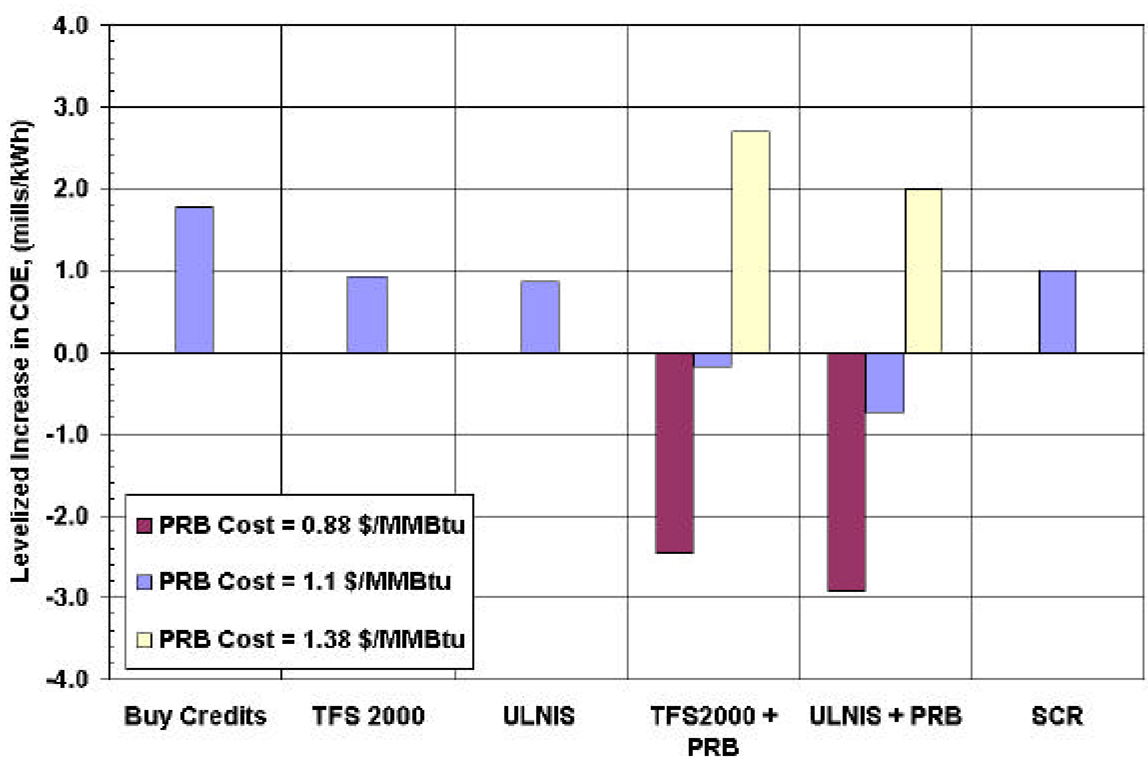

Figure 7.4.2-5: Impact of PRB Fuel Price on Cost of Electricity (mills/kWh): Midwestern 500 MW Unit.

7.4.3 Unit Designed for Subbituminous Coal

A 330 MW utility boiler located in the Western U.S. was selected for the engineering and economic analysis as the unit designed to fire a subbituminous coal. The tangential-fired unit fires low sulfur coal from the Powder River Basin. The baseline NOx and carbon in ash levels for this unit are 0.49 lb/MMBtu and 0.5% by weight, respectively as shown in Figure 7.4.3-1. Note that this unit is a pre-NSPS unit and does not have close coupled overfire air, resulting in higher baseline NOx emissions while firing a low rank fuel. With a TFS 2000™ retrofit, NOx emissions were predicted to drop to 0.15 lb/MMBtu with no significant impact on carbon in ash. An additional decrease in NOx emissions of 0.14 lb/MMBtu is predicted for the Ultra Low NOx Integrated System. SCR and SCR coupled with TFS 2000™ result in predicted NOx emissions of 0.08 and 0.044 lb/MMBtu, respectively.

The capital costs of the various NOx reduction options for the Western unit are shown in Figure 7.4.3-2. The lowest cost retrofit option is the TFS 2000™ firing system at 6.3 $MUSD, with the Ultra Low NOx Integrated System somewhat more expensive at 7.8 $MUSD. The capital cost of the SCR conversion is approximately 5 times that of the other low NOx firing system options.

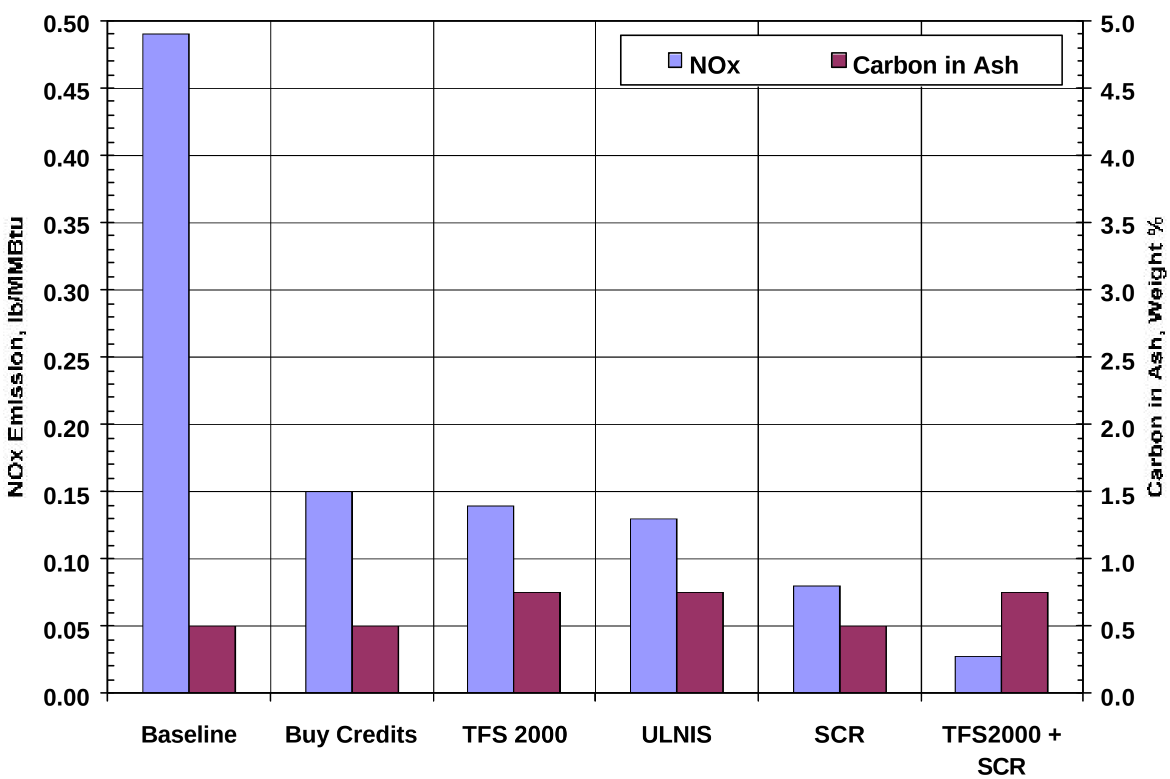

Figure 7.4.3-1: Predicted NOx and Carbon in Ash for NOx Retrofit Options: Western 330 MW Unit.

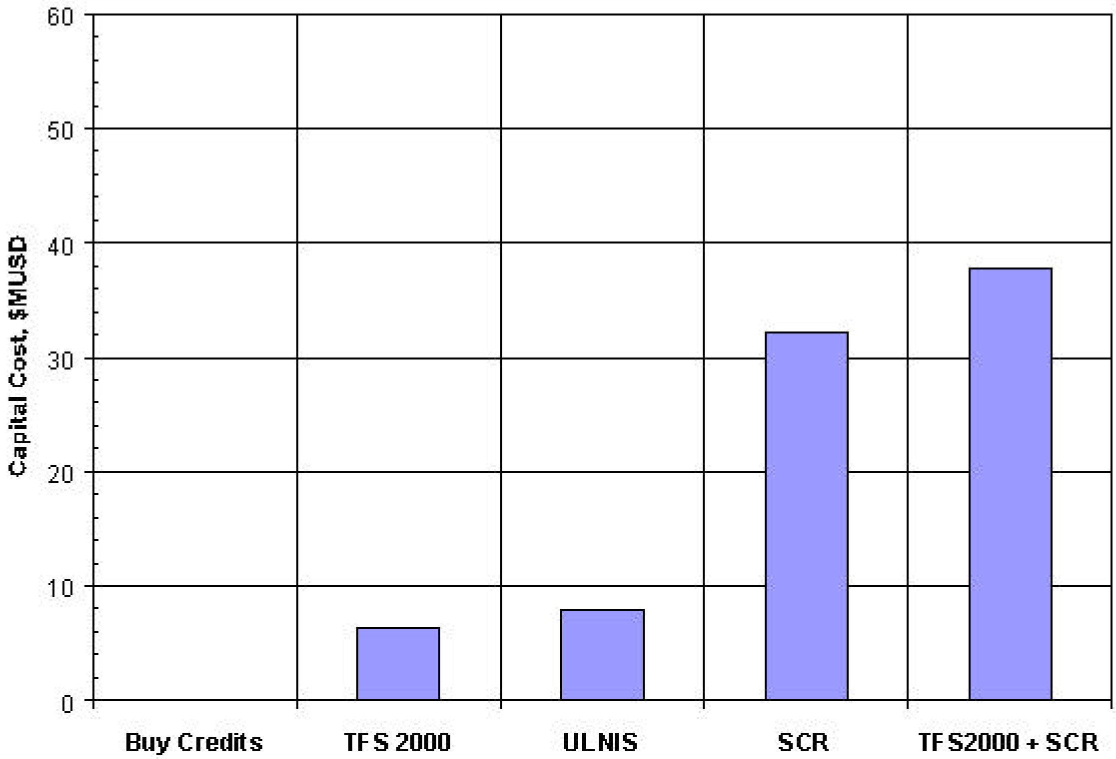

Figure 7.4.3-2: Capital Cost for NOx Retrofit Options: Western 330 MW Unit.

The impact of the various NOx reduction options on the levelized cost of electricity is shown in Figure 7.4.3-3 for the 3 different scenarios involving buying and selling of NOx credits. At the assumed price of $1500/ton, buying NOx credits is one of the more costly options as it increases the cost of electricity (COE) by 2.63 mills/kWh. The Ultra Low NOx Integrated System at a 0.13 mills/kWh increase in COE is the most cost effective NOx retrofit strategy, while use of an SCR increases the COE by 0.9 mills/kWh if excess NOx credits can be sold. If there is no market for the excess NOx emissions, the increase in COE would be 1.43mill/kWh. The additional NOx reduction achieved with TFS 2000™ and SCR is more cost effective than an SCR alone, assuming that the NOx credits could be sold. However, from this analysis, the most attractive NOx compliance strategy for a Western unit firing a PRB fuel would be the Ultra Low NOx Integrated System.

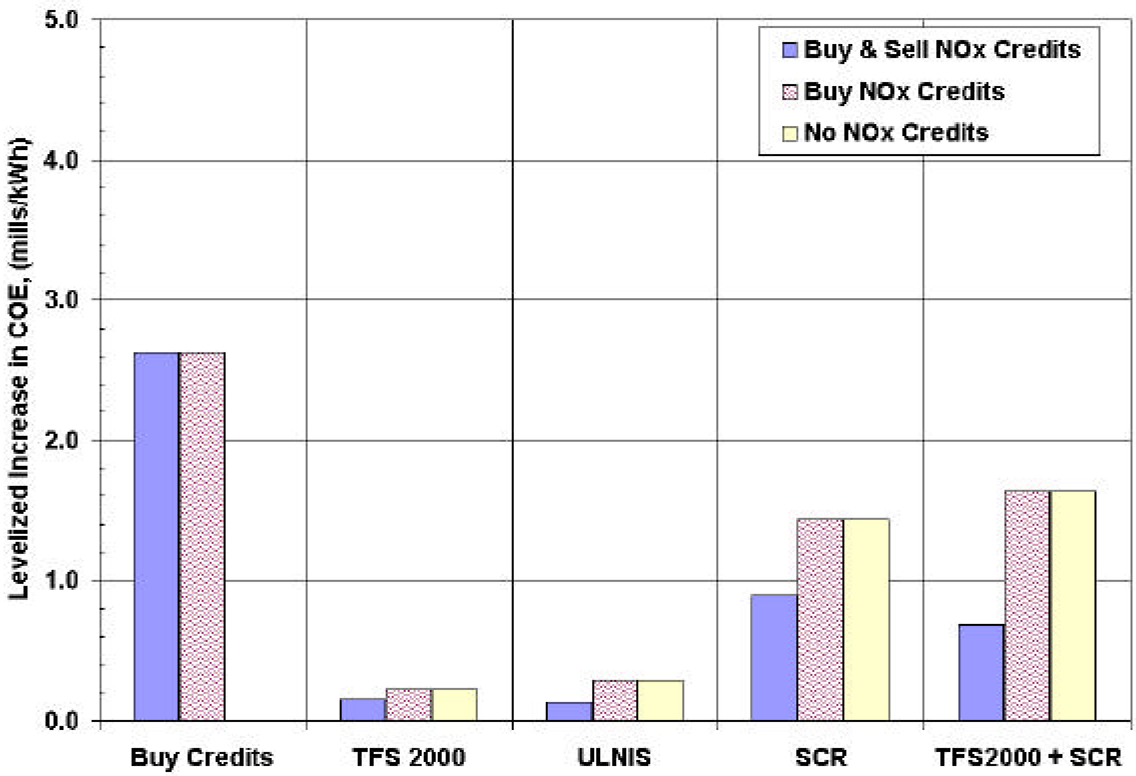

Figure 7.4.3-3: Increase in Cost of Electricity (mills/kWh) for NOx Retrofit Options: Western 330 MW Unit.

7.5 Conclusions

An engineering systems analysis and economic evaluation were performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). As expected, the optimum NOx reduction strategy was unit and fuel specific for the 3 tangential-fired utility boilers evaluated in this study, a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). Utility NOx reduction strategies must also account for current and anticipated local and national emissions regulations, potential of NOx credit trading, utility deregulation, etc. which may be unit, site, fuel, and system specific.

Key findings from the engineering and economic analysis were as follows:

- Combustion modifications (TFS 2000™ and Ultra Low NOx Integrated System) can achieve 0.15 lb/MMBtu in a Western unit firing a PRB coal.

- The most attractive NOx compliance strategy for the Western unit firing a PRB fuel was the Ultra Low NOx Integrated System.

- The Ultra Low NOx Integrated System was predicted to have the lowest NOx emissions (0.18 lb/MMBtu)for the Midwestern unit, although the 0.15 lb/MMBtu target was not achieved without a fuel switch to a PRB coal.

- Reasonable delivered fuel costs and generous boiler sizes make fuel switching to PRB coals an attractive option for Midwestern units.

- For Eastern U.S. units, the option of fuel switching to a PRB coal is very sensitive to the delivered fuel price as the fuel cost is the largest single expense for a utility boiler.

- The capital cost of an SCR installation is 4-5 times that of the typical low NOx firing system modifications.

- The NOx reduction economics are very sensitive to the projected price of NOx credits as well as the potential market for selling excess credits.

- Adding the Carbon Burn Out™ device to a low NOx firing system had little impact on the cost of electricity for the assumed ash disposal costs. However, the economics depend on the local fly ash market and landfill costs.

8.0 COMMERCIALIZATION PLAN

The market for retrofit NOx emissions control from existing U.S. coal-fired boilers will be significant for the next several years as plant owners act to comply with Clean Air Act and Ambient Air Quality environmental regulations. This market is highly competitive and plant owners are vigilant in seeking lowest costs. This environment is heightened by uncertainties in competitive position within the electrical utility industry as it undergoes deregulation and, furthermore, by an over capacity of equipment supply and service in a slow U.S. and global market for new coal power generation.

Today in the United States, coal plant owners are generally favorably cost positioned in the deregulated market with paid-down plant capital, low fuel costs, modest O&M, high availability, and a resulting low cost of electricity production, with resulting high capacity factor that further improves electricity production costs. These plant owners seek to maintain this competitive advantage by meeting NOx compliance with the lowest possible levelized costs.

There is generally a range of technically feasible options for a single power plant's unit emissions compliance plan. The challenge is to balance the cost, performance and impact on unit operation for the best overall result. This effort becomes much more difficult on a system-wide basis as the matrix of choices expands. However, if this evaluation is done systematically, opportunities exist for the greatest cost savings through the optimization of low-cost firing system modifications and the strategic utilization of higher-cost SCR systems.

With current low NOx firing system technology, the NOx emission levels that can be achieved are a function of both the furnace design and coal properties. In general, boilers designed in the 1950's were conservative in design. The furnaces were typically tall with large cross sectional areas, resulting in lower peak gas temperatures. The generous furnace height can be strategically used in an overfire air retrofit to optimize the staged residence time for maximum NOx reduction. By the mid 1960's economic pressures dictated reductions in the capital cost of new units, resulting in shorter, hotter furnaces which present a greater challenge for ultra low NOx emissions. In addition, as the unit size and electrical output continued to grow, the cross-sectional area of furnace also increased. The larger furnace sizes also impact the SOFA mixing characteristics which must be optimized for adequate combustion efficiency at optimal low NOx conditions.

As seen in both the laboratory and pilot-scale testing performed in this project, NOx emissions under low NOx conditions are a strong function of coal rank. The high reactivity, subbituminous PRB coals are able to achieve lower NOx emissions with air staging than the medium volatile bituminous coals which have less volatile matter and less reactive chars. Hence, the NOx levels that can be achieved for a particular unit depend strongly upon the coal that is fired.

The ALSTOM Power commercial strategy is to offer the plant owners the lowest cost solution to achieve the desired level of NOx reduction for their specific unit. At the start of this project, the TFS 2000™ system was the most aggressive low NOx firing system available for tangentially-fired p.c. boilers. The aim of this DOE-sponsored project was to improve upon the performance of the TFS 2000™ firing system. The large pilot-scale testing in the BSF suggested that the TFS 2000™ firing system was a good compromise between low NOx emissions and acceptable levels of unburned carbon in the fly ash. However, the testing also showed that improvements could be made to the TFS 2000™ firing system through windbox modifications, improved coal fineness, SOFA modifications, and fuel and air balancing (for units with significant imbalances in the fuel and air distributions) that would result in modest NOx reductions. However, as some of these modifications for improved NOx performance resulted in higher levels of unburned carbon in the fly ash, not all of the modifications may be desired for a given unit. There may be economic incentives to maintaining certain levels of carbon in the fly ash depending upon the local fly ash markets and landfill costs.

Originally, it was envisioned that a host site for a demonstration of the Ultra Low NOx firing system would be selected by the advisory panel and would likely be a unit owned by one of the advisory panel member's company. It was felt that a commercial demonstration of the Ultra Low NOx Integrated System would be required to bring the system to market. However, based on the large variation in units and fuels that exist in the current market, it was decided to handle each customer on an individual basis and offer a customized solution to achieve the desired unit performance. Different components of the Ultra Low NOx system will be offered as needed to each customer. In fact, various pieces of the technology developed and tested in this program have already been sold to customers and are currently being installed in the field. As the value of the new technologies are proven in the field, market demand for them should increase.

Fuel switching to Powder River Basin coals is also part of the ALSTOM Power commercial strategy for decreasing NOx emissions from pulverized coal-fired utility boilers. As was demonstrated in the large pilot-scale testing in this project, the lowest NOx emissions were obtained with the highly reactive PRB coals with minimal impact on the carbon in fly ash. ALSTOM Power also has significant commercial experience with low NOx firing systems and PRB coals where NOx emissions have been consistently less than 0.15 lb/MMBtu. For units where delivered PRB coal costs are economically feasible, fuel switching and low NOx firing system modifications should be considered.

9.0 CONCLUSIONS AND RECOMMENDATIONS

Conclusions

The overall goal of the proposed project was to develop low-cost, efficient NOx control technologies for retrofit to coal fired utility boilers as a means to keep coal a viable part of the national energy mix in the next century and beyond. Toward that end, the following specific project objectives were set by ALSTOM Power for work that was performed in response to the above goal:

- Objective: Develop retrofit NOx control technology to achieve less than 0.15 lb/MMBtu NOx from existing tangentially-fired utility boilers when firing Eastern bituminous coals

- Achievement: For the two bituminous coals tested in the BSF, one high volatile (HVB) and one medium volatile (MVB), the specific target above was met for the HVB coal (0.12 lb/MMBtu) while 0.17 lb/MMBtu was achieved for the MVB coal. The results of the large pilot-scale testing suggest that the target of 0.15 lb/MMBtu may be realistic for highly reactive bituminous coals. However, given the range and importance of specific coal properties on NOx and combustion performance, as well as the specific boiler designs, it becomes difficult to project the emissions performance of the new firing system technology to the tangentially-fired utility boiler market.

- Objective: Develop retrofit NOx control technology to achieve less than 0.10 lb/MMBtu NOx from existing tangentially- fired utility boilers when firing western, subbituminous or lignitic coals

- Achievement: When tested in the BSF the subbituminous (PRB) coal gave NOx values as low as 0.08 lb/MMBtu for the Ultra Low NOx Integrated System.

- Objective: Achieve economics which are at least 25% lower cost than the SCR-only technology

- Achievement: Capital costs for the TFS 2000™ or the Ultra Low NOx Integrated System are well under the target of "25% less than an SCR-only" installation based on commercial costing information. For the Eastern bituminous and subbituminous coal cases (taken from Section 7.0) the TFS 2000™ and Ultra Low NOx Integrated System are about 78% less than an SCR-only case; for the Midwestern coal case the TFS 2000™ and Ultra Low NOx Integrated System are on the order of 87% less than an SCR-only case.

- Objective: Validate NOx control technology through large (15 MW_t) pilot scale demonstration

- Achievement: Credible results have been obtained from ALSTOM Power's 15 MW_t pilot-scale facility on NOx emissions for the various derivatives of the low NOx systems tested. It is recognized that absolute NOx and carbon in ash emissions levels are a function of the boiler design, including furnace height, furnace cross sectional area, firing zone heat release rates, etc. Since the Boiler Simulation Facility was designed to span a range of time-temperature histories of commercial utility boilers, NOx and carbon in ash levels are often lower than what might be obtained in commercial utility boilers. However, relative results of the BSF are broadly applicable and illustrate the effectiveness of firing system modification, including those achieved with the commercial TFS 2000™ system in lowering NOx emissions and suggest that additional NOx reduction over the commercially available firing system is possible.

- Objective: Evaluate engineering feasibility and economics for several scenarios of technology components and component integration, for representative plant cases with both bituminous and subbituminous coals

- Achievement: Engineering systems analyses and economic evaluations were performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). Optimum NOx reduction strategy was unit and fuel specific for the 3 tangential-fired utility boilers evaluated in this study, a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). Utility NOx reduction strategies must also account for current and anticipated local and national emissions regulations, potential of NOx credit trading, utility deregulation, etc. which may be unit, site, fuel, and system specific.

Results from this project have directly, and positively benefited the performance of ALSTOM Power's family of low NOx firing systems, specifically the TFS 2000™ and CFS™ systems. For those boilers firing PRB type coals, for example, results from this project have shown how modifications can be made to enhance performance of the LNCFS™ firing system. Fine grinding has been shown to improve performance with lower reactivity coals in concert with the TFS 2000™ firing system.

In addition to the above responses to specific project objectives, key conclusions from Sections 4.0, 6.0 and 7.0 are reiterated here for convenience.

Test Fuels Characterization

Results from the "Test Fuels Characterization" section have proven to be very insightful relative to the stated objectives of: (1) quantifying fuel properties, (2) providing definitive information from bench-scale testing on nitrogen conversion and relevant combustion-related parameters under air staged, low NOx firing conditions, (3) providing guidance and understanding regarding pilot-scale test planning and results interpretation.

Relative to performance in a staged air low NOx combustion system, PRB coal would be the most amenable. The combination of early devolatilization, with commensurately high quantities of fuel bound nitrogen being released early in the combustion process, coupled with a highly reactive char, indicate that significant NOx reduction can occur without penalties of high unburned carbon or CO. MVB coal, by contrast would be the most challenging of the three coals regarding the task of achieving low NOx in an air staged, low NOx system while maintaining acceptable levels of unburned carbon and CO levels. HVB coal would fall in between PRB and MVB coals regarding its NOx and combustion performance in an air staged low NOx combustion system.

The trends found during bench-scale characterization, in particular results from the DTFS-1 and TGA, are consistent with those found during pilot-scale testing in the BSF, as will be shown later in Section 6.0.

Specific, key findings were as follows:

- The PRB coal should result in the lowest NOx emissions, under air staged conditions, commensurate with maintaining acceptable unburned carbon and CO levels in the flue gas.

- The MVB coal represents the greatest challenge in terms of achieving low NOx, under staged air firing conditions, both from the standpoint of early and significant fuel nitrogen release (to form molecular nitrogen) and in maintaining acceptable unburned carbon and CO levels in the flue gas.

- Employment of micro-fine coal grinding in the case of the MVB coal would provide better carbon burnout, similar to that of the HVB coal. Finer grinding for the MVB coal did not increase high temperature volatile matter release, nor nitrogen conversion to gaseous species during pyrolysis testing.

- The HVB coal would fall somewhere in between the PRB and MVB coals in terms of its expected low NOx performance and unburned carbon and CO emission levels under air staged firing conditions.

- Results of bench-scale testing provided very reliable indications of expected results during pilot-scale testing.

- Bench-scale results have provided a sound, fundamental understanding of NOx-related results from pilot-scale tests. Fuel bound nitrogen conversion for MVB coal, for example, was shown to be significantly lower (about 55% versus 85-90% for PRB and HVB coals) than the other two test coals, a major reason for its higher NOx emissions despite firing under an air staged system.

Large Pilot-Scale Combustion Testing

Pilot-scale test results have fallen largely in line with predictions from bench-scale testing as far as differences in coals are concerned. Of the three coals evaluated under staged firing conditions, the most reactive coal (PRB) showed the greatest reduction in NOx followed by the moderately reactive HVB and least reactive MVB coals. Under staged firing conditions two properties are of paramount importance, as far as NOx reduction and combustion performance are concerned. First the fuel bound nitrogen must be readily released in the near burner zone to allow the nitrogen to form molecular nitrogen. Secondly, the char must be sufficiently reactive to permit reasonably complete combustion in the burnout zone. In the case of the three coals evaluated, the PRB coal showed the highest percentage of fuel bound nitrogen being released in the near-burner zone and the most reactive char having to be burned in the burnout zone. Conversely, the least reactive coal (MVB) showed the lowest percentage of fuel bound nitrogen being released in the near-burner zone, and the least reactive char having to be burned in the burnout zone. More reactive coals also allow more aggressive conditions to be specified for the staged combustion conditions, i.e., lower stoichiometries and/or greater staged residence times.

From the above, it then follows that higher reactivity coals are more amenable to NOx reduction, with acceptable combustion performance, under staged combustion conditions.

For bituminous coals, when both NOx and combustion performance (CIA and CO) were equally weighed, the standard TFS 2000™ set of operating conditions/system components gave the best results for the three coals evaluated. Absolute minimum NOx values, for example, were usually within 0.03 lb/MMBtu of what was achievable with the standard TFS 2000™ system. However, the carbon in ash values associated with absolute minimum NOx were on the order of double of what was achieved with the standard TFS 2000™ system.

Specific, key findings from the pilot-scale testing were as follows:

- NOx decreases with decreasing main burner zone stoichiometry. The PRB coal gave lower NOx (at optimum stoichiometry) than the HVB and MVB coals. The optimum stoichiometries (for lowest NOx) were higher for the PRB coal and lower for the HVB and MVB coals.

- Carbon in ash and CO are inversely related to stoichiometry; the HVB and MVB coals showed a greater dependence on stoichiometry (steeper slope) than the PRB coal.

- NOx decreases with increasing staged residence time. The HVB and MVB coals showed a greater dependence on residence time throughout the range tested. The PRB coal showed a smaller dependence on residence time throughout the range tested.

- Carbon in ash and CO levels increased with increasing staged residence time (which translates to decreasing burnout zone time). The HVB and MVB coals showed a greater dependency on staged residence time, while the PRB coal showed very small values of CIA and CO for the range of staged residence times tested.

- Variation of the transport/coal mass ratio had little effect on NOx and CIA for the MVB coal, over the range tested.

- Non-uniformity of transport air/coal flows at various locations within the BSF had little effect on NOx or CIA for the PRB and HVB coals over the range tested.

- Micro-fine coal grinding measurably improved NOx reduction for the MVB coal, but significantly decreased CIA. Micro-fine grinding represents a technique to enable operation at optimum stoichiometries, for low NOx purposes, while still allowing acceptable CIA values to be achieved.

- Operation with a single upper SOFA when firing a high reactivity coal (PRB) showed a an improvement in NOx emissions as compared to the standard TFS 2000™ system with little impact on CIA. Operation with a single upper SOFA for the HVB and MVB coals also showed an improvement in NOx emissions as compared to the standard TFS 2000™ arrangement, but at the expense of significantly higher CIA values.

- Injection of ammonia either directly into the furnace or through the coal pipes did not significantly affect the NOx values when compared to baseline (no injection) NOx values.

Engineering Systems Analysis and Economics

An engineering systems analysis and economic evaluation were performed to evaluate various NOx reduction options including the commercially available TFS 2000™ firing system, the Ultra Low NOx Integrated System developed in this project, and selective catalytic reduction (SCR). As expected, the optimum NOx reduction strategy was unit and fuel specific for the 3 tangential-fired utility boilers evaluated in this study, a 400 MW boiler on the East coast firing an Eastern bituminous compliance coal, a 500 MW boiler in the Midwestern U.S. firing a local bituminous coal, and a 330 MW boiler in the Western U.S. firing a subbituminous coal from the Power River Basin (PRB). Utility NOx reduction strategies must also account for current and anticipated local and national emissions regulations, potential of NOx credit trading, utility deregulation, etc. which may be unit, site, fuel, and system specific.

Key findings from the engineering and economic analysis were as follows:

- Combustion modifications (TFS 2000™ and Ultra Low NOx Integrated System) can achieve 0.15 lb/MMBtu in a Western unit firing a PRB coal.

- The most attractive NOx compliance strategy for the Western unit firing a PRB fuel was the Ultra Low NOx firing system.

- The Ultra Low NOx Integrated System was predicted to have the lowest NOx emissions (0.18 lb/MMBtu)for the Midwestern unit, although the 0.15 lb/MMBtu target was not achieved without a fuel switch to a PRB coal.

- Reasonable delivered fuel costs and generous boiler sizes make fuel switching to PRB coals an attractive option for Midwestern units.

- For Eastern U.S. units, the option of fuel switching to a PRB coal is very sensitive to the delivered fuel price as the fuel cost is the largest single expense for a utility boiler.

- The capital cost of an SCR installation is 4-5 times that of the typical low NOx firing system modifications.

- The NOx reduction economics are very sensitive to the projected price of NOx credits as well as the potential market for selling excess credits.

- Adding the Carbon Burn Out™ device to a low NOx firing system had little impact on the cost of electricity for the assumed ash disposal costs. However, the economics depend on the local fly ash market and landfill costs.

Recommendations

The following recommendations are made for additional NOx reduction from pulverized coal-fired boilers:

1. During pilot-scale testing coal ballistics (trajectories) was briefly evaluated. Specifically, the angle and tilt of the bottom coal elevation was varied, even to the point of counter-rotation with respect to the mid- and upper-coal elevations. The recommendation is to further explore possible benefits of coal ballistics for more than one elevation.

2. Though pilot-scale test results on SNCR evaluation, both through the coal pipe and directly into the furnace did not show further NOx reduction, it is recommended that further testing be carried out under more carefully controlled conditions, with particular emphasis on oxygen content in the flue gas into which ammonia is injected.

3. Switching to PRB coal was a very attractive economical option for lowering NOx, without adversely affecting other combustion performance parameters like carbon in ash and CO levels. Where economical possible to ship PRB coal, the recommendation is to seriously consider this option as a high priority solution.

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