ACHIEVING NEW SOURCE PERFORMANCE STANDARDS (NSPS) EMISSION STANDARDS THROUGH INTEGRATION OF LOW-NOx BURNERS WITH AN OPTIMIZATION PLAN FOR BOILER COMBUSTION

COOPERATIVE AGREEMENT DE-FC26-03NT41418

Final Report

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Disclaimer

Abstract

The objective of this project was to demonstrate the use of an Integrated Combustion Optimization System to achieve NO_X emission levels in the range of 0.15 to 0.22 lb/MMBtu while simultaneously enabling increased power output. The project plan consisted of the integration of low-NO_X burners and advanced overfire air technology with various process measurement and control devices on the Holcomb Station Unit 1 boiler. The plan included the use of sophisticated neural networks or other artificial intelligence technologies and complex software to optimize several operating parameters, including NO_X emissions, boiler efficiency, and CO emissions.

The program was set up in three phases. In Phase I, the boiler was equipped with sensors that can be used to monitor furnace conditions and coal flow to permit improvements in boiler operation. In Phase II, the boiler was equipped with burner modifications designed to reduce NO_X emissions and automated coal flow dampers to permit on-line fuel balancing. In Phase III, the boiler was to be equipped with an overfire air system to permit deep reductions in NO_X emissions. Integration of the overfire air system with the improvements made in Phases I and II would permit optimization of boiler performance, output, and emissions.

This report summarizes the overall results from Phases I and II of the project. A significant amount of data was collected from the combustion sensors, coal flow monitoring equipment, and other existing boiler instrumentation to monitor performance of the burner modifications and the coal flow balancing equipment.

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List of Acronyms and Abbreviations

2V Two Valve **-** Used to designate a half load performance test in which two of the four turbine control valves are opened 100% and the other two control valves are fully closed.

APM Atlantic Plant Maintenance – Industrial maintenance and construction company that bid on installation work associated with the project.

B&W The Babcock and Wilcox Company – Manufacturing company that provided the boiler at Holcomb Station.

BACT Best Available Control Technology – An acronym used in environmental permitting to describe the best technology available to control emissions.

CEMS Continuous Emissions Monitoring System – Computerized system used to monitor and report combustion emissions as required by law.

CFD Computational Fluid Dynamics – A modeling technique used to calculate predicted flows, temperatures, and emissions in a given process.

CO Carbon Monoxide – A gaseous pollutant produced in coal combustion processes.

FEGT Furnace Exit Gas Temperature – The temperature of flue gas in an industrial boiler measured just below the bottom of the pendant superheaters, on a horizontal plane approximately in line with the tip of the boiler bullnose.

GE EER General Electric Energy and Environmental Research Corporation – Environmental company that was the primary engineering and material supply contractor for the project.

I/O Input/Output – Typically used to signify information passed to and from analog and digital electronic control systems.

KDHE Kansas Department of Health and Environment

LOI Loss On Ignition – A parameter that signifies the amount of unburned combustible material (typically carbon) remaining in solid particles (ash) following a combustion process.

MMI Man-Machine Interface – Computer hardware and software used to provide an interface for people to provide and receive information from an analog or digital electronic control system.

NOx Nitrogen Oxides – Gaseous pollutants produced in coal combustion processes.

NSE National Steel Erectors, Inc. – Industrial maintenance and construction company that bid on installation work associated with the project and completed a portion of the installation work associated with Phase II of the project.

O2 Oxygen – Excess oxygen is typically measured at the exhaust of an industrial boiler to provide an indication of how much excess air is being utilized in the combustion process.

OFA Overfire Air – A combustion technique in which a portion of combustion air is moved from the burner combustion zone to an area above the burner combustion zone to reduce NOx emissions. Overfire air can be admitted immediately above the burner zone (close-coupled) or farther away from the burner zone (separated).

PLC Programmable Logic Controller – A controller used to control processes using analog and digital electronic inputs and outputs.

PMC Power Maintenance and Construction, Inc. – Industrial maintenance and construction company that bid on installation work associated with the project and completed a portion of the installation work associated with Phases I and II of the project.

PSD Prevention of Significant Deterioration – A type of air operating permit design to protect air quality by defining maximum emission levels for various pollutants.

PC Pulverized Coal

PM Particulate Matter – Very small liquid and solid particles floating in the air.

PM10 Particulate Matter less than 10 microns in Diameter – This particulate matter is of greatest concern for human health because it is small enough to be inhaled into the deepest parts of the lungs.

RFP Request for Proposals – Document sent to companies to solicit monetary bids for a defined work scope. This document typically includes bidding instructions, technical specifications, and terms and conditions

SCR Selective Catalytic Reduction – A process where a gaseous or liquid reductant (most commonly ammonia or urea) is added to the flue gas stream and is absorbed onto a catalyst. The reductant reacts with NOx in the flue gas to form H2O and N2 and remove the NOx from the flue gas.

SOFA Separated Overfire Air – See definition of OFA above.

SR Stoichiometric Ratio – The exact ratio of air to fuel required to complete combustion based on the chemical combustion equations.

SO2 Sulfur Dioxide - Gaseous pollutant produced in coal combustion processes.

VOC Volatile Organic Compounds - Organic chemical compounds that have high enough vapor pressure under normal conditions to significantly vaporize and enter the atmosphere.

VWO Valves Wide Open - Used to designate a full load performance test in which all four of the turbine control valves are opened 100%.

S.0 Executive Summary

The objective of this project was to demonstrate the use of an Integrated Combustion Optimization System to achieve NO_X emission levels in the range of 0.15 to 0.22 lb/MMBtu while simultaneously enabling increased power output. The project plan consisted of the integration of low-NO_X burners and advanced overfire air technology with various process measurement and control devices on the Holcomb Station Unit 1 boiler. The plan included the use of sophisticated neural networks or other artificial intelligence technologies and complex software to optimize several operating parameters, including NO_X emissions, boiler efficiency, and CO emissions.

The program was set up in the following three phases:

- In Phase I, the boiler was equipped with sensors that can be used to monitor furnace conditions and coal flow to permit improvements in boiler operation.
- In Phase II, the boiler was equipped with burner modifications designed to reduce NO_X emissions and automated coal flow dampers to permit on-line fuel balancing.
- In Phase III, the boiler was to be equipped with an overfire air system to permit deep reductions in NO_X emissions to be achieved.

Integration of the overfire air system with the improvements made in Phases I and II was expected to permit optimization of boiler performance, output, and emissions. All work identified in Phases I and II has been completed.

The NOx reduction goal was to be achieved through a combination of burner modifications, advanced controls and instrumentation, and SOFA. Of the overall NO_X reduction, a small percentage was projected from the burner modifications and the majority of the reduction was predicted as a result of SOFA implementation. The additional unit output was expected as a result of reduced furnace exit gas temperatures and a resulting decrease in slagging potential that would allow the unit to run at higher loads for longer durations without slag buildup. Unfortunately, the burner modifications resulted in an increase in NO_X emissions and increased slagging, as well as significantly increased burner maintenance issues.

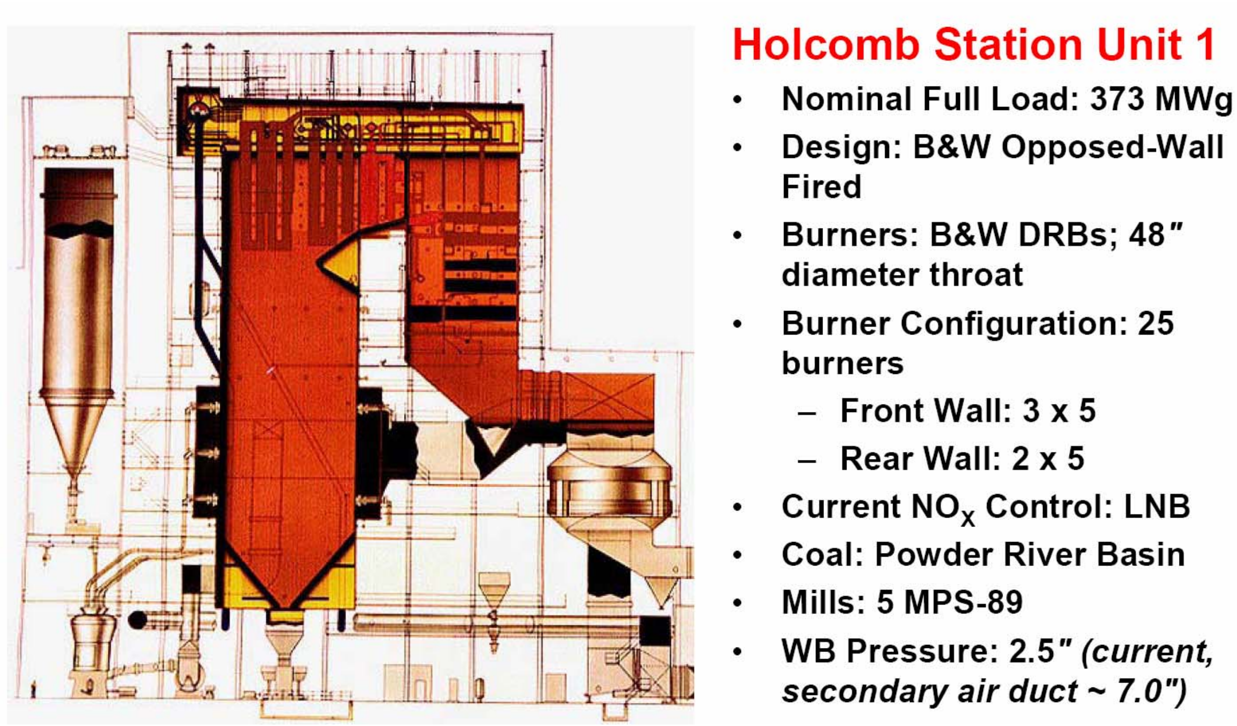
1.0 Introduction

The objective of this project was to demonstrate the use of an Integrated Combustion Optimization System to achieve NO_X emission levels in the range from 0.15 to 0.22 lb/MMBtu while simultaneously enabling increased power output. The project plan consisted of the integration of low-NO_X burners and advanced overfire air technology with various process measurement and control devices on the Holcomb Station Unit 1 boiler. The plan included the use of sophisticated neural networks or other artificial intelligence technologies and complex software to optimize several operating parameters, including NO_X emissions, boiler efficiency, and CO emissions.

Holcomb Station, shown in Figure 1, is a coal fired power plant located approximately 6 miles south of Holcomb, KS. The plant, which went online in August of 1983, was designed to burn Powder River Basin coal. The boiler is a Babcock & Wilcox (B&W) boiler with early generation low-NO_X burners. Figure 2 summarizes boiler design details. The average NO_X emission rate for Holcomb Station in the five years previous to the project was 0.283 lb/MMBtu.

Figure 1 – Holcomb Station

Figure 2 – Holcomb Boiler Design Data



The Integrated Combustion Optimization System was set up in three phases to demonstrate the synergistic effect of layering NO_X control technologies. The three phases were:

- Phase I – Advanced Sensors Upgrade / Burner and SOFA Design
- Phase II – Low-NO_X Burner Modifications and Coal-Flow Balancing
- Phase III – Advanced Separated Overfire Air System

Phase I – Advanced Sensors Upgrade was intended to demonstrate the effectiveness of novel measuring sensors with respect to the control of factors leading to reduced NO_X emissions and improved thermal efficiency with minimal physical modifications to the boiler.

Phase II – Low-NO_X Burner Modifications were intended to demonstrate the effectiveness of low-cost modifications to the existing, first generation low-NO_X burners to reduce NO_X emissions. The modifications consisted of new burner tips and other parts designed to lower NO_X emissions. This phase also included modifications to the existing pulverized coal (PC) piping to permit automated fuel balancing among all burners.

Phase III – Advanced Separated Overfire Air (SOFA) was intended to demonstrate deeper NO_X control competitive to SCR installation with the addition of an overfire air system coupled with the existing Phase I and II modifications to optimize overall system performance. The integration of all three phases of these improvements would provide the opportunity to reduce NO_X emissions and permit improvements in power plant performance and output.

This report summarizes the technical results of Phases I and II of the project. Phase III of the project was not completed.

2.0 Technical Progress

Phases I and II of the project were completed. The results of each phase are discussed below.

2.1 Task 1.0 – Phase I – Advanced Sensors Upgrade / Burner and SOFA Design

The objective of Phase I was to demonstrate the effectiveness of various measuring sensors with respect to the control of factors leading to reduced NO_X emissions and improved thermal efficiency with minimal physical modifications to the boiler. Phase I also included design work for burner modifications required to support SOFA and lower NOx. The scope of work for the Advanced Sensors Upgrade Phase was performed in the following six tasks.

2.1.1 Task 1.1 – Process Design and Performance Analysis

In this task analytical tools and methods were used to evaluate existing process engineering systems and to prepare material/energy balances for the low-NO_X burner modifications and overfire air system. System physical modeling and computer modeling were completed by General Electric Energy and Environmental Research (GE EER). GE EER also utilized a Computational Fluid Dynamics (CFD) model to evaluate heat transfer, flow rates, combustion temperatures and emission rates.

The physical model of the Holcomb boiler completed by GE EER was a 1:20 scale model of the boiler constructed out of plexi-glass, plastic, blowers, and hoses. The burners were scaled using a modified Thring-Newby approach to assure the flow characteristics of the model accurately reflected actual flow characteristics in the Holcomb boiler. Smoke and bubbles were utilized for visual observation of combustion air and overfire air mixing as well as velocity mapping and tracer dispersion measurements. Figure 3 shows a picture of the physical model of the boiler. Figure 4 shows a close up of the burners in the model. The picture labeled ‘Baseline’ in Figure 4 represents a model of the original burners, and the picture labeled ‘Modified’ represents a model of the modified GE EER burner design.

Figure 3 – Physical Model of Boiler

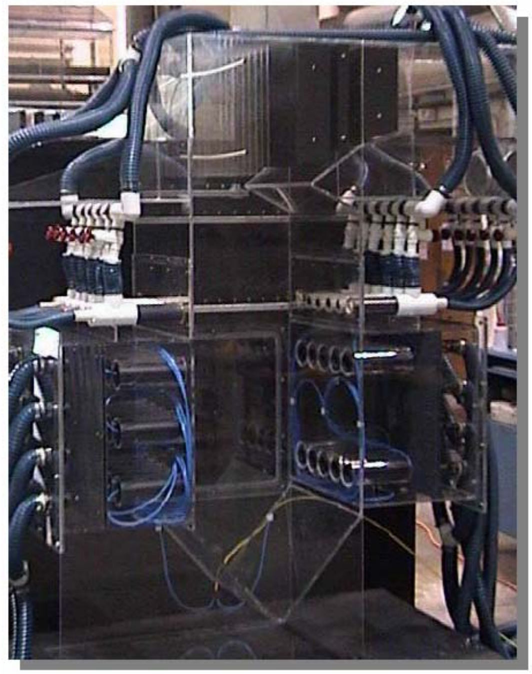
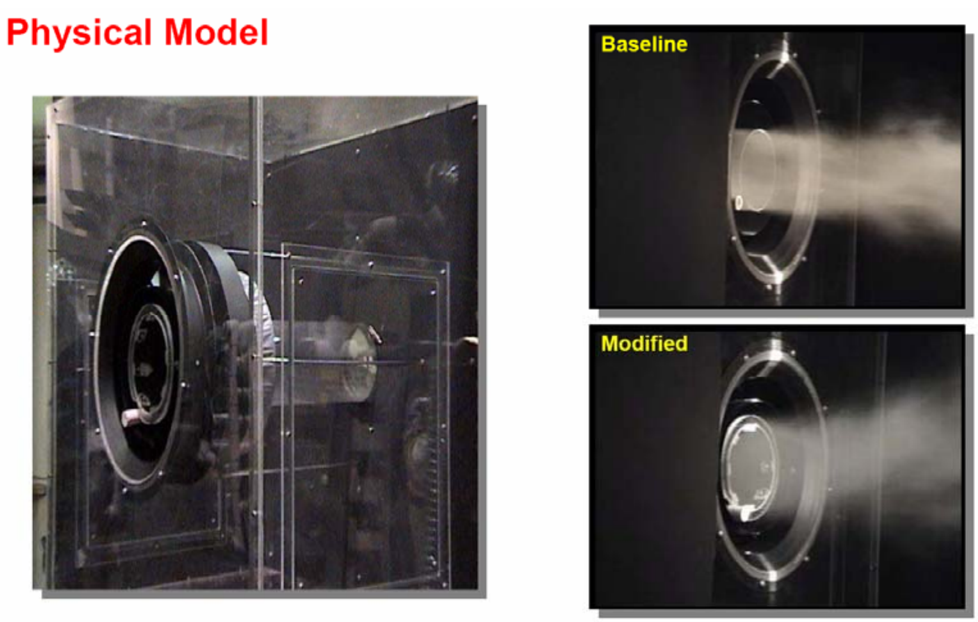
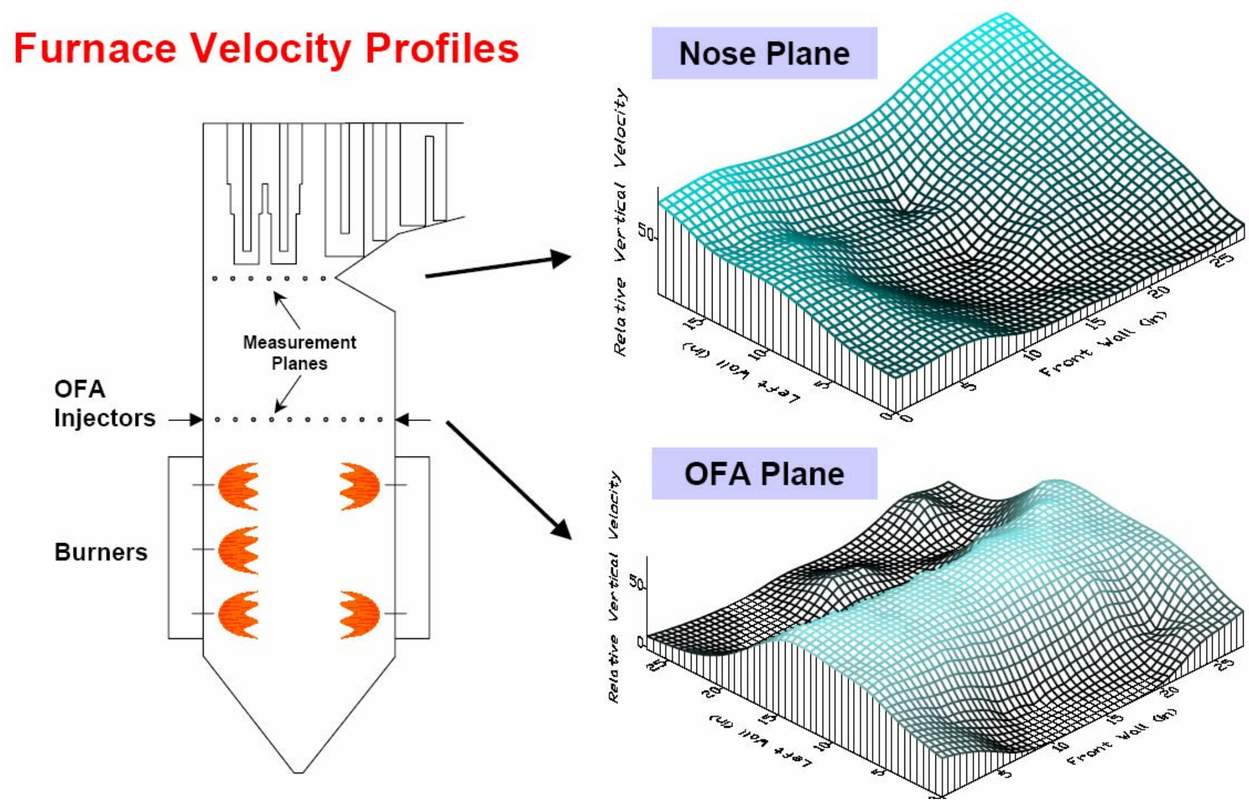


Figure 4 – Physical Model of Burners



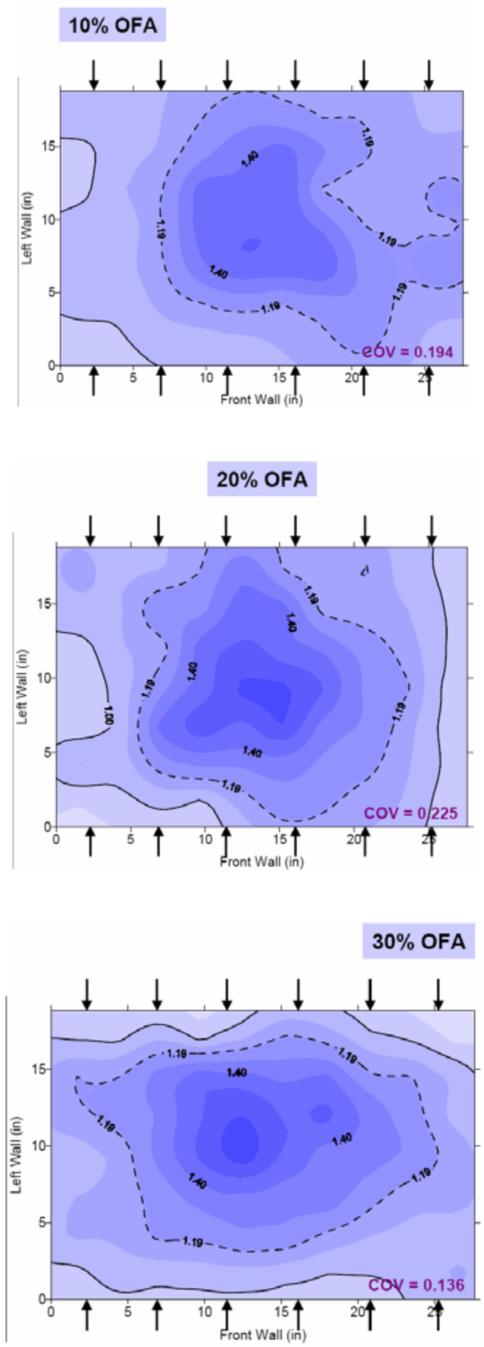
Results of flow modeling in the physical model were consistent with expected results for an opposed wall-fired boiler. The flow tended to stay in the center of the furnace between the front and rear wall. Additionally, the swirl pattern of the burners tended to push flow out towards the two side walls of the furnace. The flow modeling also showed a recirculation zone above the two upper burner elevations. Velocity profiles were also measured in two horizontal planes during the modeling. The first horizontal plane was at the elevation where the new overfire air injectors were to be installed and the second horizontal plane was at an elevation even with the tip of the furnace bullnose. The velocity profiles were consistent with results of the flow modeling. At the overfire air plane the highest velocities were measured in the center of the furnace. At the boiler nose plane the highest velocities were measured on the east and west side walls, with velocities decreasing closer to the front wall. Figure 5 shows a graphical representation of the velocity profile modeling.

Figure 5 – Velocity Profiles



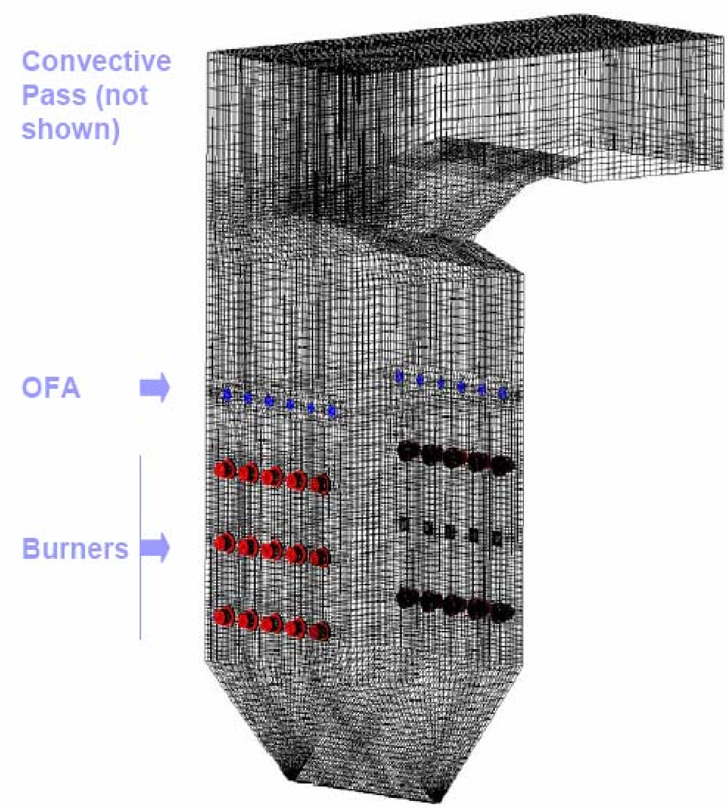
Results from the flow modeling and velocity profile tests were used to develop the model for the overfire air injectors. The overfire air configuration in the physical model utilized six injectors on both the front and rear walls. To account for the biased combustion air flow towards the furnace sidewalls, larger overfire air injectors were utilized on the four outboard injectors. Smoke visualization was used initially to evaluate how effectively the overfire air mixed with the combustion air. Tracer dispersion measurement was then used to further quantify the overfire air mixing effectiveness. Tracer dispersion was completed by injecting methane as a tracer gas in the overfire air, and then measuring the dispersion of methane at the nose measurement plane. Figure 6 shows results from the tracer dispersion measurement testing. The plots show air stoichiometric ratios at various overfire air injection levels across the nose measurement plane. The results of the physical modeling also confirmed that there was sufficient secondary duct pressure to achieve adequate mixing without the need for booster fans.

Figure 6 – Tracer Dispersion Results



A CFD model was developed by GE EER to evaluate the impact of burner modifications and overfire air on heat transfer, combustion emissions, and gas flow within the boiler. The CFD model utilized a three-dimensional representation of the boiler broken down into approximately 380,000 cells. Several advanced engineering calculational methods were used within the model to predict boiler performance. Figure 7 shows a geometrical diagram of the model.

Figure 7 – CFD Model



The CFD model was first utilized to develop flow and temperature pathlines for each burner elevation. These pathlines show the path flue gas takes from the combustion zone of each burner elevation through the furnace to the upper crossover and then entering the boiler backpass. Figures 8 through 12 show the pathlines for each of the five burner elevations at 376 MW. Note that the temperatures indicated are in degrees Fahrenheit.

Figure 8 – Flow and Temperature Pathlines for 'A' Burner Elevation

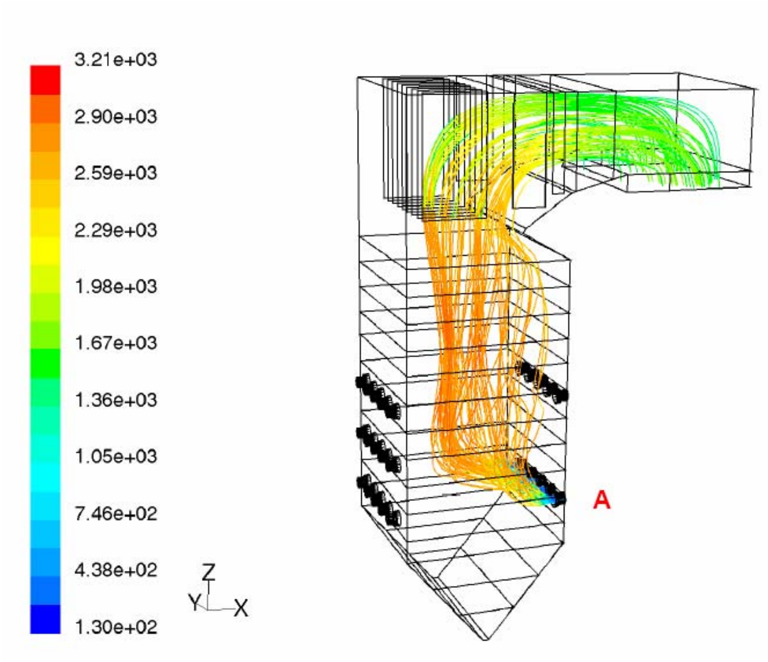


Figure 9 – Flow and Temperature Pathlines for 'B' Burner Elevation

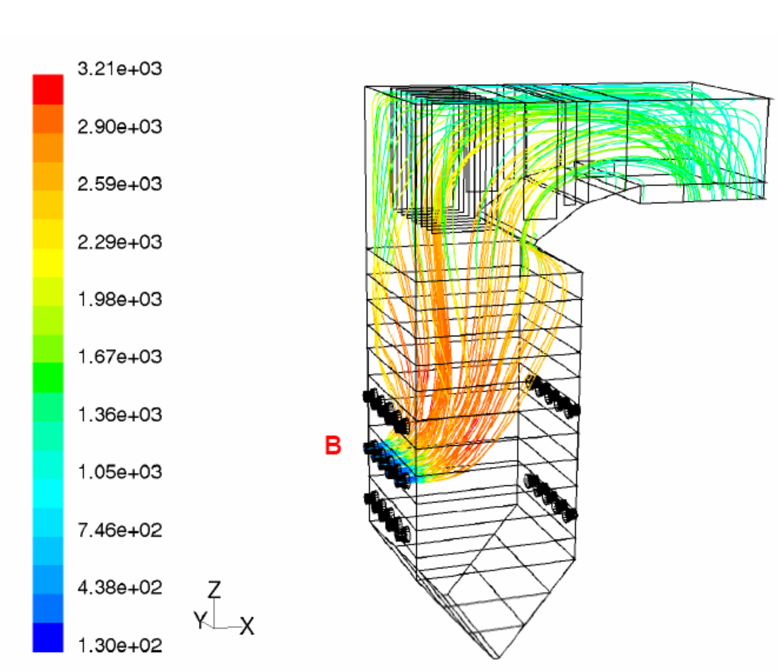


Figure 10 – Flow and Temperature Pathlines for 'C' Burner Elevation

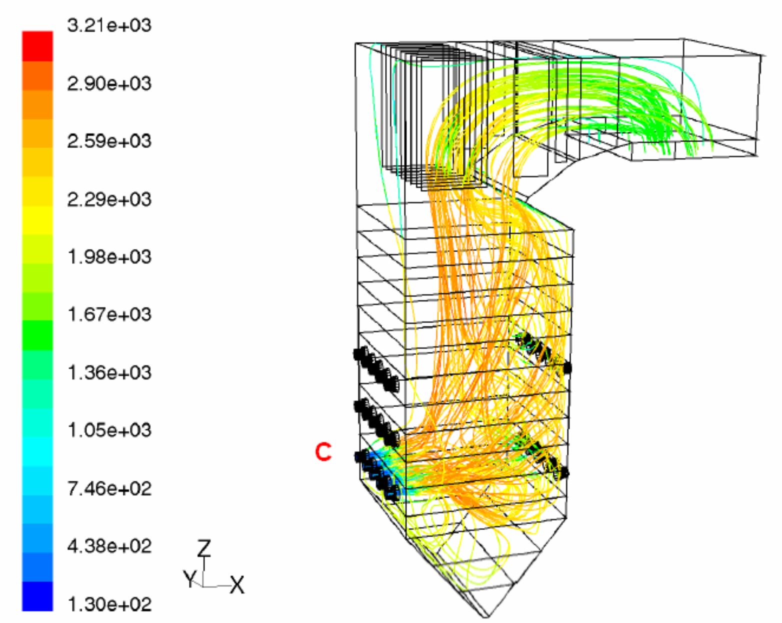


Figure 11 – Flow and Temperature Pathlines for 'D' Burner Elevation

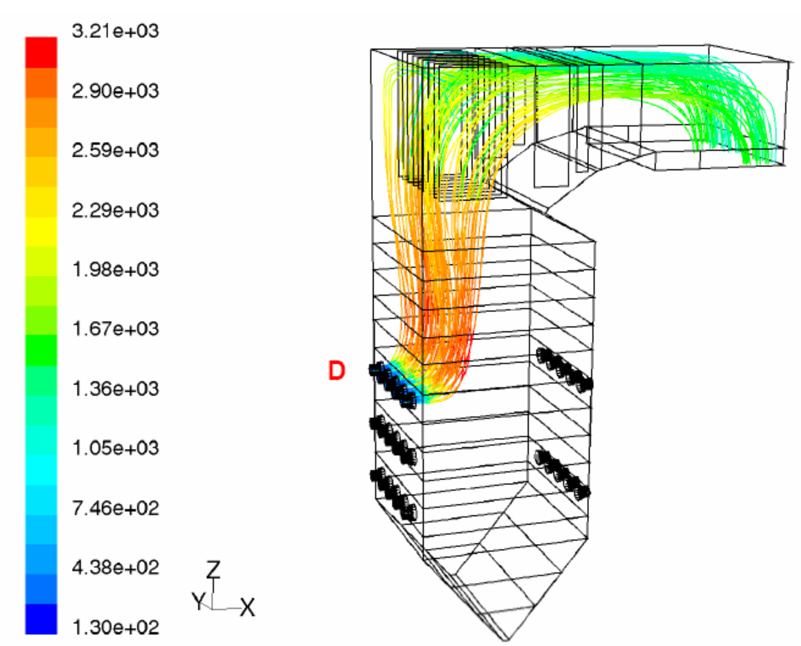
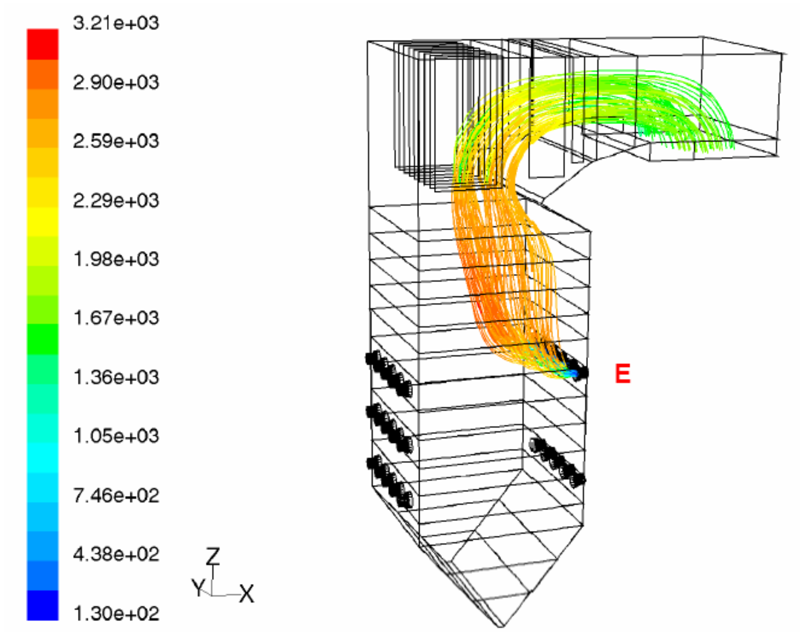
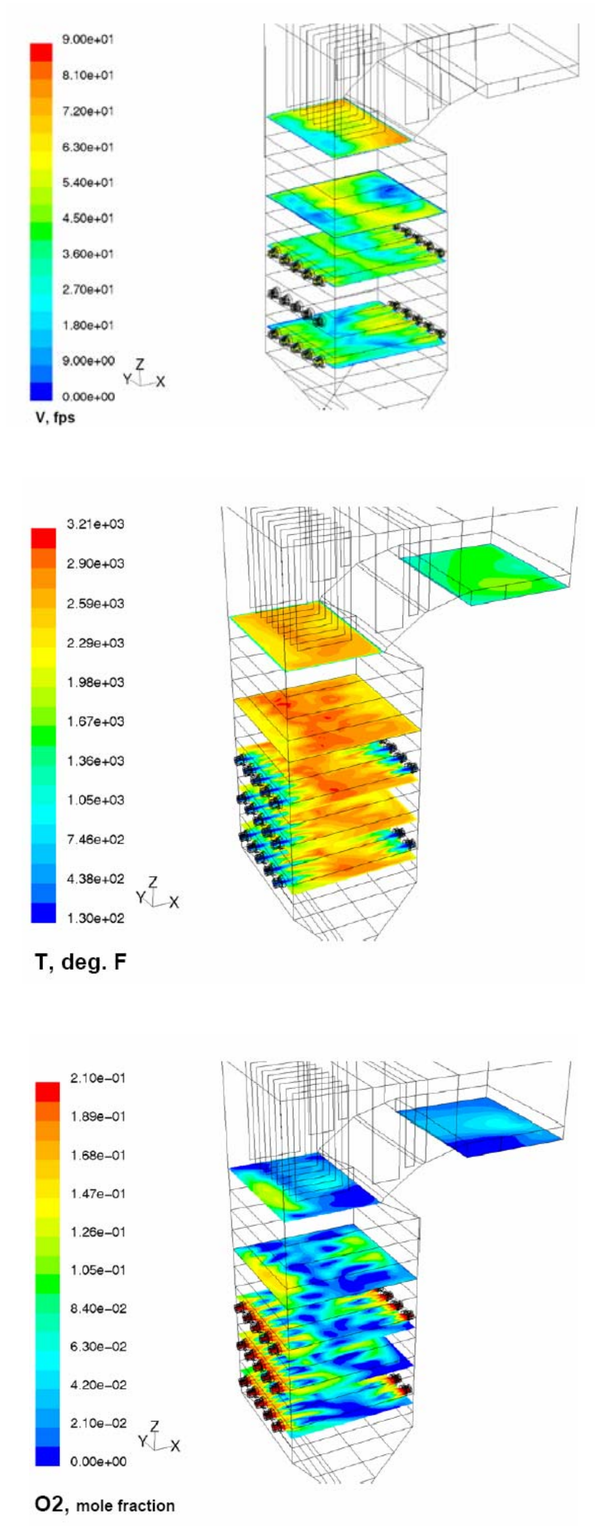


Figure 12 – Flow and Temperature Pathlines for 'E' Burner Elevation



The CFD model was also utilized to show velocity, temperature, and oxygen dispersion at various planes within the boiler. Figure 13 shows this data at full load with no overfire air.

Figure 13 – Velocity, Temperature and Oxygen Distribution @ Full Load, No OFA



The CFD model was then modified to include overfire air. Temperature and flow pathlines were first predicted for the twelve OFA ports. Figure 14 shows these pathlines for the OFA ports at full load with 20% overfire air. Note that the temperatures indicated are in degrees Fahrenheit.

Figure 14 – Flow and Temperature Pathlines for OFA Injection Ports

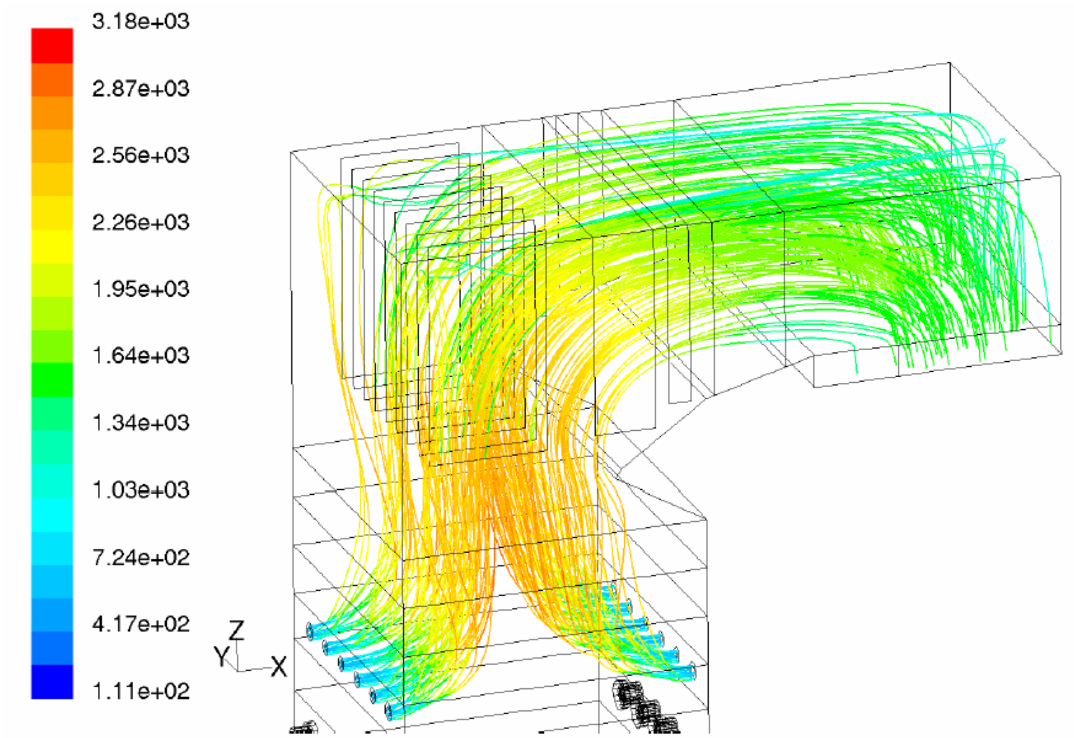
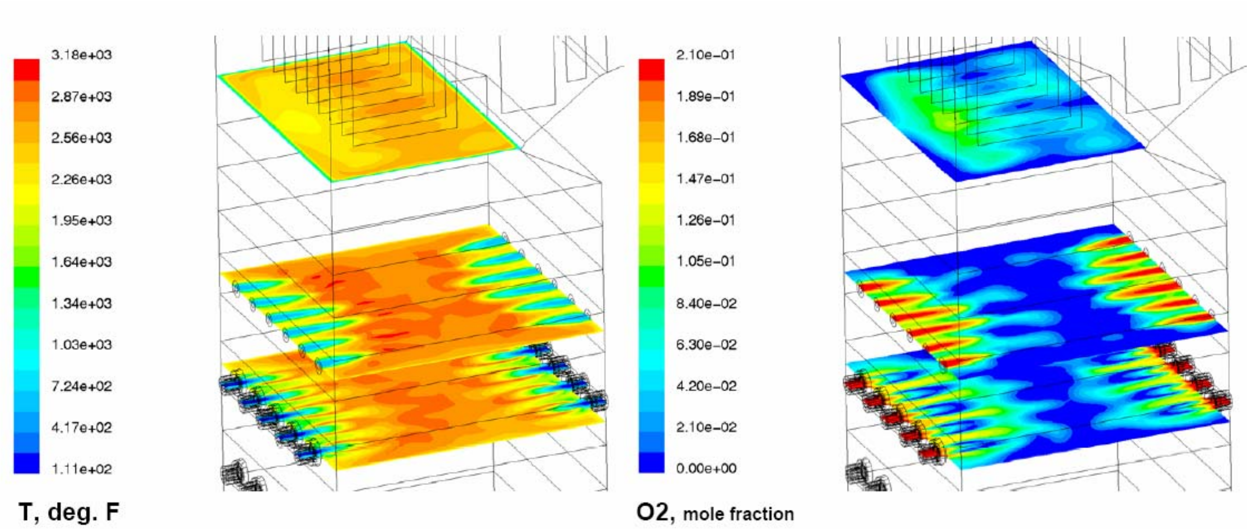


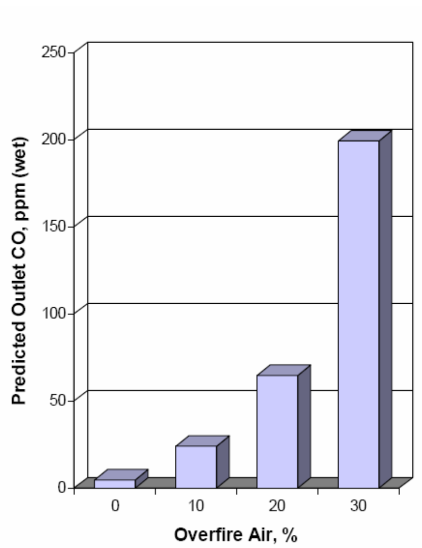
Figure 15 shows the temperature and oxygen distribution profiles across the boiler at full load with 20% OFA. A comparison of these profiles with the full-load, no OFA profiles shown in Figure 13 shows that the temperature of the flue gas at the boiler nose plane does not appear to increase with the addition of OFA. Keeping temperatures at or below existing levels was a critical factor in the success of any modifications. Increased temperatures in this zone lead to increased boiler slagging which has a detrimental affect on unit availability and reliability.

Figure 15 – Temperature and Oxygen Distribution @ Full Load, 20% OFA



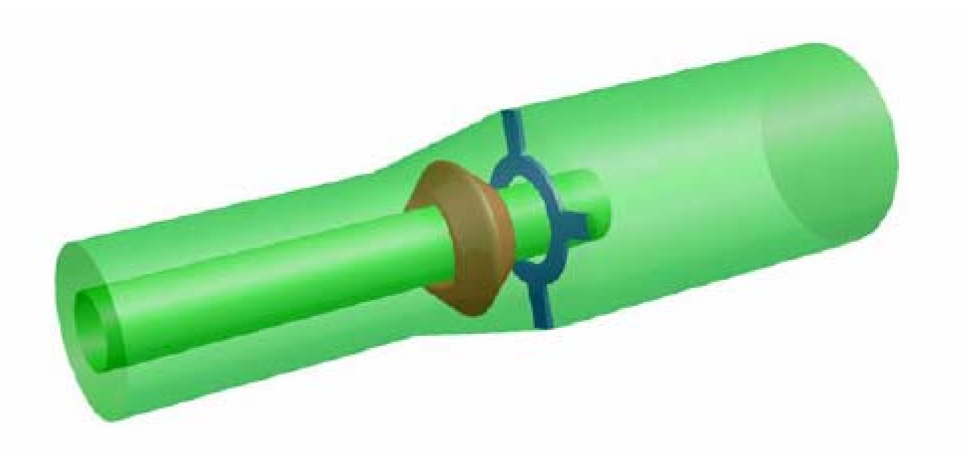
In addition to increased gas temperature, another potential negative consequence of adding OFA is increased carbon monoxide (CO) emissions. The CFD model was utilized to predict CO emissions at various OFA levels. As shown in Figure 16, the CFD model predicted increased CO emissions with OFA.

Figure 16 – CO Emissions at Various OFA Levels



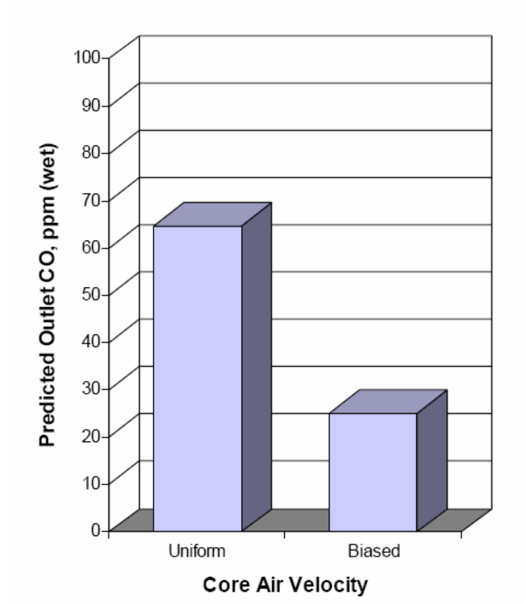
Because of the flow bias in the boiler towards the center of the furnace, GE EER felt that CO emissions could be improved by increasing velocity in the OFA ports to achieve better penetration in the center of the furnace where combustion gas flow is the highest. GE EER developed a double concentric jet port design which could be utilized to control jet penetration. The OFA port has adjustable dampers that allow flow to be biased at various ratios through the inner and outer portions of the port. Figure 17 shows a simple diagram of the port design with the double concentric discharge point on the left side.

Figure 17 – GE EER Double Concentric Jet Overfire Air Injection Port Design



GE EER used the CFD model to predict the impact on CO emissions of biasing the core jet velocity higher to achieve improved penetration. The model indicated that biasing the OFA injector ports in this way would result in improved CO emissions. Figure 18 shows the results of biasing the core jet velocity at full load with 20% OFA.

Figure 18 – CO Emissions at Full Load, 20% OFA – Biased Core Jet Velocity



The next step in the CFD modeling process was to further evaluate the effects of OFA on furnace exit gas temperature (FEGT) and overall boiler performance. To complete this evaluation the boiler was divided into several cross sections and the mean gas temperature at each cross section was calculated with advanced boiler performance modeling techniques. The mean gas temperature was then plotted on a graph showing mean gas temperature versus furnace axial position. Figure 19 shows how the boiler was divided into cross-sections. Figure 20 shows the mean gas temperature profile at full load with no overfire air.

Figure 19 – Boiler Cross Sections along Furnace Axial Length

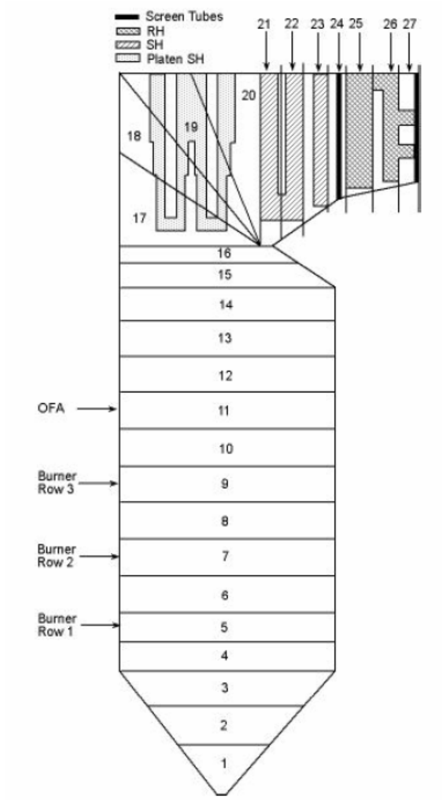


Figure 20 – Mean Gas Temperature Profile – Full Load, No OFA

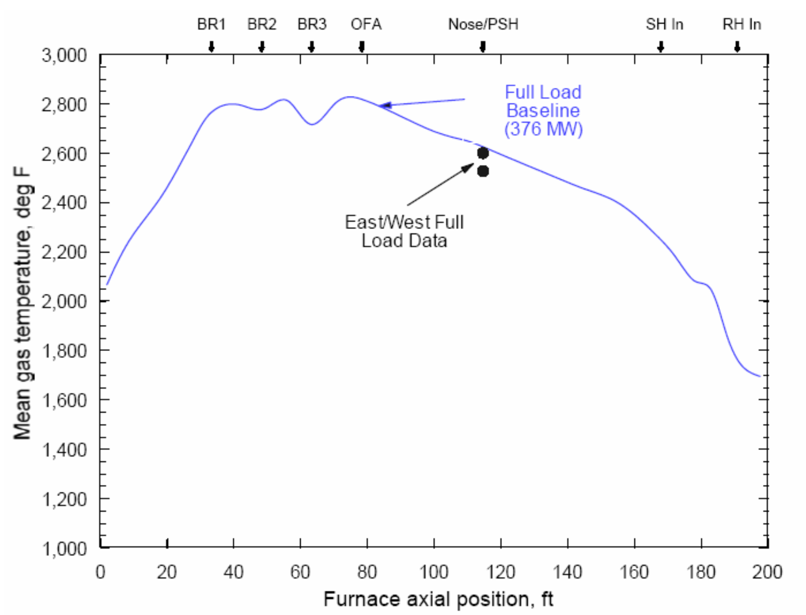
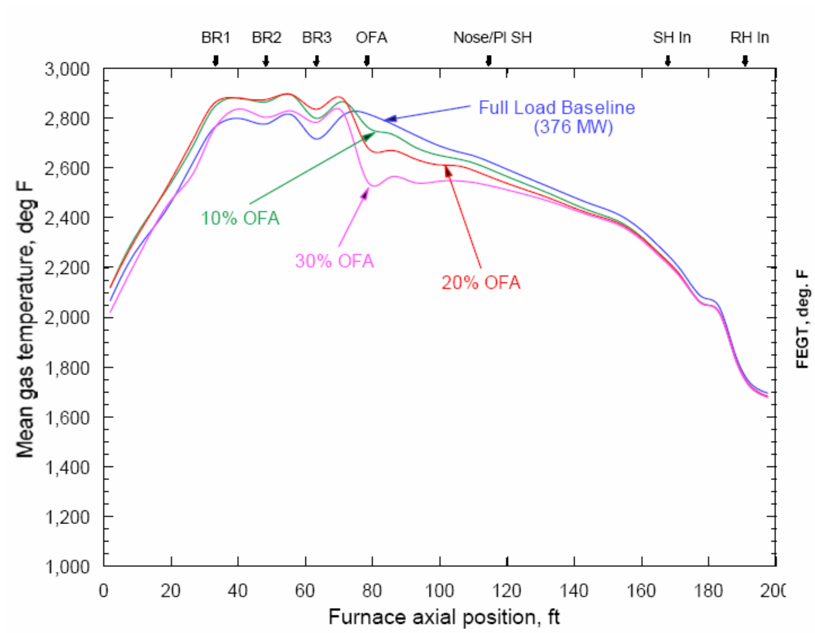


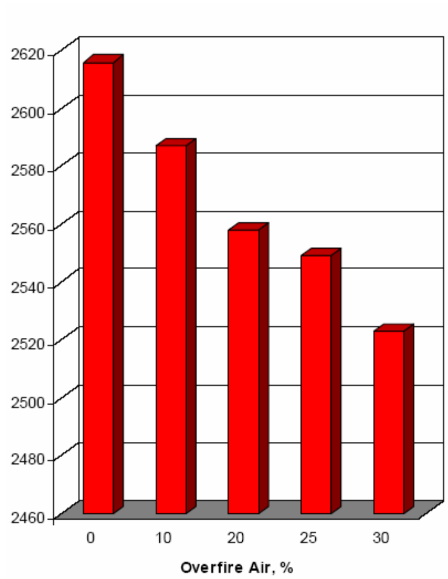
Figure 21 shows mean gas temperature profiles at various OFA levels as compared to the baseline data with no OFA shown in Figure 20.

Figure 21 – Mean Gas Temperature Profiles, Full Load



The data shown in Figure 21 indicates that the addition of OFA will result in higher gas temperatures in the burner zone but reduced gas temperatures at the furnace bullnose which is the defined measurement plane for FEGT. As mentioned previously, keeping FEGT at or below existing levels was a critical component of the project to assure that slag formation in the secondary superheater inlet section of the boiler just above the furnace bullnose would not increase. Figure 22 shows a plot of predicted FEGT at various OFA injection rates.

Figure 22 – Predicted FEGT at Various OFA Injection Rates, Full Load



The CFD model was further utilized to evaluate the impact of OFA on overall boiler performance. Figure 23 shows a table with calculated results at various OFA injection levels.

Figure 23 – Boiler Performance Parameters at Various OFA Injection Rates, Full Load

	Baseline SR_3 = 1.19	10% OFA SR_1 = 1.07 SR_3 = 1.19	20% OFA SR_1 = 0.95 SR_3 = 1.19	30% OFA SR_1 = 0.83 SR_3 = 1.19
Flue Gas O_2 (% wet)	3.00	3.01	3.02	3.08
Total Fuel Flow Rate (1000 lb/hr)	390	390	390	390
Flue gas Temperature (°F) Leaving				
FEGT	2,616	2,587	2,558	2,523
Air Heater*	333	332	332	332
Flow Rates (1000 lb/hr)				
Main Steam	2,634	2,641	2,639	2,630
Reheat Steam	2,347	2,353	2,351	2,344
Attemperation flow (1000 lb/hr)				
1st Stage	38	18	12	5
2nd Stage	51	37	38	30
Total SH	90	55	50	36
Reheater	0	0	0	0
Flue gas split in Backpass (%)				
Pri RH	20.0	26.0	27.0	26.0
Pri SH	80.0	74.0	73.0	74.0
Water/Steam Temperatures (°F)				
SSH Out	996	996	996	996
RH Out	998	998	998	998
Carbon in Ash (%)	0.042	0.243	1.172	*2.235*
ASME Heat Loss Efficiency (%)	86.43	86.44	86.37	86.27

One of the primary goals of the project was to be able to increase unit capacity while achieving reduced NO_X emission levels. This extra capacity could only be utilized if emissions were reduced at the increased load level and furnace exit gas temperatures were not increased. Figure 24 shows a table with the same calculated performance parameters as those shown in Figure 23. The values in Figure 24 are calculated at a load 7 MW greater than the full load values shown in Figure 23. The FEGT at the increased full load value with 30% OFA was predicted to be 65°F lower than the FEGT at the existing full load value with no OFA.

Figure 24 - Boiler Performance Parameters at Various OFA Injection Rates, Full Load plus 7 MW

	Baseline SR_3 = 1.17	10% OFA SR1 = 1.06 SR3 = 1.17	20% OFA SR1 = 0.94 SR3 = 1.17	30% OFA SR1 = 0.82 SR3 = 1.17
Flue Gas O_2 (% wet)	2.76	2.76	2.78	2.84
Total Fuel Flow Rate (1000 lb/hr)	398	398	398	398
Flue gas Temperature (°F) Leaving				
FEGT	2,638	2,606	2,581	2,551
Air Heater*	335	333	334	333
Flow Rates (1000 lb/hr)				
Main Steam	2,686	2,690	2,690	2,677
Reheat Steam	2,393	2,397	2,397	2,385
Attemperation flow (1000 lb/hr)				
1st Stage	39	16	13	15
2nd Stage	50	44	37	37
Total SH	89	61	50	52
Reheater	0	0	0	0
Flue gas split in Backpass (%)				
Pri RH	21.0	25.5	26.5	26.0
Pri SH	79.0	74.5	73.5	74.0
Water/Steam Temperatures (°F)				
SSH Out	996	996	996	996
RH Out	998	998	998	998
Carbon in Ash (%)	0.090	0.412	1.551	2.800
ASME Heat Loss Efficiency (%)	86.45	86.48	86.36	86.30

The results of the GE EER models indicated that NO_X emissions would be reduced with the implementation of burner modifications, and further reduced with SOFA. Their modeling also predicted that furnace gas temperatures would be reduced with the implementation of SOFA.

2.1.2 Task 1.2 – Design and Fabrication/Construction Documents

In this task design and fabrication drawings for new equipment and other similar detailed information were developed to enable the receipt of contractor proposals for equipment supply and installation. GE EER completed design and fabrication drawings for burner modifications and coal flow balancing damper installation. As part of Task 2.3 design and fabrication drawings were also developed for SOFA. The installation of these components was planned to be completed in a phased approach. The burner modifications and coal flow balancing damper installation were scheduled for completion in 2003 and the SOFA installation was planned for 2004 or later.

The design of the burner modifications was completed by GE EER based on results of the engineering design work completed in Task 1.1. The burner modifications included replacement of the existing burner coal nozzle with a nozzle that flared out and included a flame stabilization ring and stabilizing teeth. The tip of the burner was also designed to extend into the furnace an additional 4" which required an extension of the secondary air sleeve. Because of this extension and a concern about increased exposure temperatures beyond the design temperatures of the steel in the burner tips, a thermocouple was added to measure tip temperature. An adjustable shroud was also included in the design. The shroud was designed to slide axially across the burner outer register opening to allow for air flow balancing between the burners on each burner elevation. Figure 25 shows a drawing of the original B&W low-NO_X burner design. Figure 26 shows a drawing of the same burner with the GE EER design modifications.

Figure 25 – Original B&W Burner Design

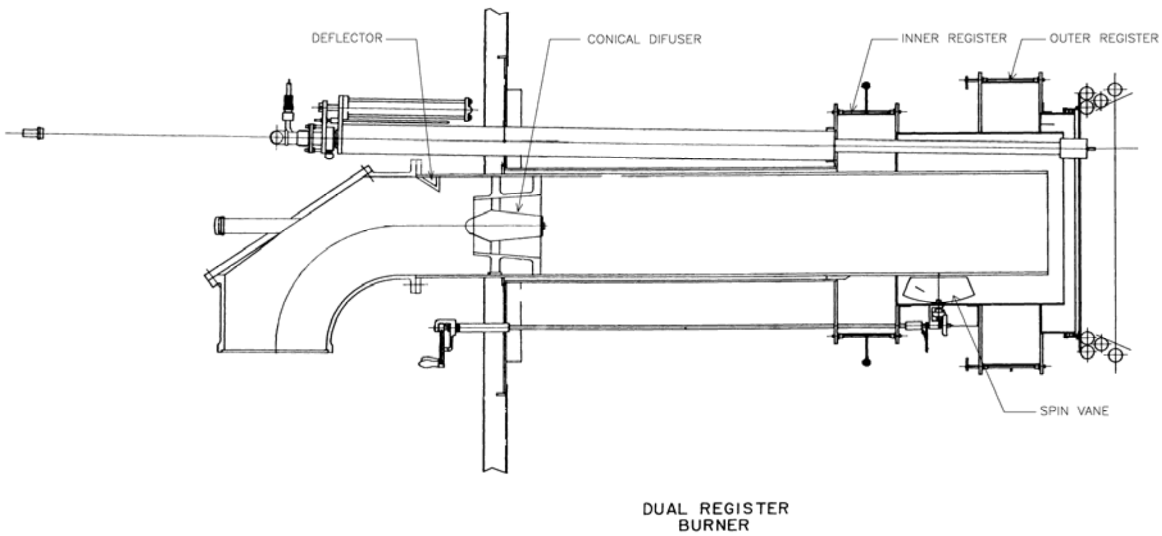
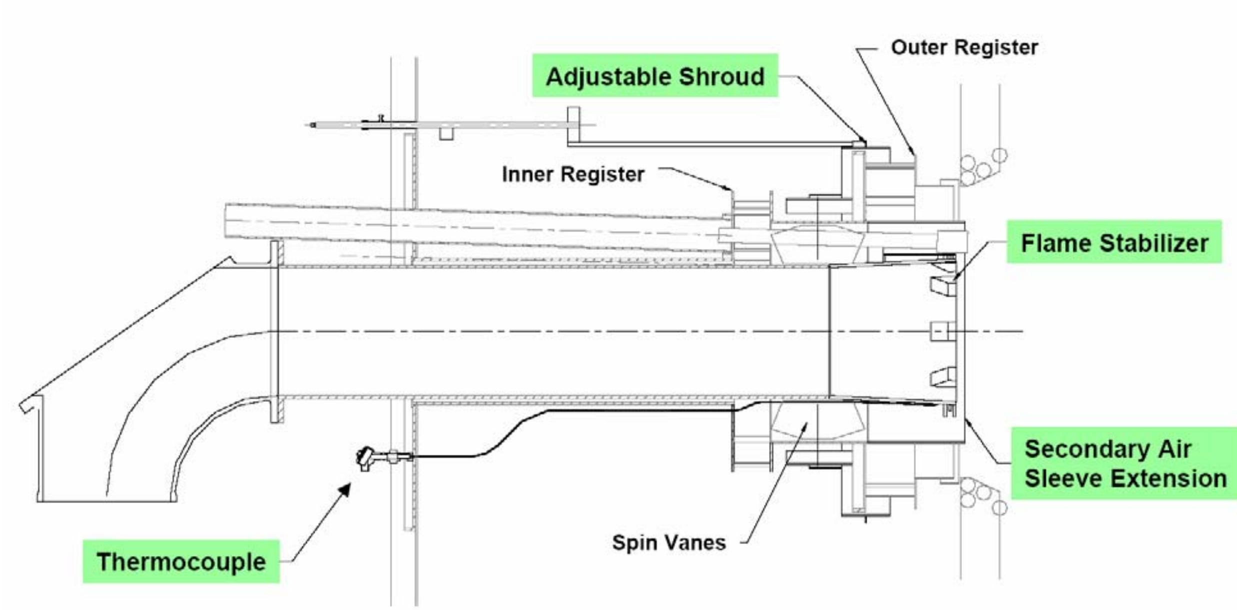


Figure 26 – GE EER Burner Design Modifications



GE EER also completed design drawings for installation of coal flow balancing dampers on the coal pipes coming off the top of each pulverizer. The dampers are a GE EER patented design called Flow MastEER. Figure 27 shows a sketch of the Flow MastEER damper design, and Figure 28 shows the location of the damper installation on top of the pulverizers.

Figure 27 – GE EER Flow MastEER Damper Design

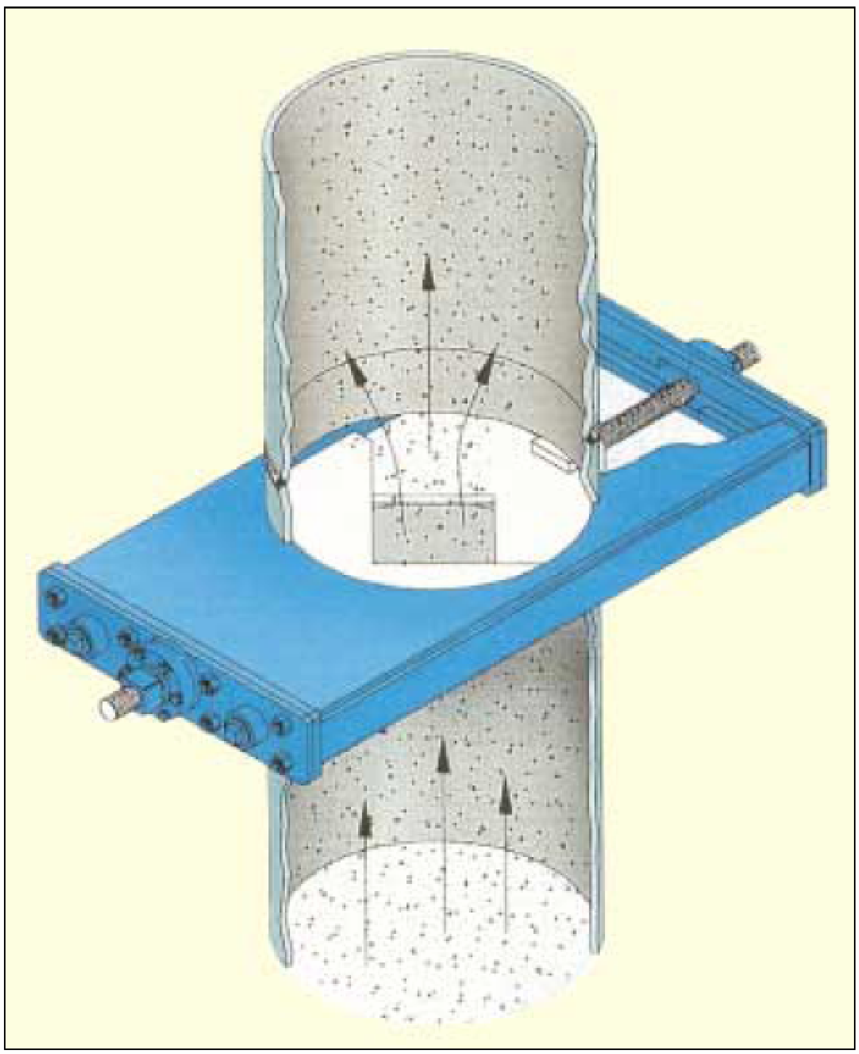
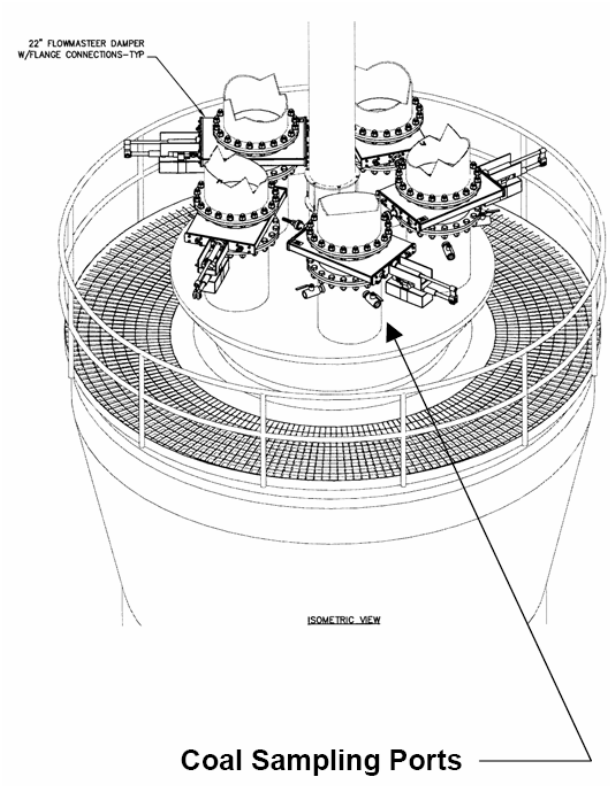


Figure 28 – Coal Flow Balancing Damper General Arrangement



Once all design was completed, GE EER developed bid specifications to be included in Request for Proposals (RFPs) which were sent to various installation contractors. The results of the bidding process are discussed in later sections of this report.

2.1.3 Task 1.3 – Boiler Combustion Optimization Sensors

In this task the Holcomb boiler was equipped with various sensors to optimize the combustion process. These sensors included a grid of 15 CO monitors in the boiler backpass, 5 Loss-of-Ignition (LOI) sensors in the upper portion of the furnace, 25 NO_X sensors, one on each burner, and coal flow measurement sensors on each burner coal pipe. The boiler sensors were provided in a package supplied by MK Engineering. The coal flow sensors were supplied by Air Monitor. All furnace sensors were installed during the Spring 2002 outage, and the coal flow sensors were installed in 2003. Figure 29 shows schematic from MK Engineering illustrating their combustion monitoring package and the various sensor locations.

Figure 29 – MK Engineering Combustion Monitoring Package

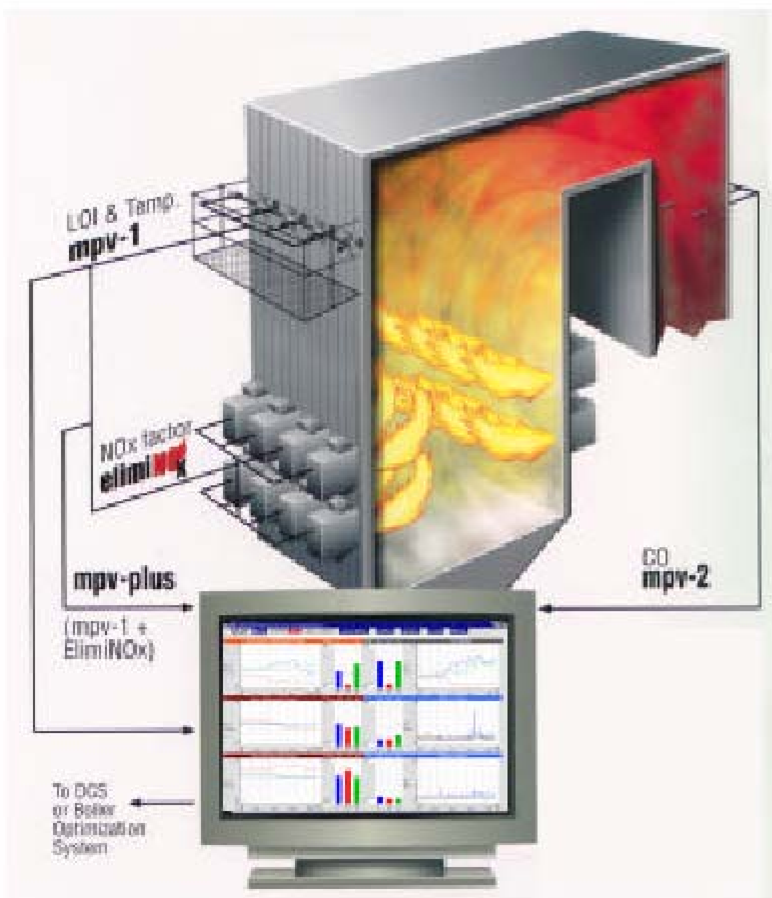


Figure 30 shows pictures from the installation of the CO sensors. The upper two pictures show the sensors and their extension sleeves. The picture on the upper right is a closeup of the CO sensor itself. The lower two pictures shows the installation sleeves that were installed in the boiler. At the end of each sleeve a steel shield was installed to protect the sensor from fly ash in the flue gas. Figure 31 shows the LOI sensors installed along the upper portion of the front wall of the furnace.

Figure 30 – CO Sensor Installation

Figure 31 – LOI Sensor Installation

2.1.4 Task 1.4 – Sensor Integration/Testing

In this task data from the new boiler and coal flow sensors was integrated into the existing plant performance monitoring system for tracking and trending. In addition, testing was completed to evaluate information obtained from the sensors. The integration of the sensors included significant computer networking in order to get the data into the plant performance monitoring system database. The existing plant performance monitoring system is a package called EtaPro supplied by General Physics. General Physics was hired to assist with incorporating the data into the EtaPro Pi database. Figure 32 shows a schematic of the computer networking configuration devised by GE EER and General Physics. The schematic also shows the GE EER PLC used for coal flow balancing control that will be discussed later in this report.

Figure 32 – Computer Network Schematic

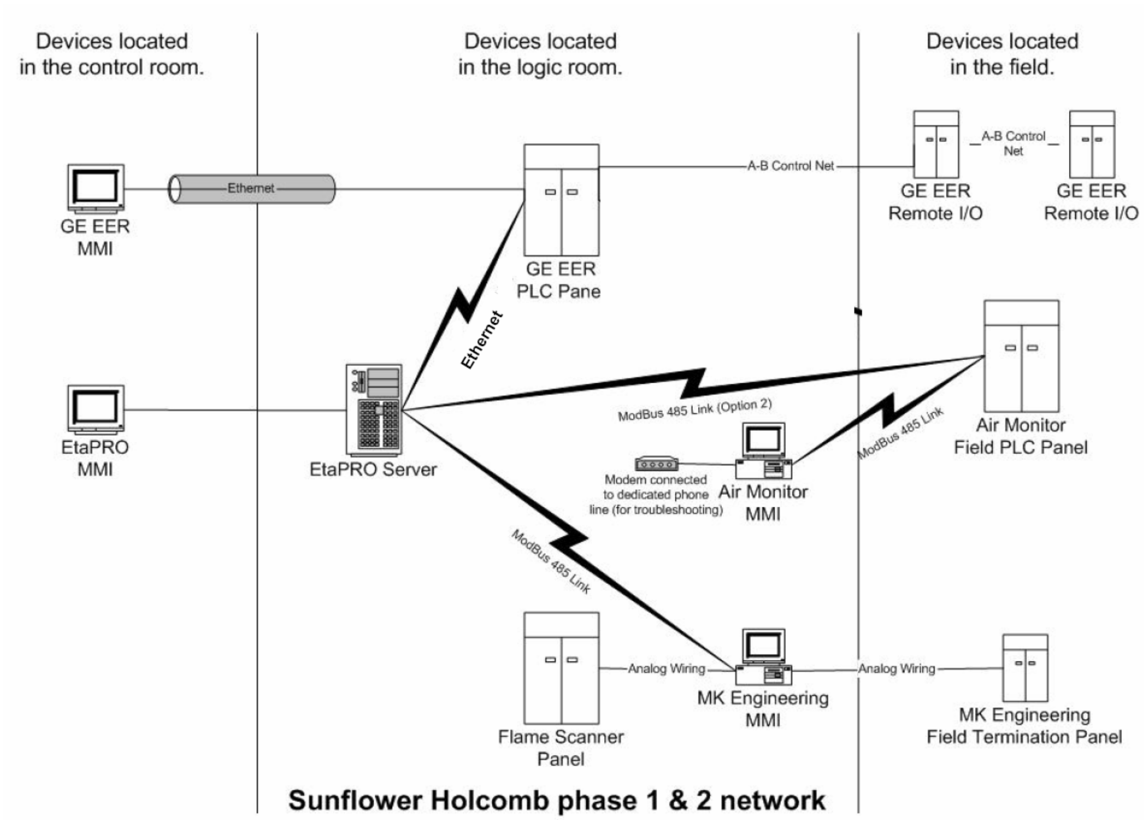
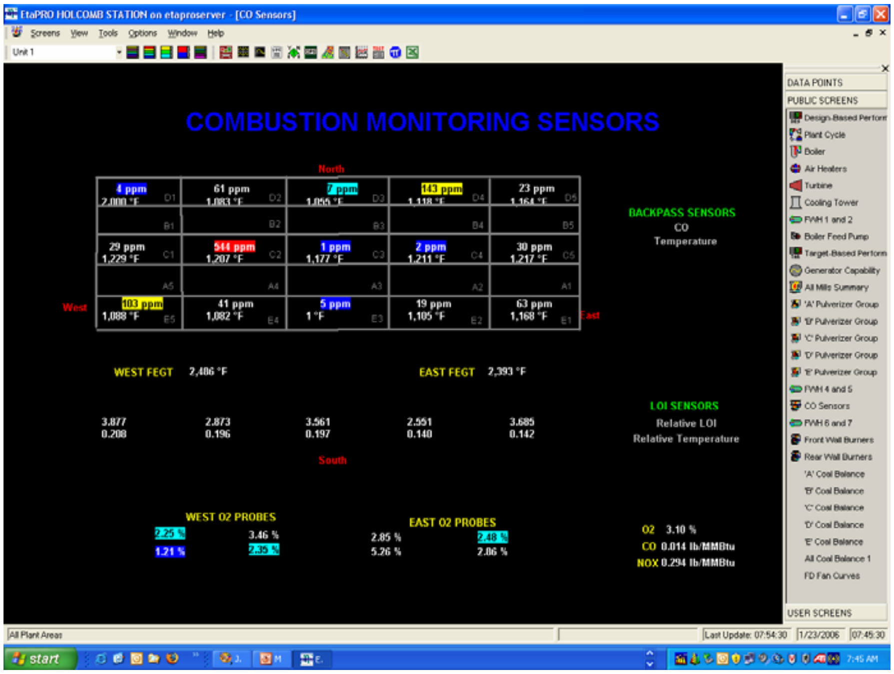


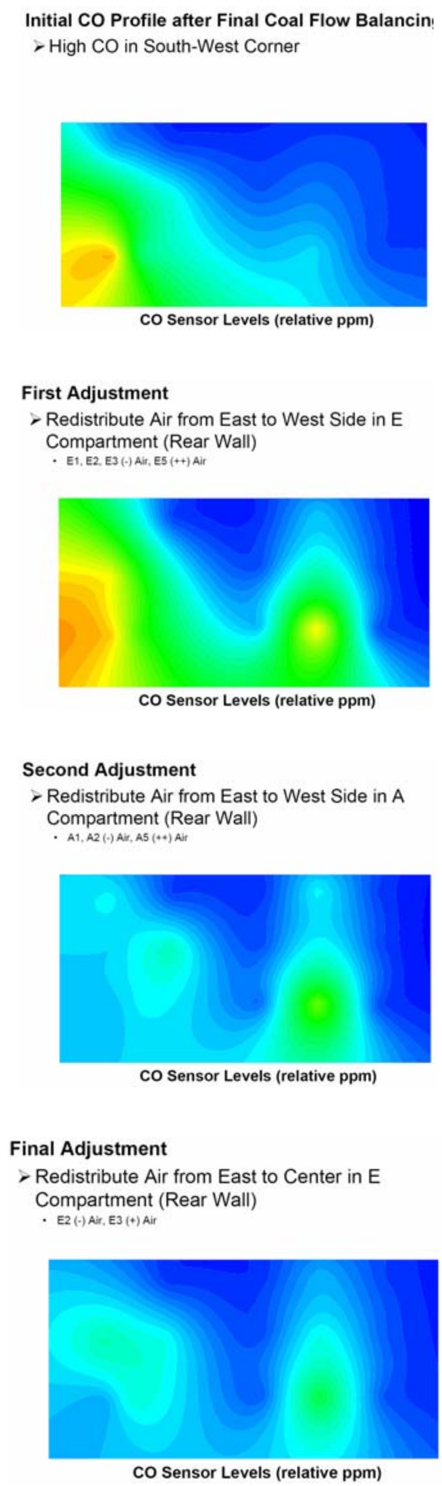
Figure 33 shows a screen shot from EtaPro showing how data from the CO sensors and LOI sensors is displayed to the operators. Similar screens were set up to display data from the NO_X sensors and the coal flow measurement sensors.

Figure 33 – EtaPro Screen Displaying Combustion Sensor Data



Data collected from the sensors during the baseline testing is presented in Section 2.1.5 of this report. Figure 34 shows an example of how data from the CO sensors in the boiler backpass was utilized to assist with boiler tuning.

Figure 34 – Example of Using CO Sensors for Combustion Tuning on 'E' Elevation



2.1.5 *Task 1.5 – Baseline Testing*

In this task tests were performed on Holcomb Station Unit 1 to gather baseline performance and emissions data prior to retrofit of the emissions control equipment. This data set served as a comparison reference for the results of optimization tests performed on the unit. The baseline testing was completed in February 2003.

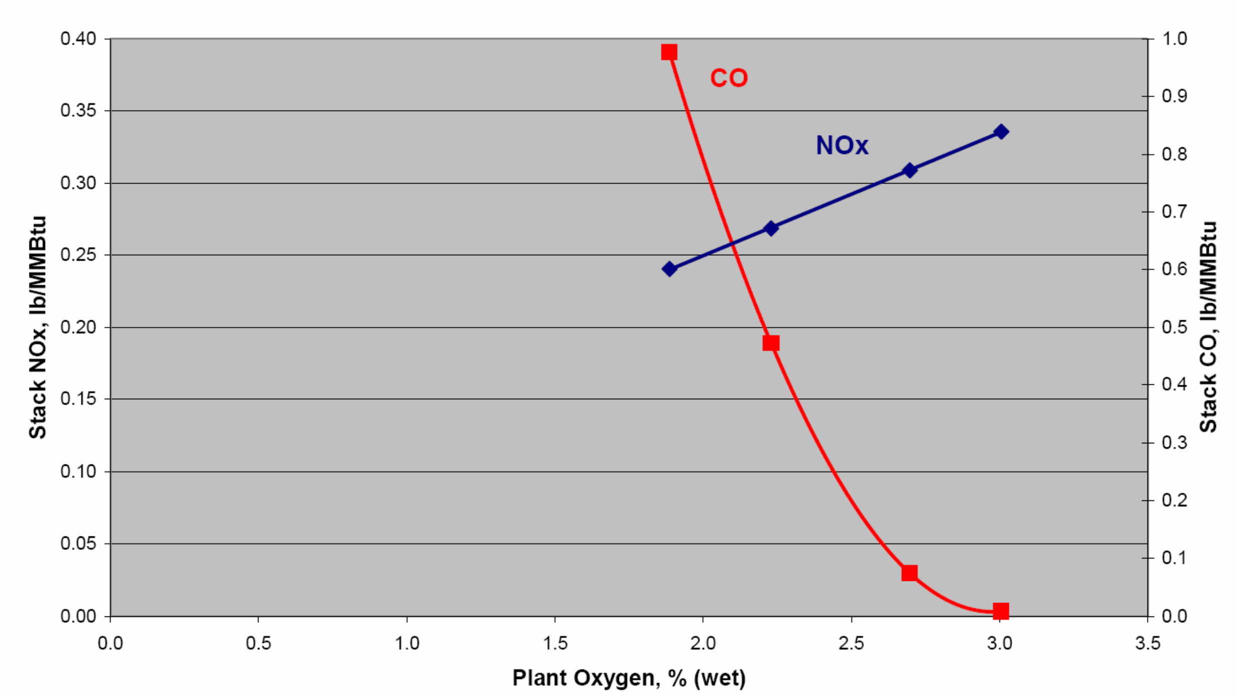
During the baseline testing several test runs were completed at various load points, excess O2 levels, and mill biasing configurations. Figure 35 shows a table summarizing the various test runs completed during the baseline testing.

Figure 35 – Baseline Test Plan

	Test No.	1	2	6	7	8	9a	10a	10b	11a	12a	13a
	Test Description	Low Load (2V)	Full Load (VWO)	Full Load, Nominal O2	Full Load, Low O2	Full Load, Minimum O2	Full Load, 'D' Mill Bias +10%	Full Load, 'E' Mill Bias +10%	Full Load, 'E' Mill Bias +20%	Full Load, 'C' Mill Bias +10%	Full Load, 'A' Mill Bias +10%	Full Load, 'B' Mill Bias +10%
Test Conditions	Boiler Load, MWg	247	376	374	376	376	373	375	375	377	375	374
	Excess Oxygen, % wet	3.64	3.01	2.70	2.23	1.89	2.37	2.33	2.26	2.48	2.40	2.52
	Mill Bias Settings	Typical	Typical	Typical	Typical	Typical	Typical*	Typical*	Typical*	Typical*	Typical*	Typical*
	Compartment Air Bias Settings	Typical	Typical	Typical	Typical	Typical	Typical	Typical	Typical	Typical	Typical	Typical
	Burner Air Registers	As Found	As Found	As Found	As Found	As Found	As Found	As Found	As Found	As Found	As Found	As Found
Boiler Data	EtaPRO	X	X	X	X	X	X	X	X	X	X	X
	Control Room	X	X	X	X	X	X	X	X	X	X	X
	Burner Settings	X	X	X	X	X	X	X	X	X	X	X
	MK Sensor	X	X	X	X	X	X	X	X	X	X	X
GE Measurements	Econ. CEMS	X	X	X	X	X	X	X	X	X	X	X
	Furnace Gas Temp.	X	X	X	X							
	Coal **		X	X			X					
	Ash	X	X	X	X	X						
	CEMS Pt-2-Pt			X	X							
	Furnace LOI											
Mill Fuel Capacity	A	75%	75%	75%	75%	75%	75%	75%	75%	75%	**85%**	75%
	B	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	**85%**
	C	75%	75%	75%	75%	75%	75%	75%	75%	**85%**	75%	0%
	D	85%	85%	85%	85%	85%	**95%**	75%	75%	75%	75%	75%
	E	85%	85%	85%	85%	85%	85%	**95%**	**100%**	75%	75%	75%
Mill Burner Excess Air	A	20%	20%	20%	20%	20%	20%	20%	20%	20%	10%	20%
	B	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	10%
	C	20%	20%	20%	20%	20%	20%	20%	20%	10%	20%	20%
	D	20%	20%	20%	20%	20%	10%	20%	20%	20%	20%	20%
	E	20%	20%	20%	20%	20%	20%	10%	5%	20%	20%	20%

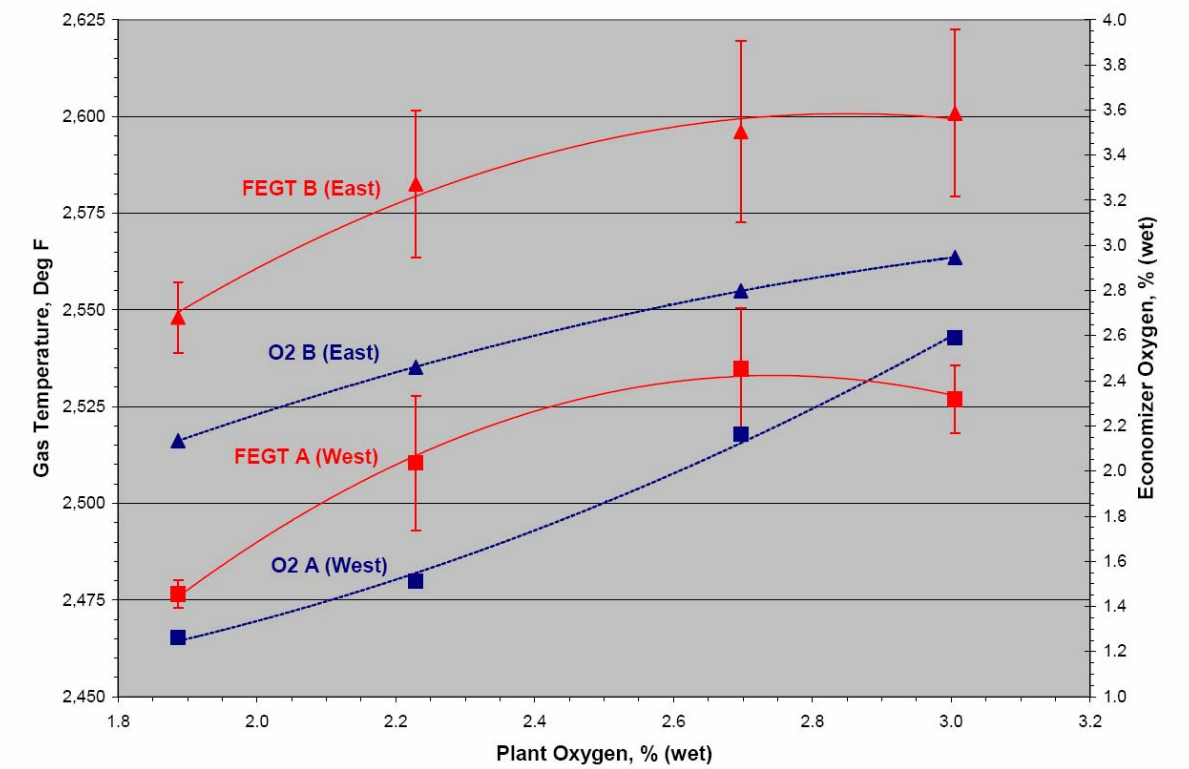
Emissions data from the full load data runs at various excess O2 levels were used to develop plots of NO_X and CO emissions versus boiler O2. Figure 36 shows the baseline emissions curves.

Figure 36 – Baseline NOx and CO Emissions Curves at Full Load



Similar data was also collected for FEGT and a comparison of plant O2 levels measured from the existing in situ Yokogawa O2 probes and economizer O2 levels measured from a grid of test probes used to pull a flue gas sample into a bubble pot for analyzing with a Teledyne portable O2 analyzer. Figure 37 shows FEGT and economizer O2 levels versus plant O2 levels.

Figure 37 – Baseline FEGT and Oxygen Data at Full Load



Baseline data was also collected from the new CO monitors, LOI combustion sensors, and burner NOx sensors. Figure 38 shows baseline data from the CO sensors. The plots on the left show the magnitude of CO (in ppm) at the horizontal cross-section of the boiler where the CO sensors are installed. The cross-section plot is shown with west-to-east data going from left-to-right on the plot and front wall-to-back wall data going from front-to-back on the plot. The plots on the right show corresponding O2 data at the vertical cross-section of the economizer outlet ducts where the in situ plant O2 probes are installed. The cross-section plot is shown with west-to-east data going from left-to-right on the plot and upper-to-lower data going from top-to-bottom on the plot. Figure 39 shows baseline data from the LOI combustions sensors. The data is shown at various boiler excess air values with the probes shown west-to-east on the plot. The values shown for Relative LOI and Relative T are dimensionless numbers used for comparison only.

Figure 38 – Baseline CO Sensor Data

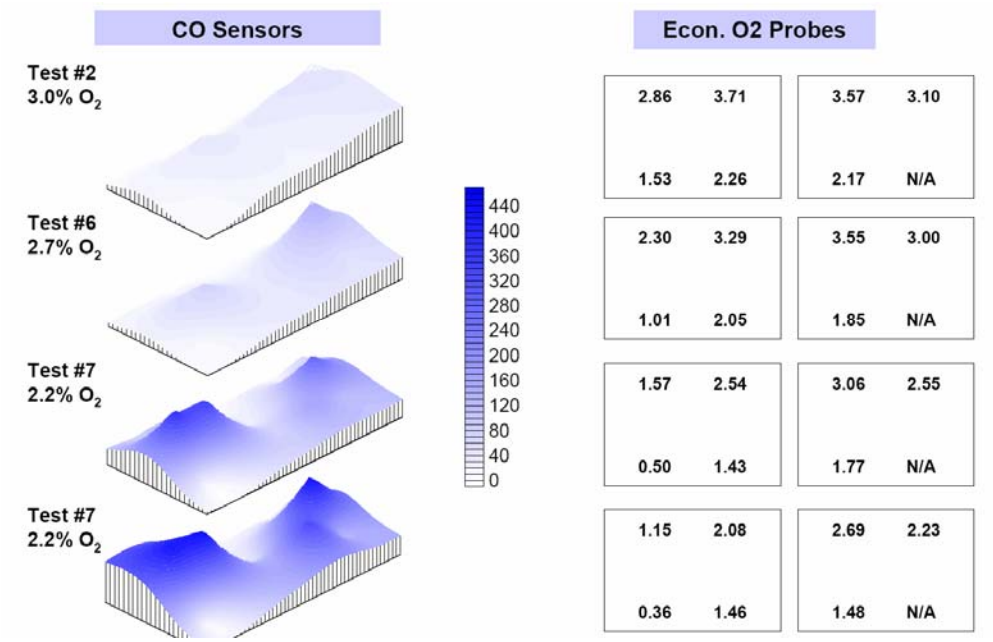
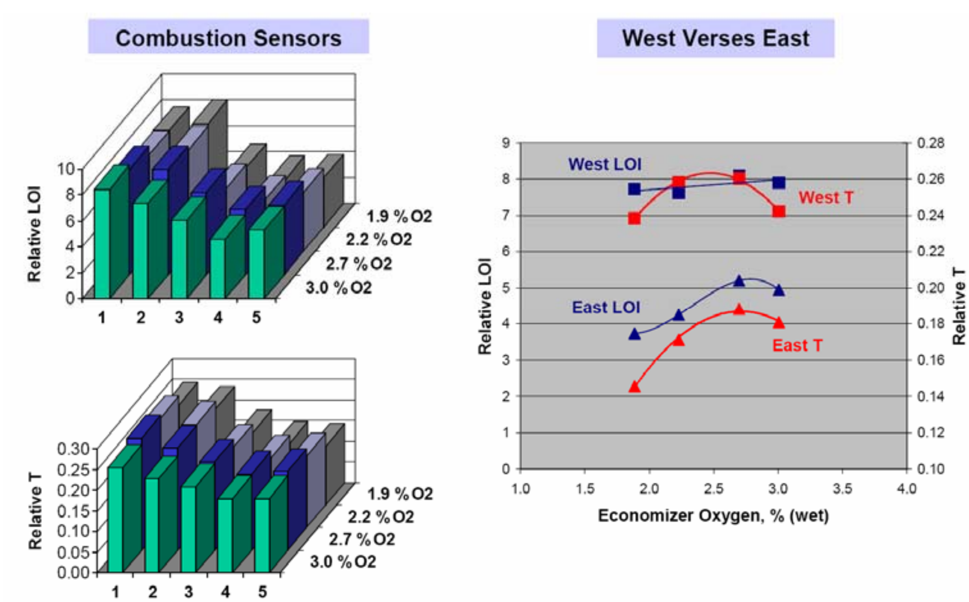


Figure 39 – Baseline Combustion (LOI) Sensor Data



Results from the baseline testing will be further discussed in Section 2.2.1.

2.1.6 Task 1.6 – PSD Review

In this task a regulatory review was to be performed to assure that the project would not impact the ambient air quality of the region. Burns and McDonnell was hired to complete the PSD review. They completed a draft permit review, however the permit review was not submitted to the Kansas Department of Health and Environment (KDHE) pending a decision on whether or not to proceed with Phase III of the project. The review determined that CO, SO2 and PM10 would be subject to a PSD review as a result of the project. Figure 40 shows a summary of the calculated potentional emissions changes compared to the PSD significance level.

Figure 40 – Emissions and Significance Levels

Pollutant	Pre-Modification Emission Rates (lb/MMBtu)	Pre-Modification Actual Emissions* (tons/year)	Post-Modification Predicted Emission Rates (lb/MMBtu)	Post-Modification Potential Emissions** (tons/year)	Actual-to-Future-Potential Emissions Change (tons/year)	PSD Significance Level (tons/year)
SO_2	**0.163**	**2,054**	**0.35**	**5,387**	**3,333**	**40**
CO	**0.028**	**360**	**0.15**	**2,309**	**1,949**	**100**
NO_X	**0.281**	**3,550**	**0.20**	**3,078**	**-472**	**40**
PM/PM_{10}	**0.016**	**198.5**	**0.03**	**461.7**	**263.2**	**25/15**
VOC	**0.005**	**57.5**	**0.007**	**68.2**	**10.7**	**40**
Lead	**0.00042*** **	**0.41*** **	**0.00042**	**0.41**	**--**	**0.6**
Sulfuric Acid Mist	**0.00018*** **	**0.16*** **	**0.00018**	**0.17**	**0.01**	**7**

* Based on data reported for 2000 and 2001.

** Based on 3,514 mmBtu/hr heat input operating for 8,760 hours annually.

*** Calculated using AP-42 emission factors and based on 3,389 mmBtu/hr heat input operating for 8,760 hours annually.

Figure 41 shows a summary of the Best Available Control Technology (BACT) analysis that was performed on the three pollutants subject to PSD review.

Figure 41 – BACT Results

Pollutant	Proposed BACT	Controlled Emission Rate
SO_2	Flue Gas Desulfurization System	0.35 lb/mmBtu
PM_{10}	Baghouse	0.03 lb/mmBtu
CO	Good Combustion Practice	0.15 lb/mmBtu

2.2 Task 2.0 – Phase II – Low-NOx Burner Modifications

The objective of Phase II was to demonstrate the effectiveness of low-cost modifications to the existing, first generation low-NO_X burners to reduce NO_X emissions. This phase also included modifications to the existing pulverized coal (PC) piping to permit automated fuel balancing among all burners. The scope of work for the Low-NO_X Burner Modifications Phase was performed in the following three tasks.

2.2.1 Task 2.1 – Low-NOx Burner Modifications

In this task the existing twenty-five B&W dual-register burners installed on Holcomb Station Unit 1 were modified to improve flame stability and reduce NO_X emissions. The modified burners were designed to optimize combustion emissions when operated in conjunction with the overfire air system that was to be installed in Phase III of the project. The burner modifications were completed during the Spring Outage in 2003. The installation work was sent out for bids and Power Maintenance and Construction (PMC) was the successful bidder. PMC also completed installation of the coal flow balancing dampers on one mill and coal flow measurements sensors on all five mills during the same outage.

Figure 42 shows pictures of the burner modifications. The upper left picture shows scaffolding in place inside the furnace and new parts staged in front of the burner fronts. The picture on the upper right shows a burner with the original coal nozzle and inner air sleeve removed. The picture on the lower left shows a burner with the new coal nozzle and inner air sleeve installed. The picture on the lower right shows one of the new adjustable shrouds in place on the outer air register assembly. Figure 43 shows pictures of the coal flow balancing valves installed above 'A' pulverizer. The picture on the left shows the coal pipes before the balancing valves were installed and the picture on the right shows the coal pipes with the new valves in place.

Figure 42 – Burner Modifications

Figure 43 – Coal Balancing Valve Installation

Post-outage combustion optimization testing began after startup following the 2003 Spring Outage. GE EER put together a test plan that included coal flow balancing (discussed in Section 2.2.2), burner tuning, CO tuning, and PA flow measurements. There were over 100 test runs completed over a two month period during the optimization process. Unfortunately the optimization testing was not successful at reducing NO_X emission levels below pre-modification levels. Figure 44 shows a plot of NO_X and CO emission levels for several test runs during the optimization process.

Figure 44 – Emissions During Optimization Process

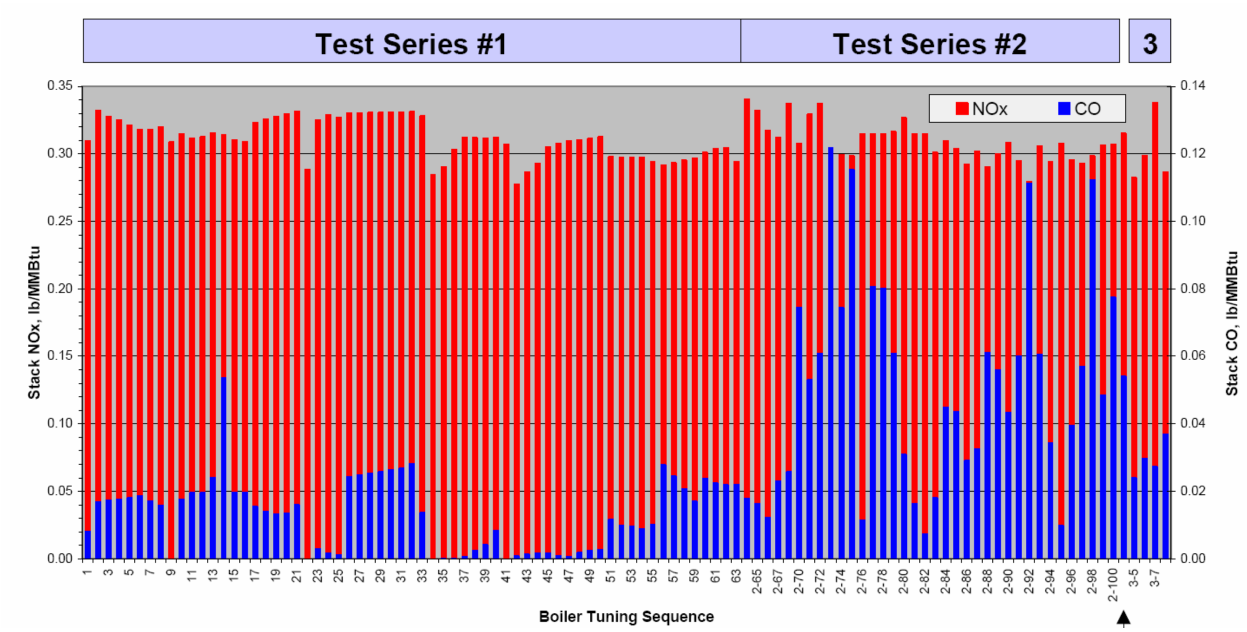
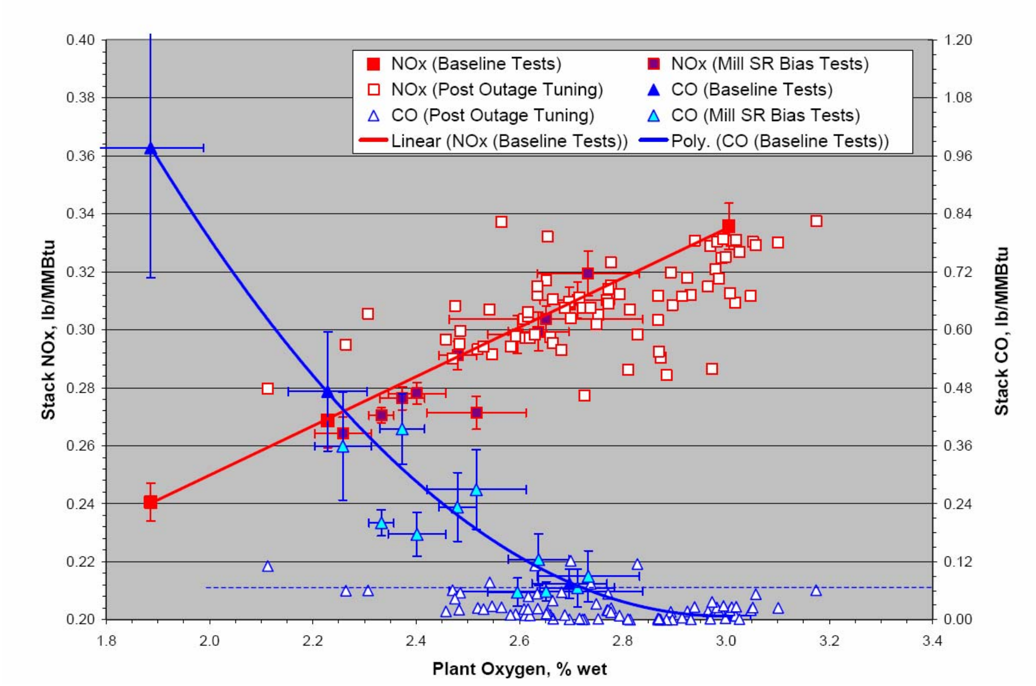


Figure 45 shows optimization data compared to baseline data for NOx and CO.

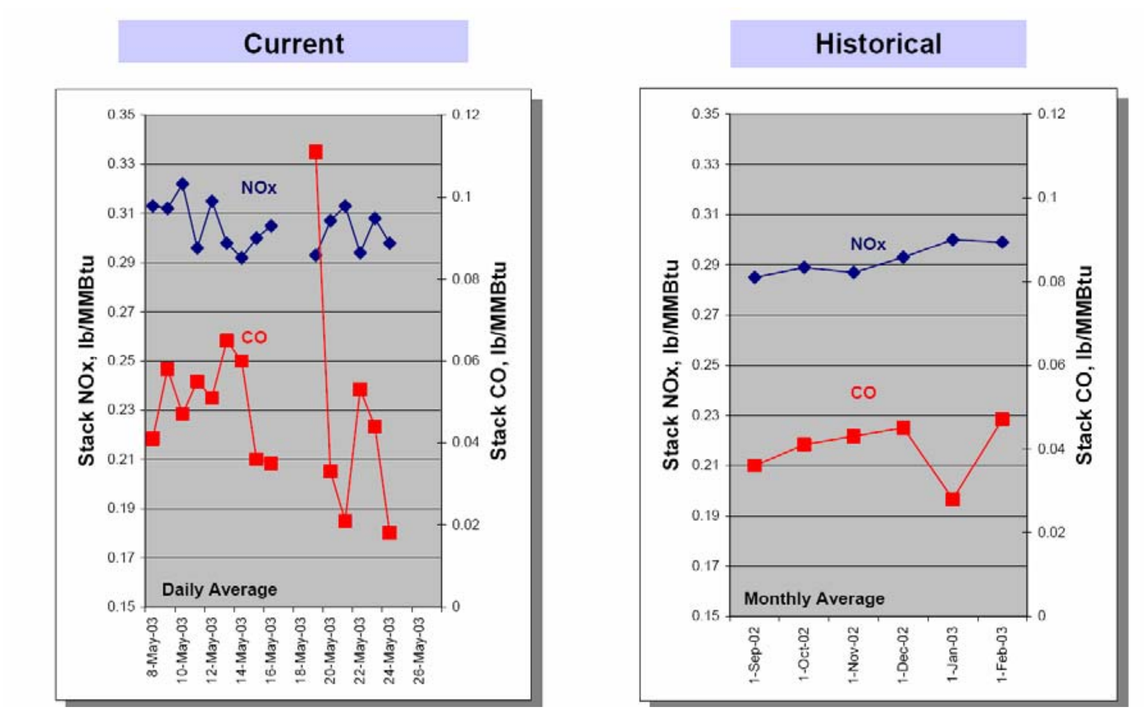
Figure 45 – Optimization Emission Data Compared to Baseline Test Data



The inability to reduce NOx emissions is shown in Figure 46. This plot shows that both NO_X and CO were higher after completion of the optimization testing.

Figure 46 – Comparision of Post-Optimization Emission Data with Pre-Modification Data

(Graph Labeled "Current" is Post-Optimization and Graph Labeled "Historical" is Pre-Modification)



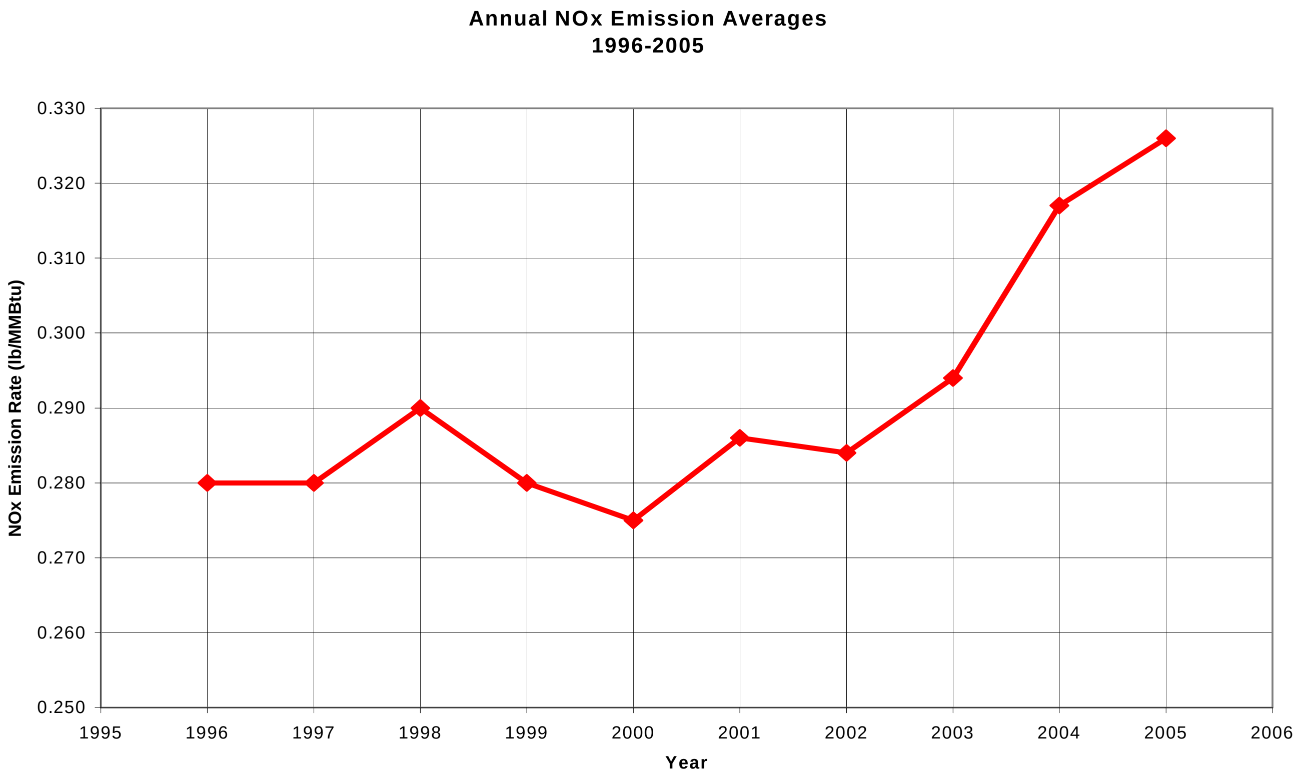
The performance of the low-NO_X burner modifications continued to be monitored closely following completion of the burner modifications and optimization testing. Prior to installation of the modifications, annual NO_X emission rates were very consistent at around 0.28 lb/MMBtu. Annual average NO_X emissions over the period 1996 - 2002 from the certified Continuous Emissions Monitoring System (CEMS) at the plant are shown in Figure 47.

Figure 47 – Historical Annual NO_X Emission Rates

Year	Annual NOx Emission Rate (lb/MMBtu)
1996	0.280
1997	0.280
1998	0.290
1999	0.280
2000	0.275
2001	0.286
2002	0.284

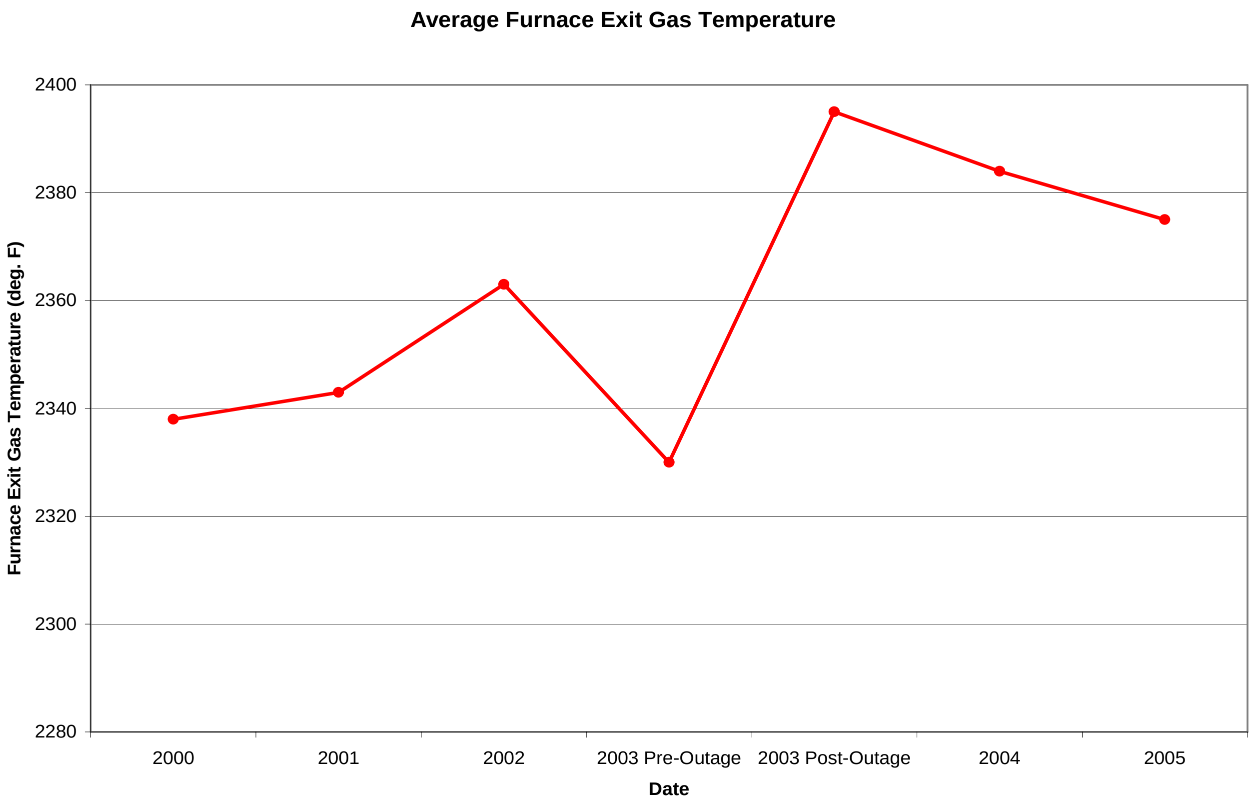
From May through September 2003, following installation of the burner modifications, daily average NO_X emissions began to increase. The average daily NO_X emission rate for this time period was 0.304 lb/MMBtu. NO_X emissions continued to run higher than normal throughout 2004. The annual average NO_X emission rate for 2004 was 0.317 lb/MMBtu. The NO_X emission rate for the first quarter of 2005 was 0.326 lb/MMBtu. This data is summarized in Figure 48.

Figure 48 – Annual NO_X Emission Averages



In addition to increasing NO_X emission rates, the burner modifications also resulted in increased furnace exit gas temperatures. These elevated temperatures resulted in increased slagging in the upper portions of the furnace. Figure 49 shows a plot of FEGT before and after the burner modifications that were completed in March of 2003.

Figure 49 – Average Furnace Exit Gas Temperatures



The burner modifications also resulted in significant maintenance issues. The modifications at the burner tips included a new, flared coal nozzle with a stabilization ring attached around the outside perimeter of the nozzle tip. Stabilization "teeth" were also added along the inner perimeter of the nozzle tip, and both the coal nozzle and the inner air sleeve were inserted 4" farther into the boiler than the previous design. Figure 50 shows the original burner configuration and Figure 51 shows the modified configuration.

Figure 50 – Original Burner Configuration

Figure 51 – Modified Configuration

The first problems encountered with the modified design were associated with the scanners and ignitors. Because of the flared coal nozzle and the stabilizing ring, the gap between the coal nozzle and the inner air sleeve was significantly reduced. This gap is utilized as a viewing port for the flame scanners. The viewing area was significantly obstructed by the stabilizing ring, making it very difficult to sight the scanners to the flame. The gap between the coal nozzle and the inner air sleeve is also where the gas ignitor is inserted before being placed into service. The reduction in this gap following the burner modifications made it very difficult to squeeze the ignitor into its fully inserted position on many of the burners. Figure 52 shows the tight fit for the ignitor on one burner.

Figure 52 – Clearance for Ignitor

The extension of the coal nozzle and inner air sleeve also resulted in overheating issues that resulted in significant overheating damage. With the extension of these components, the ignitor did not insert far enough into the boiler to extend beyond the end of the inner air sleeve. Flame impingement from the ignitor resulted in overheating of the steel in the inner air sleeve. The extension of the burner tip also exposed the burner to increased radiant heat from the furnace.

This also resulted in overheat damage to the burner tips. Figure 53 shows an example of the overheat damage that occurred. It is likely that this damage and its impact on air flow distribution contributed to the increased NO_X emissions and the increased furnace exit gas temperatures.

Figure 53 – Example of Overheat Damage on Modified Burner

Figure 54 shows a plot of net unit heat rate from 1997 through 2005. The plot shows that the net unit heat rate increased (meaning the plant became less efficient) following the burner modifications. There are several factors that affect overall plant efficiency, and it is not clear how much of the overall increase in heat rate is attributable to the burner modifications. One variable that plays a role in combustion efficiency and overall plant efficiency is the quality of the coal being burned. Holcomb Station burns coal from various mines in the Powder River Basin in Wyoming. Figure 55 shows a summary of coal analyses from 1997 thru 2005.

Figure 54 – Annual Net Unit Heat Rate

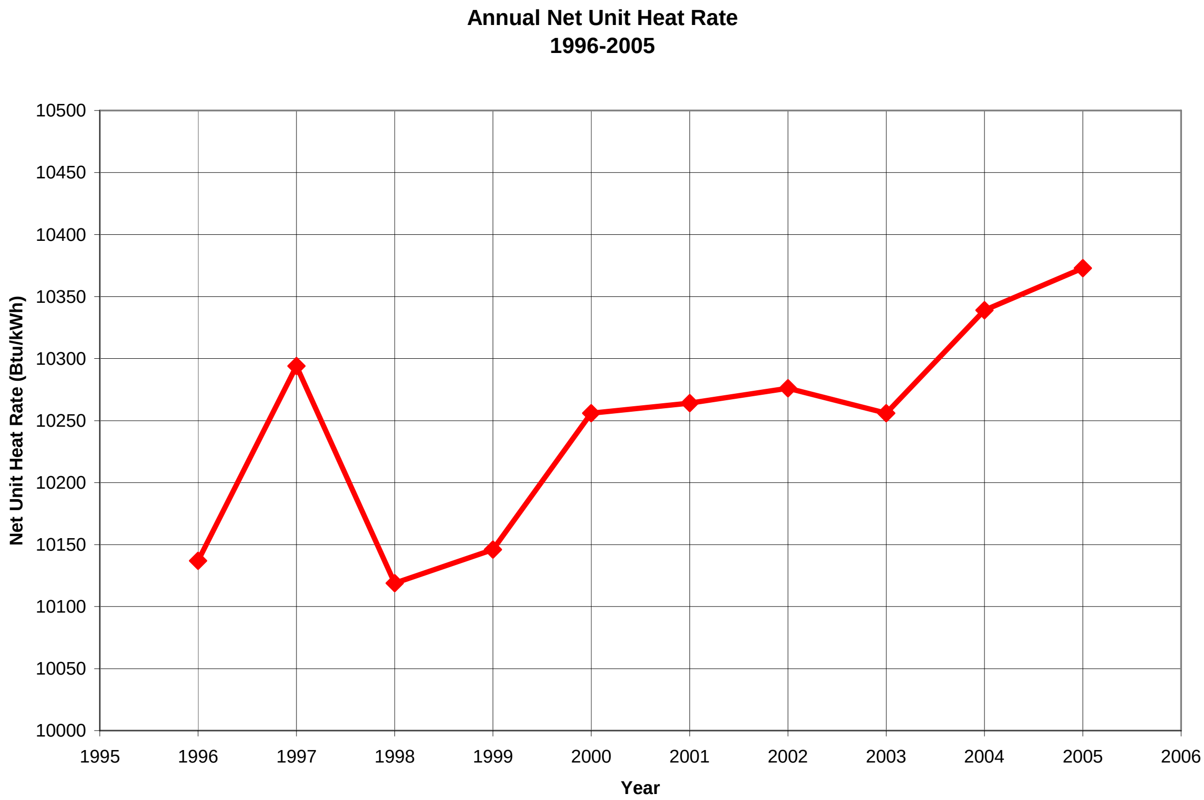


Figure 55 – Annual Coal Analyses

Annual Coal Analyses 1997 - 2005					
Year	HHV (Btu/lb)	Moisture (%)	Ash (%)	Sulfur (%)	LOI (%)
1997	8429	29.51	5.44	0.33	0.15
1998	8515	29.09	5.16	0.29	0.14
1999	8457	28.41	5.73	0.29	0.05
2000	8513	28.03	5.54	0.30	0.06
2001	8497	28.21	5.46	0.30	0.08
2002	8550	28.00	5.54	0.29	0.09
2003	8779	26.21	5.57	0.37	0.10
2004	8708	26.46	5.64	0.41	0.04
2005	8647	26.91	5.51	0.38	0.00

2.2.2 Task 2.2 – PC Piping Coal Flow Control and Balancing System/Testing

In this task, the five pulverizers were equipped with a coal-flow balancing system consisting of the automated coal-balancing dampers on each coal pipe. The automated coal dampers were integrated with the coal-flow monitoring system to provide for automatic balancing of all the burners over the boiler load range. The coal flow balancing equipment on 'C' pulverizer was automated in 2003. The remaining four pulverizers were automated in 2004. Figure 56 shows a picture of the Air Monitor coal flow measurement instrumentation installed on a coal pipe. The process used to measure coal flow is based on microwave technnology used to measure coal density and particle velocity. The flow data from these sensors were used in conjunction with the coal flow balancing valves to balance the flow of coal through each coal pipe on a given mill.

Figure 56 – Coal Flow Measurement Instrumentation

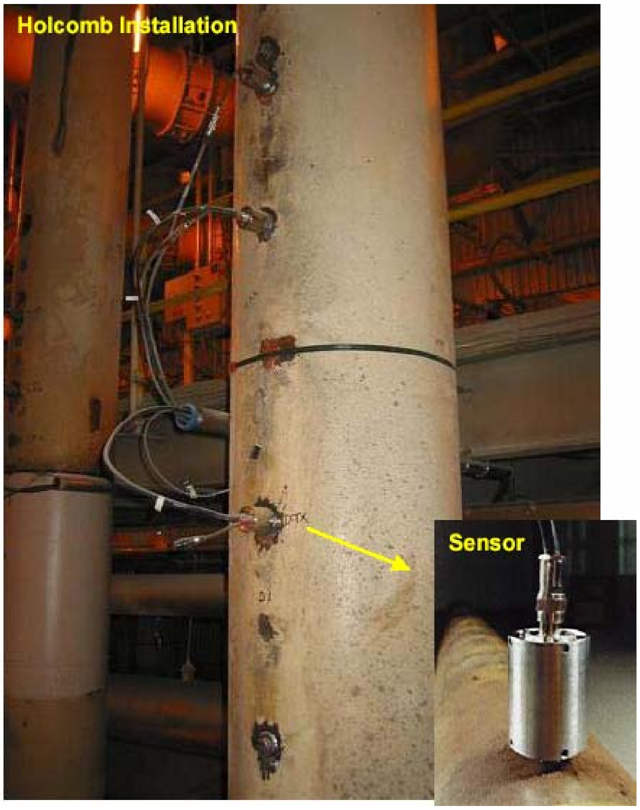
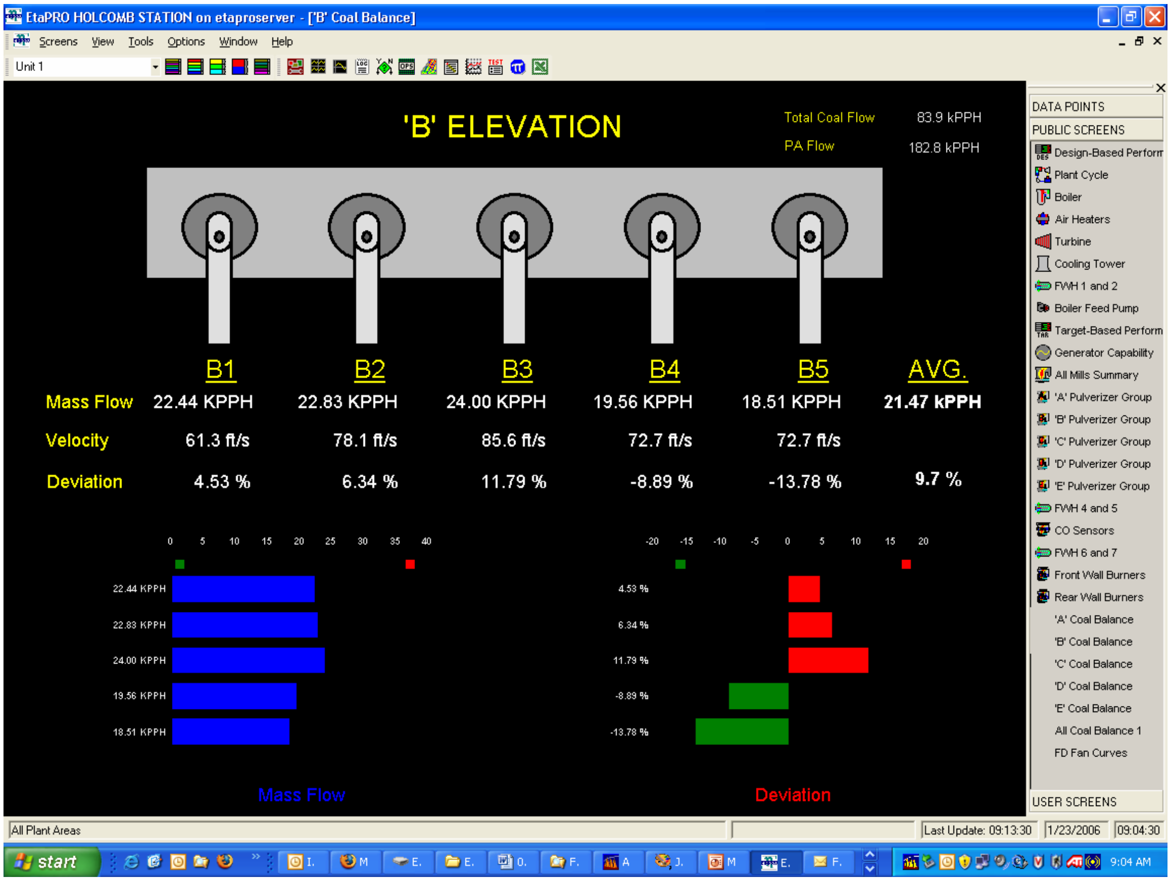


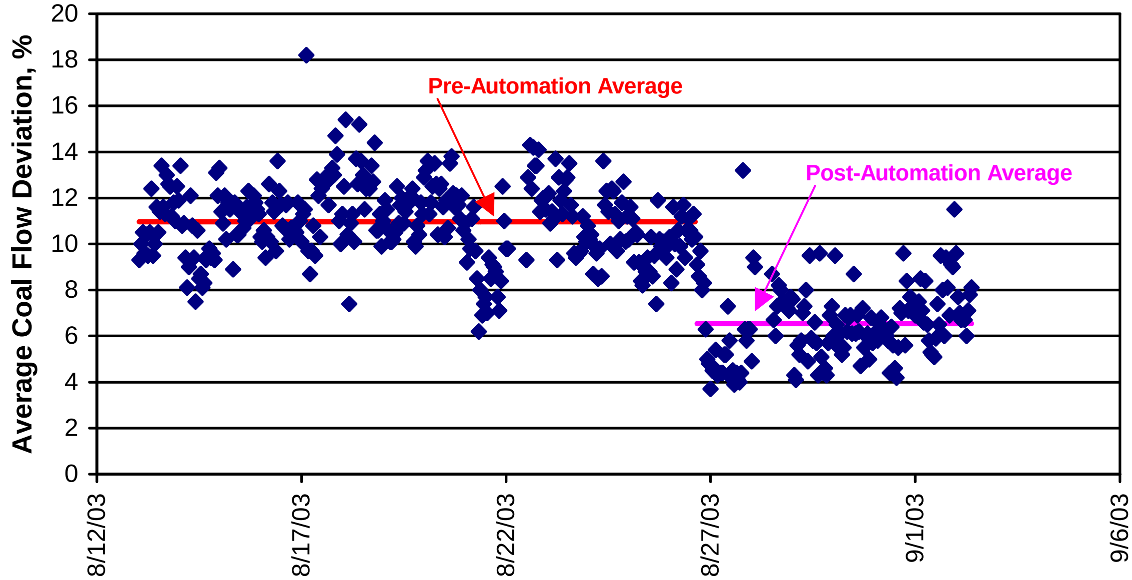
Figure 57 shows a screen shot from EtaPro showing how data from the Air Monitor coal flow sensors is displayed and how the data is used to evaluate coal flow balance.

Figure 57 – EtaPro Screen Displaying Coal Flow Data



Results of the automation of the coal flow balancing system have showed improved balancing of coal flow across the coal pipes for each burner elevation. However, the improved balancing has not translated into improved NO_X control. Figure 58 shows a trend of improved coal flow distribution with the automated coal flow system in service. The coal flow balancing dampers also created concerns about low coal particle velocity at lower mill loads when the dampers were in a throttling position. To keep velocities above the recommended value of 55 ft/sec, the primary air curves were adjusted so that the primary air flow was increased at lower mill loads. The primary air flow at full mill load remained the same.

Figure 58 – Results of Coal Flow Automation



2.2.3 Task 2.3 – Design of OFA Penetrations

To support implementation of Phase III, this task consisted of the detailed design of an optimum overfire air system for this unit. Design of the SOFA system was completed by GE EER. The system was design to pull secondary air from the existing secondary air ductwork in the plant. The number of OFA injectors was changed from six per wall to five per wall to maintain structural stability of the front and rear furnace water walls. The outboard OFA injectors on both the front and rear walls were designed larger than the inner injectors based on results of the modeling completed in Task 1.1. The design included control dampers in each of the

2.3 Task 3.0 – Phase III – Advanced Separated Overfire Air System

The objective of this phase of the project was to demonstrate NO_X control competitive with SCR installations with the addition of an overfire air system coupled with the existing Phase I and II modifications to optimize overall system performance. The integration of all three phases of these improvements was expected to provide the opportunity to reduce NO_X emissions and permit improvements in power plant performance and output.

Based on results of the burner modifications, it was determined that the modifications would not work and new burners would need to be incorporated with the SOFA design. Because of the problems encountered trying to utilize existing scanners and ignitors, a determination was also made that new scanners and igniters would have to be part of the upgrade package. An RFP was developed to provide new burners and SOFA and sent to several bidders.

All bids came in significantly higher than the original budget for Phase III. Some of the reason for the increased price was a result of the need for new burners, scanner, and ignitors. It also appeared that the original project budget significantly underestimated what would be required to complete the SOFA installation. The original budget was put together in 2001 with significant input from GE EER. The bid GE EER submitted in 2005 included SOFA equipment at a cost that was over $1.3M higher than the budgetary price prepared by GE EER in 2001. Figure 59 shows an economic analysis overview. With the costs overruns experienced, the project will not pay for itself within the expected life of the plant.

Figure 59 – Economic Analysis

Project Costs	
Item	**Amount**
Budget Period 1 Costs (Phases 1 and 2)	$3,142,201
Burner Repairs During 2004 Outage	$70,000
Budget Period 2 Costs - Estimate (Phase 3)	$5,526,000
Choke Point Items	$246,860
Total Project Cost	$8,985,061
Project Revenues	
Item	**Amount**
Expected Energy Revenue ($/MWh)	$33
Fuel Cost ($/MWh)	$12
Variable O&M ($/MWh)	$4
Revenue Less Variable Cost ($/MWh)	$18
Extra Capacity Afforded by Project (MW)	7
Extra Energy Available (MWh per year)	61320
Capacity Factor in Upper 7MW Load Range (%)	30
Extra Energy Utilized (MWh per year)	18396
Revenue from Extra Energy ($/year)	$331,128
Assumed Interest Rate	3%
Present Value of Annual Revenue After 10 Years	$2,824,589.00
Present Value of Annual Revenue After 20 Years	$4,926,348.50
Present Value of Annual Revenue After 30 Years	$6,490,254.94
Present Value of Annual Revenue After 40 Years	$7,653,948.21
Present Value of Annual Revenue After 50 Years	$8,519,845.30

After evaluating the bids that were received and their impact on the economic analysis of the project and factoring in budget constraints, the installation of SOFA and modified burners has been deferred until at least 2008.