DEMONSTRATION OF 3-STAGE COAL COMBUSTION AT THE LINCOLN DEVELOPMENT CENTER
Updated Version

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Abstract

The Ashworth Combustor[TM] is a 3-stage coal combustion multi-pollutant reduction technique that reduces NO_X, SO_2, SO_3, CO_2, Hg, other air toxics, halogens and particulate emissions (see below). It combines the Florida Power two-stage combustion technology[1] with ClearStack's three-stage technique. A 40 million Btu/hr demonstration is in progress at the Lincoln Development Center in Lincoln, Illinois. Testing began in September 2002. To date, NOx emissions of 0.14 lb/10^6 Btu and 70+% SO_2 reductions (w/limestone addition at a 0.85 Ca/S ratio) were achieved. Mercury emission reductions of 90+% were achieved based on ash and coal analyses. More technology parameters will be tested and it is expected that NO_X and SO_2 emissions will be reduced further. Midrex Technologies Inc. is a technology partner. Detroit Edison is completing all sample analyses.

Ashworth Combustor[TM]
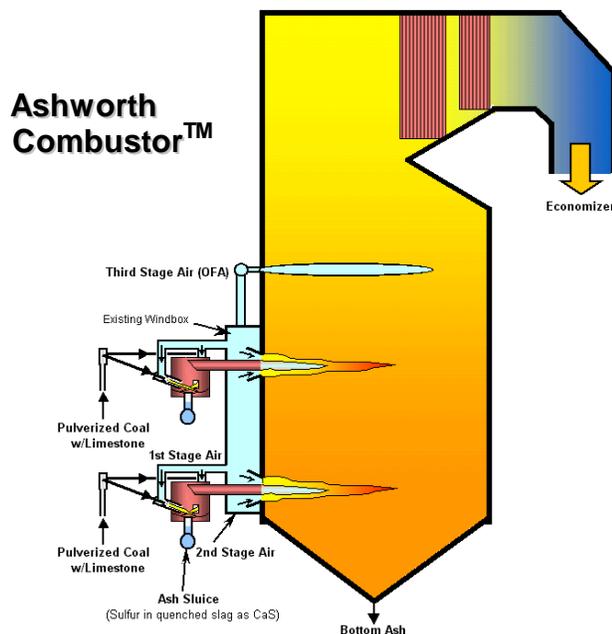
Features

- **PC- fired, 3-Stage Combustor**

- **Limestone/lime addition
  (slag fluxing, Hg & sulfur capture)**

- **NO_X emissions < 0.15 lb/10^6 Btu**

- **SO_2 reduction 70+%**

- **Mercury reduction (90+ wt %)**

- **Particulate & other elemental
  air toxic reductions**

- **HCL, HF & SO_3 reductions**

- **CO_2 & NO_X reduction
  w/biomass co-firing**

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ClearStack, the Illinois Clean Coal Review Board, the Illinois Department of Commerce and Community Affairs, the Illinois Development Finance Authority, the Electric Power Research Institute, Detroit Edison, Dynegy, Allegheny Energy Supply, the Illinois Department of Human Services are funding the demonstration.

NO$_X$ Reduction

Three-stage combustion is an improved technique for the reduction of NO$_X$. It precludes the formation of nitrogen oxides from fuel bound nitrogen and high temperature oxidizing conditions. How to reduce nitrogen oxides using combustion techniques is obvious once one understands the reaction mechanisms and combustion flow patterns.

First Stage

The first stage is operated at an air; fuel stoichiometric ratio (SR) of about 0.60. This SR is best for eliminating fuel bound NO$_X$ formation and NO$_X$ precursors, ammonia (NH$_3$) and hydrogen cyanide (HCN). Figure 1a shows equilibrium concentrations of NO$_X$, NH$_3$ and HCN as a function of SR. Figure 1b shows the University of Stuttgart results[2] for a varying SR, based on firing coal at three seconds residence time at 2372 °F (1300°C). For these tests, coal N to NO$_X$ when using a SR of 0.60 was about 4%. The first stage (gasifier) is operated at higher temperatures than that for the University of Stuttgart, so reaction rates are faster and less residence time is required.
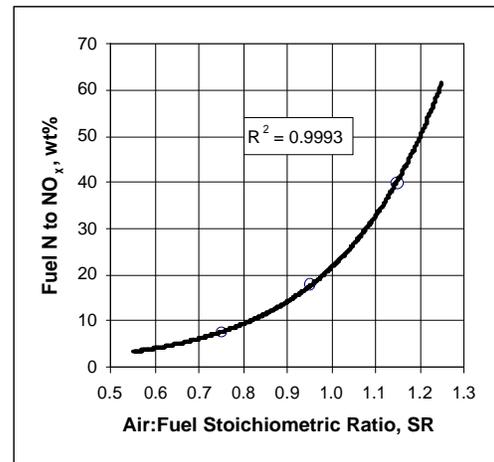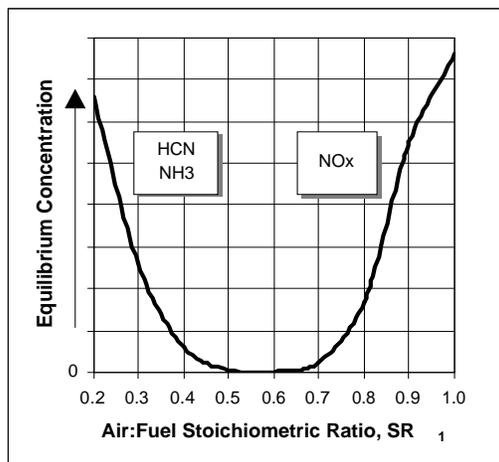

Figure 1a. NO$_X$ equilibrium concentration.

Figure 1b. Fuel N to NO$_X$ conversion.

Second Stage

Fuel gas from the first stage enters the furnace at a temperature of 2600°F to 2800°F. Second stage oxidation takes place here using a low NO$_X$ burner technique to bring the air: fuel ratio to 0.90 SR. This SR is similar to that used in Reburn technology. NO, in the lower part of the furnace, is further reduced (see Figure 2).

Third Stage

Air is added to the third stage of oxidation when the flue gas temperature (~2400°F) has been cooled to minimize formation of thermal NO_X (see Figure 3).
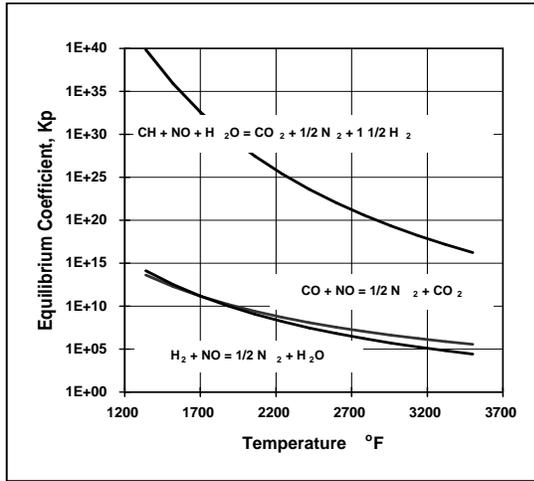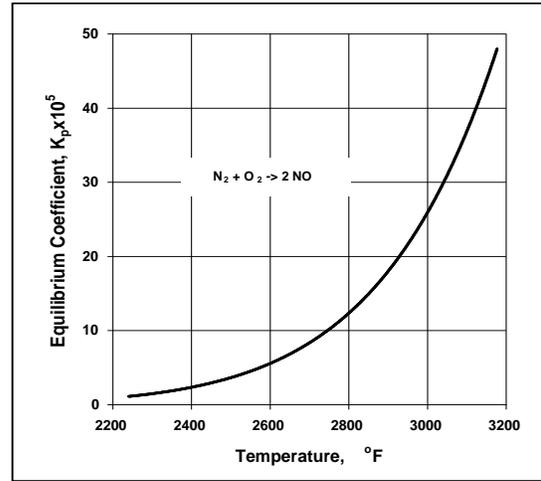

Figure 2. 2nd Stage NO_X reducing reactions.

Figure 3. 3rd Stage NO_X equilibrium.

Three-stage kinetic modeling[3] was completed and the modeling results showed that NO_X emissions should be reduced to less than 0.15 lb/10^6 Btu of coal fired and perhaps as low as 0.07 lb/10^6 Btu. Demonstration testing, discussed later, is confirming the low NO_X emissions of the three-stage technique. Cold flow modeling[4] was also completed to determine placement of the OFA system.
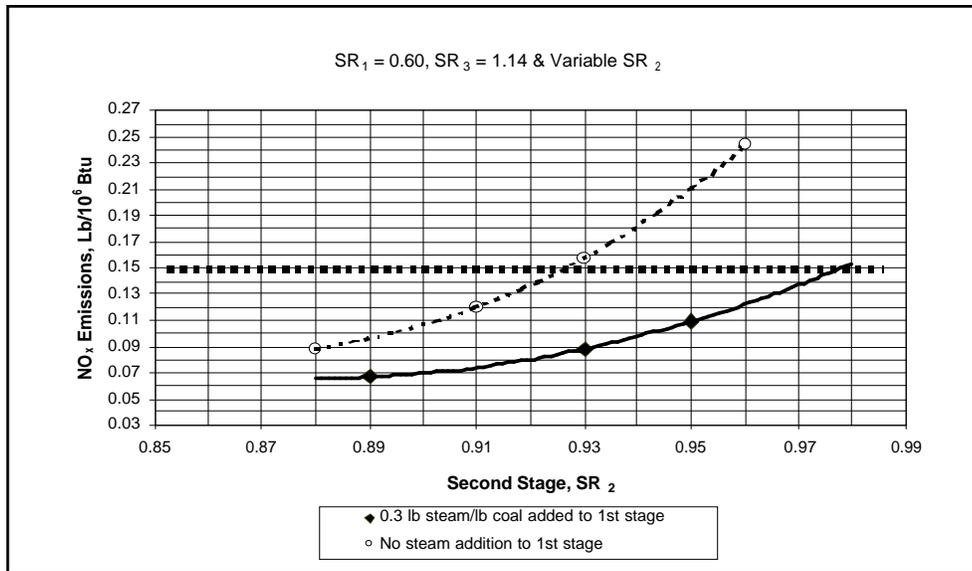

Figure 4. Overall three-stage combustion NO_X emissions.

SO$_2$ Reduction

A two-stage pilot unit[1] (12 million Btu/hr) was tested at the Foster Wheeler Development Center (FWDC). For most runs, sulfur reduction was primarily the result of SO$_2$ being captured by the alkaline fly ash. However, in Run #11 when using a hydrated lime, a five-fold increase in sulfur capture (CaS) by the slag was observed. At that time, 59 wt.% of the coal sulfur was being captured (see Figure 5). Runs #10 and #11 used the same conditions, the only difference was that limestone was used in Run #10, and hydrated lime was used in Run #11.
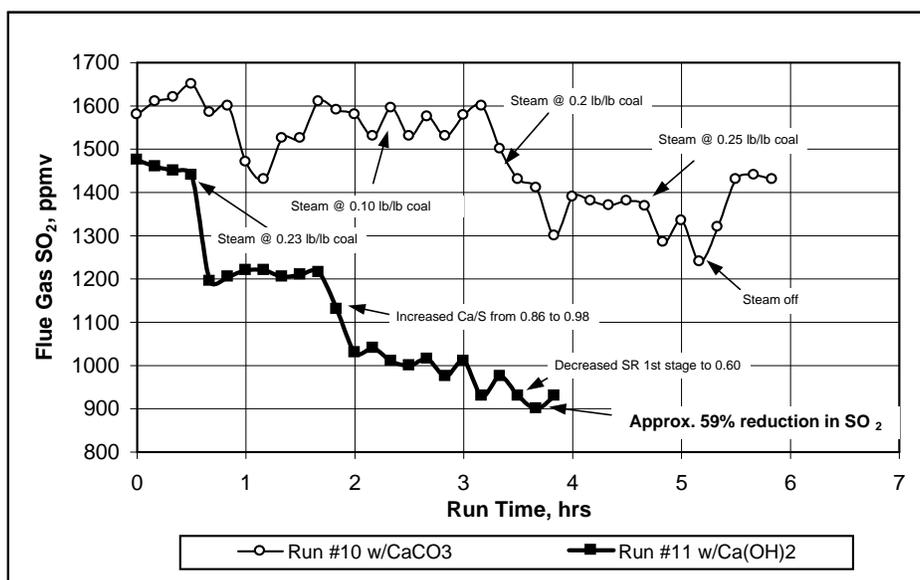

Figure 5. FPC two-stage combustor flue gas SO$_2$ versus run time.

In Figure 5, sulfur concentrations in the flue gas for these runs are shown versus time; the hydrated lime was clearly more reactive concerning sulfur capture. Steam addition also increases sulfur capture by increasing the gasification rate with the carbon-water reaction (C + H$_2$O -> CO + H$_2$). The lowest cost combustion technique for reducing SO$_2$ emissions will minimize steam addition; however, low cost low-pressure steam will suffice if required. To date we have obtained around 40-wt % capture with limestone at a Ca/S ratio of 0.85. Neither steam addition nor hydrated lime has been tested yet in the demonstration unit. Based on pilot plant testing, one would expect that steam addition should increase sulfur capture beyond that achieved to date by some 20% and even greater reduction when using hydrated lime.

Acid Aerosols and Air Toxics

Since limestone is added to the coal, acid aerosols [sulfur trioxide (SO$_3$), hydrochloric acid (HCl), and hydrofluoric acid (HF)] will also be reduced. Testing of the ash, discussed later, has shown a dramatic capture of mercury and other air toxics. At the time of the writing of this paper, Detroit Edison was testing the ash to confirm fluoride and chloride capture.

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Increased Boiler Performance

Assuming one per cent of coal sulfur goes to SO_3 in a conventional boiler, using a 3-wt% sulfur coal would yield 30 ppmv of SO_3. In limestone furnace injection tests by others, although only 50% of the SO_2 was removed, 90% of the SO_3 was removed. Assuming that 90% of the SO_3 is removed with the Ashworth Combustor, the acid dew point would drop from 298^oF to 256^oF. This would allow an enlargement of air preheaters to recover more heat from boiler flue gas and increase overall efficiency by around 1.0%. Further, it is believed that the combustion system can be operated with as low as 10 % excess air rather than the 15 % usually required for low CO emissions and high carbon conversion. This will improve boiler performance (~ +0.5 %) by reducing stack gas heat losses.

Host Site - Lincoln Development Center

The Ashworth Combustor demonstration is taking place at the Illinois Department of Human Services, Lincoln Development Center in Lincoln, IL. The Center has three - 40×10^6 Btu/hr boilers. Unit #2 was retrofitted with the three-stage Ashworth Combustor (see Figure 6). The retrofit consisted of installing a water-jacketed two-stage combustor; a coal feed system that includes a pulverizer, a (limestone or lime) storage and feed system, a slag quench and removal system, an overfire air (OFA) system, an air pre-heater and a baghouse.

Figure 6. Ashworth 40×10^6 Btu/hr 3-Stage Combustion System.

Pulverized coal and limestone (or lime), sized to 70% minus 200 mesh is fired into the slagging combustor at an air rate to maintain a SR of about 0.60. The slag flows through a tap in the center of the combustor into a water-quench drag tank. The ash is de-watered and is conveyed to a roll-off container (see Figure 7) for disposal to a conventional landfill. Like cyclone ash, commercially the slag could be used for production of asphalt shingles.

Figure 7. 1st Stage Combustor Slag to Roll-Off Container.

Second stage air is added to the fuel gas (~60 Btu/scf) from the combustor as it enters the boiler furnace to bring the SR up to 0.90. In the upper furnace, overfire air (OFA) is added to bring the SR up to 1.10 to 1.15 to complete the combustion process. Flue gas from the boiler flows to a baghouse (see Figure 8) for particulate removal and then to an atmospheric stack.

Figure 8. Baghouse.

Control System and Emissions Monitoring

A state-of-the-art DeltaV control system is being used to control the combustion system, an Allen Bradley system is being used to control the baghouse and a Rosemount Continuous Emissions Monitoring System (CEMS) is being used to measure SO_2, NO_X, CO, O_2, and Opacity (see Figures 9a and 9b).

Figure 9a. Allen Bradley and DeltaV Control.

Figure 9b. Rosemount CEMS.

Test Results at Lincoln

A continuous emissions monitoring system is used to measure nitrogen oxides, sulfur dioxide, carbon monoxide and oxygen.

NOX Emissions

Nitrogen oxides (NO_X) emissions have been as low as 0.095 lb/10^6 Btu (68 ppmv @ 3 vol % O_2 dry) with coal using the three-stage combustion technique. As yet, the conditions have not been optimized for coal, and steam addition has not been tested. The unit is gas capable and when firing natural gas at similar conditions, NO_X emissions were 0.048 lb/10^6 Btu (44 ppmv @ 3 vol % O_2 dry).

SO2 Emissions

Sulfur dioxide (SO_2) emissions to date have been as low as 1.7 lb/10^6 Btu for a high sulfur Illinois coal that yields uncontrolled SO_2 emissions of 6.14 lb SO_2/10^6 Btu - a 72 % reduction. This reduction was achieved with a limestone Ca/S ratio of 0.85. In pilot runs greater reductions were achieved with steam addition, higher Ca/S ratios and the use of hydrated lime. Future parametric testing will be completed to optimize SO_2 reduction.

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CO Emissions

With coal firing only, carbon monoxide (CO) emissions were 15 - 30 ppmv @ 3 vol % O_2 dry compared to natural gas firing at similar conditions of 10 - 20 ppmv @ 3 vol % O_2 dry.

Carbon Conversion

The carbon conversion achieved to date has been 99 wt. %. Carbon in slag from the combustor is 0.1 to 0.2-wt % and carbon in fly ash is less than 5 wt %. The three-stage combustion technique yields a light gray fly ash like that obtained prior to the advent of low NO_X burners. Low NO_X burners yield carbon in fly ash that in many cases is in the $10 - 15$ wt % range, making it unsuitable for cement manufacture.

Mercury Reduction

The Detroit Edison Fuel laboratory analyzed all of the solids streams entering and exiting the Ashworth Combustor system. Although a stack test has not been run yet, mercury reduction has been surprisingly high based on solids analyses. ClearStack has filed for a patent on Hg reduction.

<u>Hg In:</u>	Coal	=	0.075	ppmw Hg
	Limestone	=	0.03	ppmw Hg
<u>Hg Out</u>:	Slag	=	4.69	ppmw Hg
	Fly Ash	=	0.02	ppmw Hg

93.6 wt% reduction

In addition, what is even more impressive is that the mercury does not leach.

<u>Standard Leach Tests:</u>
Slag = 0 mg/l Hg, Fly Ash = 0 mg/l Hg

CO_2 Reduction

It is planned to co-fire biomass in the combustor in the future. By co-firing biomass and by improving overall boiler thermal efficiency, the technology will reduce carbon dioxide (CO_2) emissions in two ways. The EPRI Biomass Interest Group (BIG) has provided funding to the project because of its interest in using slagging combustors to increase the percentage of biomass that can be fired into a boiler. Since the coal and biomass will be fired down into a molten slag bath, the reactive alkalis in the biomass such as potassium will be tied up in a mineral complex rather than entering the boiler as corrosive potassium oxide. Some of the potassium will be removed in the bottom slag and what carries over will be in a mineral complex that is less reactive as a corrosive agent to boiler tube walls. With this technology, if biomass is available, CO_2 emissions could easily be reduced by over 10 %. CO_2 from biomass is not counted as additional CO_2 to the ecosystem because it is already part of the natural cycle.

Economics

The Ashworth Combustor, because it reduces multi-pollutants will be much less expensive than alternative methods to reduce air pollution. Capital and operating cost were developed for an Ashworth Combustor retrofit to a tangentially fired electric utility boiler. The size selected was a 200 MWe unit because units of this size and less, are not economic for adding Selective Catalytic Reduction and Wet Scrubbing systems. The capital cost for an Ashworth Combustor (see Table 2) retrofit is about \$75/kWe and for an SCR unit would be about \$100/kWe[5]. The annual operating cost, including payback of capital, for an Ashworth Combustor is around \$2.7 million compared to an SCR cost[5] of around \$3.4 million. Based on cost per ton of NO_X removed, the Ashworth Combustor is \$895 compared to SCR at \$1122/ton. However, when taking a credit for sulfur dioxide reduction of \$130/ton removed, the Ashworth Combustor cost/ton of NO_X removed is only \$531/ton or about one-half that for SCR. In 2007 when mercury emissions regulations are expected to come into effect, the Ashworth Combustor could save a 200 MWe power plant an additional \$2.5 to over \$5 million per year since nothing has to be added for mercury control. This savings is based on a US DOE estimate that it will cost, with conventional methods, \$30,000 to \$70,000 per pound of mercury removed.

Conclusion

The Ashworth Combustor looks very promising because it reduces multi-pollutants (NO_X, SO_X, Hg, other air toxics, and halogens (HCl and HF) at an annual operating cost of around half the price of SCR alone. Further unlike SCR it reduces, not increases SO_3 (opacity and acid rain problem) to the atmosphere and does not require noxious chemicals (NH_3 or Urea), as does SCR. If testing proves out as expected at the Lincoln Development Center, it could well become the Best Available Control Technology (BACT) for new coal-fired power plants.

<u>References:</u>

1. Ashworth, R. A. and Padilla, A. A., "*CAIRE" Advanced Combustor Development*, Ninth Annual Internatiional Pittsburgh Coal Conference, Pittsburgh, PA, October 14, 1992.

2. Kluger, Frank, et. al, *Comparison of Coals and Air Stage Combustion with Respect to NO_X Emissions*, 23rd International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL, March 9-13, 1998.

3. *NO_X Kinetic Modeling Report*, Energy and Environmental Research Corporation, October 23, 1998.

4. *Flow Modeling Study to Design an Overfire Air System for Lincoln Development Center Boiler No. 2,* General Electirc Energy and Environmental Research, April 24, 2000.

5. Josewicz, Wojciech, *Cost of Selective Catalytic Reduction (SCR) Application for NO_X Control on Coal-fired Boilers,* US EPA Research and Development Bulletin EPA/600/SR-01/087, January 2002.

<u>*Disclaimer:*</u>

TABLE 1.

200 MWe Tangentailly Fired Unit - Ashworth Combustor Retrofit
Capital Cost

Category	Cost	Cost/kWe
Major Equipment	$5,617,496	$28.1
Construction Labor	$2,645,670	$13.2
Construction Indirects	$2,445,344	$12.2
Engineering	$1,738,322	$8.7
Project Management	$556,771	$2.8
Taxes, Other	$292,546	$1.5
Startup	$307,146.14	$1.5
Subtotal	$13,603,295	$68.0
Contingency	$1,360,329	$6.8
Total Plant Investment	**$14,963,624**	**$74.8**

Projected Annual Incremental Operating Costs[1]

	Annual Use	Cost/Unit	Cost/ Yr	Cost/Ton NO_x[2]
Raw Material:				
Limestone[3]	13,140 ton	$8.00 /ton	$105,116	$35
Fixed Charges @ 12% TPI			$1,795,635	$596
Labor:[4]				
Maintenance @ 60% of 2% of TPI			$179,563	$60
Supervision @ 20% of Maintenance Labor			$35,913	$12
Supplies:				
Maintenance @ 40% of 2% of TPI			$119,709	$40
Admin. and Gen. Ovhd. (30% of total labor)			$53,869	$18
Insurance and Taxes (2.7% of TPI)			$404,018	$134
Total Operating Costs			**$2,693,823**	**$894**
SO_2 Allowance Credit @ $130/ton[5]			($1,093,248)	($363)
Net Operating Savings			**$1,600,575**	**$531**

1 200 MWe @ 80% capacity factor and a 10,000 Btu/kWh gross heat rate

2 NOx reduction based on baseline value of 0.50 lb $NOx/10^6$ Btu reduced to 0.07 lb $NOx/10^6$ Btu

3 Based on 3.0 wt % S coal with limestone added to meet the SO_2 limit of 1.2 lb/10^6 Btu (75% S removal)

4 No incremental operating labor

5 3.6 lb SO_2 removed per million Btu of coal fired. 12/03/02 SO_2 credits @ $130/ton