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LOW NO_x COMBUSTION TECHNOLOGIES TO MEET THE 1990 CLEAN AIR ACT AMENDMENTS

by

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Abstract

Emission reductions mandated by the Clean Air Act Amendments of 1990 will require a total combustion system approach to meet the new emission levels and maintain design steam generator performance.

This paper will provide Riley's interpretation of the recently enacted Amendments to the Clean Air Act. It will also describe the combustion technologies that Riley Stoker has to offer for coal, gas, and oil, and examples of some recent experience with each of the technologies being described.

The technology Riley offers for wall-fired coal applications, is our patented Controlled Combustion Venturi (CCV)® *burner. For Turbo boilers Riley offers its Low NO_x Tertiary Staged Venturi (TSV) burner. This burner can be supplied with or without tertiary air ports depending on the level of NO_x reduction required and the existing burner spacing. The technology that Riley would offer for gas or oil wall fired applications is the Swirl Tertiary Separation (STS)*® *burner used in conjunction with overfire air and flue gas recirculation.*

Introduction - "The Clean Air Act Amendments of 1990"

Environmental concern over power plant stack emissions has grown steadily over the past decade. In spite of this concern, the 1980's saw little change in U.S. NO_x regulations. However, in 1990, Congress enacted over 700 pages of detailed new Amendments to the Clean Air Act, which were signed into law by the President on November 15, 1990. These Amendments will establish a comprehensive framework to curb acid rain, urban smog, air toxics and ozone depleting chemicals by the turn of the century.

EPA will have to meet many deadlines and produce hundreds of new regulations throughout the next several years. There are two Titles within the Act that will influence the industrial and utility boiler retrofit market; Title I - "Provisions for Attainment and Maintenance of National Ambient Air Quality Standards" and Title IV - "Acid Deposition Control".

The purpose of Title IV is to reduce the effects of acid deposition through reductions of both sulfur dioxide (SO_2) and nitrogen oxides(NO_x) emissions. This program will be achieved in two phases. The following is a summary of Phase I & II as it affects NO_x emission limitations, deadlines and specific utilities.

Acid Deposition Control - Phase I

Affected Utilities	Those listed in Table 1. They are essentially units > 100 MW_e & SO_2 emissions > 2.5 $lbs/10^6$ Btu.
Emission Limits	NO_x reduction = Low NO_x burners Tangential fired boilers = 0.45 $lbs/10^6$ Btu. Dry bottom wall fired boilers (DBWF) = 0.50 $lbs/10^6$ Btu. Other types of utility boilers - Emission limits shall be determined by 1/1/97.
Deadlines	May 15, 1992; EPA to finalize regulations for: - NO_x emission limits for tangential & DBWF - Federal Permit Program - Continuous Emission Monitoring (CEM) & reporting requirements September 15, 1993; Utilities must submit their plans for NO_x compliance. November 15, 1993; Utilities must install CEMS. January 1, 1995; Utilities must meet NO_x reduction requirements. January 1, 1997; EPA to establish NO_x emission limits for wet bottom, cyclone & cell burner utility boilers.

Acid Deposition Control - Phase II

Affected Utilities	All Phase I utilities in Table 1. All gas, oil, & coal boilers > 25 MW_e.
Emission Limits	NO_x reduction = Low NO_x burners or equivalent. Actual emission limits to be established by EPA before January 1, 1997.
Deadlines	January 1, 1995; Units must install CEMS. January 1, 1997; EPA to establish NO_x emission limits for all Phase II units. January 1, 1998; Utilities must submit their plans for NO_x compliance. January 1, 2000; Utilities must meet NO_x reduction requirements. Extensions until 12/31/2003 for clean coal technologies.

The NO_x reduction program is not an allowance - based program. Utilities have some flexibility in obtaining the required emission limits through emission averaging. An owner or operator of two or more boilers can comply by averaging the NO_x emissions over all of their affected units. If the NO_x limits for tangential and dry bottom wall fired boilers cannot be achieved using low NO_x burner technology, the EPA may set higher limits. Conversely, if low NO_x burners prove to be more effective, the EPA may lower the limits for NO_x for Phase II affected units.

Provisions for Attainment and Maintenance of Separate National Ambient Air Quality Standards

The purpose of this section is to reduce and maintain national air quality standards (NAAQS) that have been developed for the protection of human health. The most widespread pollution problem is ozone, also called "smog". There are over 100 air regions across the country that are in violation of the NAAQS for ozone (see Figure 1).

Ozone non-attainment areas are classified into one of five categories: Marginal, Moderate, Serious, Severe, and Extreme. These categories are based upon which they exceed the NAAQS, i.e., an area classified as "Severe" has worse air quality than an area classified as "Serious". The Los Angeles area is the only area designated as Extreme. There is a special area classified as the "Northeast Transport Region", which includes all of the New England States, Delaware, Maryland, New Jersey, New York, Pennsylvania, District of Columbia, and northern Virginia.

The Transport Region requirements are between Moderate and Serious. The EPA has established specific deadlines and reduction requirements for each area in order to improve the quality of the air we breathe.

Deadlines to meet ozone NAAQS are as follows:

Marginal - 3 years
Moderate - 6 years
Serious - 9 years
Severe - 15 - 17 years
Extreme - 20 years

It is up to the individual States to provide plans (SIPS) to implement EPA deadlines. If a State fails to meet the requirements on time, EPA will cut Federal highway funding and/or require offset payments.

Both volatile organic compounds (VOC) and NO_x are known to play a major role in the formation of ambient ozone or smog. EPA is to conduct a study on the role of ozone precursors on its formation and control. A draft report should be available by November , 1991.

States with areas classified worse than Marginal will require "reasonably available control technology" or RACT on all existing major sources of VOC and NO_x throughout the entire State. A source is considered major if it emits > 100 tons per year of NO_x in Moderate areas, 50 tons per year in Serious and Transport areas, and 25 tons per year in Severe areas. Therefore, utilities and industrial boilers located in ozone non-attainment areas will most likely be required to reduce NO_x through combustion and post combustion techniques.

The impact of Title I on the marketplace is that a boiler located in a non-attainment area for ozone firing any fuel (fossil, wood, refuse) could potentially be affected. In many instances, **a non-attainment deadline requiring NO_x control will occur prior to Phase II deadlines** for utilities under Acid Deposition Control.

Introduction - Low NO_x Technology Application

Riley Stoker's involvement with developing low NO_x combustion systems has spanned the last 20 years. Work in the early 70's led to the establishment of our understanding of NO_x formation and reduction. Implementation of our first low NO_x system began in the 1970's with the Riley turbo furnace and directional flame burners. The 1980's saw the development of the Controlled Combustion Venturi (CCV) burners for wall fired units. During this time the low NO_x Turbo burner was developed to meet even lower emissions on Turbo furnaces.

From these years of experience Riley has learned that it takes a "total systematic approach" to design low NO_x systems for new units or retrofits to comply with the more stringent requirements of the new Clean Air Act Amendments.

Combustion systems are designed to meet the thermal requirements of the steam generator. As such, they are auxiliary equipment to the final process of producing steam. If the combustion design or burner modifications result in poor boiler performance and operating difficulties, then that particular design is unacceptable.

It will take the knowledge and experience of suppliers that understand fuel processing , burner design, and furnace performance to effectively supply combustion systems that meet the required NO_x and other emission rates while at the same time, maintain or improve overall unit performance.

The balance of this paper will discuss applications for each of the above referenced technologies where Riley has used the "total systematic approach" to successfully reach the emission limits required by the particular customer while still maintaining good overall unit performance.

The first is a Low NO_x burner retrofit project performed at the PSI Energy's Wabash Unit #5, a wall fired unit rated at 125 MW_e. The second is a 400,000 lb/hr industrial unit originally designed in 1982 to meet a NO_x value of .45 lb/10^6 Btu and recently tested to demonstrate further NO_x reduction capabilities. The last example is of two low NO_x gas/oil burner retrofit projects that Deutsche Babcock, the new parent of Riley Stoker, completed in Europe on the Arzberg and Vartan Power Stations.

PSI ENERGY - WABASH #5 LOW NO_x BURNER CONVERSION

PSI Energy's Wabash #5 is a Riley Stoker pulverized coal fired steam generator with a rated capacity of 805,000 pounds of steam per hour, at a design pressure of 2075 psig and a final steam temperature of 1000°F superheat and 1000°F reheat with an operating throttle pressure of 1850 psig. Pulverized coal is supplied by three single ended ball tube mills feeding 12 burners. At this steam flow rate, the unit produces 125 megawatts of electrical power. (Ref. Figure 2.) The unit was commissioned in 1955 and has been successfully operated over the last 35 years.

During meetings with PSI, a mutually agreed upon set of goals was established to address not only their interest in reducing NO_x on this Unit, but also address a lingering problem they have had over the years of handling wet coal conditions in the milling system. The goals for the retrofit project were as follows:

- Improve wet coal grinding capacity thus increasing boiler load handling capability
- Increase classifier exit temperature
- Improve burner mechanical reliability

- Reduce NO_x emissions
- Reduce unburned carbon

The consensus between PSI and Riley was that an engineered system approach was required to solving the existing problems on Unit #5. With poor fineness and low pulverized coal/primary air temperature it was clear that combustion and emission problems could not be resolved by burner replacement only. It was necessary for the entire pulverizer system to be upgraded.

To address PSI's environmental concerns, Riley Engineering was convinced that combustion and emission problems could be solved by installing Riley Controlled Combustion (CCV^{TM}) Low NO_x coal burners with Model 90 registers. The new burners would address issues of mechanical reliability with the register, and lowering NO_x emissions with Riley's patented CCV^{TM} coal nozzles.

During the initial review meeting it was quite evident a major factor in limiting reliability and capacity was wet coal. Focusing on wet coal, Riley's Engineering evaluation team looked at several alternatives and determined that increasing the wet coal handling capacity of the ball tube mill system would involve the following component changes or modifications. (Ref. Figures 3 & 4)

- Replace the original 503 duplex feeder/crushers with Riley 504 Model 80 shrouded crusher/dryers. The Model 80 is specifically designed to handle high moisture coals.
- Replace the original bar type classifier and reinjection system with a Riley Model 80 centrifugal classifier and gravity return system.
- Replace the existing two way riffle distributors with new riffles. The new riffles offer a uniform pulverized coal flow split from the exhauster discharge to each burner.
- Install a primary air bypass system between the mill inlet and the classifier. Adding the bypass increases the drying capacity of the system.

Prior to the conversion, the burner operation at PSI Wabash #5 was less than optimal, and the problems in the coal milling system further aggravated the situation.

The status of the burner system was that pulverized coal/primary air mixture temperature was seldom above 110°F; flyash carbon loss ranged from 5-20% with a norm of 10-12%; NO_x emissions were not a current problem, but a future concern. Mechanically, the burner registers were difficult to operate, and flame appearance was poor.
Windbox pressure was low ($\leq 1.0"$ H_2O) which lead to poor secondary air distribution and inefficient combustion.

Riley proposed a size 4A CCV^{TM} Burner with Model 90 register (Ref. Figure 5). The Model 90 register features separate swirl and air flow control. Burner swirl is controlled by an externally mounted register drive assembly. A moveable air shroud over the register blades controls the burner air flow, and each burner has Pitot tubes for measuring air flow. The register and secondary air barrel are connected by an expansion joint to allow for relative movement caused by varying boiler and windbox expansion rates. Control of secondary air flow to each burner is accomplished by moving the shroud. Air flow measurement to each burner is read by a Pitot and transducer that feeds the air flow signal back to the control system. By moving the shroud, air flow is balanced to each burner to match the coal flow from the mills. The shrouds are also used to maintain windbox pressure (set point 3") to assure efficient combustion throughout the load range by promoting good secondary air distribution.

The unique shroud design gives the capability of measuring the airflow to each burner in a common windbox thus assuring excellent secondary air distribution. Secondary air distribution is achieved throughout the load range by maintaining windbox to furnace pressure differential, and biasing individual burner shroud positions for burner Pitot readings and mill load.

Field Results:

Results of PSI Wabash Unit #5 Firing System Upgrade

	Before	After	Comments
Load	65 to 105 MW_e	95 MW_e	Exhauster limited, 105 MW_e was limit on dry coal
Flyash Carbon Loss	5 to 20%	3%	Reduced carbon loss by 300% (avg)
Mill Discharge Temp (Avg)	107°F	137°F	Reduced coal line surging & sticking w/18% moisture coal
NO_x	.8 to .9 lbs/10^6 Btu	.4 to .5 lbs/10^6 Btu	Represents a 50% reduction in NO_x w/ burners only
Coal Fineness	<98% thru 50 mesh <70% thru 200 mesh	99.8% thru 50 mesh 84% thru 200 mesh	Classifiers are in the wide open position. (Fineness has not been optimized.)
Windbox Pressure	≤1"H_2O	Controlled 3" H_2O	Stabilized Unit operation
Unit Operability	Poor	Good	Unit maintains load during wet coal conditions

Update:

As a follow-up to Riley's successful project completion on Wabash Unit #5, We have been awarded a second contract for a low NO_x conversion on Unit #2, after competitively bidding this work against other burner suppliers and boiler OEM's.

The boiler is a Foster Wheeler unit rated at 700,000 lbs/hr steam flow at 1005°F and 1500 psig. The project will include the replacement of twelve Foster Wheeler Intervane pulverized coal burners with Riley's low NO_x CCV burner with Model 90 registers. The scope of work also includes a new windbox, burner throat modifications, OFA system, new coal heads, coal plug valves, new three way coal riffle distributors, and miscellaneous dampers and expansion joints.

LOW NO_x BURNERS FOR A 400,000 LB/HR INDUSTRIAL BOILER

An advanced low NO_x combustion system was integrated into the original design of a 400,000 pounds steam per hour industrial boiler which used Riley's Turbo^R furnace design. This boiler was originally put into service in 1982. Figure 6 shows a front and side elevation view of the subject boiler. Six (6) TSV burners rated at 85 X 10^6 Btu/hr are mounted on the furnace sidewalls with overfire air (OFA) above and underfire air (UFA) below each burner. Three (3) Riley Atrita pulverizers are used to process and convey pulverized coal to the burners. The unit produces superheated steam at 750°F and 630 psig operating pressure.

The advanced combustion system, developed ny Riley Stoker in the early 1980's focused not only on the low NO_x TSV burner design but integrating this burner with a unique furnace design that incorporates advanced air staging. The Riley Turbo Furnace has been used for many years as an efficient way of burning a wide variety of coals and other fossil fuels because of its inherently longer retention time than more conventional wall-fired installations.

The advanced air staging system, integrated with the low NO_x TSV burner, is shown in Figure 7. The TSV burner shown in the right of the figure is a circular shaped swirl-stabilized burner. Pulverized coal is introduced into the furnace through a centrally located venturi shaped coal nozzle (Patent Numbers 4,479,442 and 4,517,904). The purpose of the venturi is to concentrate the coal air mixture and form a fuel rich combustion zone discharging from the center of the coal nozzle.

As the rich mixture passes over the coal spreader, the blades divide the coal stream into four (4) distinct streams which enter the furnace in a gradual helical pattern. The intent is to produce more distributed, controlled and gradual mixing of the coal and air for reduced NO_x emissions.

Surrounding the primary air and coal mixture is swirling secondary air imparted by an air register for flame stability and combustion control. Tertiary air is introduced through outboard tertiary air ports surrounding the burner proper. Directional vanes within these ports can be used to direct the tertiary air into or away from the primary combustion zone as desired. The burner zone is designed to operate with only 60-75% of the total combustion air.

The remainder of the air required to complete the combustion process and to provide additional staging for NO_x control is added through furnace staging ports located above and below the burners. Staged combustion, combined with low NO_x burners, has been proven to be a very effective technology for controlling NO_x emissions.

Results of TSV Burner Testing:

Testing began by measuring the same NO_x emission level that the unit was operating at six years ago following boiler start-up (0.45 lbs/10^6 Btu). Numerous tests were subsequently conducted to quantify emissions and carbon burnout efficiencies for various operating conditions and for two different coals. Following is the fuel analysis of the Oklahoma and Wyoming bituminous coals tested.

Fuel Analysis Comparison:

Proximate(as rec'd)	Oklahoma	Wyoming
Moisture, %	15.2	12.3
Volatile Matter, %	36.6	35.6
Fixed Carbon, %	43.3	38.7
Ash,%	4.9	13.4

Ultimate (dry)	Oklahoma	Wyoming
Carbon, %	73.5	66.0
Hydrogen, %	5.3	4.9
Nitrogen, %	1.68	1.47
Oxygen, %	13.14	11.69
Sulfur, %	0.60	0.61
Ash, %	5.8	15.3

HHV, Btu/lb (dry)	12,965	11,555
Ash Fusion Temp.(H=½W)	2,250	2,220

Figure 8 shows the effect of air staging on NO_x emissions at full load. Both the UFA and OFA ports were open with more staging air being introduced through the upper OFA ports. The NO_x emissions decreased from a high of 0.50 lbs/10^6 Btu to a low of 0.30 lbs/10^6 Btu for both coals. The NO_x emissions were higher for the Oklahoma coal as compared to the Wyoming coal at similar burner zone stoichiometries. This was due to the higher fuel nitrogen content for the Oklahoma coal. Lowest burner zone stoichiometries corresponding to the lowest NO_x emissions recorded were 0.86 and 0.93 for the Oklahoma and Wyoming coals respectively. The level of air staging is still considered to be "conventional" as compared to "advanced" when stoichiometries approach 0.70.

CO emissions and carbon burnout were excellent throughout the range of burner stoichiometries tested. Figure 9 shows the effect of air staging on carbon burnout and CO emissions. Flyash % LOI results averaged < 4% while CO emissions remained < 15 ppm for both coals. Coal fineness produced by the three (3) Atrita pulverizers was a standard grind of 98% passing 50 mesh and 85% passing 200 mesh. Since the CO and LOI curves tend to increase slightly with decreasing NO_x emissions or burner zone stoichiometry, it would appear that in order to achieve the same degree of excellent carbon burnout during extremely low NO_x operation (<0.3 lbs/10^6 Btu) on Eastern bituminous coals with relatively high % fixed carbon/ % volatile matter ratios, finer coal grind will most likely be required. A product fineness of > 99% passing 50 mesh and > 85% passing 200 mesh would be recommended.

As anticipated, rotating the directional air vanes in the tertiary air ports so that the tertiary air was directed into the primary combustion zone increased NO_x emissions by approximately 60 ppm from the levels produced with the directional vanes pointed away. Decreasing Unit load from 100% to 75% MCR reduced NO_x emissions by approximately 25-50 ppm.

Overall boiler performance in regard to steam temperature, boiler efficiency, Unit controllability, and reliability were not adversely affected during the low NO_x operation.

An Advanced Low NO_x Combustion System For Oil & Gas

Introduction:

Deutsche Babcock, The parent company of Riley Stoker Corporation, has had considerable experience in supplying combustion systems to meet the demands of the German and European regulations. Low NO_x combustion systems have been implemented by Deutsche Babcock on a wide variety of industrial and utility boilers. Since 1984, Deutsche Babcock has supplied low NO_x systems to over 110 liquid and gas fired boilers. More than 520 low NO_x burners have been retrofitted to a variety of boiler configurations.

In order to meet stringent emission limits many of these retrofit applications incorporate combustion modification techniques, such as flue gas recirculation and overfire air, in combination with new low NO_x burners (4). NO_x reductions of over 80% have been demonstrated with these new systems. New fuel injectors have also been developed in response to the changing quality of heavy fuel oils. This technology and experience is now available to the U.S. power industry through Riley Stoker.

One new burner system - the Swirl Tertiary Separation (STS) burner - is particularly well suited to U.S. wall fired boiler retrofit applications.

Description of STS Burner System:

New STS burner systems have been recently retrofitted on gas and oil wall fired boilers in both Germany and Sweden. In addition to reducing NO_x the burners were designed to both minimize boiler pressure part changes and maintain acceptable combustion conditions.

Figure 10 is an illustration of the STS burner equipped with swirl control. As typical in many European boiler designs, combustion air is controlled individually to each burner. A spiral box, or scroll (shown in Figure 10) is used to supply the combustion air to the burner. The scroll is divided between primary air and secondary air passages with control dampers and flow metering installed immediately upstream. Total air flow to the burner is divided between the primary and secondary air passages. The exact distribution of primary and secondary air can be adjusted depending on the level of internal burner staging required for NO_x control and overall combustion performance.

Adjustable air vanes within the scroll are used to control the degree of swirl and subsequent fuel air mixing. Between these two swirling air streams, a separate recirculated flue gas stream can be introduced forming a distinct separation layer between the primary and secondary air.

The introduction of this separating layer of inert flue gas acts to delay the combustion process and reduces NO_x in the following manner:

- Peak flame temperatures, particularly on the surface of the primary combustion zone, are reduced by a surrounding blanket of inert flue gas.

- The rapid mixing of secondary air is prevented; thereby reducing the oxygen concentration in the primary combustion zone.

Unlike flue gas mixed with the primary or secondary air streams, the flue gas separation stream is unswirled and concentrated. This serves to delay secondary air mixing until after first stage oxygen has been consumed and the flame has cooled. The intent of the separation layer, therefore is to control both thermal NO_x formation and NO_x produced from nitrogen contained in the fuel.

Additional NO_x reduction is achieved through staged combustion. A portion of the total combustion air can be introduced through overfire air ports above the burners to provide external air staging. This overfire air is controlled and metered independently of the combustion air to the burners. Low NO_x burners combined with flue gas recirculation and OFA offer an integrated approach for maximizing the reduction of NO_x emissions on gas as well as oil firing.

As shown in Figure 10, oil is burned using a centrally located steam or mechanically atomized oil gun. Natural gas is burned using spuds or canes located within the primary core of the burner.

Field Results:

<u>Arzberg Power Station</u>

Low NO_x STS burners have been installed at Arzberg Power Station unit #6 in Arzberg, Germany. The boiler shown in Figure 11 is a once-through Benson boiler rated at 1.58 million lbs of steam per hour and generates 220 MW_e. The unit is currently equipped to fire natural gas or light #2 oil. In 1988, the boiler was retrofitted with sixteen low NO_x burners, each rated at 153 million Btu/hr heat input.

Nox emission limits for this project were 50 ppm for natural gas firing and 75 ppm for light oil. The retrofit combustion system was designed with the flexibility of introducing recirculated flue gas through either the burner zone separation annulus or having it mixed directly with the combustion air to the burners. As shown in Figure 12, all flows, including primary, secondary, tertiary and recirculated flue gas were independently controlled and metered.

Prior to retrofit, NO_x emissions from natural gas firing averaged 300 ppm. Testing was conducted following the retrofit to optimize the operation and to commission the boiler. Figure 13 illustrates the effect of mixing flue gas recirculation into the combustion air on NO_x emissions for natural gas firing. At 20% FGR and 10% OFA flow, NO_x emissions were reduced to 75 ppm. By increasing the amount of recirculated flue gas to 30%, NO_x decreased to 50 ppm. Additional testing was then performed to evaluate the effect of introducing FGR flow through the burner annulus for NO_x control. The total amount of FGR flow remained at 30% with 10% OFA. Figure 14 illustrates the effect of introducing increasing percentages of FGR flow through the burner annulus or separation layer. When more than 50% of the total FGR flow was introduced through the separation layer (the remaining amount being mixed in with the combustion air) NO_x decreased significantly. The lowest measured NO_x emission approached 25 ppm when nearly all of the FGR flow was passing through the burner annulus. CO emissions remained less than 15 ppm throughout this testing and flame stability and scanability was not a problem.

A limited amount of testing was performed on #2 fuel oil. Data were collected while operating at 15% FGR and 15% OFA flow rates. NO_x emissions of 75 ppm were achieved at full load and decreased to approximately 60 ppm at 50% boiler load. CO emissions remained below 25 ppm for all test conditions.

Vartan Power Station

An advanced STS burner system has also been retrofitted at the Vartan Power Station in Stockholm, Sweden. The Vartan unit, commissioned in 1976, is rated at 250 MW_e. It is a once-through Benson style boiler designed for heavy oil firing. As shown in Figure 15, the burners are mounted on a single wall in a 4 X 4 array. Each burner is supplied individually with air and is equipped with a Deutsche Babcock oil pressure /steam pressure atomizer. In addition to STS burners, the retrofit combustion system includes both OFA and FGR. The existing FGR system was modified to supply flue gas to each burner as well as the lower furnace.

The post-retrofit NO_x guarantee limit for the Vartan unit is 0.27 lbs/10^6 Btu or approximately 210 ppm. NO_x emissions measured during recent commissioning tests are shown in Figure 16. Emission levels (at high load) for the new system are 30 to 40% lower than the guarantee value. The data spread is due to differences in operating conditions and varying fuel oil nitrogen content. Average fuel oil nitrogen content is 0.3%. During the recent tests, high load excess oxygen measured 1.3-1.4% upstream of the air heater corresponding to an excess air level of less than 7%. CO emissions were less than 40 ppm. These results were achieved with 10-11% OFA and 15% FGR. Approximately one third of the flue gas was introduced to the lower furnace for steam temperature control.

Application to U.S. Boilers

The STS burner design has been adapted by Riley Stoker to U.S. wall fired boiler firing systems. Contrary to the European practice of individual burner air supplies, U.S. wall-fired boilers are equipped with common windbox/multiple burner arrangements. Because of this, the burner inlet scroll, described in Figure 10, has been replaced by primary and secondary air swirl vane registers surrounded by flow control shrouds. All other burner components remain the same. As shown in Figure 17, the movable shrouds are operated by single actuators and can be automated with boiler load. The shrouds control the primary/secondary air flow split independently of swirl vane position. Flow measurement devices are positioned between the burner barrels to provide a relative flow indication between the burners.

A prototype 85 million Btu/hr STS burner designed for windbox applications (Figure 17) is currently being tested in Riley Stoker's large pilot combustion test facility located at the Riley Research Center in Worcester, Massachusetts. This facility is designed to simulate field combustion conditions of full scale furnaces (5). Test variables include firing rate, flow biasing ratios, the amount of flue gas recirculation and injection method, level of burner staging, swirl settings, excess air and oil gun positions. The test program has several objectives:

- To fully characterize the burner's low NO_x capability under U.S. boiler operating conditions.
- To evaluate the sensitivity and tradeoff of various burner adjustments on NO_x control and other combustion operating parameters such as flame shape and particulate emissions.

The prototype is being tested on natural gas and #6 fuel oil. The fuel oil selected is a 2% sulfur oil with an asphaltene content of approximately 10%. Test results indicate that Riley Stoker has been successful in duplicating the achieved results of the STS burner on European installations while having adopted the register and shroud arrangement necessary for application on U.S. boilers with common windbox arrangements. Details of these results will be the subject of a future paper to be presented at a NO_x conference in the U.S.

Summary

Riley Stoker has demonstrated several successful NO_x control technologies for the U.S. boiler industry on both wall-fired and turbo boiler configurations for coal firing. Riley further believes it has a "state-of-the-art" low NO_x gas and oil burner that is now ready for commercial application in the U.S. With the addition of the STS burner to the full line of Low No_x burners that Riley already offers, we are now able to address the needs of our customers for any of the above listed fuel applications.

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TABLE 1

PHASE I - TARGETED UTILITIES

Alabama
- Colbert - 1
- Colbert - 2
- Colbert - 3
- Colbert - 4
- Colbert - 5
- E.C. Gaston - 1
- E.C. Gaston - 2
- E.C. Gaston - 3
- E.C. Gaston - 4
- E.C. Gaston - 5

Florida
- Big Bend - 1
- Big Bend - 2
- Big Bend - 3
- Crist - 6
- Crist - 7

Georgia
- Bowen - 1
- Bowen - 2
- Bowen - 3
- Bowen - 4
- Hammond - 1
- Hammond - 2
- Hammond - 3
- Hammond - 4
- J. McDonough - 1
- J. McDonough - 2
- Wansley - 1
- Wansley - 2
- Yates - 1
- Yates - 2
- Yates - 3
- Yates - 4
- Yates - 5
- Yates - 6
- Yates - 7

Illinois
- Baldwin - 1
- Baldwin - 2
- Baldwin - 3
- Coffeen - 1
- Coffeen - 2
- Grand Tower - 1
- Hennepin - 2
- Joppa Steam - 1
- Joppa Steam - 2
- Joppa Steam - 3
- Joppa Steam - 4
- Joppa Steam - 5
- Kincaid - 1
- Kincaid - 2
- Meredosia - 3
- Vermilion - 2

Indiana
- Bailly - 7
- Bailly - 8

Indiana
- Breed - 1
- Cayuga - 1
- Cayuga - 2
- Clifty Creek - 1
- Clifty Creek - 2
- Clifty Creek - 3
- Clifty Creek - 4
- Clifty Creek - 5
- Clifty Creek - 6
- E.W. Stout - 5
- E.W. Stout - 6
- E.W. Stout - 7
- F.B. Culley - 2
- F.B. Culley - 3
- F.E. Ratts - 1
- F.E. Ratts - 2
- Gibson - 1
- Gibson - 2
- Gibson - 3
- Gibson - 4
- M.T. Pritchard - 6
- Michigan City - 12
- Petersburg - 1
- Petersburg - 2
- R. Gallagher - 1
- R. Gallagher - 2
- R. Gallagher - 3
- R. Gallagher - 4
- Tanners Creek - 4
- Wabash River - 1
- Wabash River - 2
- Wabash River - 3
- Wabash River - 4
- Wabash River - 5
- Wabash River - 6
- Warrick - 1

Iowa
- Burlington - 1
- Des Moines - 7
- George Neal - 1
- M.L. Kapp - 2
- Prairie Creek - 4
- Riverside - 5

Kansas
- Quindaro - 2

Kentucky
- Coleman - 1
- Coleman - 2
- Coleman - 3
- Cooper - 1
- Cooper - 2
- E.W. Brown - 1
- E.W. Brown - 2
- E.W. Brown - 3
- Elmer Smith - 1
- Elmer Smith - 2

Kentucky
- Ghent - 1
- Green River - 4
- H.L. Spurlock - 1
- Henderson #1
- Henderson #2
- Paradise - 3
- Shawnee - 10

Maryland
- Chalk Point - 1
- Chalk Point - 2
- C.P. Crane - 1
- C.P. Crane - 2
- Morgantown - 1
- Morgantown - 2

Michigan
- J.H. Campbell - 1
- J.H. Campbell - 2

Minnesota
- High Bridge - 6

Mississippi
- Jack Watson - 4
- Jack Watson - 5

Misouri
- Asbury - 1
- James River - 55
- Labadie - 1
- Labadie - 2
- Labadie - 3
- Labadie - 4
- Montrose - 1
- Montrose - 2
- Montrose - 3
- New Madrid - 1
- New Madrid - 2
- Sibley - 3
- Sioux - 1
- Sioux - 2
- Thomas Hill - 11
- Thomas Hill - 2

New Hampshire
- Merrimack - 1
- Merrimack - 2

New Jersey
- B.L. England - 1
- B.L. England - 2

New York
- Dunkirk - 3
- Dunkirk - 4
- Greenridge - 4
- Milliken - 1
- Milliken - 2
- Northport - 1
- Northport - 2
- Northport - 3
- Port Jefferson - 3
- Port Jefferson - 4

Ohio
- Ashtabula - 5
- Avon Lake - 8
- Avon Lake - 9
- Cardinal - 1
- Cardinal - 2
- Conesville - 1
- Conesville - 2
- Conesville - 3
- Conesville - 4
- Eastlake - 1
- Eastlake - 2
- Eastlake - 3
- Eastlake - 4
- Eastlake - 5
- Edgewater - 4
- Gen. J.M. Gavin - 1
- Gen. J.M. Gavin - 2
- Kyger Creek - 1
- Kyger Creek - 2
- Kyger Creek - 3
- Kyger Creek - 4
- Kyger Creek - 5
- Miami Fort - 5
- Miami Fort - 6
- Miami Fort - 7
- Muskingum River - 1
- Muskingum River - 2
- Muskingum River - 3
- Muskingum River - 4
- Muskingum River - 5
- Niles - 1
- Niles - 2
- Picway - 5
- R.E. Burger - 3
- R.E. Burger - 4
- R.E. Burger - 5
- W.H. Sammis - 5
- W.H. Sammis - 6
- W.H. Sammis - 7
- W.C. Beckjord - 5
- W.C. Beckjord - 6

Pennsylvania
- Armstrong - 1
- Armstrong - 2
- Brunner Island - 1
- Brunner Island - 2
- Brunner Island - 3
- Cheswick - 1
- Conemaugh - 1
- Conemaugh - 2
- Hatfield's Ferry - 1
- Hatfield's Ferry - 2
- Hatfield's Ferry - 3
- Martin's Creek - 1
- Martin's Creek - 2
- Portland - 1

Pennsylvania
- Portland - 2
- Shawville - 1
- Shawville - 2
- Shawville - 3
- Shawville - 4
- Sunbury - 3
- Sunbury - 4

Tennessee
- Allen - 1
- Allen - 2
- Allen - 3
- Cumberland - 1
- Cumberland - 2
- Gallatin - 1
- Gallatin - 2
- Gallatin - 3
- Gallatin - 4
- Johnsonville - 1
- Johnsonville - 2
- Johnsonville - 3
- Johnsonville - 4
- Johnsonville - 5
- Johnsonville - 6
- Johnsonville - 7
- Johnsonville - 8
- Johnsonville - 9
- Johnsonville - 10

West Virginia
- Albright - 3
- Fort Martin - 1
- Fort Martin - 2
- Harrison - 1
- Harrison - 2
- Harrison - 3
- Kammer - 1
- Kammer - 2
- Kammer - 3
- Mitchell - 1
- Mitchell - 2
- Mount Storm - 1
- Mount Storm - 2
- Mount Storm - 3

Wisconsin
- Edgewater - 4
- La Crosse Genoa - 3
- Nelson Dewey - 1
- Nelson Dewey - 2
- N. Oak Creek - 1
- N. Oak Creek - 2
- N. Oak Creek - 3
- N. Oak Creek - 4
- Pulham - 8
- S. Oak Creek - 5
- S. Oak Creek - 6
- S. Oak Creek - 7
- S. Oak Creek - 8

Ozone Areas Violating Standards During 1987-1989

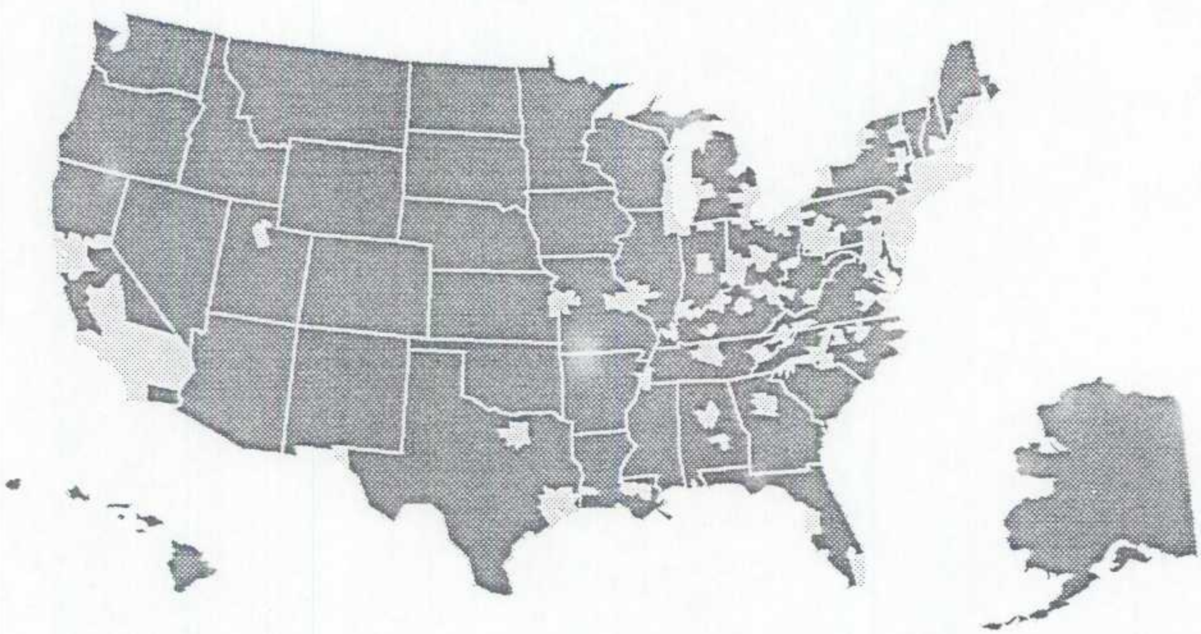


Figure 1

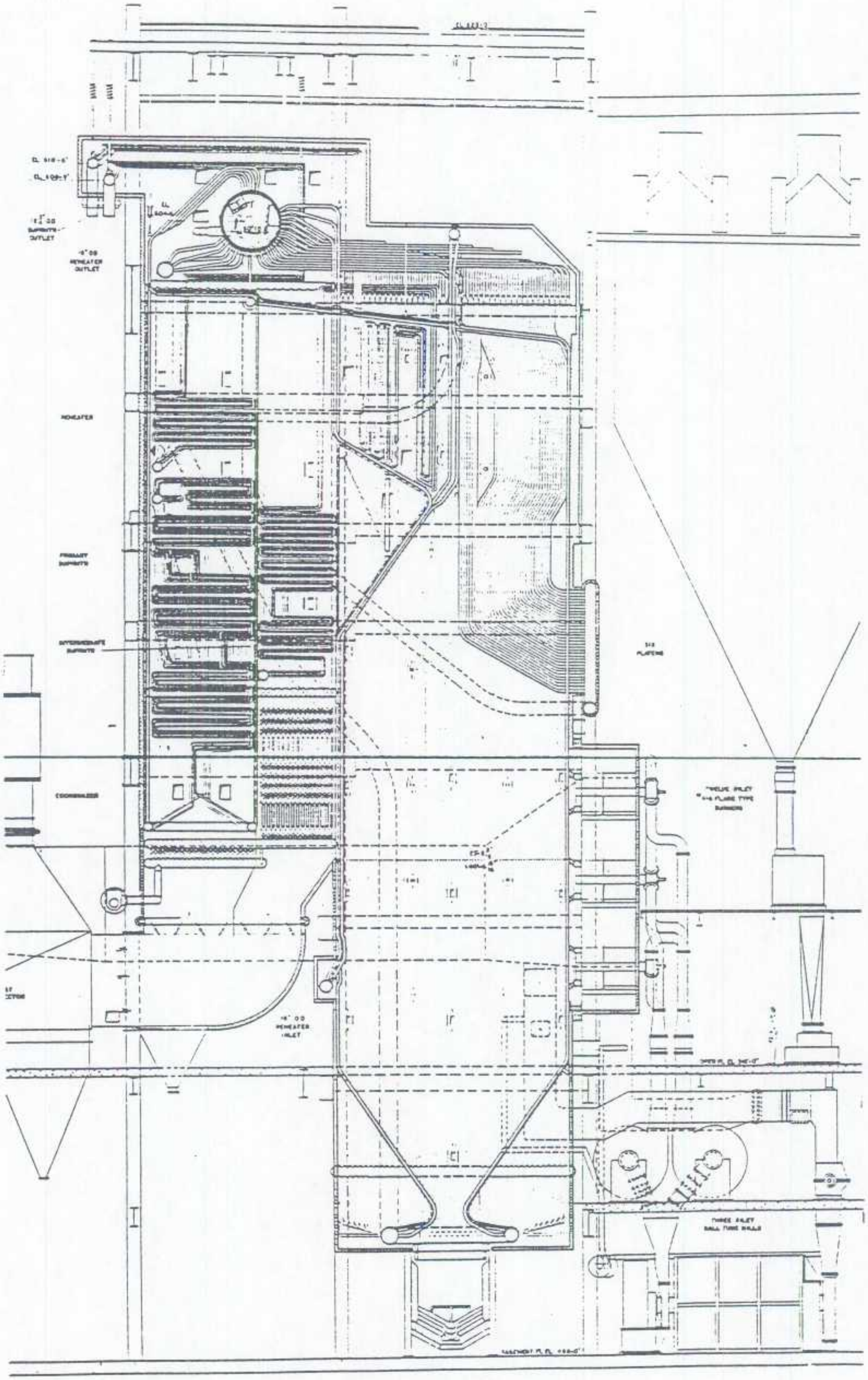


Figure 2 Wabash River Station

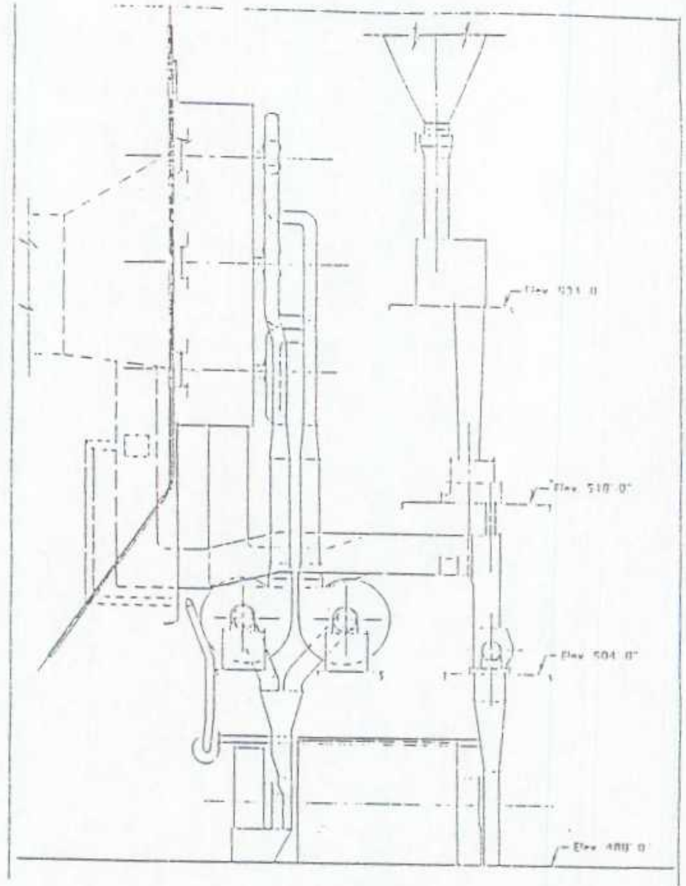


Figure 3 Original Fuel Burning System

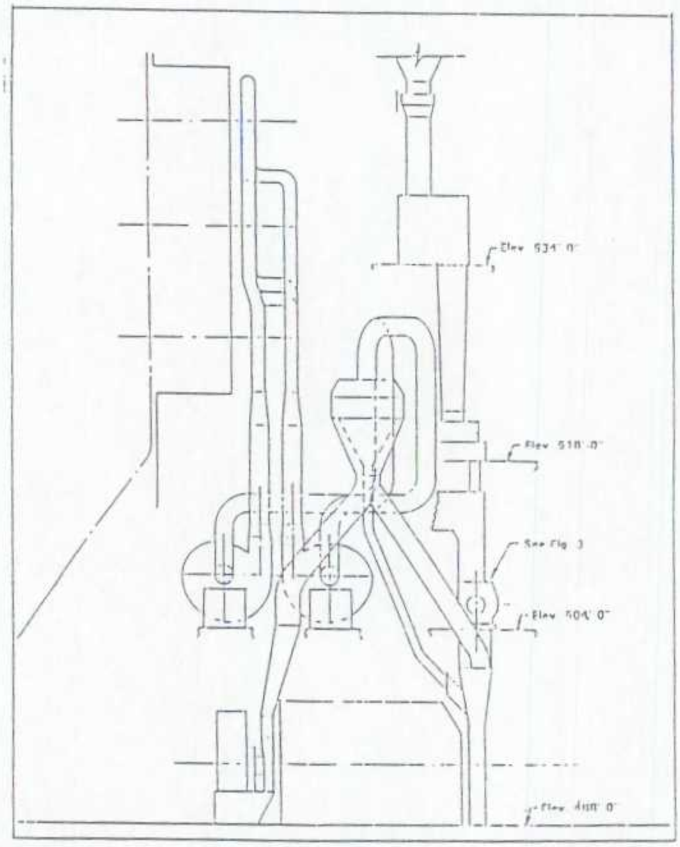


Figure 4 Up-Graded Fuel Burning System

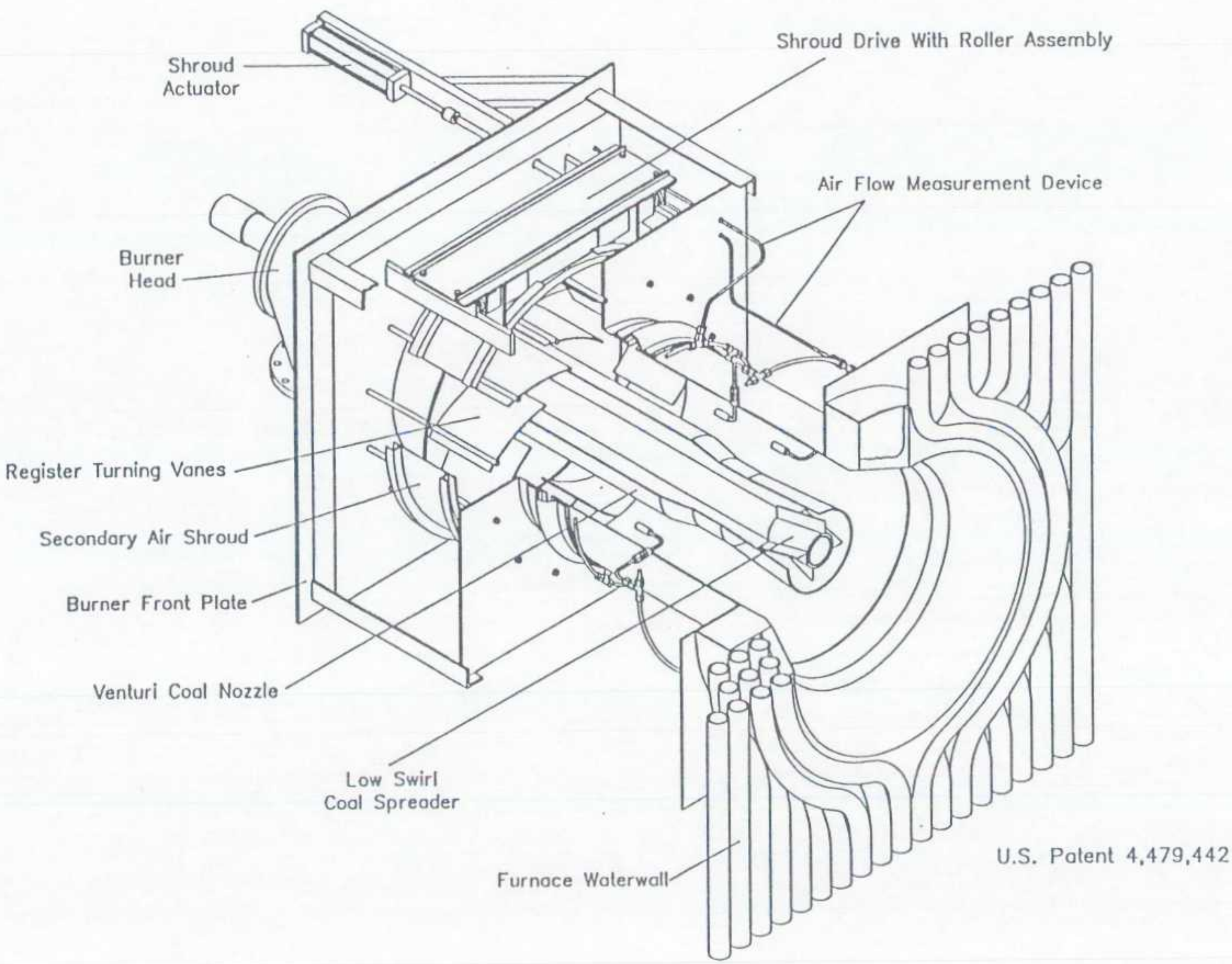


Figure 5 Riley Controlled Combustion Venturi (CCV) Burner for Wall-Fired Boilers

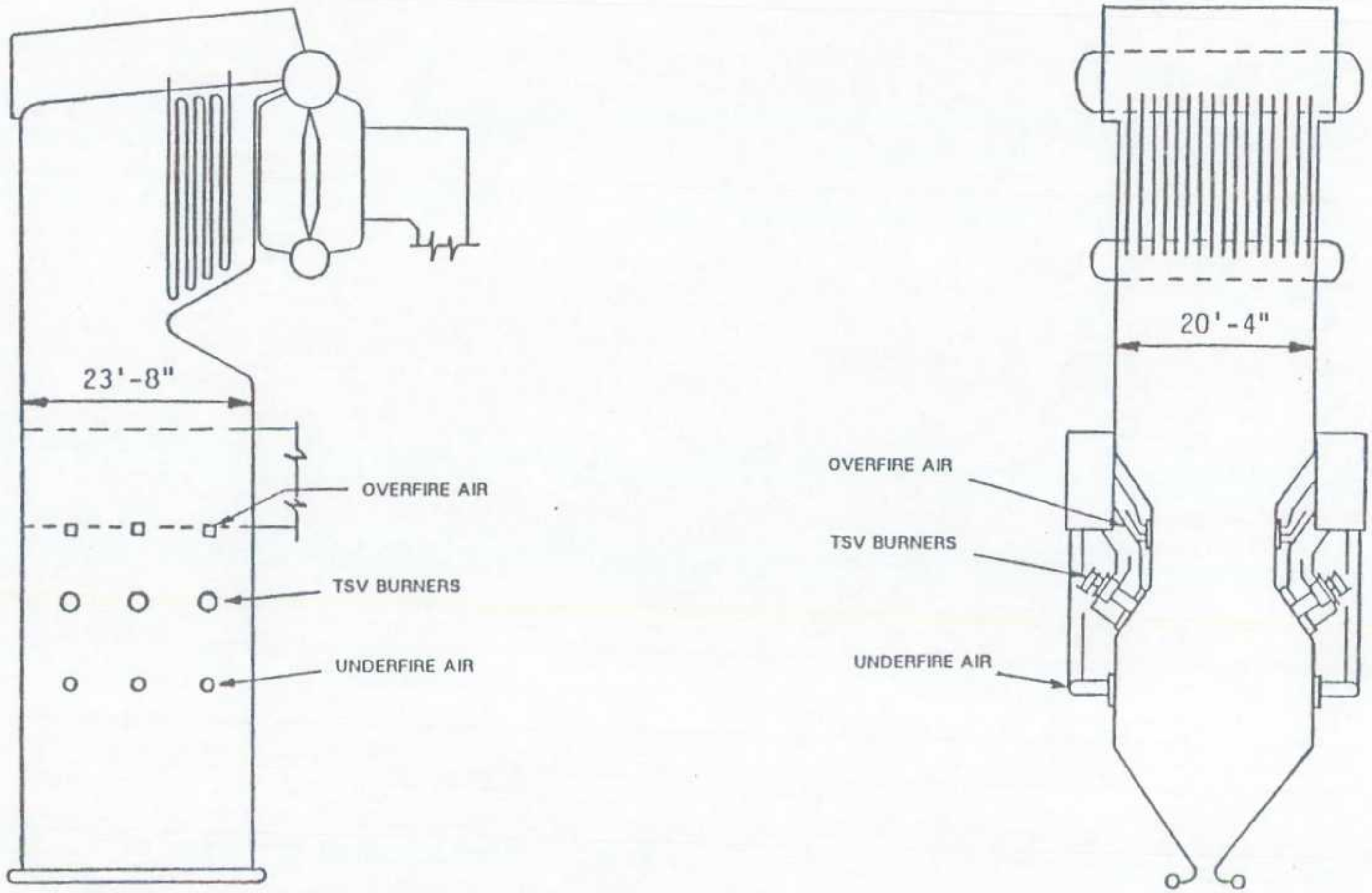
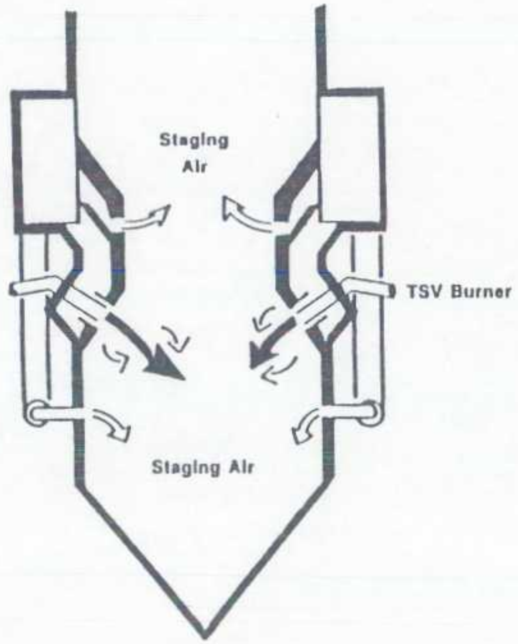
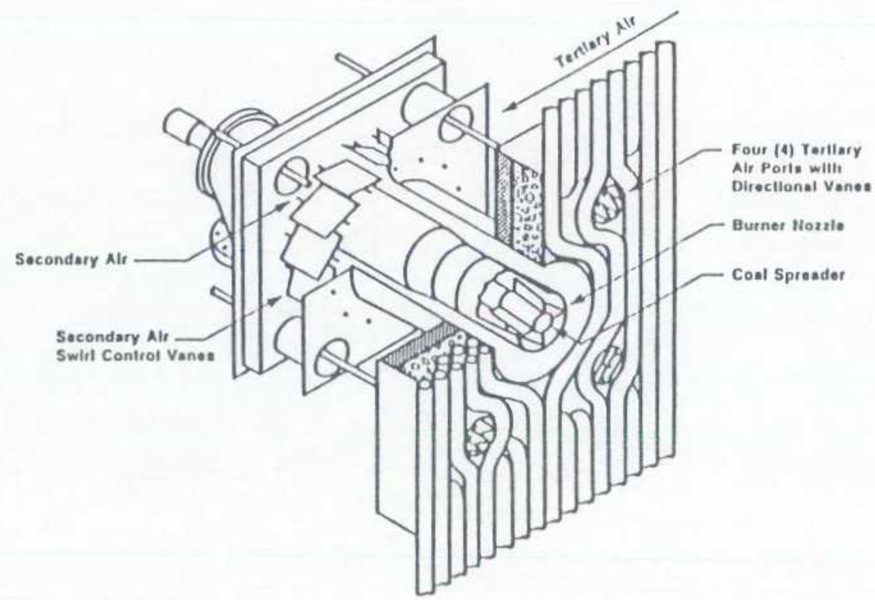


Figure 6 400,000 lb/hr Unit



Advanced TURBO Furnace Staging System



TSV Burner

Figure 7 Riley Low NOx TSV Burner and
Turbo Furnace Staging System

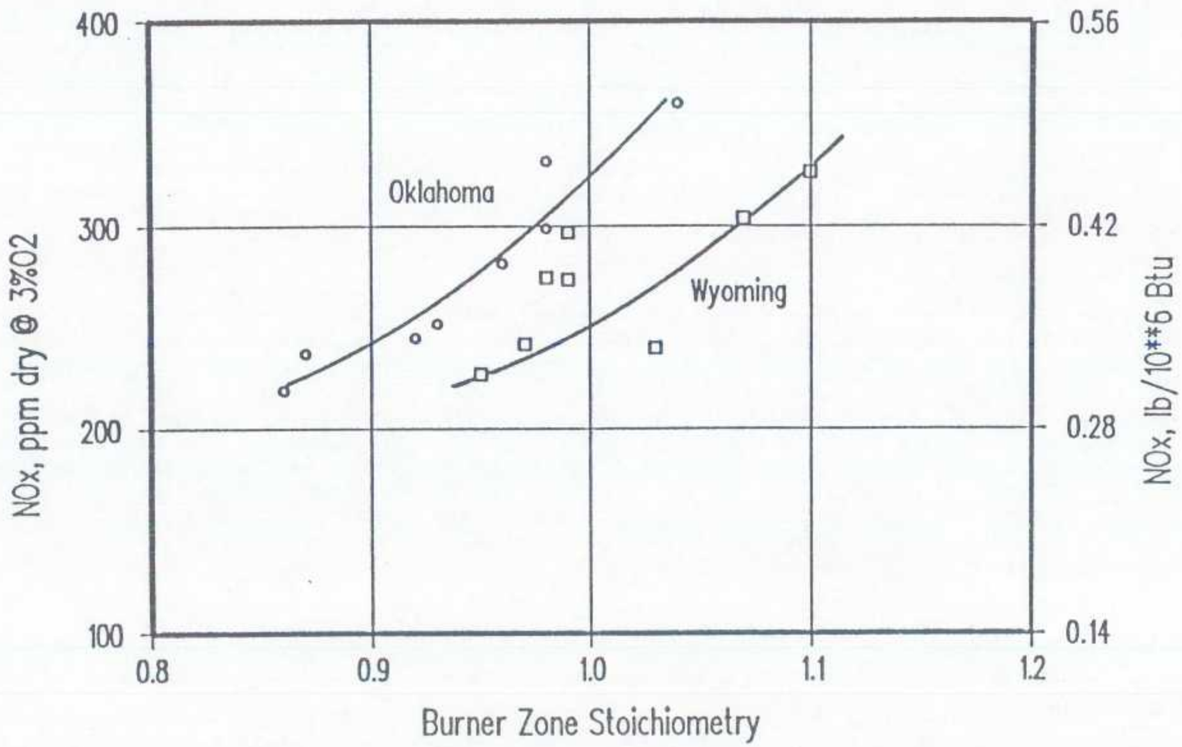


Figure 8 The Effect of Air Staging on NOx Emissions

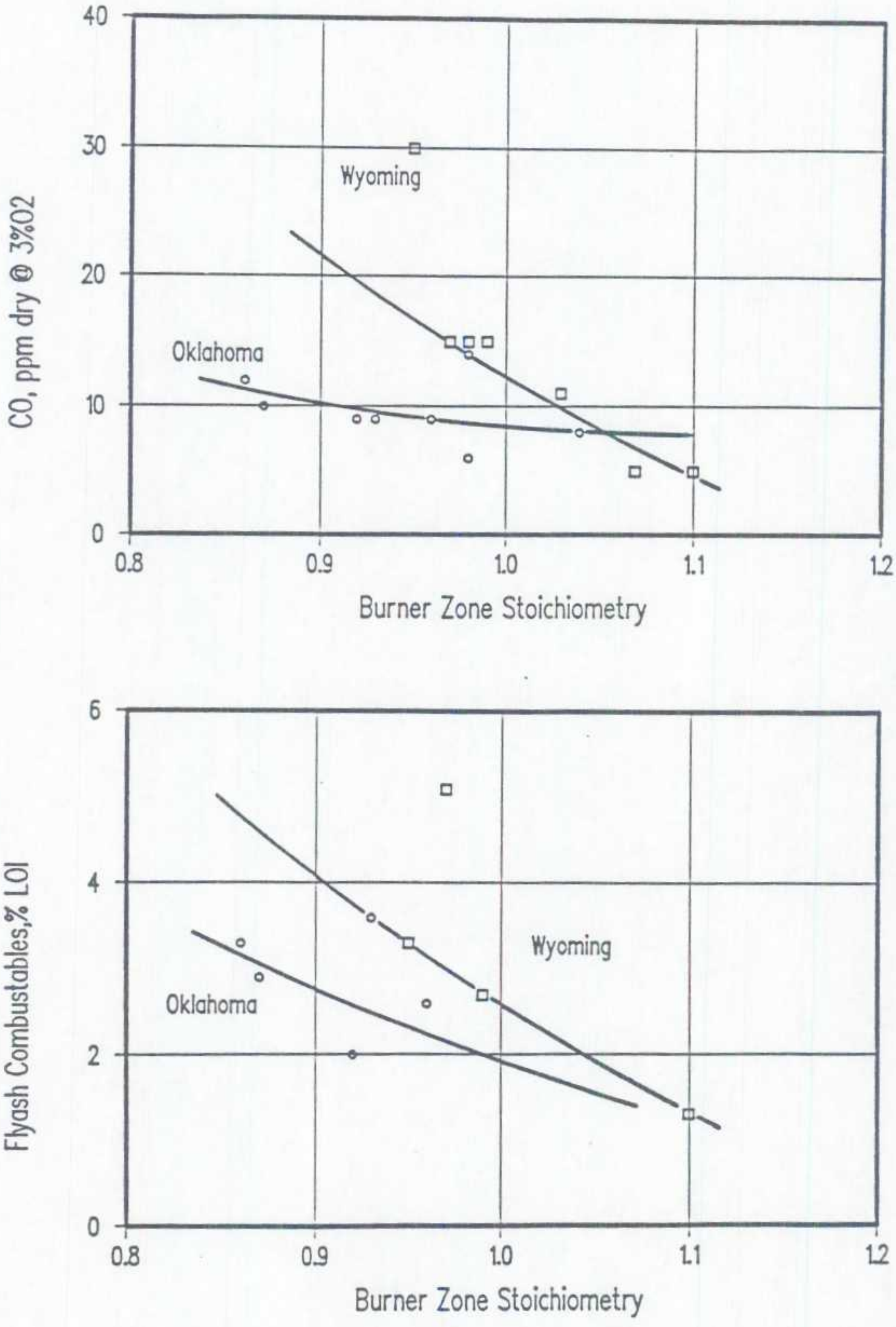


Figure 9 The Effects of Air Staging on CO Emissions and Carbon Burnout

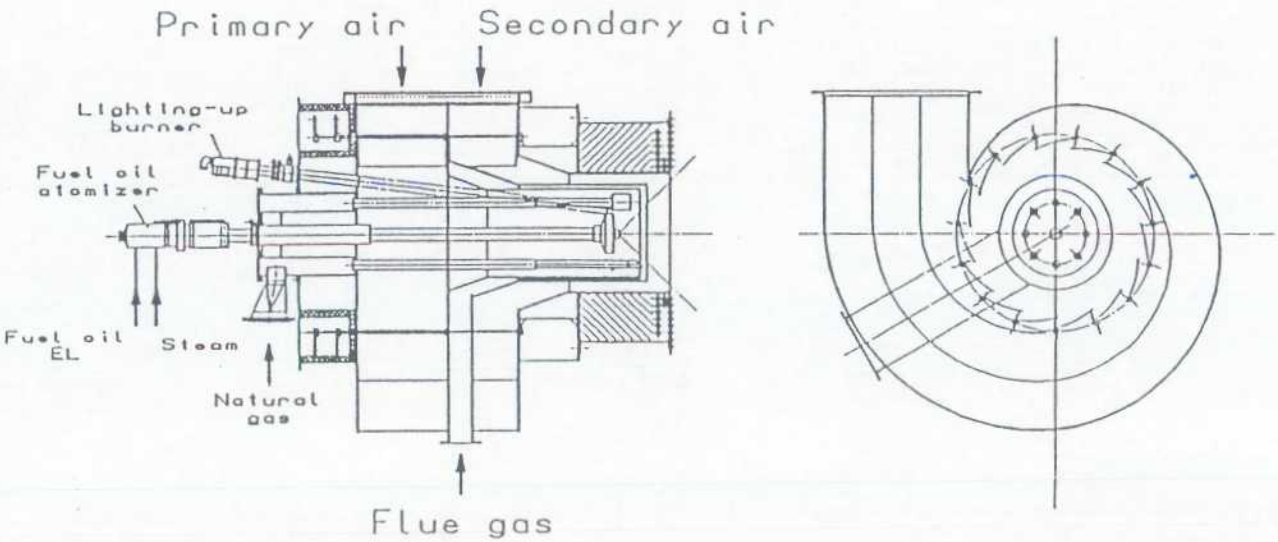
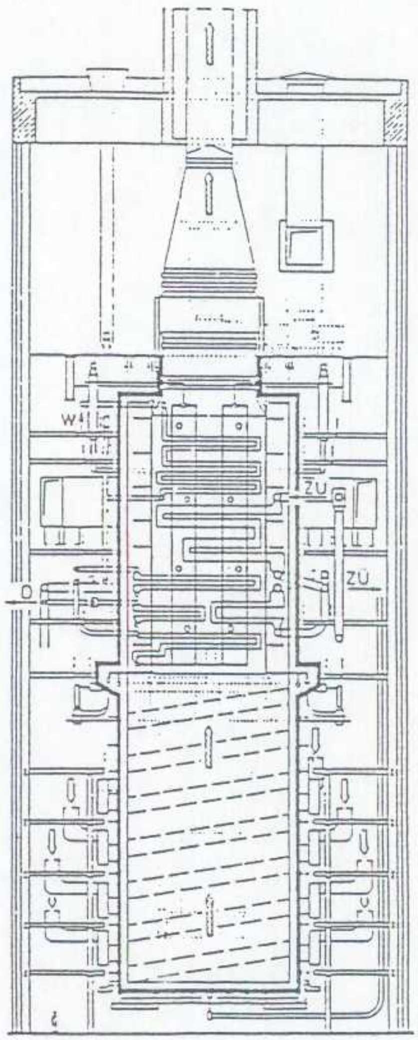
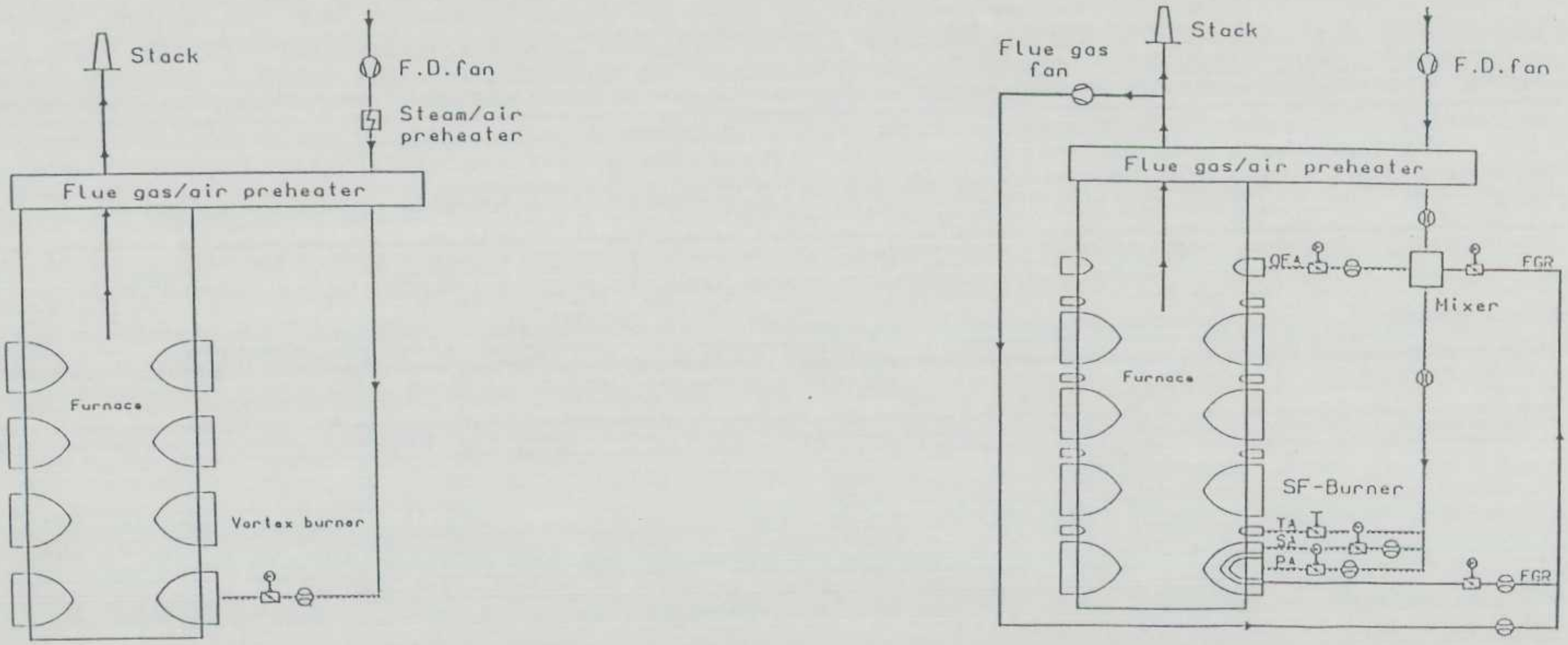


Figure 10 Low NOx STS Burner Equipped for Gas and Oil Firing and Individual Air Supply



Figuare 11 Arzberg Power Plant Unit NO. 6



a. Original System

b. Low-NO_x Retrofit System

Figure 12 Low NOx Combustion System at Arzberg Power Station

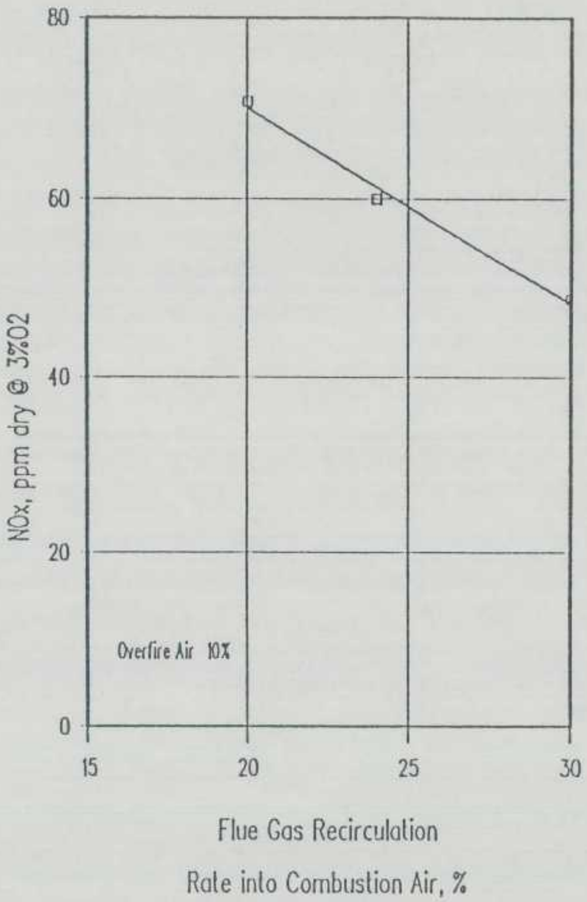


Figure 13 NOx as a Function of FGR into the Combustion Air - Natural Gas Operation

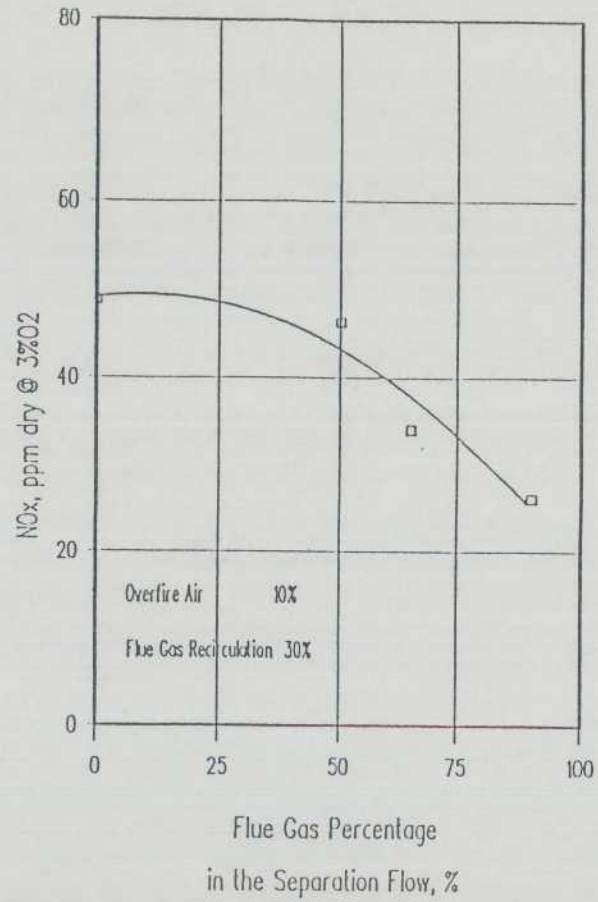


Figure 14 NOx as a Function of FGR into the Annulus - Natural Gas Operation

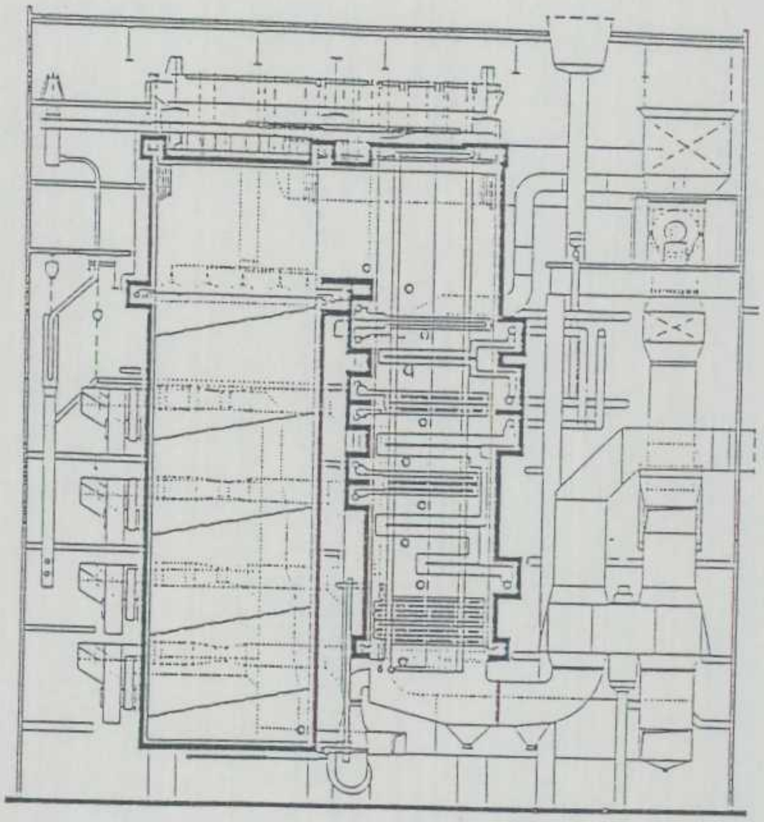


Figure 15 Vartan Power Station

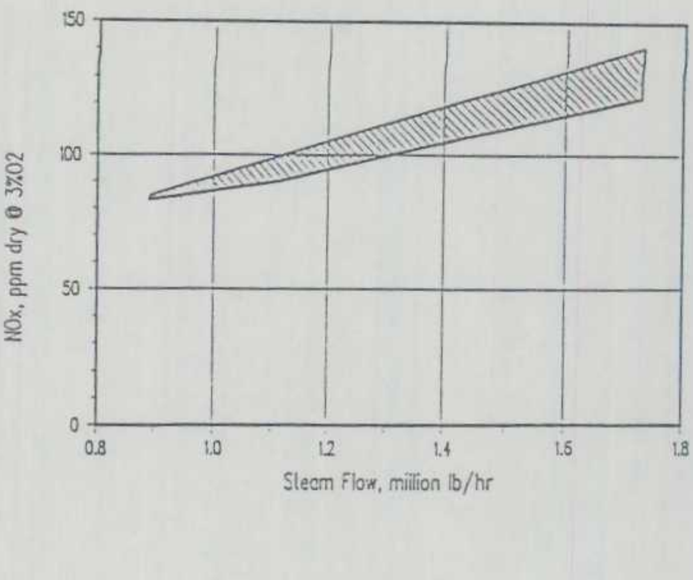


Figure 16 NOx Versus Boiler Load
Post-Retrofit Heavy Oil Firing

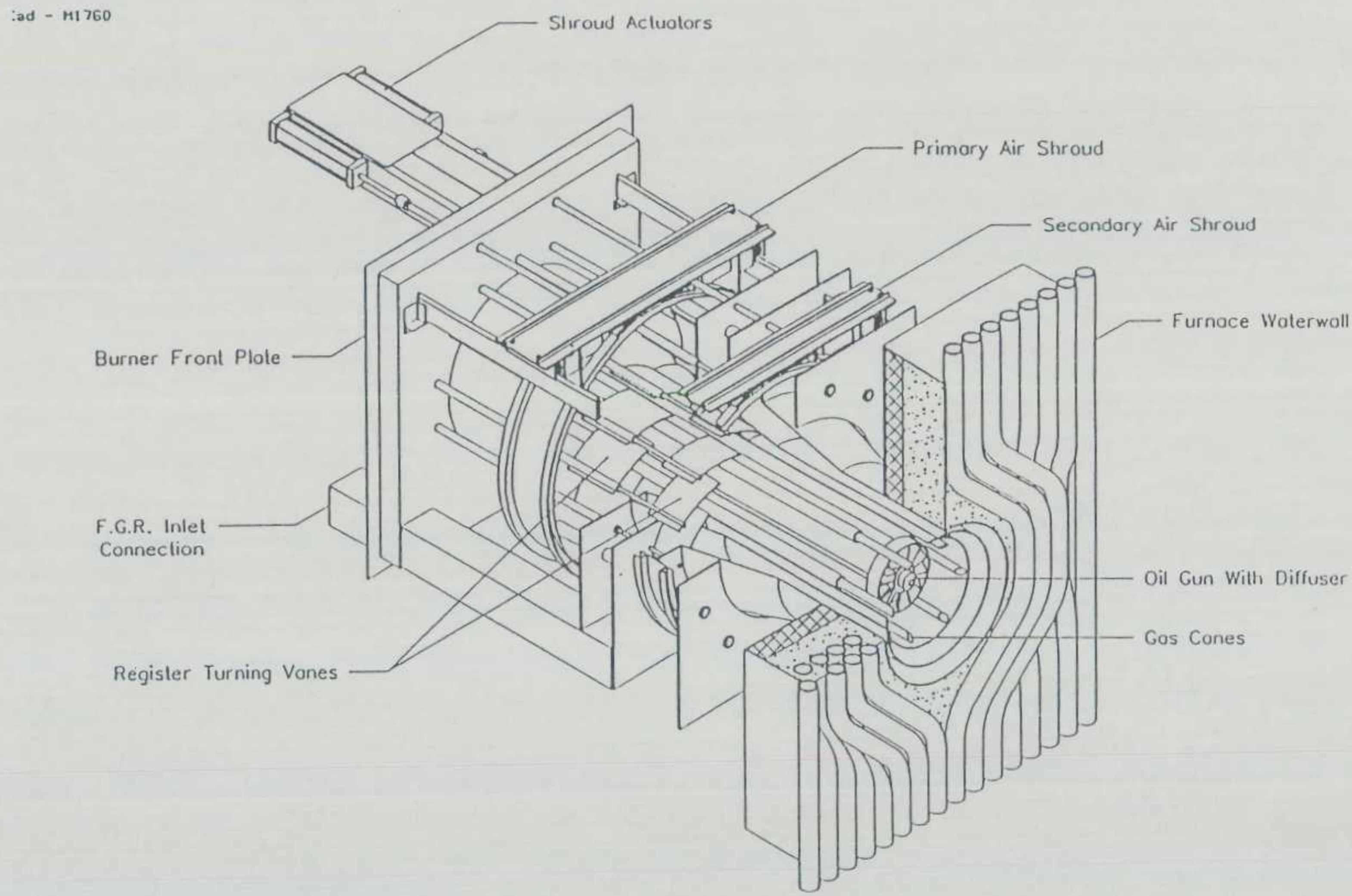


Figure 17 Riley Low-NOx STS Burner (Model 90) for Windbox Burner Arrangements