A DB RILEY TECHNICAL PUBLICATION

LOW NO_x RETROFIT PROBLEMS AND SOLUTIONS: A JOINT PERSPECTIVE

by

Craig A. Penterson, Senior Staff Engineer
and
Darrell E. Dorman, Engineer
DB Riley, Inc.

Presented at the
International Joint Power Generation Conference
October 9-11, 1995
Minneapolis, Minnesota

RST-133

DEUTSCHE BABCOCK
DB RILEY, INC.

Post Office Box 15040
Worcester, MA 01615-0040

LOW NO RETROFIT PROBLEMS AND SOLUTIONS: A JOINT:PERSPECTIVE

by
Craig A. Penterson, Senior Staff Engineer
and
Darrell E. Dorman, Engineer
DB Riley, Inc.

ABSTRACT

*Several utility boilers have been retrofitted with low NOx burner technology during the past five years in response to the 1990 Clean AirActAmelments.Though most of the projects have been successful in achieving the primary objective 'rrf rg NO emissions, other problems have been created. The most significant problem **has** been with increased flyash unburned carbon.*

This paper discusses experiences, problems and some solutions involving three low NOx retrofit projects implemented by American Electric Power Service Company which included these utility boilers: Glen Lyn Unit 6 240 MW front wall fired

Muskingum River Unit 5 - 600 MW opposed wall cell fired

Conesville Unit 3 - 165 MW front wall fired

Performance data will, be presented as well as solutions to some of the problems encountered.

INTRODUCTION

In response to the 1990 Clean Air Act Amendments, several utility boilers have been retrofitted during the past five years with NOx emissions control technology under the Phase I rulings. This technology has focused on altering the combustion process using low NOx burners (LNB), overfire air (OFA) or a combination of both. While most of the installations have been successful in reducing NOx by 30-60% from uncontrolled levels, the task has not been easy. Other problems have been created.

The most significant problem concerns the adverse impact low NOx technology has on flyash unburned carbon (UBC). The increased levels of UBC and other chemical residuals in the ash has had a major impact on ash disposal and utilization. Given the increasing pressure on utilities to reduce the quantities of non-useful combustion byproducts created in power generation, this is potentially a very serious problem[s]. Other problems include flame impingement on furnace waterwalls and superheaters, steam temperature control, mechanical installation and fit-up of low NO_X burners, and burner lightoff.

During the past two years DB Riley has retrofitted low NO_x burners or low NO_x burner components into three coal-fired boilers owned by American Electric Power Service Company (AEPSC), based in Columbus, Ohio. The boilers included Glen Lyn Unit 6, Muskingum River Unit 5 and Conesville Unit 3. Each retrofit project was unique with specific objectives and goals. The common goal was to reduce or maintain NO_x emissions at levels that were at least 50% below uncontrolled emission levels.

The following describes experiences, problems and some solutions encountered in each of these retrofit projects.

GLEN LYN UNIT 6

Unit Description

Glen Lyn Unit 6, located in Glen Lyn, Virginia, was originally designed and manufactured by Babcock and Wilcox (B&W) in the mid-1950's. The boiler, which is operated by Appalachian Power Company, is designed to produce superheated steam at a rate of 1,692,000 lb/hr and 1050°F with a 2075 psig operating pressure. The design reheat outlet temperature is also 1050°F. The electrical generating capacity is 240 MWe net.

As shown in Figure 1, the unit is equipped with 24 burners on the front wall arranged in four levels of six burners per level. The burners are fed pulverized coal from six B&W EL 70 pulverizers. The furnace dimensions are approximately 50 feet wide x 24 feet deep. The unit burns various coals from Southwest Virginia.

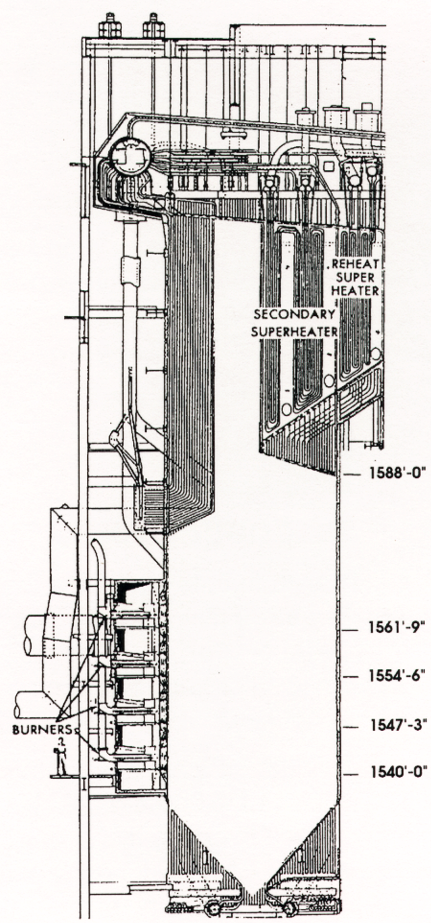

Figure 1 AEP Glen Lyn Unit 6

Low NO_x Burner Component Retrofit

Glen Lyn Unit 6 had been suffering from flame impingement, steam temperature control problems, and extremely high unburned carbon (UBC) as a result of retrofitting with the original equipment manufacturer's (OEM) low NO_x burners in the summer of 1993. While full load NO_x emissions were reduced by 30% to .50-.53 lb/10^6 Btu, flyash UBC increased significantly from approximately 16% to the 20-50% range. CO emissions typically exceeded 750 ppm. Abnormally long flames caused impingement on the rear waterwall and the flame length extended into the superheater. As a result, tube metal temperatures were often in alarm and continuous control of steam temperature was very difficult. Furthermore, the operators experienced boiler and opacity upsets when mills were taken in and out of service.

AEPSC approached Riley for a solution to correct the operational problems resulting from retrofitting with the OEM's low NO_x burners. The goal was to resolve the operational problems while maintaining reduced NO_x emission levels.

Several options were considered. The approach selected was to install critical components from the DB Riley low-NO_x CCV® burner into the OEM's low NO_x burner. These components, shown in Figure 2, include the CCV® venturi coal nozzle, low swirl coal spreader, secondary and tertiary air diverters and new coal heads. The secondary and tertiary air register designs were left unchanged. Recent laboratory testing of a prototype burner of similar design indicated that CO emissions and flame length could be effectively reduced without adversely impacting NO_x emissions, which gave us confidence in this low-cost solution.

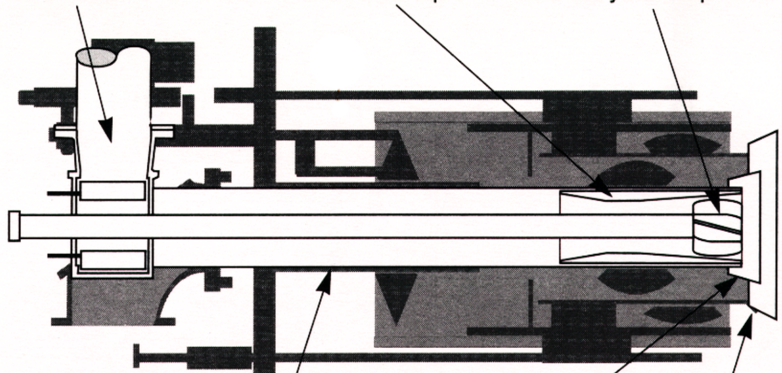

Figure 2 Retrofit of CCV® Burner Components into B &W XCL Burners at AEP Glen Lyn Unit 6

Components were fabricated and installed during a short outage in fall, 1994. Figure 2 identifies the new burner components that were retrofitted into the existing air registers. Figure 3 is a photograph of the CCV® burner components as installed. Subsequent testing following unit start-up included an evaluation of various coal spreader designs, primarily different vane angles, for optimizing the unit. Table 1 shows different combinations of 30° and 15° spreaders tested. The higher swirl 30° spreaders typically produce more mixing, better combustion, and higher NO_x than the lower swirl 15° spreaders.

In all cases, unit operation greatly improved with the new burner components installed. Test data for the final configuration indicated that CO was reduced from >750 ppm to <300 PPM, and at times <20 PPM depending on the coal source. LOI decreased from the 20%-50% range to the range of

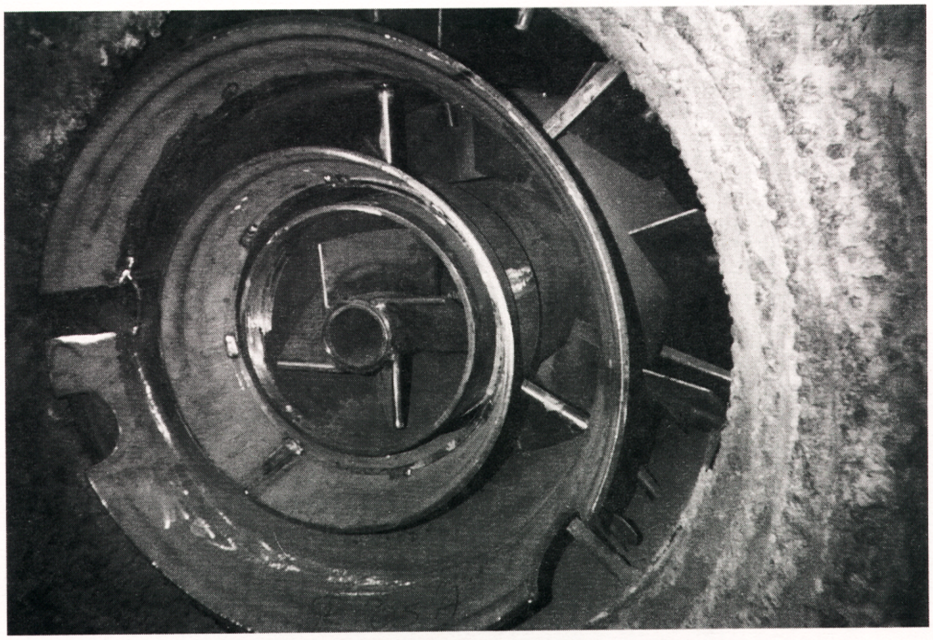

Figure 3 CCV® Burner Throat at Glen Lyn Unit 6

Glen Lyn Unit 6 Summary of Results

Condition	As Found	CCV® Burner Components		
Diffuser/Spreaders Configuration	50% Conical[1]	100% - 30°	75% - 15°[2]	50% - 15°[3]
LOI, %	20 - 53	9 -16	10 - 20	10 - 15
CO, PPM	> 750	< 50	50 - 750	100
NO_x, lb/10^6 Btu	0.50 - 0.53	0.67 - 0.70	0.48 - 0.53	0.50 - 0.58
Observations				
Rear Wall Impingement	Significant	None	Moderate	Light
Secondary SH Impingement	Significant	None	Light	Very Light
Steam Temperature Control	High frequency of tube metal temperature alarms and heavy attemperation	Low frequency of tube metal temperature alarms and low attemperation	Moderate frequency of tube metal temperature alarms and moderate attemperation	Low frequency of tube metal temperature alarms and low to moderate attemperation

[1] Bottom two rows with conical diffusers, top two rows no diffusers

[2] Bottom three rows with 15° spreaders, top row with 30° spreaders

[3] Top and bottom rows with 30° spreaders, middle rows with 15° spreaders

Table 1

10%-20%. Flame length was reduced and the boiler controls were again capable of bringing mills in and out of service automatically without causing upsets in operation. NO_x emissions increased slightly, averaging between .48-.53 lb/10^6 Btu depending on boiler slag accumulation and coal characteristics.

AEPSC has on their own continued to evaluate other arrangements of the 15° and 30° coal spreaders in an effort to further tune the operation of Unit 6. The latest configuration uses 30° spreaders in the top and bottom burner rows only with 15° spreaders installed in the intermediate burner rows. The result was further improvement in LOI to 10-15%, CO emissions of <100 PPM and NO_x emissions varying between .50 and .58 lb/10^6 Btu.

Muskingum River Unit 5

Unit Description

Muskingum River Unit 5, in Beverly, Ohio, is a B&W supercritical boiler built in the early 1960's. The boiler, operated by Ohio Power, produces superheated steam at a rate of 4,035,000 lb/hr, 3800 psig operating pressure, and 1000°F operating temperature. The electrical generating capacity is a nominal 600 MWe.

As shown in Figures 4 and 5, the previous pulverized coal firing arrangement included twenty B&W two-nozzle cell burners and ten standard circular burners arranged in an opposed fired configuration. The unit has five B&W MPS size 89 pulverizers which feed ten coal nozzles each. The furnace dimensions are approximately 63 feet wide x 39 feet deep. MR5 burns a high volatile bituminous coal from Central Ohio and East Kentucky.

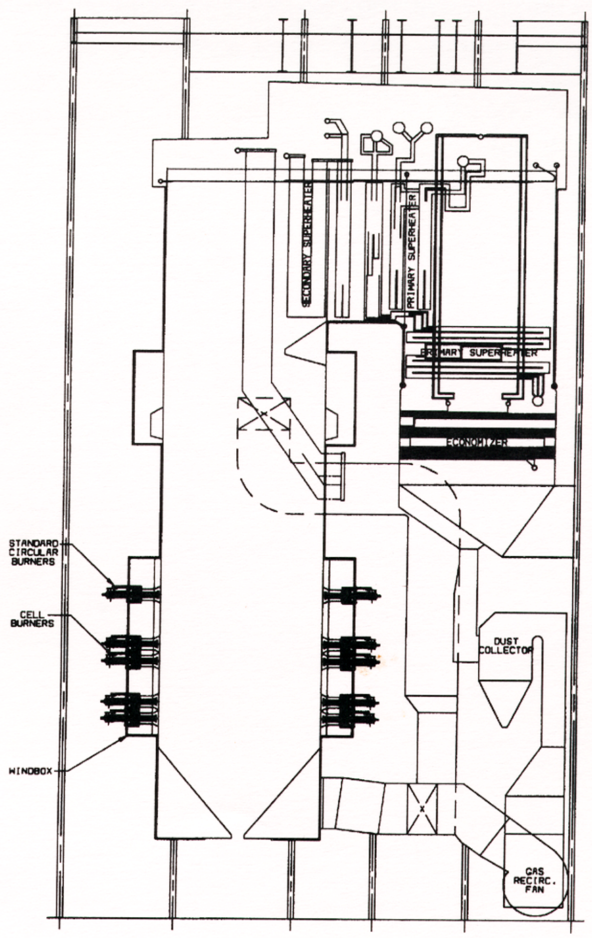

Figure 4 AEP Muskingum River Unit 5

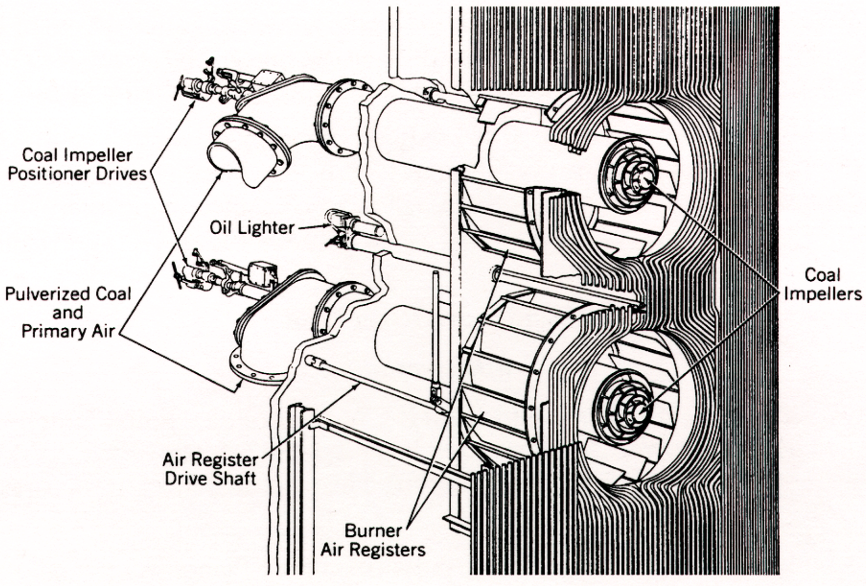

Figure 5 Original Two-Nozzle Cell Burner

Low NO_x Burner Retrofit

The unit was retrofitted in the spring of 1993 with fifty low NO_x CCV® burners each rated for 107 MMBtu/hr heat input at MCR conditions. The basic CCV® burner design is shown in Figure 6 while Figure 7 shows the CCV® burner in a cell arrangement (CCV® cell burner). Common to these designs is the venturi coal nozzle and secondary air diverter. These components produce the fuel rich combustion conditions necessary for low NOx[2].

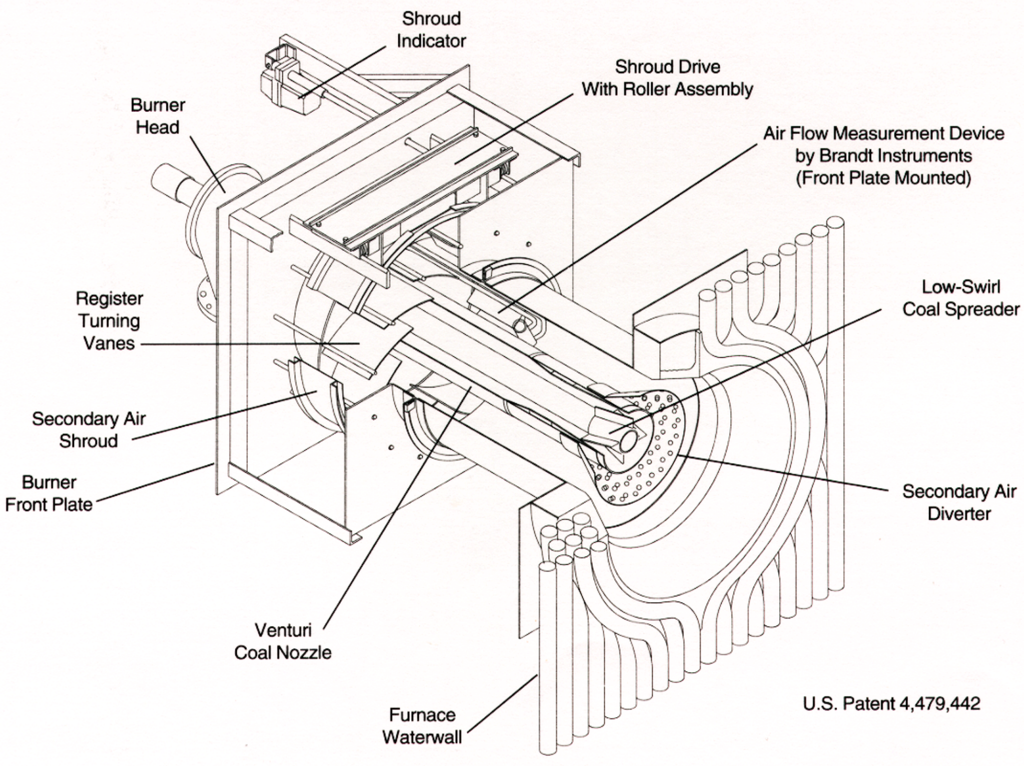

Figure 6 Riley Low -NO_x CCV® Burner

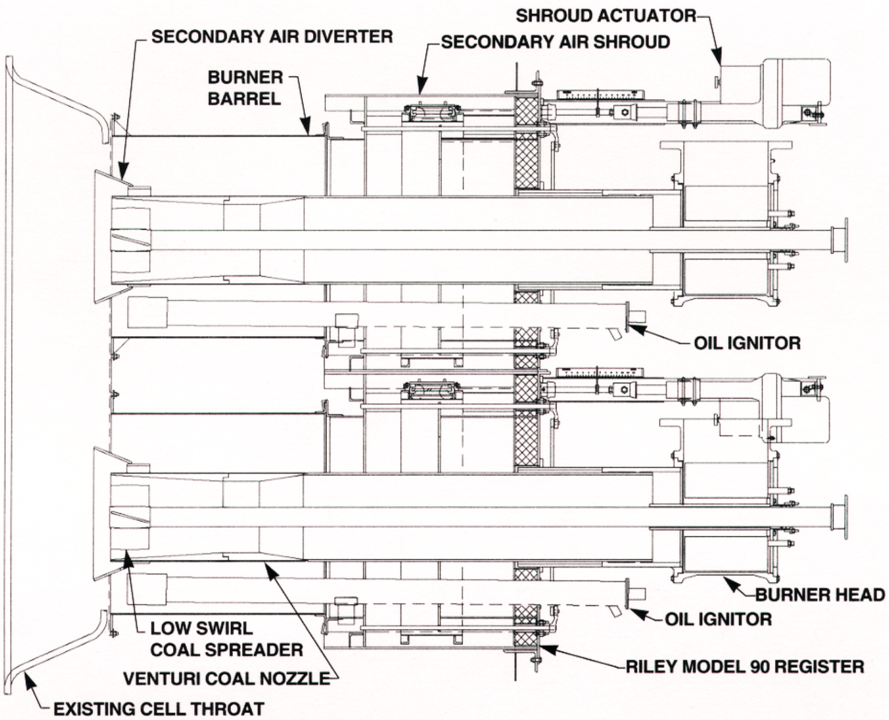

Figure 7 DB Riley Low-NO_x CCV® Cell Burner

Start-up of MR5 began in December, 1993. However, difficulties quickly occurred while attempting to lightoff the new burners using the original light oil mechanically-atomized oil lighters or ignitors. These ignitors, located between the two nozzles of each cell burner (Figure 5) are intended to lightoff both coal streams. The narrow fuel-rich coal streams produced by the CCV® burner in a cell configuration would not light from the ignitor flame.

The lazy and rather weak flames produced by the original ignitors would not provide enough heat energy at the base of the CCV® coal streams for reliable ignition. A development program with Combustion Components Associates (CCA) of Monroe, CT was implemented to develop split flame atomizers intended to concentrate and direct an individual ignitor flame toward each of the two narrow coal streams. As shown in Figure 8, the split flame atomizer was intended to direct nearly 50% of the ignitor flame up and 50% down toward the coal streams. A water spray booth using laser doppler holography to measure droplet size distributions was used to study potential atomizer designs. A photograph of the spray booth with a split flame atomizer is shown in Figure 9.

Subsequent testing of the split flame atomizers at MR5 indicated the heat energy was still insufficient for the two narrow coal streams.

The standard circular burners on the top row did, however, lightoff using individual ignitors. Therefore, we felt the only alternative for reliable lightoff of a CCV® cell burner was to install individual ignitors for ignition of each burner coal stream. New ignitors were installed and MR5 started up without incident.

The unit was tested and optimized. Initial results showed a 50% reduction in NO_x to <0.6 lb/10^6 Btu without a deterioration in boiler performance while burning high sulfur, high volatile coal from Central Ohio[2].

Long term parametric testing is currently being conducted to reoptimize unit operation when some deterioration in NO_x performance occurred after switching to lower sulfur West Virginia and East Kentucky coals.

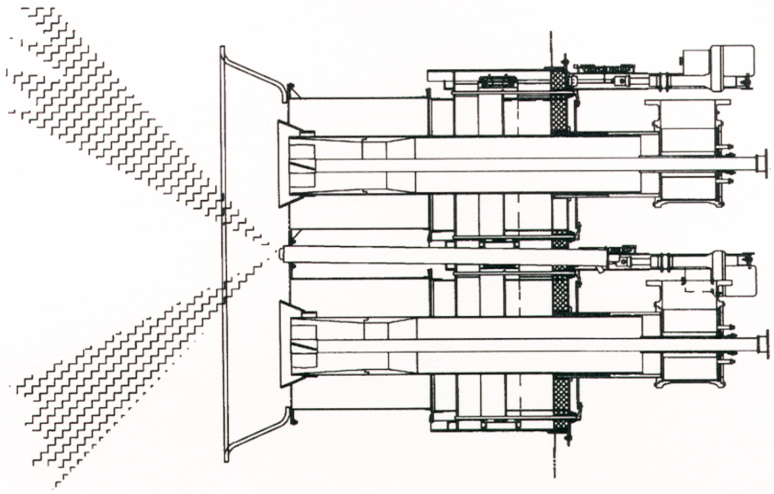

Figure 8 Split Flame Atomizer for CCV® Cell Burner

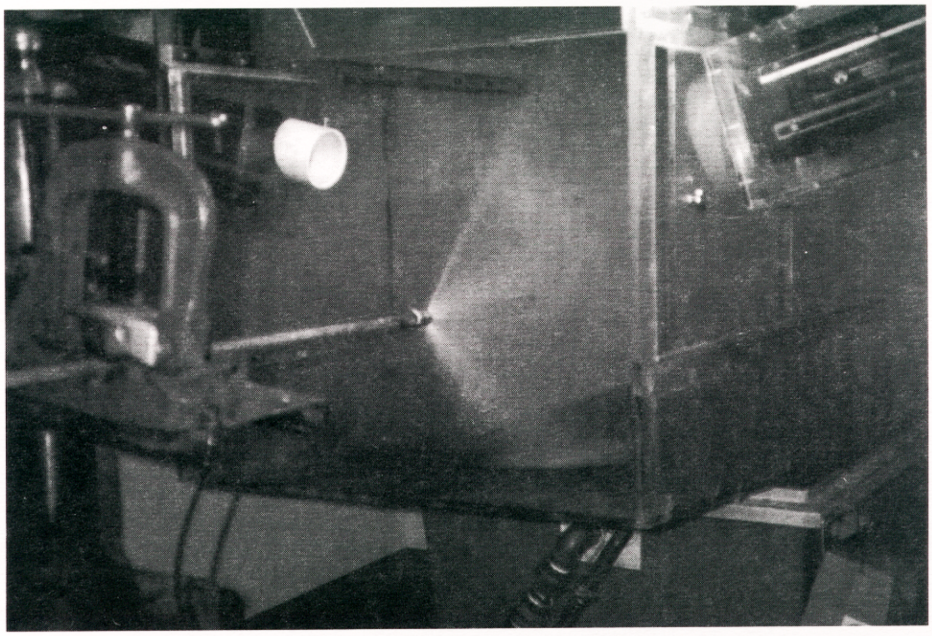

Figure 9 Split Flame Atomizer Being Developed at Combustion Components Associates (CCA)

Conesville Unit 3

Unit Description

Conesville Unit 3 in Conesville, Ohio (Figure 10) was designed and manufactured by Riley Stoker Corporation in the early 1960's. The front wall fired boiler was originally designed to operate at a Maximum Continuous Rating (MCR) of 1,124,000 lbs/hr superheated steam flow at 1589 psig and 1005°F, and a reheat steam flow of 968,000 lbs/hr at 507 psig and 1005°F. Original design peaking capacity was 1,240,000 lbs/hr superheated steam and 1,210,000 lbs/hr reheat steam. The unit was converted from forced draft to balanced draft operation in the mid 1970's. The electrical output for the unit is 165 MWe gross at the original MCR condition, but the unit is currently operated at the peak condition of 1,240,000 lbs/hr main steam flow which corresponds to a 175 MWe gross output (106% MCR).

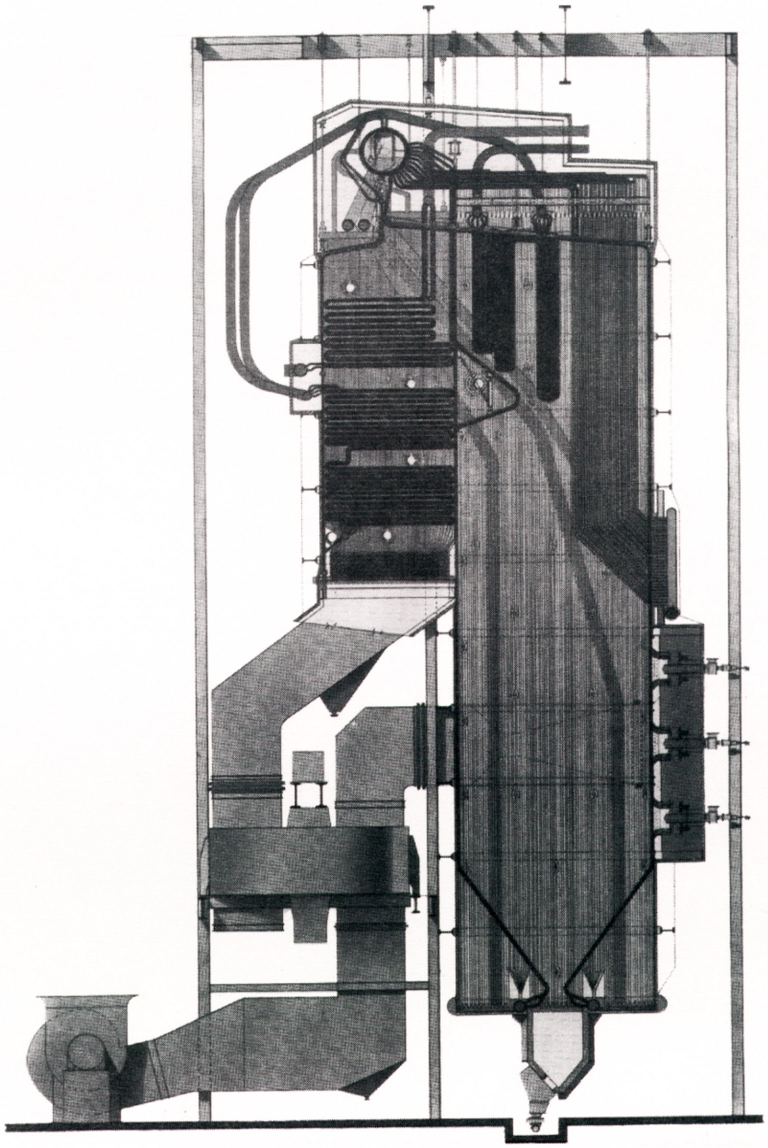

Figure 10 AEP Conesville Unit 3

The unit was originally equipped with sixteen Riley Flare Type burners, arranged in two rows of six burners and one row of four burners, designed for pulverized coal firing only. Pulverized coal is supplied by four Combustion Engineering #683 RPS exhauster mills. The approximate furnace dimensions are 47 feet wide x 25 feet deep.

Low NO_x Burner Retrofit

AEP contracted with DB Riley for the design, fabrication and installation of sixteen low NO_x CCV® burners with gas firing capability for Conesville Unit 3. The main objectives of the retrofit were to install low NO_x burners having dual fuel firing capability and to achieve <0.50 lb/10^6 Btu NO_x firing either fuel without the use of an OFA system.

Shortly after the start of the outage, several problems and concerns became apparent. During the replacement of the existing inner windbox casing, the front waterwall was found to be bowed into the furnace by as much as one inch at the top burner elevation and 4 to 5 inches at the lower burner elevation, effectively increasing the windbox depth. Although the burner register and secondary air barrels could be properly positioned by modification to the windbox casing, the waterwall displacement required the CCV® coal nozzles and spreaders to be positioned much deeper in the burner throat than normal design practice would allow. Since the potential for negative impact on burner performance was significant and the actual impact was unknown, this became an area of concern. A waterwall restraining system, shown in Figure 11, was designed and installed to prevent further waterwall bowing with the unit in service. The CCV® coal nozzles were installed as close as possible to the original design settings.

Post-retrofit testing showed no apparent negative effects. There was no noticeable flame impingement on the burner throat tiles by the main coal, oil or gas ignitor flames. NO_X reduction was greater than or equal to results from comparable units retrofitted with CCV® burners. This is discussed below.

The second problem was discovered shortly into the unit outage. It was found that gas canes in CCV® burners at other installations with gas firing capability were experiencing overheating. This was due to slagging and subsequent plugging of the gas cane tips during extended periods of coal firing. Frequent fuel changes were anticipated, so other solutions such as manually withdrawing the gas canes during periods of coal firing were deemed inappropriate for this particular unit. Installation of a purge air system was selected as the most reliable method of preventing gas cane tip slagging and plugging during extended periods of coal firing. The purge air system was integrated with the scanner and ignitor cooling air system, which required a larger cooling air blower and purge air control valves (installed during the spring 1995 outage). The effectiveness of the gas cane purge air system has not been verified to date, as no coal has been fired since completion of the optimization testing for gas firing.

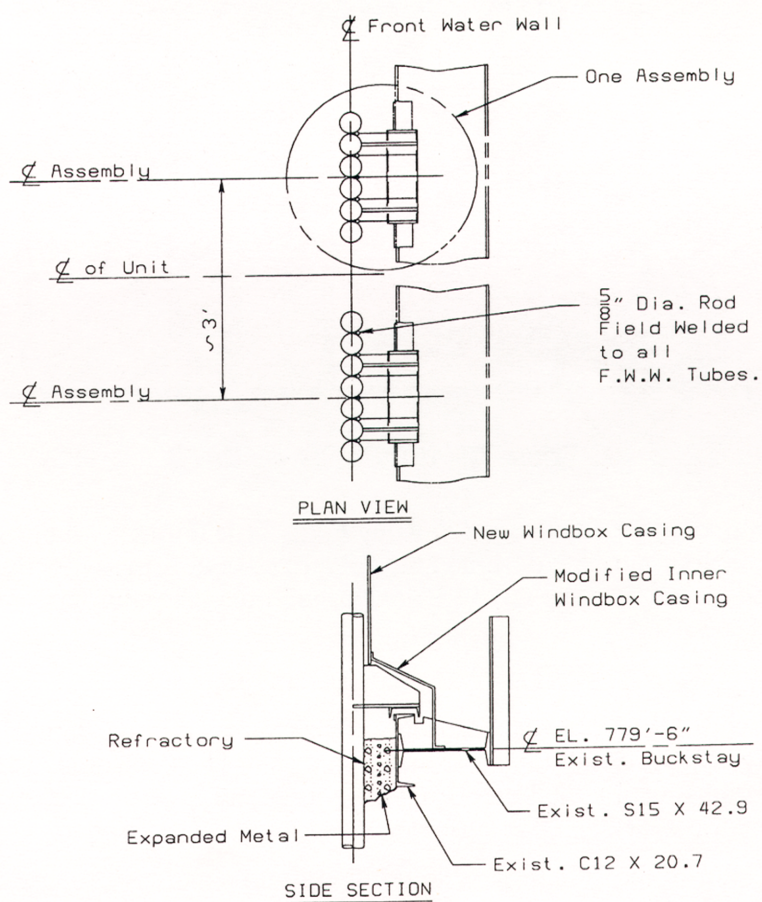

Figure 11 Front Waterwall Tube Restraining System Developed for AEP Conesville Unit 3

Conesville Unit 3 Summary of Results

Coal Firing

	Pre-Retrofit Baseline	Post-Retrofit Optimization	
Test Number	2 - 100	16	15
Date	7/2/93	10/19/94	10/14/94
Load, % MCR	110	110	101
Gross Generation, MWe	175	174	165
Superheat Outlet Temperature, ˚F	1013	1005	1001
Reheater Outlet Temperature, ˚F	1009	1004	1003
Excess Air, %	23	21	21
NO_x at Stack by CEMS, lb/106 Btu	1.10	0.53	0.48
CO at Economizer Outlet, PPM	-	<50	<50
Flyash LOI, %	4.1	9.7	9.8

Gas Firing

	Pre-Retrofit Baseline	Post-Retrofit Optimization	
Test Number	-	2	5
Date	-	3/15/95	3/16/95
Load, % MCR	-	108	98
Gross Generation	-	173	160
Superheat Outlet Temperature, ˚F	-	1007	997
Reheater Outlet Temperature, ˚F	-	1003	984
Excess Air, %	-	11	11
NO_x at Stack by CEMS, lb/106 Btu	-	0.38	0.35

Table 2

Post-retrofit testing was conducted in September 1994 for pulverized coal firing. This showed that NO_x was reduced to 0.53 #/MM Btu for the peak firing condition and 0.48 #/MM Btu for the original MCR condition corresponding to 52% and 56% reductions respectively from pre-retrofit levels. CO levels were negligible for both load conditions. Flyash LOI was 9.7% and 9.8% on a weighted average basis for peak and MCR conditions respectively as compared to a baseline LOI of approximately 4.1% for peak load. This information is summarized in Table 2.

Post-retrofit testing conducted in March 1995 for natural gas firing showed NO_x levels of 0.38 and 0.35 lb/10^6 Btu were achievable at peak and MCR conditions, respectively, for operation at 11% excess air. Table 2 summarizes these results. Boiler operation was satisfactory from 175 MWe gross (peak) down to approximately 40 MWe gross, at which point steam temperature became the limiting factor. Reasons for the apparent disparity between actual steam temperatures at reduced loads and predicted temperatures based on a 1992 modeling study are currently being investigated.

Beginning in May of 1995, a joint testing program between AEP, Riley and the Gas Research Institute (GRI) will be conducted to further study the effect on boiler and emissions performance for gas firing, coal firing and co-firing of coal and gas.

SUMMARY

Retrofitting Low NO_x Burners into utility boilers to meet Phase I requirements of the 1990 Clean Air Act Amendments have been ongoing for five years and will continue beyond the year 2000 for Phase II. Though most retrofits have successfully reduced the NO_x emissions, other problems have occurred along the way. However, a concerted effort between DB Riley and AEPSC and other utilities has resolved or minimized some of these problems.

The high unburned carbon issue at Glen Lyn Unit 6 as a result of initially converting to low NO_x has been mitigated by the installation of Riley CCV® burner components. Burner lightoff at Muskingum River Unit 5 was corrected by new replacement ignitors. Potential burner performance issues due to mechanical fitup and alignment problems at Conesville Unit 3 were avoided by designing and installing a new waterwall restraining system. The potential for gas cane tip plugging and subsequent overheating at Conesville 3 was minimized by installing a purge air system that tied into the existing scanner cooling air system.

It is only through dedicated and concerted efforts by the utility and burner manufacturer that problems such as these can be corrected or avoided. This cooperation must continue for the success of future low NO_x retrofit projects.

REFERENCES

1. Hemmings, R., Venta, G., Golden, D., "Impacts of NO_x Reduction Technologies on Carbonaceous Material in Coal Ash". Presented at the DOE Conference on Unburned Carbonaceous Material on Utility Fly Ash, Pittsburgh, Pennsylvania, February 1995.

2. Penterson, C., Vierstra, S., "Alternative Solutions for Reducing NO_x Emissions from Cell Burner Boilers". Presented to EPRI/EPA NO_x Symposium on Stationary Combustion Sources, Kansas City, Missouri, May 1995.