POWER-GEN International 2000 Conference
Orange County Convention Center
Orlando, Florida Nov. 14 - Nov. 16, 2000

DEMONSTRATION OF ASHWORTH COMBUSTOR

(*NO_X, SO_2, and Particulate Reduction*)

ClearStack Combustion Corporation (ClearStack)
Bob Ashworth
Steve McClure
Fred Murrell

Illinois Department of Human Services (DHS)
Don Shroyer

Abstract

The Ashworth Combustor^{TM} technology is three-stage pulverized coal combustion technique designed to reduce the three major air pollutants (NO_X, SO_2, and particulate) from coal combustion. A 40 million Btu/hr combustion system is being retrofitted to a coal-fired stoker at the Lincoln Development Center in Lincoln, Illinois. The project will cost $3.34 million. ClearStack, the Illinois Department of Commerce and Community Affairs, the Illinois Clean Coal Review Board, and the Ohio Department of Development - Ohio Coal Development Office are funding the project. There is also in-kind cost sharing from the Illinois Department of Human Services and the City of Orrville, Ohio. Installation of equipment foundations was begun in mid October, startup and testing are scheduled for early 2001.

A two-stage slagging gasifier-combustor is used in combination with overfire air (OFA). Pulverized coal, with limestone, is fired/calcined in the gasifier-combustor proper. The alkali is added to capture sulfur as calcium sulfide in a non-leaching molten slag eutectic. In pilot plant runs, sulfur dioxide reductions of up to 60% were achieved and with the new combustor, design 70+% SO_2 reductions are projected. The gasifier (first stage) is fired at an air:fuel stoichiometric ratio (SR) of 0.60 to minimize found bound NO_X production. The second stage is fired at an air:fuel stoichiometric ratio of 0.90 to further reduce any NO_X that was produced in the first stage. The third stage of combustion occurs in the upper furnace (OFA) after the gases have cooled enough so as not to produce thermal NO_X. Flame kinetic modeling shows that NO_X emissions can be reduced to 0.15 lb. $NO_X/10^6$ Btu and less. This is the level that EPA has mandated, and the courts have delayed, that will come into effect on May 31, 2004 for Eastern and Midwestern States. In addition, a 65% reduction in particulate emissions to the atmosphere, are projected for the Ashworth Combustor when retrofitted to pulverized coal-fired units equipped with electrostatic precipitators. Included in this reduction will be fine particulate matter ($PM_{2.5}$) and air toxics. When demonstrated, the three-stage combustion technique will offer the electric utility industry a low cost option to the wet scrubbing plus selective catalytic reduction (SCR) to reduce acid gas emissions. The annual operating cost, including payback of capital of an Ashworth Combustor retrofit, is only 35% of the cost of combining an SO_2 scrubber with an NO_X reduction Selective Catalytic Reduction (SCR) system. When demonstrated, the three stage combustion technique will offer the electric utility industry a low cost option to the wet scrubbing plus selective catalytic reduction (SCR) to reduce acid gas emissions.

INTRODUCTION

In October of 2000 ClearStack was awarded a $1 million grant form the Illinois Clean Coal Review Board. This provided the final funding needed to demonstrate the three-stage *Ashworth Combustor™* system. With this technology, the three major air pollutants (NO_X, SO_2 and particulate) from coal combustion are significantly reduced.

ASHWORTH COMBUSTOR

The *Ashworth Combustor* includes two complimentary combustion techniques. A two-stage combustor owned by Florida Power Corporation (FPC) that reduces sulfur and nitrogen oxide emissions. It is protected under U. S. Patents 4,395,975; 4,423,702; and 5,458,659 and several foreign patents. ClearStack has the exclusive worldwide licensing rights to the FPC technology. The second technology is the addition of a third stage of combustion, owned by ClearStack, that achieves the ultra-low NO_X emissions. It is protected under U. S. Patent 6,085,674.

Background

The FPC two-stage combustor is a small coal gasifier that replaces existing burners. Alkali is added to capture sulfur as CaS in a molten slag eutectic. It incorporates certain features of the Rummel molten slag bath gasifier, an oxygen-blown unit that produced a synthesis gas for hydrogen and ammonia production. The Rummel gasifier, burning German Brown coal (high alkali ash) was found to capture 70% of the coal sulfur in the molten slag removed from the gasifier. A FPC two-stage pilot unit (12 million Btu/hr) was tested at the Foster Wheeler Development Center (FWDC) in Livingston, New Jersey[1]. The thrust of the work was to improve coal gasification rates. Work centered on burner modifications and steam injection to increase gasification rates and provide a more reducing condition in the first stage of combustion. For most test runs, sulfur reduction was primarily the result of SO_2 being captured by alkaline fly ash. However, in one run when using a hydrated lime, a five-fold increase in sulfur capture (CaS) by the slag was observed. At that time, 58.8 wt.% overall coal sulfur was being captured. Following pilot testing, the combustor was evaluated to determine why greater percentages of sulfur were not captured in the alkaline molten slag. Some eighty chemical reactions (solid-gas and gas-gas) were evaluated thermochemically to determine what reaction(s) were interfering with the sulfur capture reaction:

$$\mathrm{CaO + H_2S \rightarrow CaS + H_2O}$$

Based on analysis of the possible sulfur specie reactions that could take place in the combustor, the interfering reaction was found. It is as follows:

$$\mathrm{2CaS_{(slag\ eutectic)} + O_2 \rightarrow 2CaO_{(slag\ eutectic)} + S_{2(diatomic\ sulfur)}}$$

The fact that this reaction was interfering with sulfur capture is supported by test data. In one run, using a specific coal nozzle, no H_2S, COS or SO_2 could be measured in the first stage gas and yet SO_2 was measured in the stack. This observation showed that oxygen in the first stage air must be consumed rapidly so that sulfur, captured as CaS, is not blown out of the slag as diatomic sulfur (S_2). With this insight, the original combustor design was re-visited. It became obvious why air blown gasifiers failed to meet the sulfur capture performance of their oxygen blown counterparts.

Pilot plant NO_X emission rates were low (~ 0.30 lb/10^6 Btu) considering no special design provisions were included in the second stage of combustion to minimize NO_X production. The new combustion system will use a three-stage combustion technique that further reduces NO_X emissions. The highest particulate capture observed in the pilot combustor was 60 wt. % of the ash plus alkali fed. In the pilot unit, a slotted internal gas baffle was used and slag was blown through the slot into the boiler. The new design eliminates the problem; slag is removed from the bottom center of the first stage.

Ashworth Combustor NO_X Reduction

The three-stage combustion technique is optimal for the reduction of NO_X. The first stage is operated at a stoichiometric air:fuel ratio (SR) of around 0.60. This SR is best for reducing NO_X and NO_X precursors, ammonia (NH_3) and hydrogen cyanide (HCN), from the fuel bound nitrogen. Figure 1a shows, the equilibrium concentrations of NO_X and NO_X precursors as a function of SR. Figure 1b shows the University of Stuttgart laboratory results[2] for a varying SR, based on firing coal with 1 wt.% (MAF) N and three seconds of residence time at a temperature of 2372 °F (1300°C). The test data show the effect of stoichiometric ratio on fuel bound NO_X formation. Coal N to NO_X using a SR of 0.60 is only about 4%.

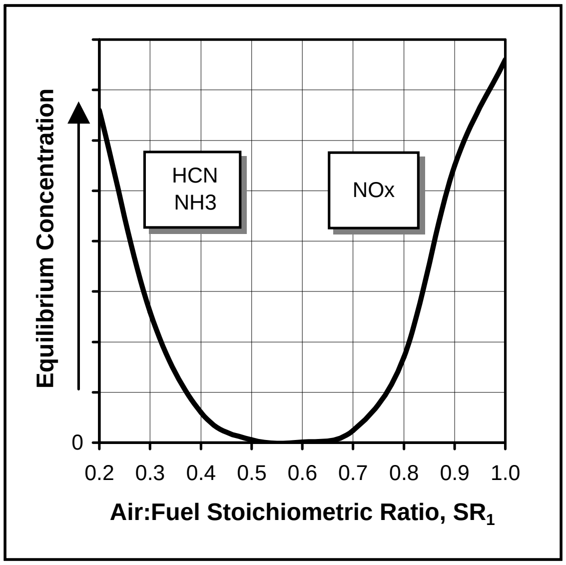


Figure 1a. NO_X Equilibrium Concentration

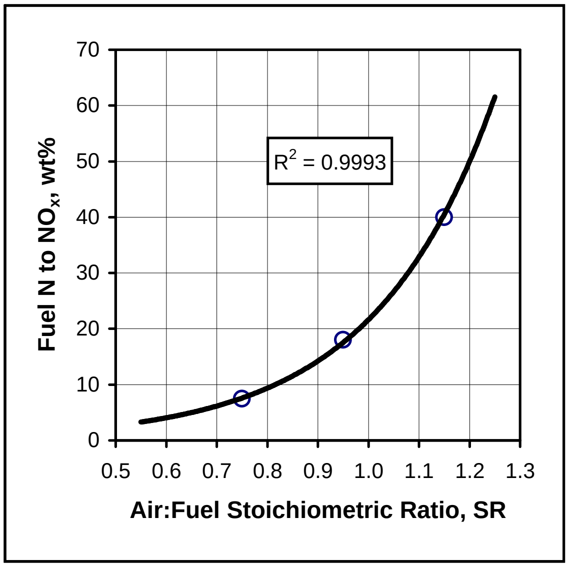


Figure 1b. Fuel N to NO_X Conversion

The Ashworth Combustor is operated at higher temperatures, so reaction rates are faster and less residence time is required. In pilot plant testing 0% NO_X was found in the first stage flue gases. Fuel gas from the 0.60 SR first stage enters the furnace at a temperature of 2600°F to 2800°F. Second stage partial oxidation takes place here. A low NO_X burner design is used to bring the air:fuel stoichiometric ratio up to 0.90 SR. This SR is similar to that used with Reburn technology. NO in the lower part of the furnace, is further reduced by the following overall reactions:

$$[CH] \text{ (hydrocarbon fragments)} + NO + H_2O = CO_2 + 0.5N_2 + 1.5H_2,$$
$$CO + NO = CO_2 + 0.5N_2, \text{ and}$$
$$H_2 + NO = H_2O + 0.5N_2$$

GE-EER completed kinetic modeling[3] for the *Ashworth Combustor* and cold flow modeling for the Lincoln unit. The kinetic model held the first stage SR_1 at a value of 0.60 to minimize fuel bound NO_X production. The second stage SR_2 was varied and the third stage SR_3 was held constant at 1.14. In Figure 2, the kinetic model predicts that three-stage combustion will reduce NO_X emissions to <0.15 lb/10^6 Btu of coal fired.

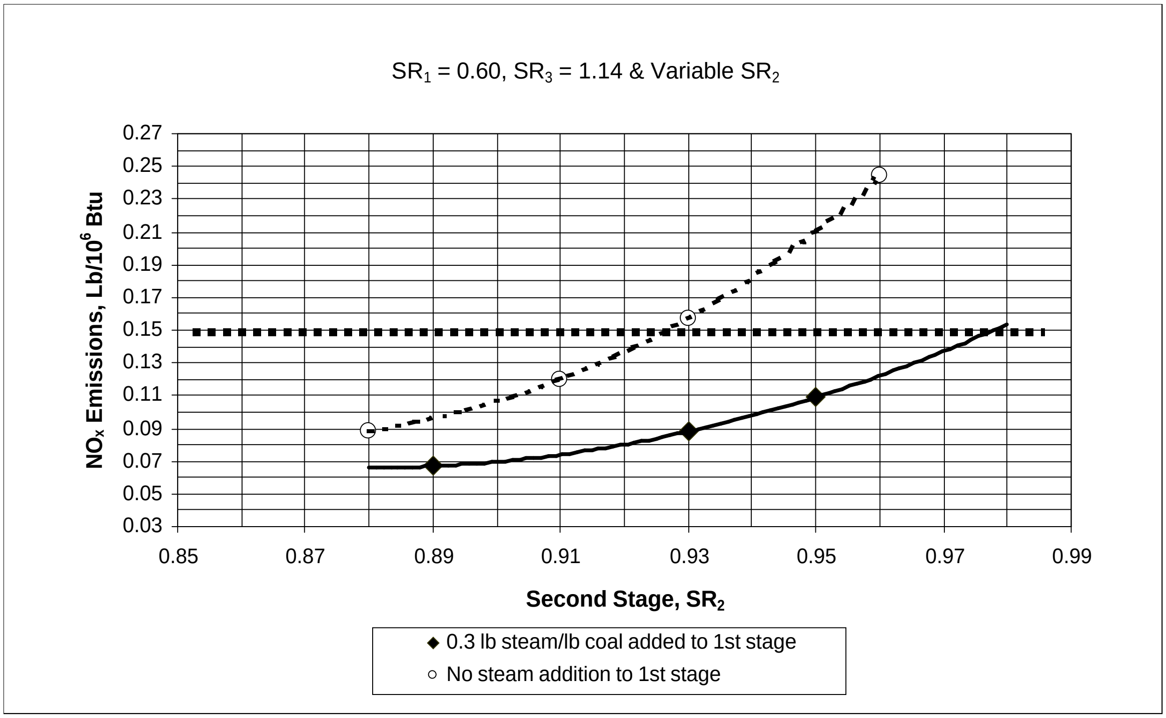


Figure 2. Overall Three-Stage Combustion NO_X emissions.

The combustor was redesigned to eliminate recognized design flaws in the pilot combustor. New features are incorporated that yield increased sulfur capture in the molten slag, provide for non-troublesome slag removal, and further reduce NO_X emissions.

The process goals are to; 1) reduce sulfur oxide emissions by 70+%, 2) reduce nitrogen oxide emissions to ≤ 0.15lb per million Btu of coal fired, and 3) reduce particulate emissions (including PM-2.5, PM-10 and certain HAPS) by 60 - 65% (*when applied to pulverized coal-fired units*). When limestone is added acid aerosols of sulfur trioxide, hydrogen chloride, and hydrogen fluoride will also be reduced. In addition, certain air toxics will be reduced. Mercury emissions are likely to be controlled by the EPA in the future. An assessment will be made for air toxics (16 elements) capture in the Ashworth Combustor ash. Some mercury (10%) has been captured by cyclone-fired boiler ash. Since the Ashworth Combustor first stage will be some 400 °F (2600 vs. 3000+°F) lower in temperature than a cyclone barrel, it is expected that more air toxics will be captured in the molten slag than that shown for cyclones[4] in Table 1. Capture of elemental air toxics by the molten slag and fly ash will be a technology plus.

TABLE 1. CYCLONE-FIRED BOILER AIR TOXIC ANALYSES

	SLAG By Wt.	**ESP** By Wt.	**TOTAL*** By Wt.
As	4%	13%	17%
Ba	61%	23%	84%
Be	58%	20%	78%
Cd	10%	34%	44%
Co	53%	17%	70%
Cr	77%	23%	100%
Cu	31%	13%	44%
Hg	8%	2%	10%
Mn	77%	22%	99%
Mo	11%	32%	43%
Ni	70%	30%	100%
P	79%	21%	100%
Pb	22%	23%	45%
Sb	46%	54%	100%
Se	0%	9%	10%
V	68%	32%	100%

*Elements adding up to 100% reflect normalized valu
because total based on analysis exceeded 100 %

Host Site - Lincoln Development Center

The *Ashworth Combustor* demonstration will take place at the Illinois Department of Human Services, Lincoln Development Center in Lincoln, IL. The Center's boiler house, see Figure 3, has three, nominal 40×10^6 Btu/hr boilers. Units #1 and #3 are coal-fired stoker boilers and Unit #2 is a coal-fired stoker that was converted to natural gas. The Center seldom uses the gas-fired unit due to the higher price of purchased natural gas compared to coal. Unit #2 was therefore selected as the host boiler for the *Ashworth Combustor* retrofit.

The retrofit will consist of the following major equipment items; a water-jacketed two-stage combustor, a coal feed system that includes a coal crusher and pulverizer, a (limestone or lime) storage and feed system, a slag quench and removal system, an OFA system, an air pre-heater and a baghouse. Pulverized coal and limestone (or lime), sized to 70% minus 200 mesh will be fired in the slagging combustor to maintain a SR of about 0.60.

Under this reducing or gasification condition, alkaline molten slag will react with coal sulfur to produce a calcium sulfide that will be tied up in a molten slag eutectic. The slag containing CaS will flow through a tap in the center of the combustor into a water-quench drag tank. The ash will be de-watered as it is dragged out of the quench tank and will then be conveyed to a roll-off container for batch disposal to a conventional landfill. Although the ash from the demonstration plant will be landfilled, commercially it could most likely be sold, like bottom ash from cyclone units, for use in the manufacture of asphalt shingles.

Figure 3. Lincoln Development Center Boiler House

Since the stoker unit does not have an air heater, a steam air heater followed by a direct-fired gas air heater will be used. The rate of gas fired will be very small, only that required to increase the preheated air up to a temperature of 600 °F.

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 1.20 to complete the combustion process. To control this staged combustion technique, an innovative and accurate technique that requires only airflow measurements and oxygen concentration at the boiler exit will be used.

Flue gas from the boiler flows to a baghouse for particulate removal and then to an atmospheric stack. To protect the bags against too high of temperatures (> 500F) a damper will be included on the flue gas line to the baghouse to draw in a small amount of cooling air prior to entering the baghouse. Figure 4 shows a simplified process flow diagram of the combustor retrofit to Lincoln Unit #2.

High ash capture in the combustor will be an advantage to units that have electrostatic precipitators (ESPs). Particulate emissions to the atmosphere (including certain air toxics) will be reduced. ESPs are constant efficiency removal devices, so the less particulate in, the less particulate out. Therefore, based on similar fly ash resistivity, as particulate loading to an ESP decreases so does the outlet loading in the flue gas going to the atmosphere.

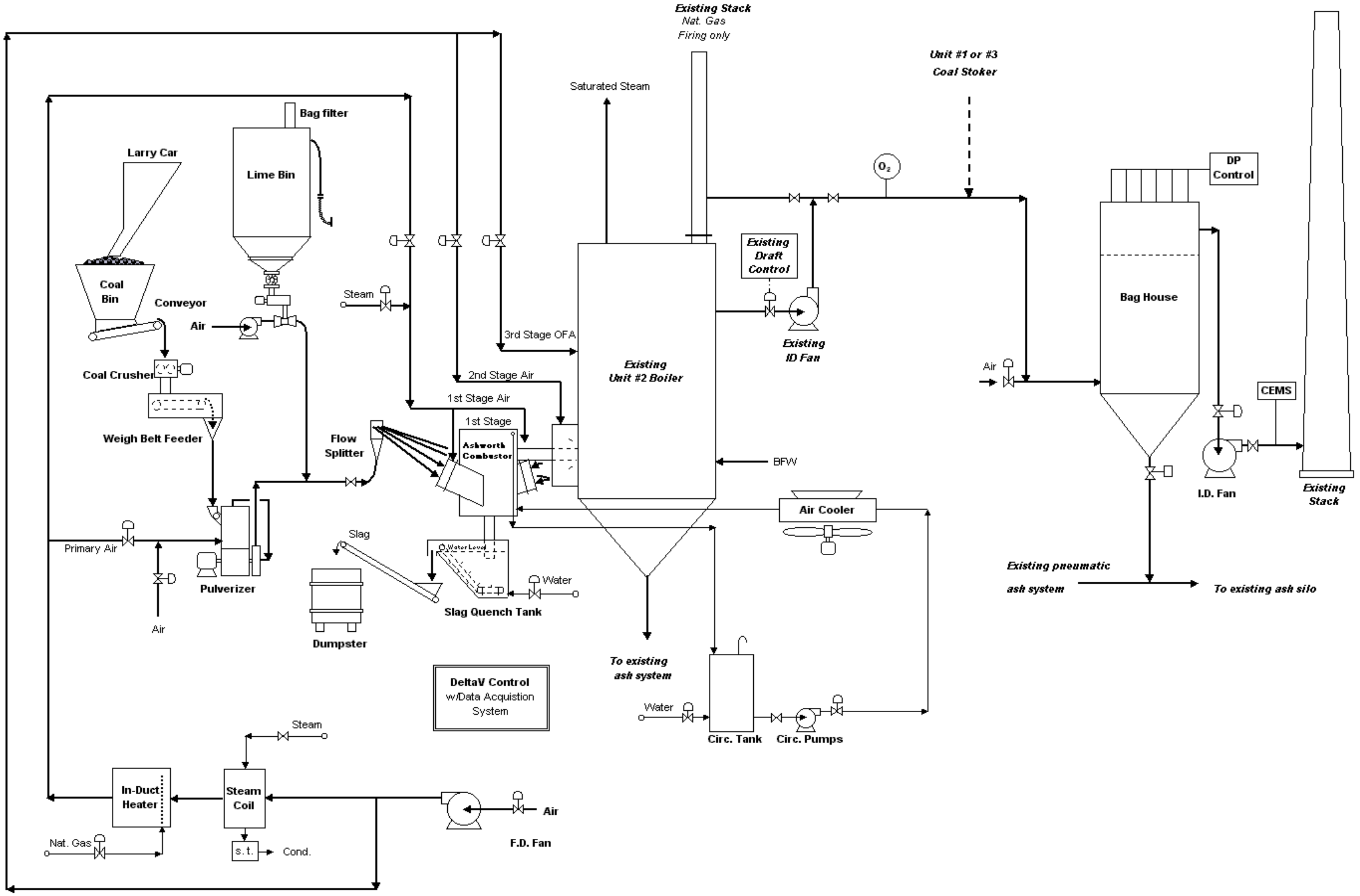


Figure 4. Simplified process flow diagram of *Ashworth Combustor* retrofit to Lincoln Unit #2.

Lincoln Developmental Center Test Program

After equipment checkout and startup, the test program will be initiated. It will include the testing of Illinois and Ohio coals. Samples of coal and alkalis used during the tests will be analyzed using ASTM methods. Test measurements and methods are shown in Table 2.

TABLE 2. TEST MEASUREMENTS AND METHODS

Measurement Parameter	**Sampling Method**	**Analytical Method**
Raw Materials		
Coal	Time interval grab samples	Proximate/ultimate anal.
Limestone	Grab sample	Mineral component
Lime/Nacholite	Grab sample	Mineral component
Raw material air toxics	Grab sample	ICP
1st Stage		
Fuel gas temperature	N/A	Thermocouple
O_2 and CO concentrations	Suction pump	Draeger Tubes
H_2S, SO_2, COS, NO_X conc.	Suction pump	Draeger Tubes
Molten slag carbon/sulfur	Time interval grab samples	Elemental analyzer
Molten slag leaching	Time interval grab samples	TCLP
Molten slag:	Time interval grab samples	X-ray fluorescence
Sulfur & Carbon	Time interval grab samples	X-ray diffraction
Air toxics	Time interval grab samples	ICP
Furnace		
Furnace temperature	N/A	Thermocouple
Fly ash carbon/sulfur	Exhaust gas line filter	Elemental analyzer
Fly ash leaching	Exhaust gas line filter	TCLP
Fly ash air toxics	Exhaust gas line filter	ICP
Air Pollutant Emissions		
Particulate matter	Heated filter	Gravimetric
NO_X	Extractive sample system	Chemiluminescent analyzer
SO_2	Extractive sample system	NDUV analyzer
CO	Extractive sample system	NDIR analyzer

A comprehensive test matrix will be used. The test matrix will be a dynamic one, what is learned from initial testing will be used in later testing to optimize performance regarding sulfur removal and NO_X reduction. Steam injection into the primary air of the first stage will be tested to determine its effect in improving both sulfur capture and carbon burnout. Various first and second stage combustion air:fuel stoichiometric ratios will be tested to evaluate the effect on NO_X reduction and carbon burnout. Elemental carbon and sulfur contents of the bottom ash and fly ash will be run to determine carbon burnout and sulfur capture. Although sulfur is captured as calcium sulfide, which by itself will hydrolyze to form hydrogen sulfide (H_2S), in pilot testing, no H_2S was liberated from the ash quench tank. The reason for this is that the CaS is tied up in a mineral slag eutectic that precludes hydrolysis.

TCLP (toxicity characteristic leaching procedure) analyses will be run on the fly ash and bottom ash to characterize their leaching characteristics. Air toxics in the coal, sorbents, bottom ash, and fly ash will be analyzed to determine their final disposition. These air toxic tests, in combination with the TCLP analyses, will characterize emission aspects of the combustor relative to potential air and water-soluble toxics contamination of soils and/or groundwater.

STATE-OF-THE-ART COMPARISON

A combustor retrofit to a coal-fired unit was compared to the same size and type of coal-fired unit retrofitted with commercially available technologies, a Selective Catalytic Reduction (SCR) system to reduce NO_X emissions, and a wet limestone scrubber to remove sulfur dioxide. The Ashworth Combustor is a combustion technique that reduces the three major air pollutants (SO_2, NO_X, and Particulate) from coal combustion. SCR and wet limestone scrubbing are post combustion techniques that remove sulfur dioxide and reduce NO_X emissions, respectively.

Ashworth Combustor

Although not yet commercially demonstrated, kinetic modeling indicates that the three-stage Ashworth Combustor will reduce NO_X emissions to levels below the US EPA ozone season limit (< 0.15lb/10^6 Btu). For high sulfur coals, the Ashworth Combustor provides the added benefit of removing sulfur in a molten slag from the combustor proper. It is expected that 70 to 80% of the coal sulfur will be captured. A simplified process flow diagram of the three-stage combustion technique is shown in Figure 4.

To retrofit this three-stage combustion technique to a utility boiler (wall-fired unit discussed here), the following modifications will be required:

1) Addition of limestone bin(s) with feeder(s) to each coal pulverizer
2) Replacement of coal burners with combustors
    - Furnace waterwall tie-ins, similar to that for cyclone barrels
    - Installation of pulverized coal feed line splitters to feed each combustor
    - Air flow sensing and control devices on the air lines to each combustor
    - Tie-ins to existing furnace tubewalls- combustor w/tubewall construction
3) Installation of a slag quench and sluice system from each combustor level on the boiler and a slag removal/disposal system similar to that for a cyclone-fired boiler
4) Installation of an overfire air (OFA) system

The existing burner throats will remain intact. To control the staged combustion, an innovative and accurate technique, that requires only airflow measurements and the oxygen concentration at the economizer exit, will be used. Accurate airflow measurements are required. Total airflow to the boiler, first stage airflow, and OFA flow rates will be used in combination with the furnace exit oxygen concentration to control the staged combustion process.

Items of concern for the technology are relegated to corrosion issues in the lower part of the furnace and possibly higher fly ash carbon. In three U. S. DOE Reburn demonstrations wherein part of the furnace was kept at a SR of 0.90, no boiler tube corrosion, or erosion, over and above that of normal wear was found. When the furnace is maintained at a SR of 0.90, the concentration of CO in the furnace is about 3%. At this level of CO, testing has also shown that tube corrosion occurs. This slightly reducing condition will exist in the lower part of a furnace retrofitted with the Ashworth Combustor, so corrosion should not be a problem.

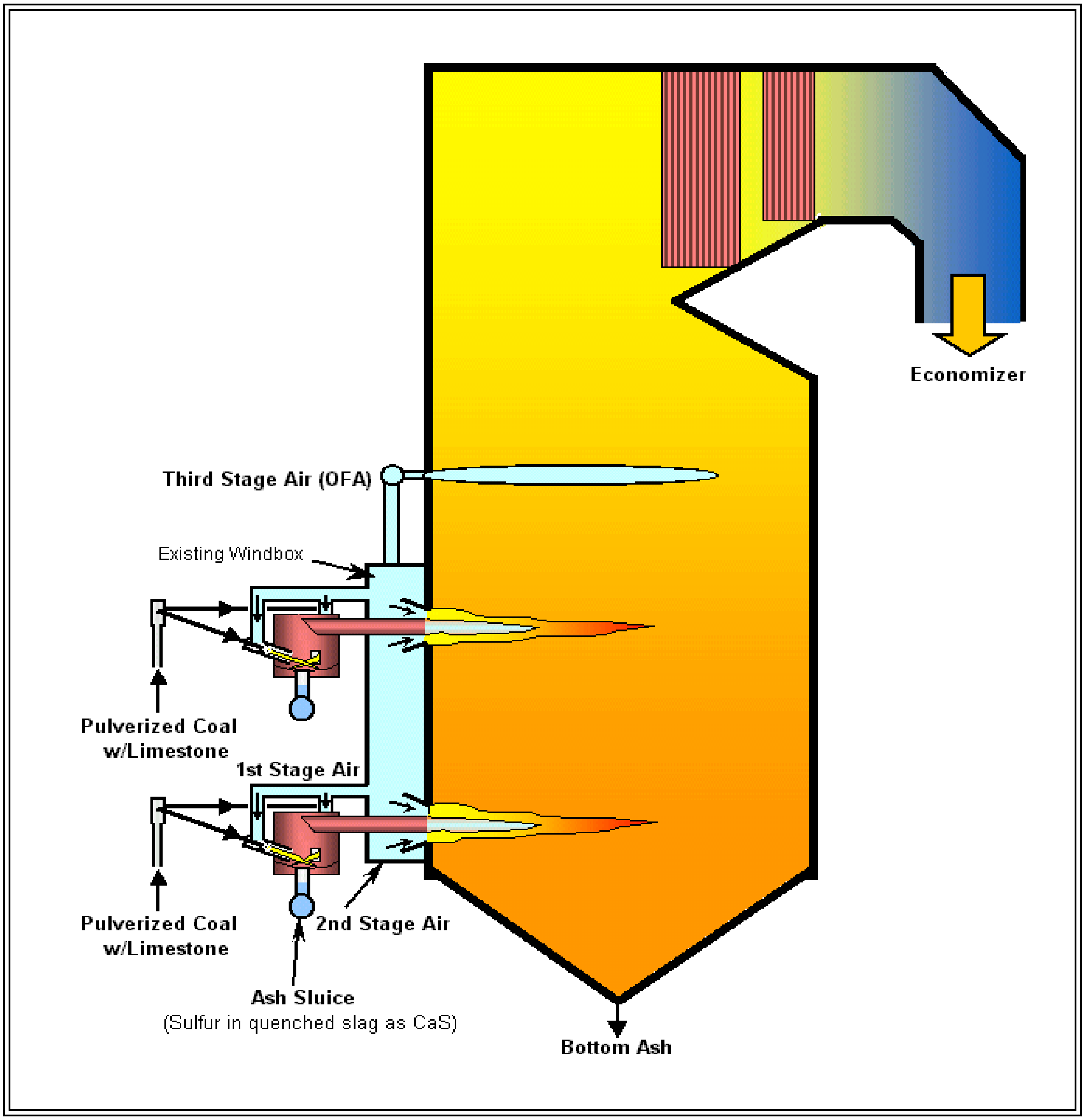


Figure 4. Simplified process schematic of Ashworth Combustor.

Regarding fly ash carbon content, the staged combustors add high temperature residence time to the overall combustion process and good carbon burnout is expected. Low-pressure steam can be added to the first stage for low reactive coals should higher carbon burnout be desired. In addition, most of the ash will exit the combustor proper as molten slag. In the two-stage pilot operation when using the nozzles used in Run #8, the carbon in the molten slag was only 1.3 wt % with 60% slag capture and the overall combustion efficiency was calculated at 98.6%. With the projected higher slag capture (70 to 80%) for the new design, in combination with the longer residence times and hotter furnace boxes of electric and industrial utility boilers, the combustion efficiency should exceed 99%.

Another advantage of staged combustion applied to a wall-fired unit is that much of the mineral matter will be removed from the combustor. For units that have electrostatic precipitators (ESPs), air toxic emissions to the atmosphere will be reduced since ESPs are constant efficiency removal devices, based on identical fly ash resistivities, as the flue gas particulate loading entering an ESP decreases, so does the outlet grain loading.

SCR Technology

An SCR system is placed upstream of the wet scrubber, ESP and air heater, see Figure 5. It includes the addition of ammonia to the flue gas upstream of beds of vanadium/titanium based catalyst wherein the NO_X (primarily nitric oxide - NO) produced in the boiler furnace is converted to diatomic (air) nitrogen, in accord with the following overall reaction:

$$4NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O$$

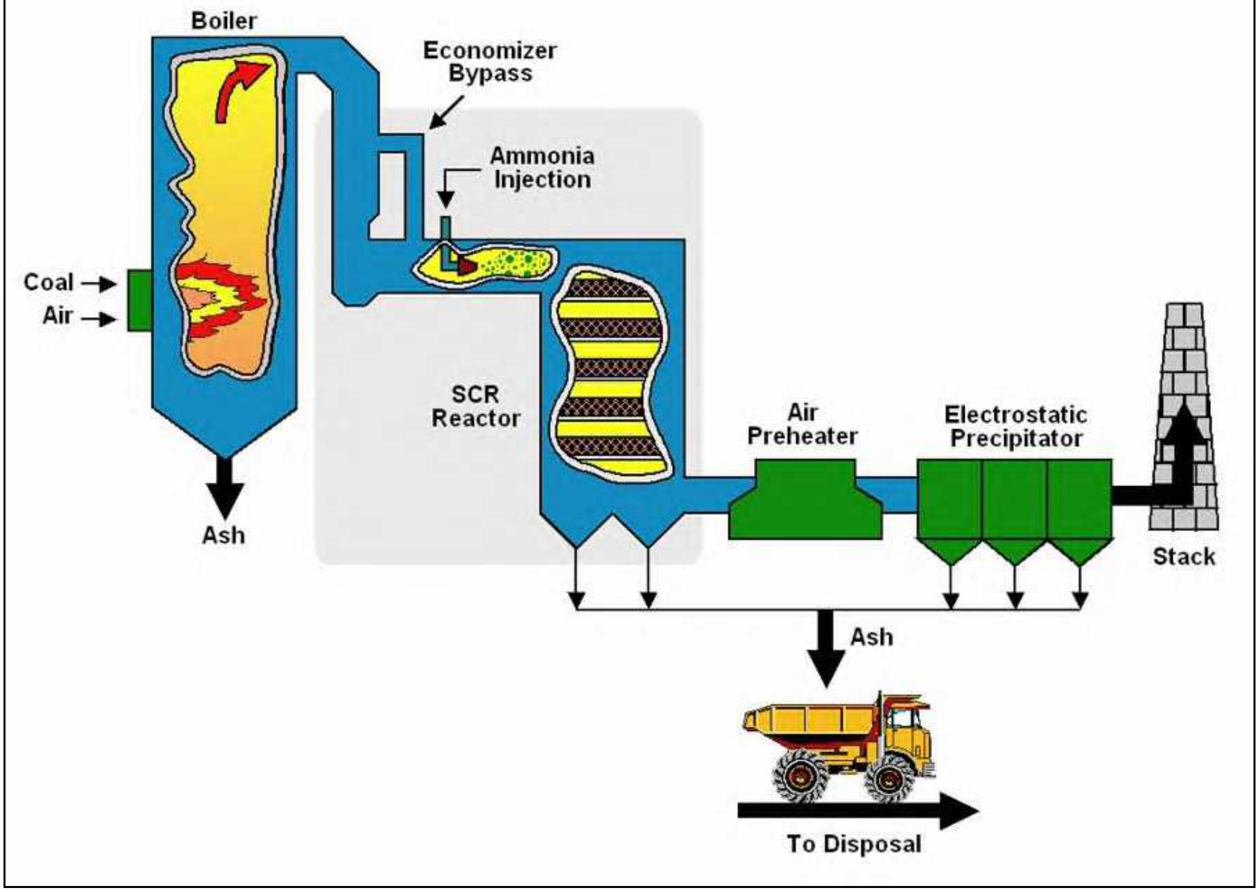


Figure 5. Simplified flow schematic of Selective Catalytic Reduction (SCR) process.

Although SCR is an effective method of reducing NO_X emissions, it has some serious operational considerations associated with it. When operating within a temperature range of 570 °F to 750 °F the catalyst performs well. Above 750 °F the catalyst will start to sinter, reducing its reactivity.

Below 570 °F, the formation of ammonium bisulfate (NH_4HSO_4) from the reaction of ammonia with sulfur trioxide starts to increase. The ammonium bisulfate blinds the catalyst and shortens its life:

$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_{4\,(\mathrm{liquid})}$$

Coals, high in arsenic content (e.g. 100 ppmw), will deactivate the catalyst, and shorten its life when operating in the normal temperature range. In addition, high calcium ash coals can cause calcium sulfate plugging of the catalyst. These concerns require electric utilities to be very careful concerning the quality of the coal purchased. In addition, the SCR temperature operating range constraints require that flue gas bypasses be installed around the economizer and catalyst reactor bed.

Further ammonia that slips through the catalyst beds will be adsorbed by the fly ash captured in the downstream ESP. Ammonia is pungent gas, and its presence makes it difficult to sell the ash to the cement industry. In addition, special air heater designs with spray washing features are preferred to allow for easier removal of ammonium bisulfate that forms near the cold end of the air heater.

Wet Limestone Scrubbing

Wet limestone scrubbers are located downstream of the power plant electrostatic precipitator (ESP). Incoming flue gas is cooled and humidified before passing into the absorber for the removal of sulfur dioxide. Limestone ($CaCO_3$) is added to the absorber feed tank and air is sparged through the tank to provide for the oxidation of the calcium sulfite ($CaSO_3$) to calcium sulfate ($CaSO_4$). Wet scrubbers typically remove around 90%+ of the sulfur dioxide in the flue gas. A simplified flow schematic of the CT-121 FGD process in shown in Figure 6.

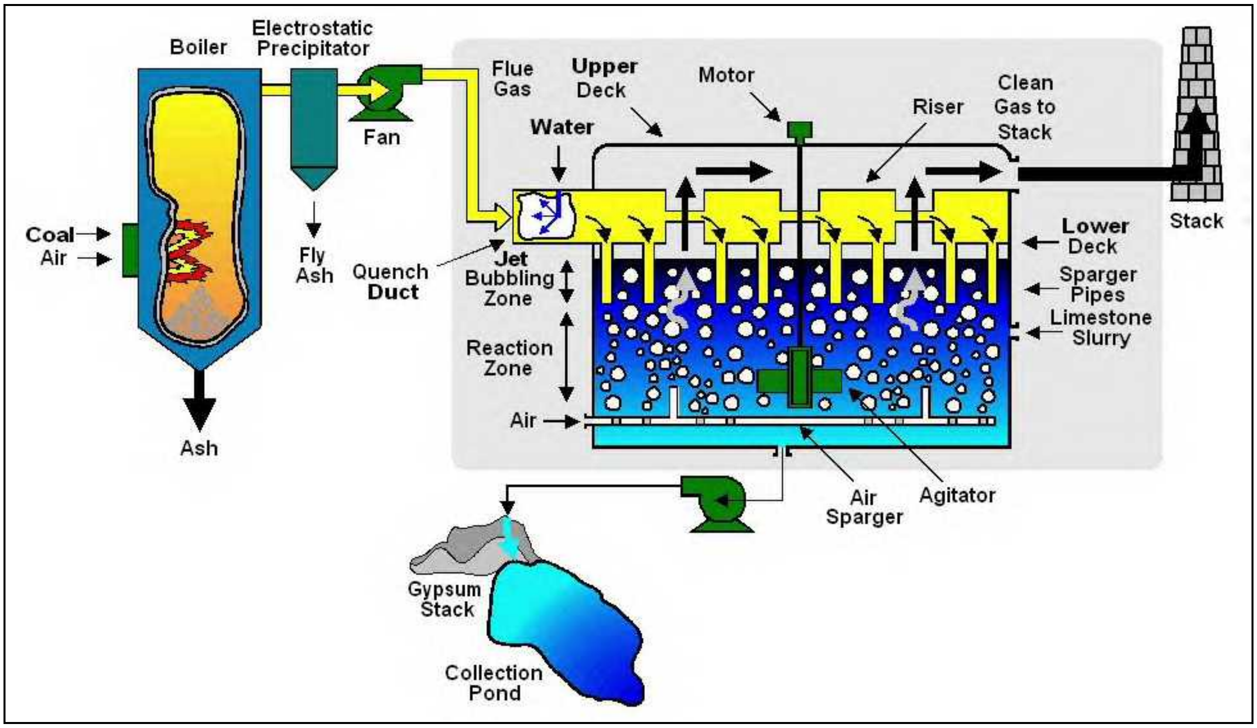


Figure 6. Simplified flow schematic of the CT-121 FGD process.

The produced calcium sulfate (gypsum) is dewatered and sent to a landfill, or with some processes the gypsum is dewatered, then washed and filtered or centrifuged to produce a wall-board quality gypsum. The following major reactions occur in the wet limestone scrubbing process:

Adsorption:
$SO_2 + H_2O \rightarrow H_2\ SO_3$
$SO_3 + H_2O \rightarrow H_2\ SO_4$

Oxidation:
$CaSO_3 + \frac{1}{2}\ O_2 \rightarrow CaSO_4$

Neutralization:
$CaCO_3 + H_2SO_3 \rightarrow CaSO_3 + CO_2 + H_2O$
$CaCO_3 + H_2SO_4 \rightarrow CaSO_4 + CO_2 + H_2O$

Crystallization:
$CaSO_4 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O$

The technical drawback of wet scrubbing systems is that it is like having chemical plants, with all of their associated operational and maintenance problems on the backend of a power plant. Further, unless reheat is applied, a large white vapor plume enters the atmosphere and dilute concentrations of sulfuric acid and nitric acid in the condensate from these plumes is corrosive to nearby equipment, piping, etc. From an aesthetic viewpoint, a white vapor plume with nitrogen dioxide (reddish-brown gas) in it draws attention to the power plant as a polluting neighbor.

Economic Comparison

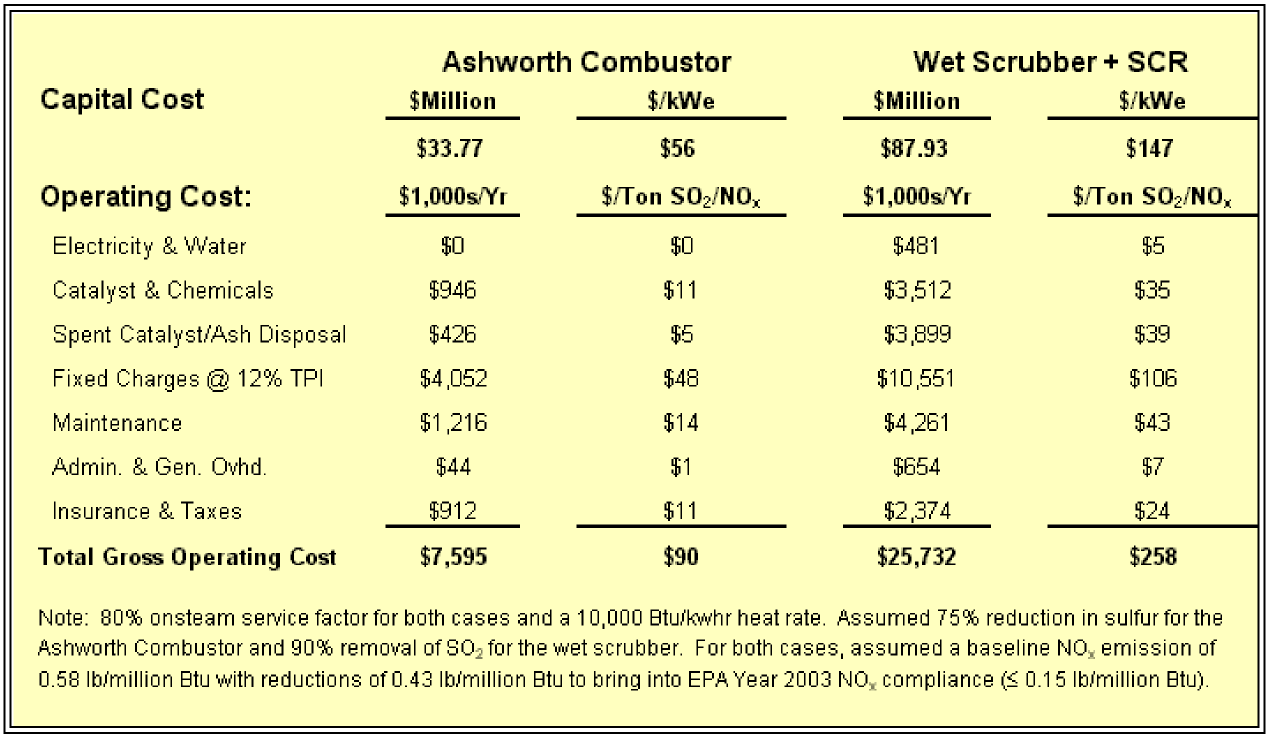
In Table 3 is the capital and operating cost comparisons for a retrofit of the Ashworth Combustor system and a Wet Limestone Scrubber plus SCR system. The comparison was made based on retrofits to a 600 MWe wall-fired electric power generating unit. The Wet Limestone Scrubber capital cost was based on work completed for ClearStack by Energy Ventures Analysis in 1999.

The annual operating costs for the Wet Limestone Scrubber were based on a study of existing wet scrubbers completed in 1999 by Burns and McDonnell Engineering Company. Both the SCR capital and annual operating costs were based on a 1999 in-house study that was compared with other published studies to assure that it was reasonable. The capital and annual operating costs for the Ashworth Combustor were also developed in-house. The comparison is based on firing a 3-wt% high sulfur coal with a heating value of 12,500 Btu/lb. For the comparison, it was assumed that the 600 MWe power plant would be operated at an 80% capacity factor.

Sulfur dioxide reductions of 75% and 90% were used for the Ashworth Combustor and the Wet Limestone Scrubber, respectively. NO_X reductions of 0.43lb/million Btu were used for both the Ashworth Combustor and the SCR system. The NO_X reduction value was chosen to reduce emissions to levels under the EPA ozone season limit for electric utility boilers in Eastern and Midwestern states that comes into effect May 31, 2004.

As seen in the table, the capital cost of the Ashworth Combustor system is about 38% of the cost of the Wet Limestone Scrubber plus SCR system. In addition, the operating cost to reduce SO_2 and NO_X emissions, based on cost per ton, using the Ashworth combustor is 35% of the cost of the Wet Limestone Scrubber plus SCR.

TABLE 3. CAPITAL AND OPERATING COST COMPARISON



	Ashworth Combustor		Wet Scrubber + SCR	
Capital Cost	**$Million**	**$/kWe**	**$Million**	**$/kWe**
	$33.77	**$56**	**$87.93**	**$147**
Operating Cost:	**$1,000s/Yr**	**$/Ton SO_2/NO_x**	**$1,000s/Yr**	**$/Ton SO_2/NO_x**
Electricity & Water	$0	$0	$481	$5
Catalyst & Chemicals	$946	$11	$3,512	$35
Spent Catalyst/Ash Disposal	$426	$5	$3,899	$39
Fixed Charges @ 12% TPI	$4,052	$48	$10,551	$106
Maintenance	$1,216	$14	$4,261	$43
Admin. & Gen. Ovhd.	$44	$1	$654	$7
Insurance & Taxes	$912	$11	$2,374	$24
Total Gross Operating Cost	**$7,595**	**$90**	**$25,732**	**$258**

Note: 80% onsteam service factor for both cases and a 10,000 Btu/kwhr heat rate. Assumed 75% reduction in sulfur for the Ashworth Combustor and 90% removal of SO_2 for the wet scrubber. For both cases, assumed a baseline NO_x emission of 0.58 lb/million Btu with reductions of 0.43 lb/million Btu to bring into EPA Year 2003 NO_x compliance (≤ 0.15 lb/million Btu).

CONCLUSION

The Ashworth Combustor three-stage combustion technique offers significant technical and economic advantages over the commercially available Wet Scrubber plus SCR combination of technologies. It could shortly become the low cost option for existing coal-fired power plants to meet the stringent Year 2000+ environmental regulations for SO_2 and NO_X emissions.

References:

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. *CWS Co-firing Demonstration* , EPRI Upgraded Coal Interest Group Report, January 20, 1997.

Disclaimer:

The findings, opinions, and recommendations expressed therein are those of the authors only and not necessary those of Southern Illinois University, the IL Clean Coal Review Board or the Ohio Coal Development Office.