COMMERCIAL/INDUSTRIAL COMBUSTION SYSTEMS SESSION

A COAL-FIRED COMBUSTION SYSTEM FOR INDUSTRIAL PROCESS HEATING APPLICATIONS

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1.0 INTRODUCTION AND BACKGROUND

The Pittsburgh Energy Technology Center (PETC) of the U.S. Department of Energy awarded Vortec Corporation contract No. DE-AC22-91PC91161 for the development of "A Coal-Fired Combustion System for Industrial Process Heating Applications" effective August 3, 1991. The program established by this contract and the work completed to date are described below.

This advanced combustion system research program is for the development of innovative coal-fired process heaters which can be used for high temperature melting, smelting, recycling, and refining processes. These process heaters are based on advanced glass melting, waste vitrification, and ore smelting furnaces developed and patented by Vortec Corporation. The process heater systems have multiple use applications; however, the Phase III research effort is being focused on the development of a process heater system to be used for the vitrification of waste ashes. In many cases, the vitrified glass product can be used for the production of value added products such as mineral wool.

The Vortec CMS represents a significant advancement in glass melting/vitrification technology. This suspension melting process can be used for a variety of high temperature process heating applications. The primary components of the CMS are a counter-rotating suspension preheater and a cyclone melter. An artist rendering of the basic CMS concept is shown in Figure 1.

A unique feature of the Vortec CMS versus other coal-fired cyclone combustion concepts is the in-flight heating of feedstock materials in the flame zone of the counter-rotating vortex (CRV) combustor prior to melting in the cyclone reactor. The CRV is a well-stirred/plug flow combustor which rapidly preheats various feedstock materials in suspension and along the walls of the combustor assembly. The well-stirred region of the CRV is a zone of strong turbulence and gas recirculation produced by the interaction of opposed vortex rings which are generated by tangentially opposed air/gas inlets at different elevations along the longitudinal periphery of the combustor. The plug flow region, downstream of the well stirred region, is produced by balancing the angular momentum of the opposed vortex rings. In typical operation, pulverized coal and pulverized feedstock materials are introduced into the top end of the CRV along the longitudinal axis via a co-axial injector assembly. The strong turbulent mixing and recirculation in the well-stirred zone of the CRV produces excellent flame stabilization for pulverized coal or other fuels in the presence of substantial amounts of inert particulate matter. Because of the strong turbulent mixing within the CRV, convection is the primary heat transfer mechanism for rapidly elevating the temperature of the feedstock materials.

Correspondingly, the rapid heating of the feedstock materials rapidly quenches the combustion gas temperatures within the CRV, which inturn provides an effective means of limiting local

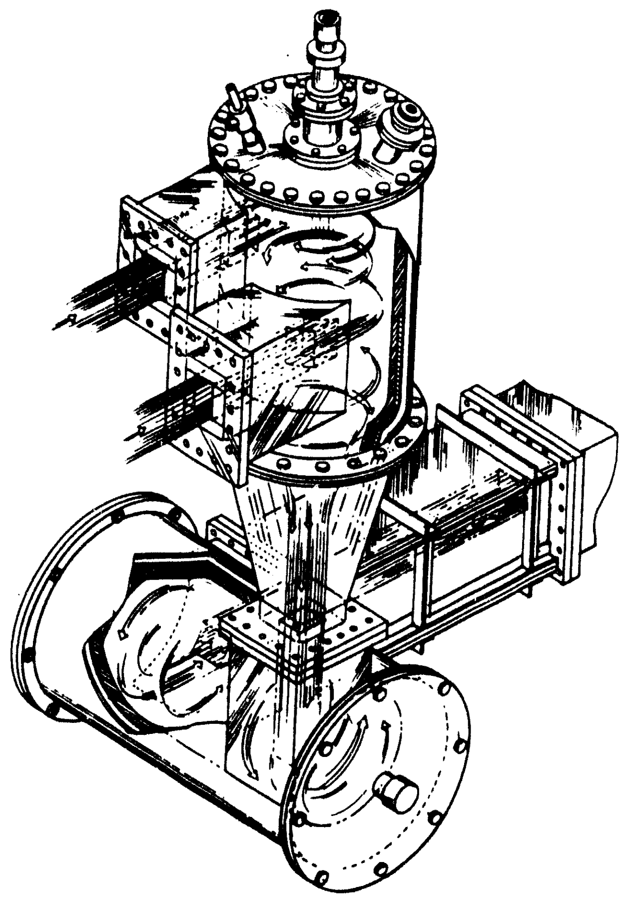

Figure 1 Artist Rendering of Vortec CMS

temperatures and NOx emissions. Rapid temperature quenching of the combustion products by the inert waste glass particles and staged combustion are the primary means of limiting NOx emissions. Experimental data obtained during the course of feasibility experiments with the pilot-scale CMS indicate NOx emissions are lower than the California emission standards (4.5 lbs per ton of glass produced) for glass melting furnaces. In this regard, it should be noted that the California glass melting emission standards for NOx are currently the most stringent in the United States.

The combustion products and heated feedstocks exiting the CRV enter the top of the cyclone reactor through a tangential inlet. The feedstock materials are separated to the walls of the cyclone reactor by gas dynamically induced centrifugal forces. Typical feedstock temperatures are in the range of 1700°F to 2800°F. Rapid chemical reactions and homogenization of the feedstock materials occur within the cyclone reactor, along with secondary combustion of the combustion products. Typical liquid temperatures exiting the cyclone reactor are in the range of 2000°F to 2800°F, depending on the materials being melted.

The products of combustion and the melted product exit the cyclone reactor through a tangential channel located at the rear of the cyclone. The melted material is then collected in a reservoir for further processing of the melted materials. The combustion products exit the reservoir through a side or top port to a heat recovery device and/or an air pollution control subsystem.

The uncontrolled particulate emission levels of the CMS are about the same as conventional gas-fired glass melting furnaces. Therefore, the use of commercially available particulate control devices will be incorporated into the design as dictated by local flue gas emission regulations.

2.0 OBJECTIVES

This contract is the third phase of a three phase R&D program which was initiated during March 1987. The objective of the program is to develop an advanced industrial process heater capable of using pulverized coal or coal derived fuels as the primary fuel.

The primary objective of the Phase III project is to develop and integrate all the system components, from fuel through total system controls, and then test the complete system in order to evaluate its potential marketability. Vortec believes that the coal-fired process heater has multiple applications including the manufacture of mineral fibers from utility flyash, the production of value-added glass products from industrial waste, and the vitrification of hazardous ashes to render them essentially non-leachable. As a result, the entire test program has opportunities built into it to demonstrate the systems capability to vitrify alternative feedstocks.

An additional task was added by the DOE for the pilot-scale melt testing of simulated Toxic Substance Control Act (TSCA) ash. The objective of this testing was to demonstrate the ability of the Vortec CMS to remediate ash from DOE operated TSCA waste incinerators processing solid materials with low-level radioactive constituents. The pilot-scale testing was composed of two demonstration tests. The first demonstration test provided a database on the performance and operation of the CMS when vitrifying surrogate TSCA incinerator ash feedstocks. The feedstock (including surrogates for radionuclides) was a mixture of municipal solid waste incinerator (MSWI) bottom ash and fly ash, and heavy metal oxides. The primary purpose of the first test in the sequence was to evaluate the melting performance and to define the expected range of flue gas emissions from the Vortec CMS when processing a surrogate TSCA incinerator ash containing approximately 5 wt% carbon.

A second demonstration test was performed with a surrogate TSCA incinerator ash containing 12 wt% carbon. The goal of the second test was to obtain additional data on the performance of the CMS when processing simulated TSCA ash and to evaluate the effect of the relatively high carbon content in the ash on the capture rate of the heavy metal and radionuclide surrogates in the vitrified product.

3.0 CURRENT STATUS

<u>Testing Results</u>
Preliminary and Proof-of-Concept testing has been completed using utility boiler flyash, industrial boiler flyash, Municipal Solid Waste Incinerator (MSWI) ash, and simulated TSCA ash. The Vortec CMS produced homogeneous fully vitrified glass products using each of these ashes as feedstocks. Data from the most recent test, the simulated TSCA ash, is presented below.

The surrogate TSCA ash was a mixture of municipal solid waste incinerator (MSWI) bottom ash and fly ash, coal, and metal contaminants as shown in Table 1. The metal contaminants are comprised of the surrogate heavy metals and radionuclides. A combined bottom ash and fly ash mixture was used as the base material for the surrogate TSCA ash. Arsenic, barium, cadmium, chromium, and lead were added to the surrogate ash mixture as metal oxides to increase the concentration of these heavy metals to the level desired by DOE. Cerium and cesium were added to the surrogate ash mixture as simulated radionuclides. Simulated radionuclides are non-radioactive metals, the behavior of which will simulate the behavior of the true radionuclide species in the CMS. Cerium was added as cerium oxide to simulate the behavior of uranium within the CMS, for its chemical properties are similar to those of uranium. Cesium was added as cesium chloride, as specified by DOE, to simulate the behavior of radioactive cesium within the CMS. Mercury, selenium, and silver were excluded due to their high cost or because Vortec

Table 1 TSCA Feedstock Formulations used in the Two Feasibility Tests and the Resulting Concentration of the Metal Contaminants

	Test 1 lbs	Test 2 lbs
MSWI bottom ash	2729	2337
Fly ash	2145	1837
Coal	193	600
As2O3	19.8	19.4
BaO	12.7	11.5
CdO	16.65	16.35
Cr2O3	18.6	18.6
PbO	1.1	2.4
CeO2	15.0	14.7
CsCl	15.4	14.7

Element	Test 1 Concentration of Element ppm	Test 2 Concentration of Element ppm
As	2975	3082
Ba	3022	2877
Cd	2910	3019
Cr	2938	3026
Pb	2730	2757
Ce	2361	2453
Cs	2353	2382

presently considers these materials to be too hazardous to handle at our pilot facility. However, the metals which were added to the surrogate ash represent both semi-volatile and non-volatile metals; therefore, the behavior of the excluded metals can be estimated based on the behavior of the metals included in the surrogate ash.

The carbon content of the surrogate TSCA ash varied between the two tests to study its effect on the capture rate of the heavy metal and radionuclide surrogates in the vitrified product. The carbon content of the surrogate ashes used in the feasibility tests were 5 wt% and 12 wt%. In order to vary the carbon content of the ash mixture, appropriate quantities of pulverized coal were added to the surrogate ash mixture. The chemical composition of the coal used as an additive in the feasibility testing is listed in Table 2.

The batch tank was loaded with the appropriate surrogate ash and coal feedstock, and the feedstock was pneumatically blended. The resulting chemical composition of the blended feedstocks is presented in Table 3.

Prior to the initiation of either of the feasibility tests, the system was brought to a temperature of approximately 2650°F. The first test was conducted using the 5% carbon feedstock. The test (Test 1a) was initially conducted using a molten glass temperature of 2500°F at a feed rate of 1000 lbs/hr. Later, the test conditions were changed (Test 1b) by allowing the glass temperature to decrease to 2300°F to investigate the effect of temperature on the partitioning of the metal contaminants among the effluent streams.

The second test was conducted using the feedstock containing 12% carbon. During the initial portion of this test (Test 2a) the molten glass temperature was held at 2300°F and the feed rate was set at 500 lbs/hr. Later during the test (Test 2b), the feed rate was increased to 1000 lbs/hr and the temperature was increased to 2500°F.

Glass samples were taken continuously during both feasibility tests in two forms: glass patty, which was air quenched, and glass cullet, which was water quenched. The glass samples were obtained, handled, and prepared for analysis according to the sampling and custody procedures described in the test plan. The glass chemistry and PCT analyses were conducted by Corning Engineering Laboratory Services (CELS), and the TCLP testing was conducted by Blue Marsh Laboratories. Also, the feed rate and temperature were held constant for 1 hour so that EPA Method 5 sampling of the flue gas effluent could be conducted.

Table 2 Chemical Composition of Coal

Proximate Analysis	dry wt%	Ash Analysis	dry wt%
ash	1.23	SiO2	47.17
volatile	35.38	Al2O3	30.9
fixed carbon	63.39	K2O	1.46
sulfur	0.61	Na2O	1.32
		CaO	3.46
Ultimate Analysis	wt %	Fe2O3	10.09
carbon	85.44	MgO	0.89
hydrogen	5.32	SO3	1.32
nitrogen	1.62	BaO	0.32
chlorine	-	TiO2	1.89
sulfur	0.61	P2O5	0.31
ash	1.23	SrO	0.39
oxygen	5.78	Mn3O4	0.06

Table 3 Composition of the Combined Feedstocks used in the Two Feasibility Tests

	Test 1	Test 2	
Element	Oxide	wt% of oxide	wt% of oxide
Al	Al2O3	9.1466	8.6063
As	As2O3	0.3927	0.4068
Ba	BaO	0.3384	0.3222
B	B2O3	0.1226	0.1028
Cd	CdO	0.3317	0.3442
Ca	CaO	17.738	17.227
Ce	CeO2	0.2904	0.3017
Cs	CsCl	0.2981	0.3017
Cl	Cl	3.6794	3.3415
Cr	Cr2O3	0.4289	0.4417
Fe	Fe2O3	6.052	5.3874
Pb	PbO	0.2949	0.2977
Mg	MgO	4.9534	5.502
K	K2O	1.463	1.3131
Si	SiO2	33.0417	30.4023
Na	Na2O	3.463	3.1379
S	SO3	3.406	3.358
C	C	5.013	12.184
Hg	HgO	ND	ND
Se	Se	2 ppm	5 ppm
LOI		13.11	20.80

ND = Not detected.

From a qualitative standpoint, the glass produced from the surrogate TSCA ash was consistently black in color throughout both tests. Within a single glass sample, no color variations could be seen in the glass cullet. Table 4 presents the chemical composition of the glass formed during the feasibility tests. The chemical analysis was performed by CELS.

The effect of operating temperature and carbon content in the ash on the composition of the glass seems to be negligible for all the glass forming compounds and the metal contaminants, except for cadmium. The concentration of cadmium in the glass increased by a factor of two for Test 2a—the low temperature, low feed rate test.

Both glass cullet and glass patty samples, collected during both feasibility tests, were sent to Blue Marsh Laboratories for TCLP testing. The TCLP leachates were analyzed for the metal contaminants added to the surrogate TSCA ash. The results of the TCLP testing, along the concentration of the metal contaminants in the glasses, are displayed in Table 5. All the TCLP analyses indicate that all the glass produced during Vortec's feasibility testing has excellent leach resistance for the heavy metals and simulated radionuclides.

Both glass cullet and glass patty samples, collected during both feasibility tests, were also sent to CELS for PCT analysis. CELS performed PCT procedure B on the glasses, and analyzed the leachates for the glass forming elements (K, Na, B, Ca, Mg, and Si). The PCT testing followed all the specifications of PCT procedure A, but PFA Teflon vessels were used instead of stainless steel. CELS also reported the final pH of the leachate. The results of the PCT testing are displayed in Table 6. The current PCT specification for nuclear waste glasses is a weight loss of 1 g/m2/day for Li, Na, K, Si, and B combined. The PCT result for the vitrified product resulted in a sodium-based glass leach rate of approximately 0.02 g/m2/day.

Table 4 Chemical Composition of Glass Produced during Feasibility Tests

Compound	Test 1a Cullet	Test 1a Patty	Test 1b Cullet	Test 1b Patty	Test 2a Cullet	Test 2a Patty	Test 2b Cullet	Test 2b Patty
	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%
Cs2O	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02
K2O	0.73	0.76	0.76	0.74	0.78	0.78	0.68	0.68
Na2O	2.88	2.86	2.91	2.91	2.91	2.91	2.74	2.75
Al2O3	12.5	12.2	12.4	12.6	11.8	11.9	11.9	12.0
As2O3	0.14	0.12	0.15	0.14	0.17	0.15	0.16	0.13
B2O3	0.17	0.16	0.18	0.19	0.14	0.14	0.14	0.15
BaO	0.38	0.39	0.38	0.38	0.36	0.38	0.40	0.39
CaO	22.5	22.3	22.1	22.1	21.6	21.9	22.4	22.6
CdO	0.023	0.02	0.042	0.039	0.080	0.081	0.033	0.035
CeO2	0.24	0.32	0.28	0.29	0.46	0.27	0.35	0.28
Cr2O3	0.48	0.47	0.47	0.47	0.44	0.45	0.52	0.51
Fe2O3	7.60	7.75	7.48	7.37	7.51	7.61	7.46	7.53
HgO	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
MgO	6.29	6.10	6.52	6.53	7.10	7.20	7.23	7.37
PbO	0.16	0.16	0.17	0.17	0.17	0.19	0.15	0.15
SiO2	42.2	42.9	42.3	42.3	42.7	43.1	42.0	42.2
C	0.008	0.008	0.007	0.007	0.008	0.009	0.008	0.009
SO3	0.17	0.17	0.068	0.049	0.044	0.045	0.031	0.038
Se	<1 ppm	<1 ppm	<1 ppm	<1 ppm	<1 ppm	<1 ppm	<1 ppm	<1 ppm
Cl	0.29	0.32	0.27	0.20	0.069	0.088	0.12	0.13

Table 5 Concentrations of the Metal Contaminants in the Glasses Produced during Vortec's Feasibility Testing and Their Corresponding TCLP Results

	Glass Cullet Glass Composition ppm	Glass Cullet TCLP ppm	Glass Patty Glass Composition ppm	Glass Patty TCLP ppm	TCLP RCRA Limit// Practical Quantitation Limit ppm
			Test 1a		
As	1061	ND	909	ND	5.0 // 0.1
Ba	3393	0.14	3482	0.14	100. // 0.05
Cd	202	ND	175	ND	1.0 // 0.02
Cr	3288	ND	3219	ND	5.0 // 0.02
Pb	1482	0.3	1482	0.3	5.0 // 0.1
Ce	1951	0.1	2602	0.1	NA // 0.1
Cs	187	ND	283	ND	NA // 0.1
			Test 1b		
As	1136	0.4	1061	ND	5.0 // 0.1
Ba	3393	0.14	3393	0.19	100. // 0.05
Cd	368	ND	342	ND	1.0 // 0.02
Cr	3219	ND	3219	ND	5.0 // 0.02
Pb	1574	0.2	1574	0.2	5.0 // 0.1
Ce	2276	0.1	2358	0.2	NA // 0.1
Cs	187	ND	187	ND	NA // 0.1
			Test 2a		
As	1288	ND	1136	ND	5.0 // 0.1
Ba	3214	0.16	3393	0.20	100. // 0.05
Cd	702	0.02	711	0.03	1.0 // 0.02
Cr	3014	ND	3082	ND	5.0 // 0.02
Pb	1574	ND	1759	0.1	5.0 // 0.1
Ce	3740	0.1	2195	0.2	NA // 0.1
Cs	187	ND	187	ND	NA // 0.1
			Test 2b		
As	1212	ND	985	ND	5.0 // 0.1
Ba	3571	0.09	3482	0.19	100. // 0.05
Cd	290	ND	307	ND	1.0 // 0.02
Cr	3562	ND	3493	ND	5.0 // 0.02
Pb	1389	ND	1389	0.1	5.0 // 0.1
Ce	2846	0.1	2276	0.2	NA // 0.1
Cs	187	ND	187	ND	NA // 0.1

ND = The compound indicated was not detected at or above the practical quantitation limit.
NA = Not applicable.

Table 6 PCT Results of the Glasses Produced during Vortec's Feasibility Testing

	Test 1a Cullet ppm	Test 1a Patty ppm	Test 1b Cullet ppm	Test 1b Patty ppm	Test 2a Cullet ppm	Test 2a Patty ppm	Test 2b Cullet ppm	Test 2b Patty ppm
K	1.8	2.0	2.6	2.4	2.5	4.3	2.5	2.9
	1.8	2.1	2.5	2.4	2.4	4.1	2.6	2.8
Na	5.3	5.6	7.0	6.5	8.5	12.1	7.3	8.0
	5.3	5.8	6.8	6.4	8.4	11.8	7.5	8.0
B	0.13	0.12	0.14	0.14	0.15	0.20	0.14	0.17
	0.12	0.12	0.13	0.13	0.15	0.19	0.14	0.16
Ca	17.3	17.1	20.6	20.4	22.3	16.4	22.7	23.8
	17.7	17.6	20.1	20.7	22.3	16.2	23.2	23.9
Mg	0.007	0.006	0.004	0.004	0.004	0.010	0.004	0.004
	0.005	0.005	0.004	0.003	0.003	0.007	0.003	0.002
Si	14.5	15.1	16.3	16.4	16.3	16.3	17.1	16.8
	14.3	15.0	16.2	16.6	16.6	16.3	16.8	16.9
pH	10.7	10.8	10.9	11.0	11.1	11.0	11.0	11.1
	10.7	10.8	11.0	11.0	11.1	11.0	11.0	11.1

NOTE: The initial pH of the extraction solution was 4.9.

4.0 SUMMARY AND FUTURE PLANS

All of the facility modifications have been completed and demonstration testing is underway. The demonstration testing is being conducted using utility boiler flyash as the primary feedstock component.

The conclusion of the TSCA feasibility testing is that the CMS can successfully process surrogate TSCA ash, resulting in a fully-reacted vitrified product without the need for additional glass forming agents. These results are consistent with previous CMS test results of MSWI flyash vitrification.

Optimization testing using the TSCA ash should be performed to determine the optimal ranges of operating temperatures and feed rates. The operating temperatures used in the feasibility testing were higher than required for effective operation of the CMS. Experience has shown that molten flyash has a steep viscosity curve. Due to lack of experience with the surrogate TSCA ash, higher system temperatures (approximately 100-200°F higher than required) were used throughout the feasibility testing to ensure proper operation, without concern of plugging. Additional testing using the simulated TSCA ash will be performed as funding permits.

DEVELOPMENT AND TESTING OF AN INDUSTRIAL SCALE ,

COAL FIRED SLAGGING COMBUSTION SYSTEM

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Contract: DE-AC22-91PC91162

Period of Performance: 9/30/91 to 9/30/95

PROJECT OBJECTIVES

The primary objective of the present effort is to perform extended duration testing of a 20 MMBtu/hr commercial scale, air cooled, slagging coal combustor. Combustor applications include coal and solid fuel combustion in industrial steam boilers and power plants. The tests focus on durability and automatic control of the combustor. Another goal is to achieve 0.4 lb./ MMBtu of SO_2 emissions, 0.2 lb./MMBtu of NO_x emissions, and 0.02 lb. particulates/MMBtu in the combustor boiler system. The average NO_x level for all test conditions to date was 0.5 lb/MMBtu at a combustor stoichiometric ratio of 0.75. At optimum staged combustion conditions, the lowest NO_x level measured was 0.26 lb./MMBtu. With sorbent injection into the combustor at an effective Ca/S mol ratio of 3, the average SO_2 level at the boiler outlet was 0.7 lb./MMBtu, equal to a 70% reduction in 1.7% sulfur coals. The maximum reduction achieved was about 85%, equal to 0.36 lb/MMBtu in a 1.5 % sulfur coal. Separately, SO_2 levels of 0.6 lb./MMBtu, equal to 81% reduction in a 2% sulfur coal was measured with only boiler injection of the sorbent. Therefore, a combination of sorbent injection inside the combustor and inside the boiler should meet the project goal for SO_2.

The original project plan to meet these objectives calls for 800 hours of testing, of which 300 hours were in tasks 2 and 3, and 500 hours in task 5. The initial objectives of combustor durability and automation have been met in task 2 and 3 tests of 262 hours total duration, of which 147 were with coal. In tasks 2 and 3 tests, the steam was blown off. For the final task 5 site demonstration tests, the combustor-boiler system is being relocated to a site where the boiler output will be utilized for heat and power generation. This will allow additional testing of up to several 1000 hours of operation.

The final task, which is to evaluate site specific commercial power and steam generating applications for the combustor, has been completed. Systems studied include a 20 MW combined cycle power plant, a 20 MW steam repowering plant, several industrial waste-coal cofiring combustor-boiler systems, and several stand alone industrial waste combustor-boiler systems. In all cases studied , the present combustor-boiler system was substantially lower in costs that alternate options.

ACCOMPLISHMENTS & CONCLUSIONS

1. Introduction

The experimental effort is being implemented on Coal Tech's patented, 20 MMBtu/hr, air cooled cyclone coal combustor that is installed on an oil designed, package boiler. For the initial tests in tasks 1,2, and 3, an existing installation at a boilerhouse in an industrial plant in Williamsport, PA was used. Since installation in 1987, the combustor has undergone about 2000 hours of development and demonstration testing. The primary fuel has been coal. Other fuels were No.2 and No.6 oil, natural gas, and municipal refuse derived fuels. In addition, considerable testing on vitrification of fly ash was performed.

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The combustor's novel features are air cooling and internal control of SO_2, NO_x, and particulates. Air cooling, which regenerates the heat losses in the combustor, results in a higher efficiency and more compact combustor than similar water cooled combustors. Internal control of pollutants is accomplished by creating a high swirl in the combustor which traps much of the mineral matter injected in the combustor and converts it to a liquid slag that is removed from the floor of the combustor. SO_2 is controlled by injected calcium oxide based sorbents into the combustor to react with sulfur emitted during combustion. The larger spent sorbent particles are dissolved in the slag and removed with it, thereby encapsulating the sulfur in slag. The smaller spent sorbent particles exit the combustor with the combustion gases. NO_x is controlled by staged, fuel rich combustion inside the combustor.

Excellent progress has been made in the past several years in meeting the combustor performance objectives. One of the more important objectives is to demonstrate very high SO_2 reduction in the combustor. Prior to the start of the present project, the peak SO_2 reduction achieved with sorbent injection in the combustor has been 56%, (+/-) 5%. Subsequent tests indicated solids feed and combustion uniformity impact the SO_2 reduction process. Progress in both areas has been achieved by the use of computer control of the combustion process and by optimization of the feeding and mixing the coal and sorbents. In the summer of 1992, tests performed in a prior project yielded SO_2 reductions in the range of 85% in a 1.5% sulfur coal at a Ca/S mol ratio somewhat in excess of 3.

Tests in the current project revealed that further modifications were needed to the coal and sorbent feed systems to maintain very uniform coal and sorbent feed injection conditions for extended operating conditions. Also, modifications were needed to extend combustor durability. As a result, little effort emphasis was placed on optimization of SO2 and NOx reductions. Average 70% SO2 reductions were achieved during the present test effort at effective Ca/S mol ratios somewhat greater than 3. It was also determined that calcium hydrate is three times more effective than limestone for sulfur capture. .

Combustor durability is an essential requirement for commercial utility of the combustor. Due to the aggressive nature of the combustion process and the need to utilize refractory materials inside the combustor to withstand the 3000^{o}F gas temperatures, durability has been one of the key challenges in the development process. Wall refractory material has been replenished by deposition of coal slag on top of the refractory wall. This procedure has been refined and fully demonstrated in the task 3 tests. It has substantially increased combustor wall durability, and the entire task 3 tests of nearly 200 hours of operation were performed with no significant refurbishment of the combustor walls. Also in task 3, the longest continuous operation to date of 27 hours at a steady high thermal input with coal alternating with oil was performed. Since many industrial applications require cycling of the combustor, it is planned in the task 5 site demonstration tests to operate the combustor primarily during the day shift, 5 days per week, 12 months per year. .

Work on this project began on January 1, 1992 with the effort on task 1. It consisted of the design, installation and checkout testing of the modifications to the combustor that are necessary to implement the initial project test activities, and it was completed by the end third quarter of 1992. The Task 2 "Preliminary Systems Tests", which consisted on a series of six one day tests, totaling 77 hours of operation, was completed in May, 1993. The task 3, "Proof of Concept Tests", which consisted of 185 hours of operation, including two tests of 24 and 27 hours of continuous operation, began in June 1993, and were completed in December 1993. The Task 4, ,"Economics and Commercialization Plan", effort began in early 1992 and was completed in 1993. In December 1993, the 20 MMBtu/hr combustor facility in Williamsport, PA was disassembled for relocation to the Philadelphia region. Here long duration testing will be implemented under conditions where the boiler's steam output will be utilized for heat and power generation. As part of this task 5 effort extensive combustor modifications are being implemented. This paper will summarize the activities of the past year on this project..

2. Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature (> 3000 F) device in which a high velocity swirling gas is used to burn pulverized coal. Figure 1 shows a schematic of Coal Tech's patented, air cooled combustor. A gas and oil burner is used to pre-heat the combustor and boiler during startup. Dry pulverized coal and sorbent powder for SO_2 control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by using a ceramic liner, which is cooled by the swirling secondary air. The liner is maintained at a temperature high enough to keep the slag in a liquid, free flowing state. The slag is drained through a tap at the downstream end of the combustor.

3. Description of the 20 MMBtu/hr Combustor-Boiler Test Facility

The 20 MMBtu/hr combustor was installed in 1987 on a 17,500 lb./hr steam boiler at an industrial plant in Williamsport, PA. Figure 2 shows a side view drawing of the combustor attached to the boiler. The coal is pulverized off-site, and it is delivered to the site in a tanker truck. A 4 ton capacity coal storage bin next to the boiler house receives the powdered coal from the tanker. The coal is metered through a pneumatic line to the combustor. The bin is refilled without combustor shutdown. A wet particulate scrubber is used to meet local emission requirements. Slag drains from the combustor into a water filled tank from which it is removed with a conveyor belt and deposited in a drum. The fuel and air streams to the combustor are computer controlled using the combustor's thermal performance as input variables. Diagnostics consist of measurement of fuel, air and cooling water flows, combustor wall temperatures, and stack gases, including O_2, CO_2, CO, SO_2, NO_x, HC. Gas samples are taken in the stack above the boiler, upstream of the wet particle scrubber.

4. Project Tasks

Task 1: Design, Fabricate, and Integrate Components: This task consists of design, fabrication, installation, and shakedown tests of the combustor to allow coal fired operation for periods of up to 100 hours.

Task 2: Preliminary Systems Tests: The modified combustor will undergo six, one day parametric test to validate the design changes introduced in task 1.

Task 3. Proof of Concept Tests: The durability of the combustor will be determined in a series of tests of between 50 and 100 hours of continuous operation. The total test period will be up to 200 hours.

Task 4. Economic Evaluation & Commercialization Plan: The economics of one or at most two different industrial scale steam based cycles using the combustor will be evaluated. A commercialization plan will be developed for marketing the combustor for industrial applications in the US and overseas.

Task 5. Conduct Site Demonstration: This task will be the final test activity in the project. Its objective will be to demonstrate the durability and hence the commercial readiness of the combustor for its intended industrial application(s). The effort will consist of two sub-tasks. In the first one, any changes required as a result of prior tests will be made to the combustor. In the second one, a series of tests, each of up to 100 hours of continuous coal fired operation will be performed, with a total test time of 500 hours. Due successful test results in prior tasks, it is now planned to substantially increase the test duration in this task to several 1000 hours.

Task 6. Decommissioning Test Facility: The test facility will be removed from the boiler installation and disposed in accordance with required regulations.

5. Project Status

Task 1: Design, Fabricate, Integrate Components

The planned combustor modifications in task 1 were completed in September 1992, and the results were reported in last years contractor's meeting.

Task 2. Preliminary Systems Tests

The results of the first four task 2 tests are included in the paper published in the Proceedings of the 1993 DOE-PETC Contractors Meeting. The final two of the six planned tests in this task were completed in May 1993.

A key objective of these last two tests was to verify the performance of a newly installed actively cooled exit nozzle design. This cooling replaced the prior adiabatic design which had limited high thermal input operation to about one shift of 8 to 10 hours. In the final task 2 test, after a 1.5 hour heatup, coal fired operation at 13.6 MMBtu/hr with 83% thermal input provided by coal and the balance natural gas, continued for 11.5 hours until the 4 ton coal bin was empty. It was the longest coal firing period of the task 2 tests. With the newly installed exit nozzle cooling, the wall temperature gradually increased from ambient to 575^{o}F after 11 hours of operation, after which it remained constant for the balance of the test. This temperature was about one-half that measured in a previous 11 hour long task 2 test in December 1992 with the uncooled, adiabatic exit nozzle wall. Additional data on the cooled nozzle will be present with the task 3 results, where high thermal input 24 hour long tests were performed.

One applications of the present combustor is vitrification of high carbon fly ash such as is produced in low NO_x coal burners. In the fifth task 2 test, 200 pounds of fly ash, supplied by an independent power producing company, was vitrified. The fly ash had a 30% carbon content. Vitrification will enable the company to recover the heat content of the carbon while converting the ash to slag. No carbon was found in the slag was zero and the carbon in the stack was such that the effective carbon content of the original ash was reduced from 30% to 4.5%.

The original project plan had only six one day tests in task 2. In practice, a total of seven 1 day tests were performed in task 2 and two 1 day tests were performed in task 1. A total of 77 hours of gas, oil and coal fired operation were completed in these tests, of which 41 hours were on coal.

Task 3. Proof of Concept Tests.

The task 3 tests were performed and completed in the period between June and December 1993. A key element in these tests was to evaluate the effect of the combustor-boiler system modifications on performance and durability. In addition to the actively cooled exit nozzle installed during the task 2 effort, the following additional modifications were installed and tested during the task 3 effort:

1) Despite numerous modifications, the reliability of the original coal screw feeder, which installed with the original coal storage and feed system in 1987, remained unreliable. Therefore, at the beginning of task 3, a new feeder of different design was acquired, and it performed flawlessly throughout the task 3 tests.

2) In the slagging combustor operation ii is essential that the slag tap remains open at all times. Several years ago, Coal Tech developed a combined heat and mechanical device to accomplish this task. During task 1, the mechanical device was automated. At the beginning of task 3, the device was further modified to improve its reliability, and slag tap plugging was not a operational problem in the task 3 tests.

3) Another key improvement introduced at the beginning of task 3 was to automate the combustor's air cooling system by the addition of auxiliary cooling components. With this procedure it was possible to maintain the combustor wall temperature with 50^{o}F range around a mean value of about 2000^{o}F. This wall temperature control result is shown in figure 3 for the task 3 test performed on July 15, 1993. The dip at 18:30 hours was caused by a temporary flameout. Prior to the introduction of this wall control method, the wall temperature would vary by several 100 degrees Fahrenheit during steady coal fired operation.

4) A major part of the task 3 effort was devoted to achieving very uniform and reliable coal, sorbent, and air injection and mixing at the inlet section of the combustor. Over one-half dozen different injection methods were tested, including various combinations off-axis and axial injection directions. It was found that the best slag/ash retention in the combustor and boiler was obtained with off axis multi-point injection. Due to other factors that influence ash/slag retention, such as coal particle size, stoichiometric ratio, wall heat transfer rate, and combustion temperature, an exact correlation has not been obtained. Qualitatively, axial directed injection had as much as a factor of two higher ash carryover to the stack scrubber than off axis injection.

Figure 4 shows the slag and collected for all the project tests beginning with task 1 to near the end of task 3 in October 1993. This figure contains over one-half of the task 3 test time. The lower curve shows the slag collected through the slag tap in the combustor, which averages only 20% of the total ash. The middle curve shows that most of the ash, about 50%, is collected as slag flowing out of the exit nozzle into the boiler and as bottom ash in the boiler. The remaining 30% is captured in the stack particle scrubber, as seen from the top curve. These results are not directly comparable with earlier combustor tests because in the present tests the mineral solids loading was generally higher, and a substantial part of the sorbent mineral matter consisted of calcium hydrate. The latter has an average size of 7 microns which will mostly escape the combustor. This result suggests that a longer combustion chamber would have better slag retention inside the combustor. This was confirmed with 2 dimensional BYU combustion code, and a longer combustor will be used in task 5 tests

The following are some other key results of the task 3 tests:

A total of 185 hours of combustor operation, of which 106 hours were on coal, were performed in task 3. During this 6 month period, no significant refurbishment of the combustor occurred.

Two tests of 24 and 27 hours of continuous, high thermal input operation were performed in August 1993. In the first 24 hour test on August 5 and 6, thermal input ranged from 13 to 15 MMBtu/hr. In the second test, on August 19 and 20, this thermal input range was increased for several hours to the 17 to 19 MMBtu/hr range. The combustor is rated at 20 MMBtu/hr. Due to personnel limitations, coal fired operation was limited to daytime. Overnight operation was with a combination of natural gas and No.2 oil at about the same average thermal input. This was the first time that the combustor was maintained at a high thermal input for periods longer than 14 to 16 hours. During these tests, a 20 ton pulverized coal tanker was parked outside the boilerhouse, and it was used to refill the 4 ton coal bin as it neared empty. Bin refilling occurred while the combustor continued on coal firing. Figure 5 shows a record of the steam flow in the first of these tests during the period from 12:37 PM on August 5th to 10:15 Am on the 6th. Figure 6 shows the wall temperature at one location in the exit nozzle during this same period. Note that after thermal equilibrium is reached the nozzle wall temperature remained nearly constant throughout the balance of the test period. As noted above, prior to installing this wall cooling, the temperature at this location was double in value and it continuously increased, thereby limiting the operating time.

A measure of the substantial progress made in combustor durability and automatic control was that over half of the task 3 tests were completed in the space of 4 weeks in November 1993. During that time a total 9 days of testing, with a total of over 100 hours of operation, were completed. All these tests were performed with a new improved multipoint off axis coal injection system. Throughout these November tests, no operational problems were encountered in the coal feed and injection system.

Another new result in task 3 was the development and use of a gas sampling probe that could be inserted through the rear boiler wall to a position about 2 feet from the nozzle exit. This was used for gas sampling of O_2, CO_2, CO, NO_x, and SO_2, directly at the combustor exhaust, and to compare the results with the gas sampling of these species at the boiler outlet at the base of the stack. A detailed analysis was performed for tests from task 2 (5/11/93), and task 3 (6/8/93 & 7/15/93). These test consisted of fuel rich (FR) and fuel lean (FL) conditions in the combustor, followed by final air injection in the boiler to achieve fuel lean conditions. The O_2 and NO_x results were essentially identical at both locations in the FL-FL test and FR-FL tests, which indicated that effective mixing was occurring immediately at the exit nozzle exhaust. For the FL-FL test, the CO level increased by 67% from the boiler to the stack, although the absolute levels were only 36 ppmv and 60 ppmv. The increase was attributed to incomplete combustion of char particles carried out of the combustor into the boiler. These particle burn in the immediate exhaust zone but rapid gas cooling freezes the reaction in the boiler. In the FR-FL case, the reverse condition takes place in that the CO at the exit nozzle is decreases by about 50% to 53 ppmv in the stack. In this case, the CO gas leaving the combustor is converted to CO_2 in the boiler. In the FR-FL cases, the combustion efficiency ranged from 83% to 93%. Therefore, some unburned char particles were most probably carried over into the furnace and boiler.

Figure 7 shows the SO_2 results for the two tests conditions FL-FL and FR-FL. In the former case, the SO_2 level decreases toward the stack, while latter case it increases. Based on the CO data, it is deduced that the char carried over into the boiler continues to burn and evolve SO_2. This SO_2 reacts with the smaller CaO particles leaving the combustor, which in the FL-Fl lean case results in further reduction in SO_2 toward the stack. Although as noted for the CO data, char is also carried over into the boiler in the FR-Fl case. However, for the fuel rich case the higher final combustion temperature at the nozzle exit can deadburn the small CaO particles, thereby reducing their sulfur capture effectiveness. Therefore, the char released SO_2 is not captured as effectively and the SO_2 levels to the stack increases. While the figure 7 data superficially suggests a higher capture effectiveness in the fuel rich test, this is not the case. The coal in the FR-FL test had a 1.67% sulfur content, while the FL-FL test coal had a 2.42% sulfur content. Therefore, the absolute reduction in both tests was almost identical, being 52% in the FR-FL test and 58% in the FL-FL test. In conclusion, the significance of these probe tests is that a powerful diagnostic tool has been developed that allows accurate determination of the combustion and environmental performance under all stoichiometric operating conditions. This probe was used in many of the subsequent tests. To date, much of the task 3 test data collected between August and December 1993 has not been fully analyzed.

As was shown in connection with figure 6, active air cooling reduced by about 50% the exit nozzle's refractory wall temperatures compared to the prior uncooled nozzle. Figure 8 shows this same temperature, TC3 (the bottom curve) as a function of the test date. Also shown are two other temperature measurements that were taken nearer the inner radius of the nozzle. One notes that with the passage of time, these inner temperatures increased, especially the inner one, TC1. This increase in the inner temperature was due to melting of refractory material that was patched inside the original fused refractory nozzle wall in April 1993. This patching was necessitated due to extremely high wall temperatures that were achieved in February 1993 in a series of No.6 oil fired tests. This patching material is adequate for the air cooled combustor liner because material loss there can be replaced with slag. However, the exit nozzle cooling is not as concentrated as the liner cooling. Therefore, with the passage of time, the patched plastic dissolved in the slag and increased the inner wall temperature. Despite this loss of the patched plastic the limited exit nozzle air cooling was very effective until the end of the task 3 tests. In view of the success of the nozzle air cooling, it has been decided replace the refractory exit nozzle with an actively fully air cooled design for the task 5 tests.

Another durability procedure that was used late in the task 3 effort was slag replenishment of the combustor wall. The combustor liner had been installed in 1988. Since that time, the wall has been patched several times. The most recent extensive wall patching took place after the completion of the above noted No.6 oil fired tests in February 1993. After the development of very accurate combustor wall temperature control early in task 3 (as shown in figure 3), it was decided to perform a series of tests in November 1993 on wall liner replenishment by the injection of fly ash with coal into the combustor. Wall temperature measurements in the backside of the refractory liner showed that slag replenishment lowered the temperature at that point from 1400°F to 1300°F. The effectiveness of replenishment was confirmed after the completion of the task 3 tests when the refractory inside the combustor was removed as part of general refurbishment for task 5. Visual observation showed two distinct layer of refractory material on the side wall of the liner. Subsequent chemical analysis revealed that this outer layer had a composition similar to coal slag while the inner layer consisted primarily of alumina, the material that was used to refurbish the liner in March-April 1993. In the roof section, the liner thickness was about one-half that of the sidewall and about 1/3 of the original liner thickness. Nevertheless, the roof section remained intact with no exposed metal cooling wall. This result provides further proof that the computer controlled wall temperature control can maintain the liner in a safe operating range even after substantial wall material loss.

Another key durability issue is ash deposition on the convective tubes in the boiler. Over a period of time the gas temperature at the base of the boiler stack increased from its normal value with gas/oil firing of 450°F to as high as 620°F. The latter value indicates extensive ash deposits of the boiler tubes. Although the boiler is equipped with steam soot blowers, they had not been used in the task 3 tests prior to the September 23, 1993 test. At that time, they were operated for 10 seconds and the stack gas temperature decreased immediately from 620°F to 450°F. This is a very important result because it shows that ash deposits are dry and easily removed.

Due to the low cost of coarse coal pulverizers, a pair of tests were performed with coal having a 44% through 200 mesh and 35% through 100 mesh. Normal coal sizes have been 70 to 80% through 200 mesh. These tests have as yet not been fully analyzed. Combustion appeared to be satisfactory. Combustion modeling with the BYU code showed that complete combustion with these coal sizes could be achieved by lengthening the combustor. This was one of the reasons for lengthening the combustor for the task 5 tests.

In conclusion, at the completion of the task 3 tests reliable combustor wall cooling, effective exit nozzle cooling, slag wall replenishment, reliable and uniform coal feeding, reliable slag tap operation, and effective soot blowing had been accomplished. The slag and ash retention results indicated that the combustor should be lengthened to improve slag retention inside the combustor.

Task 4. Economic Evaluation & Commercialization Plan

Several case studies on the application of the combustor to industrial boilers and small power plants were performed as part of the task 4 commercialization effort.

The test results on combustion of fly ash containing 30% carbon were noted in the task 2 test results described above. The fly ash tested was produced in an 80 MW power plant at the rate of 6 tons/hour. A single slagging combustor can vitrify this ash and burn its carbon with the addition of coal and sorbent. For the 80 MW plant studied, the increased combustion efficiency from carbon recovery in the fly ash and from elimination of fly ash disposal would allow recovery of the cost of the slagging combustor installation in less than 1 year.

Another application studied was the conversion of a pair of 120,000 lb/hr industrial coal fired boilers with the air cooled combustor. The installed cost of the conversion was less than $10/lb of steam, i.e. $2.4 million. This cost was obtained from budgetary vendor quotations for the fabrication of the combustors, all the combustor auxiliary components, the combustor instrumentation and controls, and the installation of the combustors on the boilers. Since the use of this combustor allows selection of a lower grade, high ash coal as a fuel, the potential fuel saving alone was sufficient to recover the conversion cost in two to three years.

Another application evaluated was the repowering of an existing 20 MW steam turbine generator in a utility power plant with an air cooled combustor-boiler system. In this case, the added equipment consisted of a coal pulverization and feed system, a limestone storage and feed system, an oil storage and feed system, a boiler, a slag removal system. a system for fly ash re injection into the combustor from the baghouse, a baghouse, a stack, and a boilerhouse and associated structures. The existing turbine-generator, feedwater heating, and power transmission system would be refurbished. The estimated installed cost, using budgetary vendor quotations, was $650/kW. A blended fuel would be used consisting of 75% (by weight) of a high ash coal waste, 20% bituminous coal, and 5% number two oil, with a combined cost of $0.66/MMBtu. Income is derived from power sales to a regional electric utility for a 10 year period. The economic analysis used 20% equity, 80% debt financing at a 7.5% interest rate, seven year amortization, and a 40% tax rate. This yielded an attractive internal rate of return on equity of 28%. Other rate of returns can be derived by varying these economic assumptions.

Task 5. Site Demonstration

The final test task in this project is to conduct a site demonstration of at least 500 hours total duration. From the various site specific applications studied in task 4, it was determined that a major factor in commercial acceptability of the combustor was demonstration of its operation in a commercial environment over extended periods. The Williamsport tests site did not meet this requirements because the only use for the steam output of the boiler was for winter space heating where the maximum required steam energy required was only about two-thirds of the rated boiler capacity and the average requirement was only one-third of its capacity.

The analysis of the tests data in the previous tasks including its comparison with two dimensional combustion modeling indicated that lengthening the combustor would improve the combustion efficiency and the slag retention. Also, the economic analysis in task 4 showed that the use of coarser coal size distributions would allow the use of much lower cost coal pulverizers or coal crushers. As noted above, two brief coarse coal tests were performed task 3 which yielded acceptable combustion. Finally, in view of the substantial improvement in exit nozzle thermal performance with the limited air cooling used, it was desirable to replace the thick refractory exit nozzle wall design with one based on the combustor's air cooling.

For all the above reasons, it was planned to remove the combustor from the Williamsport tests site, and refurbish it and add a new extension section and exit nozzle to the combustor. The combustor-boiler will be reinstalled at a new site that will either be a steam and/or power host. Plans are to operate the combustor for up to 2000 hours annually. The combustor was removed in December 1993 and design of the combustor-exit nozzle extension began in January 1994. In addition, design of a coarse coal storage and pulverization system was initiated in order to enable task 5 tests to be implemented with run-of the mine coal.

To date, the fabrication of the combustor extension section has been initiated and quotation for the other equipment needed to meet the task 5 test objectives have been procured. In addition, negotiations were implemented with a number of potential steam and power hosts in SE Pennsylvania.

PLANS

It is planned to complete the acquisition of the combustor modifications and auxiliary equipment needed to implement the task 5 site demonstration in 1994. Simultaneously final site selection and combustor system installation will be implemented at a site that meets project test objectives and allow total operating times for the thousand hours needed for commercial product acceptability.

ACKNOWLEDGMENTS

The authors wish to acknowledge the advice and assistance of Mr. Clifford Smith, the DOE Project Manager, on the implementation of this project as part of the Industrial Combustion Program. They also wish to acknowledge the assistance of Dr.Scott Brewster, Brigham Young University, who performed the two dimensional combustion modeling, and Professor Charles Marston, Villanova University, who performed the two dimensional heat transfer analysis of the exit nozzle.

Figure 1: Schematic Diagram of the Coal Tech Air Cooled Combustor

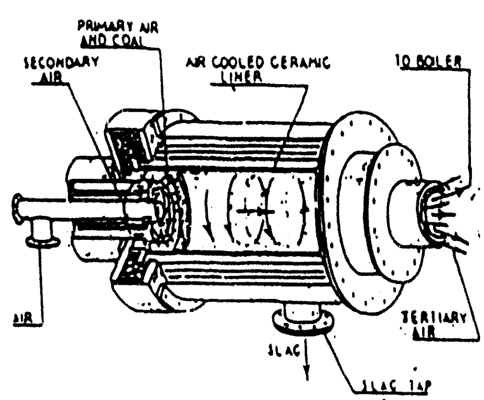


Figure 2: Drawing of Coal Tech's Air Cooled Combustor Installed on a 20 MMBtu/hr Oil Designed Boiler

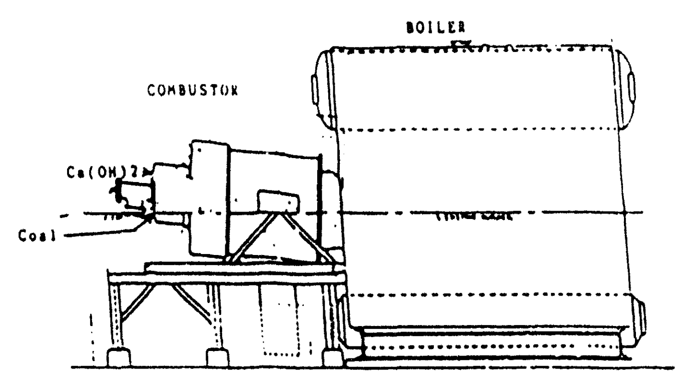


Figure 3 Combustor Wall Temperatures 7/15/93 Test

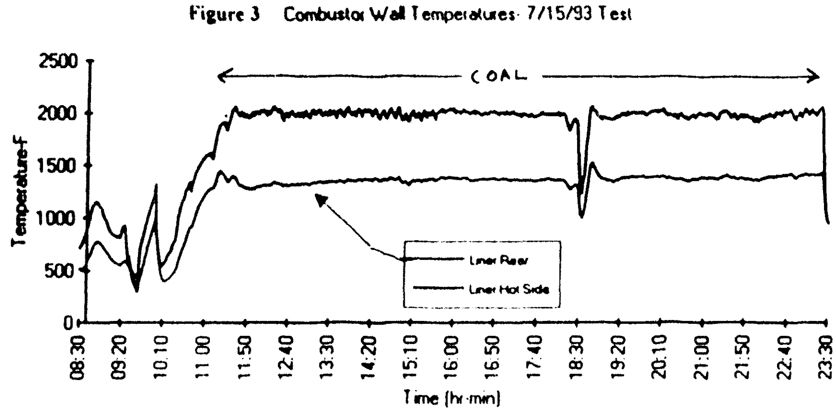


Figure 4:Total Ash & Slag Retention versus Project Test No. (8/92 to 10/93)

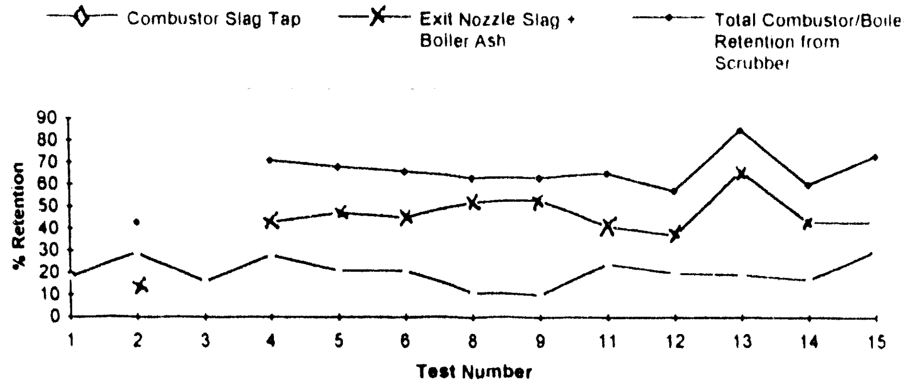


Figure 5: Steam Flow -8/5-6/93 Test

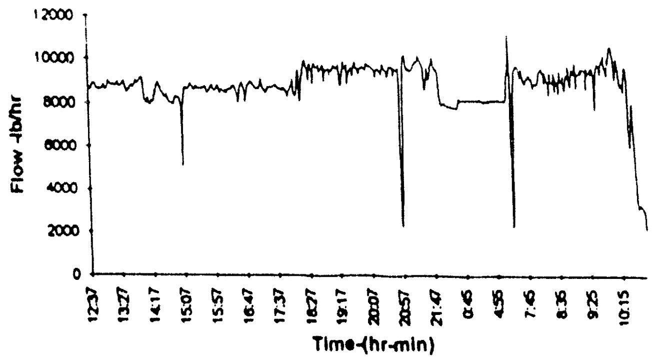


Figure 6: Exit Nozzle Wall Temperature- 8/5-6/93 Test

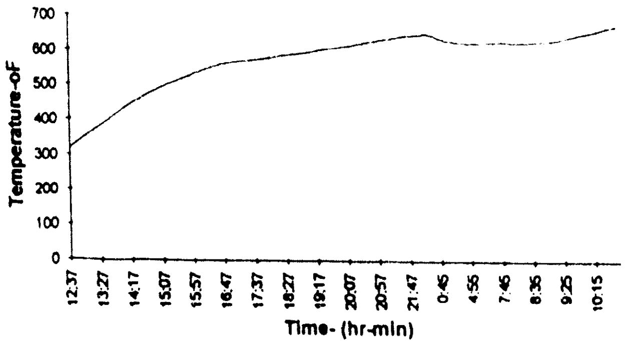


Figure 7: Comparison of SO_2 Data at Combustor Nozzle Exit and Boiler Outlet (5/11/93, 6/8/93 & 7/15/93 Tests)

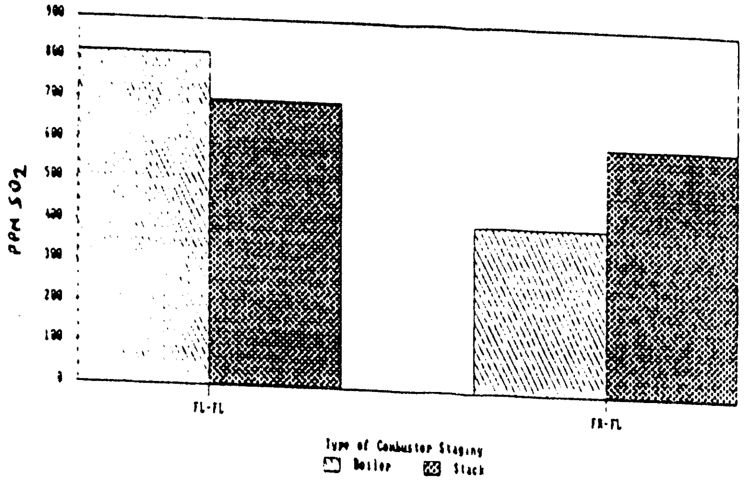
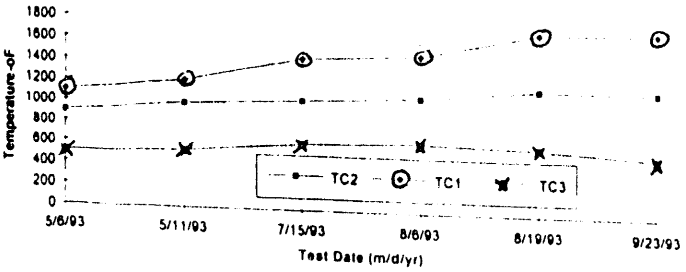


Figure 8: Air Cooled Exit Nozzle Wall Temperatures vs Test Date (For location of TC1,2, & 3, see text)



DEVELOPMENT AND TESTING OF A HIGH EFFICIENCY ADVANCED COAL COMBUSTOR: INDUSTRIAL BOILER RETROFIT

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INTRODUCTION/ BACKGROUND

Under U.S. Department of Energy, Pittsburgh Energy Technology Center (PETC) support, the development of a High Efficiency Advanced Coal Combustor (HEACC) has been in progress since 1987 at the ABB Power Plant Laboratories (Rini, et al., 1987, 1988). As summarized in previous publications on the subject, the initial work produced an advanced coal firing system that was capable of firing both water-based and dry pulverized coal in an industrial boiler environment (Rini, et al., 1990).

With continued DOE-PETC support, carried out in cooperation with the Energy and Fuels Research Center of The Pennsylvania State University (Penn State), the HEACC burner concept has been used as a major component in a system design intended for industrial-scale, coal fired retrofit applications. The overall objective of the current work is to demonstrate the technical and economic feasibility of retrofitting a gas/oil-designed industrial boiler to burn micronized coal. In this respect, the major technical goals for the combustion system design have included:

- A compact, easy to retrofit burner design
- Low NOx generation, while maintaining high combustion efficiency
- Commercially acceptable combustion air pressure drop and burner turndown ratio
- Integration of coal preparation system controls into boiler control system

The design of the HEACC burner is based on the well established principle of internal air staging for NOx control. In an internally staged flame, combustion is initiated at the burner exit in a primary zone that contains less air than is required to completely burn the coal (substoichiometric); this promotes the conversion of fuel nitrogen to molecular N_2 instead of NOx. Combustion is then completed downstream of the burner where stoichiometric ratios of 1.15 to 1.25 exist to maximize carbon burnout. Burner swirl and mass flow control are employed to establish the substoichiometric primary zone. This zone also recirculates hot combustion products back to the root of the flame, providing ignition energy and, thus promoting flame stability. With a properly designed air register, the primary zone can be maintained at the correct stoichiometric condition throughout the load range. Superimposed on the requirement for the desired burner performance is the significant constraints of limited residence time.

The work carried out under this program consists of five major tasks:

1) A review of current state-of-the-art of coal firing system components.
2) Design and experimental testing of a prototype HEACC burner.
3) Installation and testing of a HEACC system in a retrofit application.
4) Economic evaluation of the HEACC concept for retrofit applications.
5) Long term demonstration under user demand conditions.

The results of Tasks 1 and 2 have been summarized in recent technical publications (Rini, et al., 1993, Jennings, et al., 1993). Task 3, which involves testing the HEACC system in a gas/oil - designed package boiler at Penn State, is currently underway as is Task 4. This paper will summarize the latest experimental results from this ongoing program.

PROTOTYPE TESTING AT ABB POWER PLANT LABORATORIES

Under the second task of the development program, a commercially oriented, redesigned HEACC burner was tested at a scale of 18.5 x 10^6 Btu/hr. This design, as shown in Figure 1 contained features from Combustion Engineering Inc's (CE's) commercial wall-fired burner (the RO II) to facilitate its commercial application. The RO II is a utility sized wall fired burner for the low NOx retrofit market (Darroch, et al., 1991). Key features of the RO II incorporated into the HEACC were the tangential fuel inlet and the venturi coal diffuser. For commercial applicability, the air side of the HEACC register was simplified. For the tertiary air, burner swirl is produced by air entering tangentially to the register. The swirl is then regulated and evenly distributed by a series of adjustable blades located within the register. For the secondary air, a removable, axial flow type swirler design is used to produce the swirling flow.

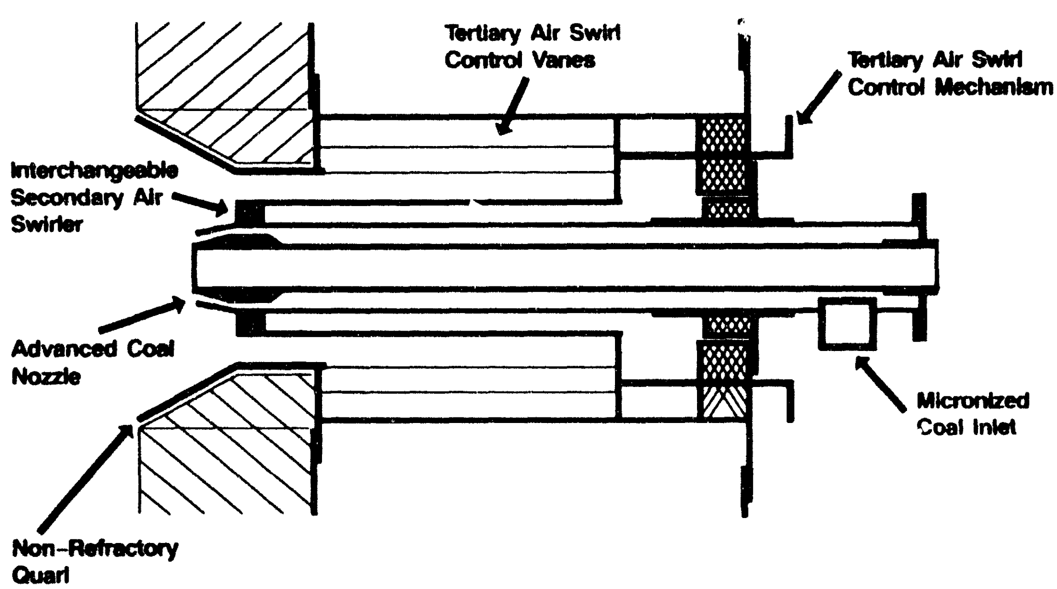

Figure 1 ABB/CE Industrial Scale Micronized Coal Burner

The prototype industrial scale HEACC burner was designed to fire at a rate of 50 MBtu/hr which is a thermal input approximately 2.5 times higher than that required of the burner in the Penn State boiler. Scaling by a constant velocity criteria was used to design the 18.5 MBtu/hr burner for the Penn State boiler. The swirlers, coal nozzles, and other aspects of the burner were scaled using this criteria and previous CE burner design experience. The burner was sized to satisfy the geometric constraints of the host boiler: i.e., windbox, burner openings, mounting plate sizes, fuel pipe locations, etc. Also, natural gas firing capability was added to make this a dual fuel burner.

Since the secondary air swirl is critical to the control of near field aerodynamics, a series of the secondary air swirlers were designed. Three co-rotational swirlers with swirl numbers of 0.8, 1.0 and 1.5 and one counter-rotational swirler (swirl number = 1.0) were designed and fabricated. Two coal nozzles were designed. One was the Impinging Jet (I-Jet) injector developed under the earlier phases of the HEACC program. The patented I-Jet provides eight individual coal streams that converge to produce a low axial momentum, concentrated cloud of pulverized coal. This type of solids/gas flow pattern when produced in a hot, substoichiometric environment has been shown to limit NOx formation. The second coal nozzle tested was a variation of CE's optimized commercial product for the RO II burner.

This second generation HEACC burner was tested in the Industrial Scale Burner Facility (ISBF) located at Combustion Engineering's ABB Power Plant Laboratories (PPL) in Windsor, Connecticut. This facility was designed to replicate the residence time and thermal environment of a typical industrial boiler. A key objective of the 100 hour burner validation tests at PPL was to confirm burner operating characteristics and demonstrate operation over the range of conditions expected for the field boiler tests.

The improved HEACC successfully achieved the project performance goals during these performance verification tests. For example, the effect of various hardware configurations on NOx emissions is shown in Figure 2. The 400 test series (I-Jet and reverse secondary air swirler) produced the best results (a flame environment in which the incoming coal was rapidly mixed, heated and devolatilized in a near-ideal substoichiometric environment for controlling NOx).

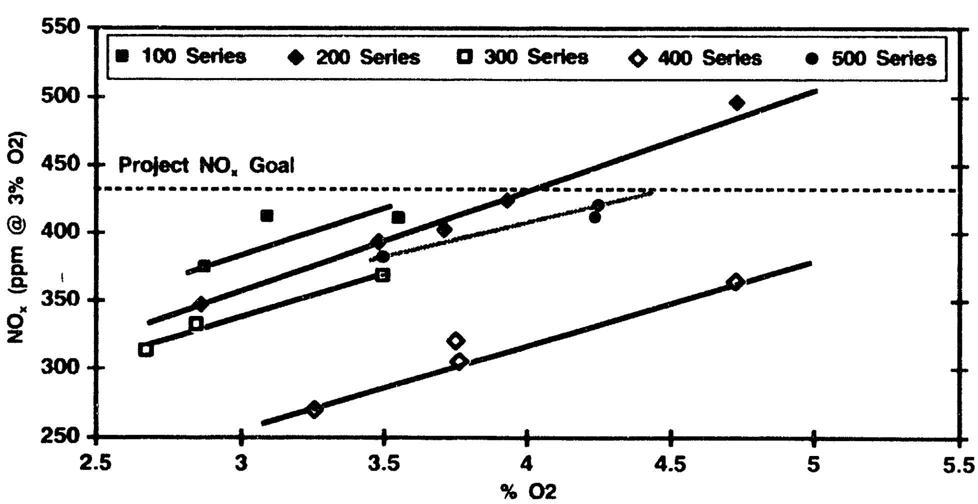

Figure 2 Effect of Hardware Configurations on NOx Emissions

SYSTEM INSTALLATION IN AN INDUSTRIAL BOILER

The successful testing at PPL demonstrated the technical validity of the design improvements incorporated into the second generation HEACC. This burner was then installed as part of a complete coal handling and firing system in Penn State's demonstration boiler for the 400 hour test program.

A schematic of the micronized coal firing system is shown in Figure 3. As can be seen, the cleaned coal comes on site and is stored in a large hopper. The coal is crushed and sent via a screw feeder to the micronized coal mill. The coal is then micronized to 80% through 325 mesh (18 microns MMD) and pneumatically conveyed to the HEACC burner where it is then burned in the Penn State boiler. This boiler is an oil/gas designed Tampella Keeler Model DS-15; a packaged D-type watertube boiler capable of producing 15,000 lb/hr of saturated steam at 300 psig. It represents a typical gas/oil - designed system with a furnace volumetric heat release of 50,000 Btu/hr ft^3, standard for this class of boiler. Furthermore, its design is similar to many other manufacturers' (including Combustion Engineering) models.

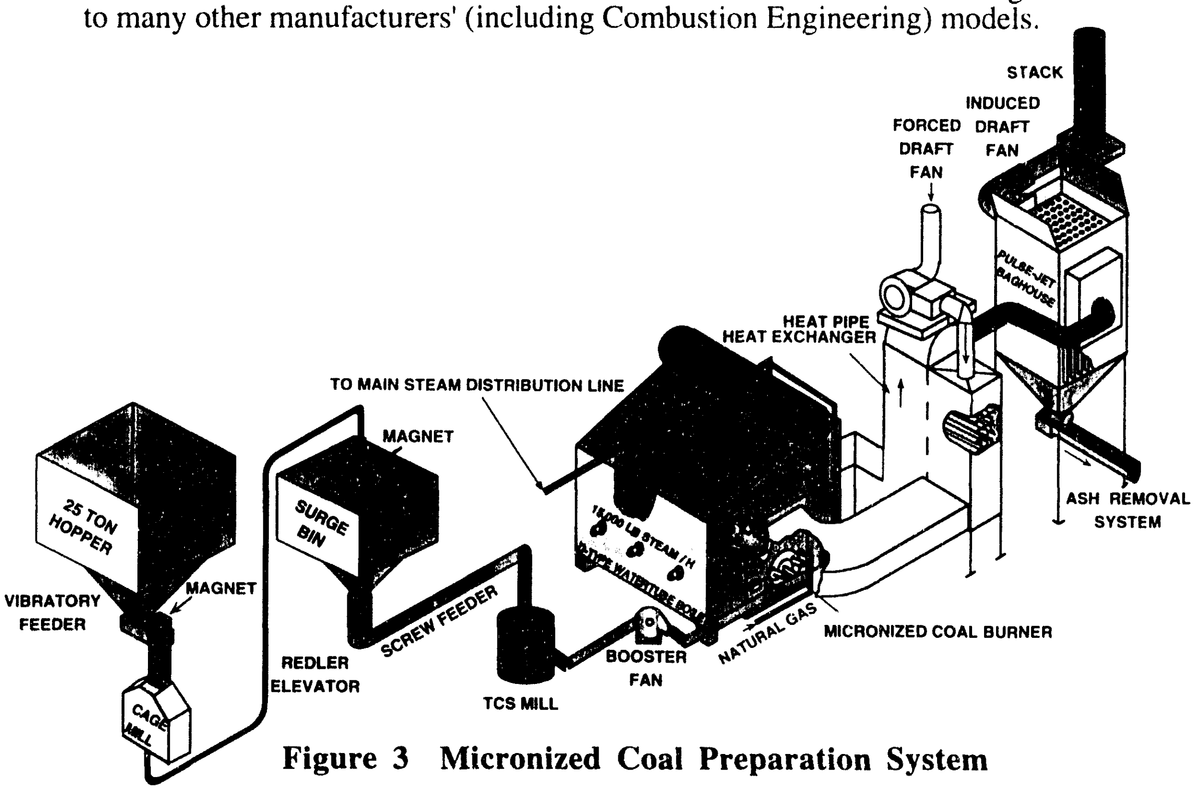

Figure 3 Micronized Coal Preparation System

As will be summarized next, the initial tests of the burner included a shakedown series of tests using natural gas firing. After the shakedown period, a brief series of tests were performed for various hardware configurations to confirm the optimum hardware configuration for this boiler and system. The chosen hardware configuration was then to undergo further testing during a 400 hour test program.

During the currently ongoing 400 hour test period, the system will be operated over a range of operating conditions to determine system performance. The boiler will be tested over a variety of load ranges, excess air, combustion air damper settings and burner swirl levels. In addition, for selected test points a second coal will be tested to compare the system performance with the first coal. During the test period, boiler performance data, emissions data, electric parasitic power and house compressed air consumption data as well as other data required for the technical and economical analysis of the system will be obtained. If the initial testing demonstrates technical feasibility and cost effectiveness, a 1000 hour demonstration of the system, while under user demand, will be conducted.

EXPERIMENTAL RESULTS: INDUSTIAL BOILER RETROFIT

A) NATURAL GAS TESTING

In September and October of 1993, natural gas baseline testing was performed. This testing was conducted to evaluate the HEACC burner on natural gas and to obtain baseline technical and economic data for comparison to micronized coal firing. The natural gas testing included variations in load, excess oxygen, tertiary air swirl level and tertiary/secondary air split. Prior to the baseline testing coal ash deposits were thoroughly cleaned from the boiler tubes. All boiler operating and emissions data were taken during the testing and boiler efficiency was calculated for each test point.

Under a previous coal water fuel test program at Penn State (Miller, et al., 1991) a baghouse was installed to control particulate emissions. Although natural gas contains no sulfur, residual fly ash in the baghouse from previous coal firing does contain sulfur and thus the baghouse inlet could not be operated below 250 °F for acid dew point reasons. As a result, all natural gas baseline tests were run at 75 and 100% load. Excess oxygen levels for the tests were maintained at 1, 2 and 3%. Although testing was not performed at low load, the burner exhibits stable (attached, steady flame) characteristics at a turndown ratio of at least 8/1.

Boiler efficiency averaged 83.1% at 100% load and 2% oxygen. No significant differences were noted when changing swirl levels or air splits. As expected, boiler efficiency decreases for increasing excess air. Boiler efficiency was also shown to increase to 83.8% at the 75% firing rate (again at 2% oxygen), as shown in Figure 4. NOx emissions for this burner ranged from 0.17 Lbs / MBtu to 0.24 Lbs / MBtu. These emission levels are typical for a burner using preheated combustion air without flue gas recirculation. Carbon monoxide emissions were consistently low; the highest average was 33 ppm (at 1% O_2).

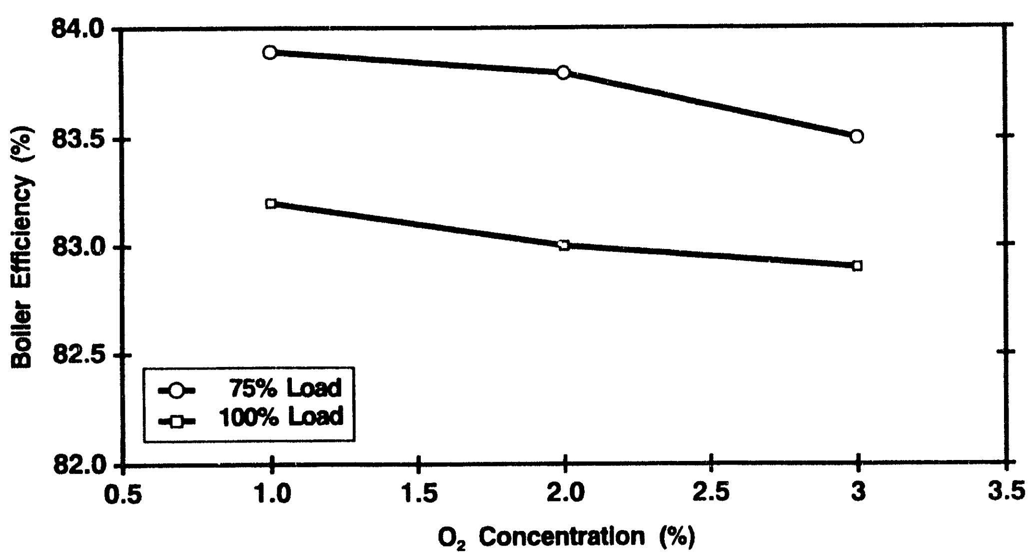

Figure 4 Boiler Efficiency : Natural Gas Firing

One aspect of coal firing in a natural gas designed boiler is the effect of coal ash deposits on performance characteristics while firing the baseline fuel (natural gas in this case). One of the perfromance goals was that no degradation of boiler performance should occur when firing the baseline fuel due to fouling from previously firing micronized coal. Therefore, after "seasoning" the boiler on coal, two natural gas tests were run. The sootblower located in the boiler convective section was blown prior to testing, however, the furnace was left in its "as found" condition. Boiler efficiencies at 2.8% O_2 and 4.2% O_2 were 82.4% and 81.8%, respectively, which is slightly lower than the clean boiler average of 83.1%. It should be noted that the post coal firing tests were conducted at a slightly higher firing rate than the baseline tests. Boiler outlet temperatures for the two post coal fired "dirty" boiler tests were 591 and 573 °F which compares to 576°F for the baseline tests. NOx and CO emissions were comparable for the two conditions.

B) COAL FIRED EXPERIMENTS

A key objective of demonstration testing is to determine operating characteristics of a complete, integrated system as opposed to the operation of its components. Although all of the system components installed at The Pennsylvania State University were proven in either commercial operation or prior testing, the complete system from coal mine to steam production at this scale had not been proven. Also, it has been reported by industrial burner suppliers that there are numerous problems to be considered in an industrial boiler commercial design (Facchiano, 1992). The testing at Penn State has indicated areas that should be carefully engineered in a commercial design. Although it was anticipated that if any problems occurred, they would be centered around the burner (the least developed system component), the coal handling and feeding sub-system has proven to be a critical component during initial testing.

Due to the relatively small quantities of coal required and the need to control the ash content of the prepared fuel, the coal was cleaned in a batch mode by heavy media cyclone and stored at a local yard. During the winter, snow and ice have covered the relatively small pile and it has proven difficult to obtain dry coal from the pile. This has created numerous problems in the coal handling components. In a commercial system, if the coal is cleaned in a batch mode (as compared to cleaning on an as needed basis) care must be taken to assure the coal is protected from the elements during storage. The added handling creates additional costs that are being compiled.

The present testing has also shown that the boiler/burner is very sensitive to fuel/air input conditions. This is due to the tight confines of the boiler and the limited residence time. Fuel feed oscillations, fuel transport air pressure swings and coal maldistribution in the burner are not as easily forgiven as in a multi-burner, large utility configuration. All three factors as noted above have created instability problems at the demonstration boiler. In commercial installations, tight control over the primary (transport) air and fuel feed will be necessary.

The above mentioned problems have been resolved and steady state tests have been conducted when burning 100% coal. These tests have all been short term (10 hours or less). The 400 hour test program is underway and is scheduled for completion at the end of April 1994. As of this writing, well over 100 hours of coal only testing has been performed. Most coal firing to date has been conducted at firing rates between 75 and 80% of full load. The latest boiler efficiencies on coal have ranged from 83 to 84.6% (at 3% excess oxygen). These boiler efficiencies were obtained with carbon conversion efficiencies (CCE) of 93.8 and 96.2%, respectively, which is lower than the target range of 98% or greater. As of this writing, analytical modeling is being performed to determine how best to increase CCE in this industrial system.

At low levels of CCE (93-94%) NOx emission values have been below the target goal of 0.6 Lbs/MBtu (450 ppm at 3% O_2) while at the higher CCE (95-96) NOx values have ranged up to 0.78 Lbs/ MBtu (575 ppm at 3% O_2). The system has not yet been optimized for low NOx and high CCE.

In addition to 100% coal tests and natural gas baseline tests, quite a few tests have been performed on coal with natural gas co-firing. A series of tests were performed with natural gas co-firing between 0% and 45% on a heat input basis. Highlights of this testing show that the coal combustion efficiency (disregarding the carbon in the gas which is 100% consumed) ranged from 94.4% to 97.4%. Gaseous emissions for the co-firing tests indicated that CO, SO_2 and NOx all decrease proportionately with increasing levels of natural gas input. This is shown in Figure 5.

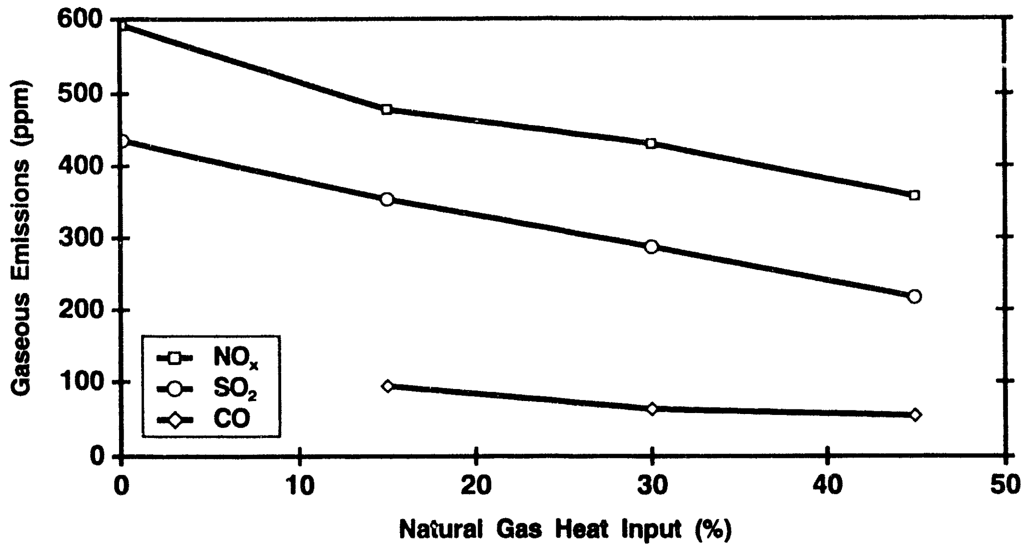

Figure 5 Effect of Co-Firing on Gaseous Emissions

SUMMARY

Under this program, the previously developed High Efficiency Advanced Coal Combustor has been redesigned as a commercially oriented burner and this redesign was tested at the ABB Power Plant Laboratories. This testing confirmed the effective control of NOx, high combustion efficiency, acceptable fan head requirements, flame shaping capability and the turndown required of a commercial burner. This redesigned and tested burner was then installed in a package boiler at Penn State to determine the performance in a true commercial retrofit system and to determine the actual costs of using this system.

The system is currently installed at Penn State and testing is underway. Tests have been conducted on natural gas, coal and coal with natural gas co-firing. The testing has already shown areas, especially fuel handling and feeding, that require more attention in an industrial installation as compared to typical utility boilers. When current testing is completed, the results will be analyzed to obtain the technical and economic data required to determine boiler performance. In addition, a commercialization plan will be formulated. Pending acceptable technical and economic results, a 1000 hour demonstration test will then be performed. This test will be performed under normal user demands to evaluate the system's capability to perform commercially.

The goal of the long term demonstration is to show that cost effective, environmentally acceptable micronized coal systems can be used to displace premium fuels such as gas and oil in industrial combustion systems. The widespread use of this technology could significantly reduce our dependence on imported fuels and result in a balanced use of our energy resources.

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The following manuscript was unavailable at the time of publication.

EVALUATION OF TECOGEN'S RESIDENTIAL COMBUSTION SYSTEM

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The following manuscript was unavailable at the time of publication.

DEVELOPMENT OF A COAL-FIRED PULSE COMBUSTION SYSTEM FOR COMMERCIAL-SCALE BOILER RETROFIT

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DEVELOPMENT OF A COAL WATER SLURRY-FIRED

COMMERCIAL SCALE SPACE HEATING SYSTEM

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TECOGEN DIVISION OF THERMO POWER CORPORATION
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INTRODUCTION

Coal is the most plentiful energy resource in the United States today, but since the 1950's, its use has been largely restricted, for environmental and economic reasons, to utility power generation. Oil and natural gas are the predominant fuels used within the residential, commercial, and industrial market sectors. The objective of this program is to demonstrate the technical and economic viability of a coal-fired combustion system capable of meeting the space heating needs of schools, office buildings, apartment complexes, and other similar structures which make up the commercial market sector. In general, these buildings require firing rates of 1 to 10 million Btu/hr.

An important consideration in meeting this objective is the fuel form to be utilized. In attempting to restore coal to relatively small markets, it is important to recognize ease of handling and storage as important criteria. For this reason, coal water slurry fuel has been chosen as the fuel form for this development effort. Coal water slurry eliminates the need to use dry pulverized coal with its attendant handling, metering, and dusting problems, as well as its explosive potential. Equally important in selecting a fuel form is the impact on emission levels and pollution control equipment requirements. Coal water slurry (CWS) is amenable to coal washing, since coal cleaning technologies are generally water-based processes requiring fine grinding of the coal.

APPROACH

Development and demonstration of the CWS-fired space heating system was carried out through a three stage, 42-month program which concluded in March of 1994. During the first stage, which covered the first 14 months, program activities focused on component development and system integration. The second stage involved proof-of-concept testing, which took place over a 10 month period. In the final stage, the space heating system was installed in a commercial facility and operated through the winter of 1993/94 to assess system performance and operability.

In addition to the subsystems and equipment making up the integrated space heating system, a fuel preparation system was also included as part of the demonstration effort. It is recognized that CWS fuel is not easily obtained or widely produced at this time. To ensure a supply of CWS for the program and also to demonstrate that coal water slurry can be economically produced, a slurry preparation facility was set up and operated at the demonstration site. It is recognized that to get coal water slurry fuel into the commercial scale marketplace, it will take a combined effort to develop both the combustion equipment and fuel supply simultaneously.

In designing the overall system, commercially available equipment and technologies have been utilized wherever practical. One piece of equipment which is not commercially available is the combustor itself. The commercial scale space heating system combustor is a scale-up of a CWS-fired residential combustor developed by Tecogen under contract to the Department of Energy, Pittsburgh Energy Technology Center (DOE/PETC).

The combustor, which can be generally described as an inertial reactor with internal separation (IRIS), has demonstrated combustion efficiencies of over 99% using coal water slurry fuels without the need for preheated air or fine atomization. The combustor concept (see Figure 1) employs centrifugal forces combined with a staged combustion process to achieve high carbon conversion efficiencies. The combustion chamber is divided into multiple zones by partitions to retard the axial flow of unburned coal particles over a given size. In this fashion, the residence time for combustion of the CWS fuel is significantly increased to enable nearly complete carbon conversions for a wide range of particle droplet sizes. Once the particles are small enough to pass through all the partitions, they enter a secondary combustion chamber where the char burnout is completed.

SYSTEM DESIGN

A process schematic of the CWS-fired space heating system is shown in Figure 2. The system has been designed for a nominal firing rate of 4 million Btu/hr. As discussed above, an IRIS combustor is utilized for combustion of the coal water slurry fuel. The commercial scale unit has an internal diameter of approximately 24" and an overall length of C0". Inlet areas are sized for an inlet velocity of 150 ft/sec. Several different combustor internal wall configurations were investigated to eliminate ash accumulation in the combustor. The combustor design evolution was influenced strongly by the need to burn progressively higher ash coals with changing ash properties. The final combustor configuration (shown in Figure 3) results from a thorough investigation of design and operating parameters including combustor wall material, partition location and size, atomizer spray angle, and combustion air staging.

Although refractory surfaces could be used in the combustor when burning high ash fusion temperature coals, ash attachment to the refractory surfaces was problematic for low ash fusion temperature coals. Best results were obtained with metal liners and water-cooled partitions making up the combustor internal surfaces. Various arrangements were investigated to control metal liner temperatures while at the same time controlling heat extraction from the combustor and allowing for liner growth. The final arrangement (Figure 3) is to allow the liners to operate as floating shields. In this configuration, rather than having a refractory material between the liner and water-cooled shell, and controlling liner temperature through conduction, the liner is offset from the water-cooled shell by a quarter inch air gap and is allowed to radiate back to the shell. This configuration allows for unrestrained circumferential expansion of the liner and eliminates the possibility of hot spots, which can develop if the liner separates away from the refractory. The combustor outer shell is water-cooled.

The combustor is oriented in a downward firing mode, and a transition chamber is utilized to connect to the heat recovery boiler and provide for large particle ash collection. The transition chamber has an inner diameter of 42" and an overall length of 48". It is also water-cooled and has a 3" thick refractory lining. Boiler water is utilized as cooling water for the combustor and transition chamber.

The combustor is integrated with a York-Shipley waste heat recovery fire tube boiler. The boiler is a conventional three pass unit, and has been fitted with particulate drop-out hoppers at the turning boxes and a compressed air soot blowing system.

A variable spray angle externally mixed twin fluid atomizer is used for slurry atomization. The atomizer design is an extension of the twin-fluid CWS atomizer technology developed by Tecogen under the DOE/PETC CWS-Fired Residential Warm Air Heating System Program mentioned earlier. The atomizer operating conditions can be set to provide the wide cone angle required of the radial top-center-firing configuration of the commercial scale system. This atomizer is illustrated in Figure 4. The atomizer uses two perpendicular atomizing streams to shear the CWS into a thin, unstable ligament sheet that breaks up into small droplets external to the atomizer.

The external atomization feature of this nozzle prevents erosion and allows for a large CWS passageway, which minimizes the head that the CWS pump must produce and the likelihood of pluggage. In addition to providing fine atomization due to the high shear that is imparted by the two perpendicular atomizing streams, by varying the flow rate of each of these streams, the spray angle can be changed on-line without any mechanical modification to the atomizer.

To meet the targeted emissions goals of no more than 1.2 lbs of SO_2 and 0.03 lbs of particulate per million Btu, a dry duct injection flue gas desulfurization system working in conjunction with a fabric filter is utilized. Sodium bicarbonate is injected into the exhaust duct between the boiler exit and baghouse inlet. The sorbent is fed by a screw feeder and is pneumatically conveyed to the exhaust duct. The baghouse, manufactured by Flex-Kleen, is a pulse jet unit with a cloth area of 457 ft^2. The filter bag material is 16 oz. P84, a thermostable organic fiber of synthetic origin characterized by a copolyimide structure. Staged combustion is utilized to meet the NO_x emissions requirement of 0.3 lbs per million Btu.

The CWS-fired space heating system has been designed to match the automatic nature of gas and oil systems. System light off and warm-up is with fuel oil with the system purge and ignition verification of a standard oil-fired system. Once the combustor reaches a pre-selected temperature, automatic switchover to CWS is initiated. The control system consists of a General Electric Fanuc Series 90-30 Programmable Logic Controller for ladder logic sequencing and PID control. The controller provides for complete automatic or manual control of the system, including push button start and stop, load following safety interlocks, automatic fuel changeover, and alarm messages. Operator interface is through a CRT-based operator interface terminal. This terminal has flow schematics which display key process variables and setpoints, and programmed function keys to allow complete control of the system, including selection and manipulation of all proportional control loops in manual mode.

SLURRY PRODUCTION

At the start of this development program, it was recognized that, although CWS has great potential as an alternative fuel form for the smaller scale applications, CWS fuel is not currently easily obtained or widely produced. To ensure a supply of CWS for the program and also to provide both an engineering and economic data base for slurry production at larger scales, a slurry preparation facility was set up to produce CWS for the program.

A process flow diagram for the system is given in Figure 5. Crushed coal (3" x 0") is received in 1-ton supersacks and fed to a hammermill via a variable speed screw feeder. From the classifier, the coal is conveyed to a series arrangement of primary and secondary cyclones and discharged into a mixing tank via rotary valves. In the mixing tank, the pulverized coal is fully wetted with the help of tank mixers and a fluid circulation loop which takes suction from the bottom of the mixing tank and discharges the coal/water mixture onto the surface.

The system is operated in a batch mode by pre-filling the mixing tank with the necessary water and additives, and running the pulverizer until the coal/water mixture reaches a pre-determined starting point. The density of the slurry has proven to be a key process control variable in that it is an indirect measurement of slurry loading. Coalmaster A23, manufactured by Henkel Corporation, is used as a dispersant, and Flocon C, manufactured by Pfizer Chemical, is used as a stabilizer.

During the course of the demonstration program, upwards of 130 tons of coal have been processed into approximately 50,000 gallons of slurry. Three coals have been processed: Eastern Kentucky Hazard Prince Mine, Illinois No. 5 Wabash Mine, and Illinois No. 6 Delta Mine. Table 1 gives the proximate and ultimate analysis for the three coals. These are run of mine coals without any additional washing or beneficiation other than that performed at the mine to ensure consistent quality.

Table 2 gives the typical slurry properties for the three coals. As can be seen in the table, coal loadings were between 55% and 60%. For each of the coals, the maximum coal loading while maintaining a viscosity of 200 cp at 60 reciprocal seconds was utilized.

DEMONSTRATION SITE CONFIGURATION

As part of the system demonstration, the space heating system was installed to service the High Bay Building at the Illinois Coal Development Park (ICDP). The ICDP is operated under a cooperative research and development agreement between Southern Illinois University at Carbondale and the Illinois Department of Energy and Natural Resources (IDENR). The High Bay Building is a multi-use facility housing classrooms, laboratories, combustion equipment, and offices. The building has a floor plan of 12,400 ft^2 and an enclosed volume of approximately 330,000 cubic feet. The high bay area is 36' by 122' with a 36' roof height. The high bay area was previously heated exclusively with electric unit heaters. Figures 6 and 7 show the equipment configuration at the demonstration site. A load dump radiator was included with the equipment to permit operation of the system during periods when the building load is low and to baseload the system for full load operation.

TEST OPERATIONS

Three tests series have been completed as part of the development program. The first series of tests, component and system tests, were performed to provide preliminary evaluation of the component and system performance, identify key operating variables and their ranges, and establish appropriate operating conditions for subsequent proof-of-concept testing. These tests verified that the combustor technology had been successfully scaled to the commercial market size, that the integration of the major system components, especially integration of the combustor with a fire tube boiler, was feasible, and that the system had the potential to meet the performance goals. This testing included over 100 hours of system operation.

The second series of tests, proof-of-concept tests, were performed in the laboratory to evaluate overall performance of the space heating system and to demonstrate that the concept is technically feasible, both from a performance standpoint and from a maintenance and reliability standpoint. Combustion and thermal efficiencies, tendencies to slag, foul, erode and corrode, and gaseous and particulate emissions were evaluated. During the proof-of-concept test period, the integrated system was operated for over 500 hours with slurry-firing making up close to 70% of these operating hours. During the course of the testing, approximately 7,000 gallons of Kentucky slurry, 6,500 gallons of Illinois No. 5 slurry, and 3,500 gallons of Illinois No. 6 slurry, were burned.

Table 3 summarizes the overall system performance on each of the three coals evaluated during proof-of-concept testing, and compares achieved performance to the program goals. Best performance results were obtained with the low ash Eastern Kentucky coal, but even with the higher ash, lower heating value Illinois coals, performance goals were met. With the Illinois coals, especially Illinois No. 6 with greater than 10% ash, system operation was more sensitive to slight changes in coal loading, slurry viscosity, and operating setpoints.

The third series of tests involved operation of the space heating system at the demonstration site. Initial equipment shakedown was performed using low ash Eastern Kentucky parent coal slurry. The bulk of the system operation was performed using Illinois No. 5 parent coal slurry. This Wabash mine coal had a significantly higher ash content, approximately 10.5%, than that utilized during the proof-of-concept testing (7.25%), due to market/operating conditions at the mine.

During the demonstration period, the system was operated for upwards of 800 hours with slurry-firing making up approximately 600 of these hours. An important milestone was reached in achieving unattended, automatic operation. The system was left unattended during off-shift hours of operation.

To eliminate the possibility of ash accumulation in the combustor effecting combustor operation, an automatic shutdown procedure was incorporated into the automatic programming to periodically thermally shock and sweep away, with increased combustion air flow, any material build-up in the combustor. This shutdown occurred every 6 hours, and the combustor was back on-line in less than 20 minutes.

During the demonstration, the system was operated between 2 and 3.5 MM Btu/hr with an average combustion efficiency of 97%. Approximately 25% of the coal ash was collected in the transition chamber and 75% in the baghouse. Ash accumulation in the transition chamber limited the maximum continuous operation without maintenance, indicating the need for an automatic ash removal system for this area.

ACKNOWLEDGEMENTS
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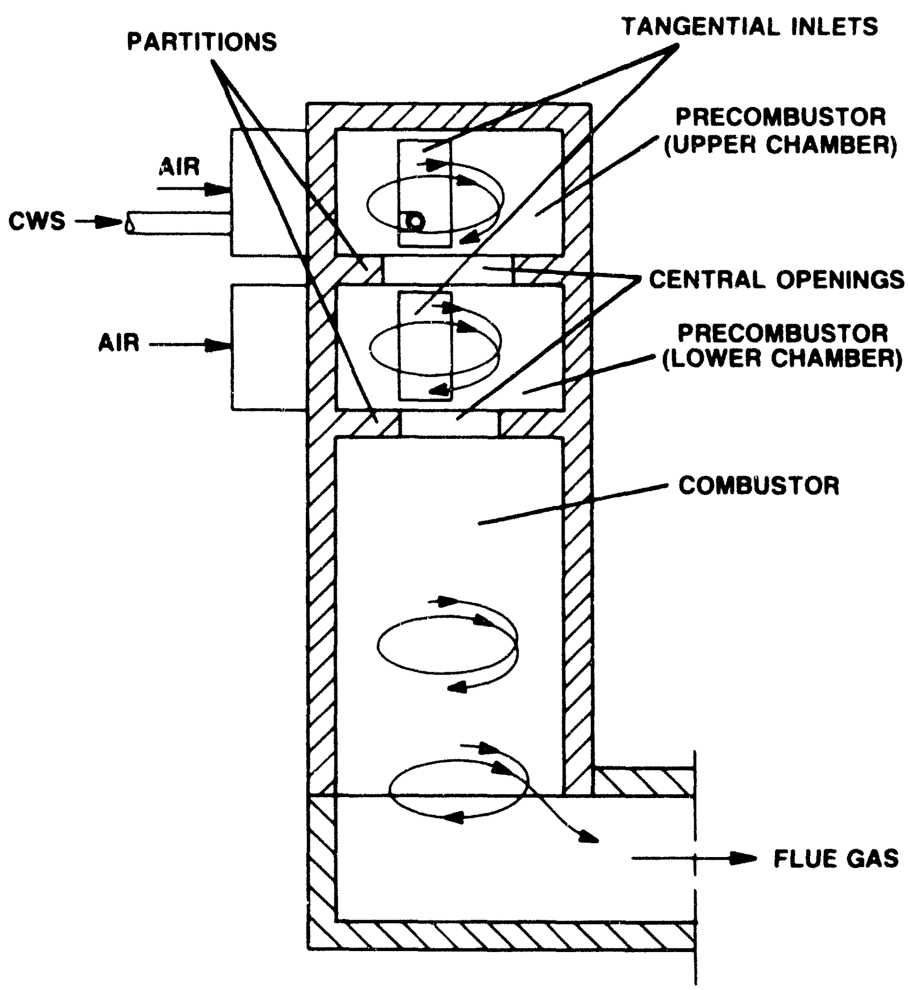

Figure 1. Combustor Principle of Operation

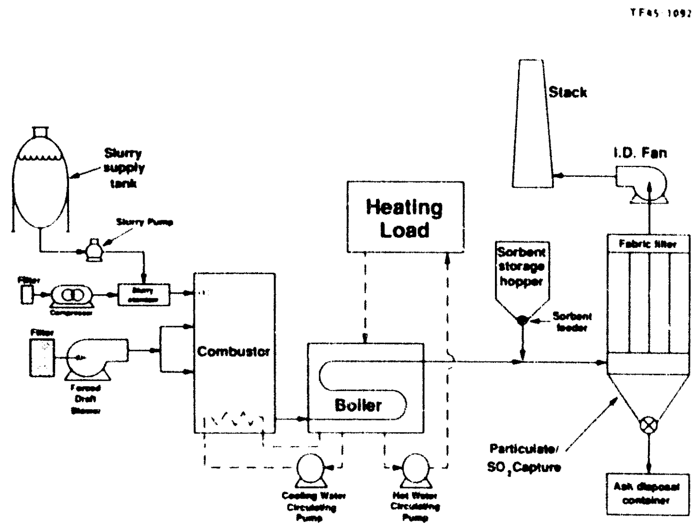

Figure 2. Process Flow Diagram

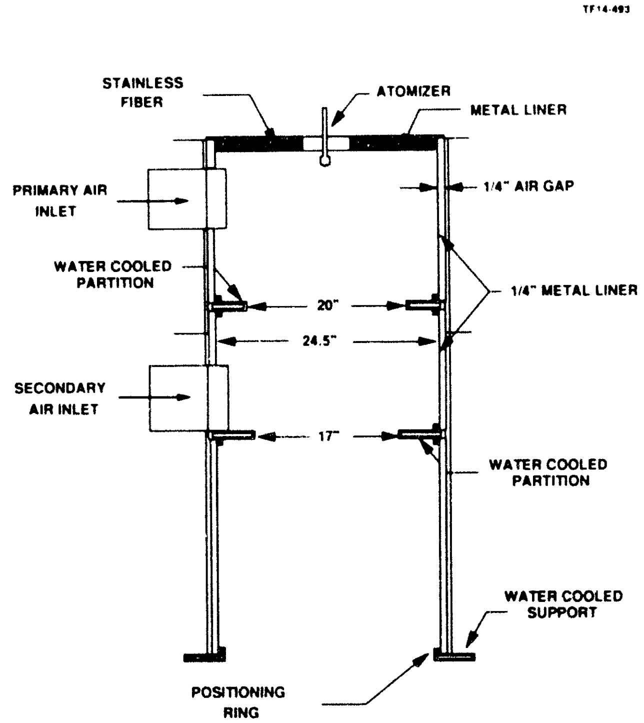

Figure 3. Combustor Geometry

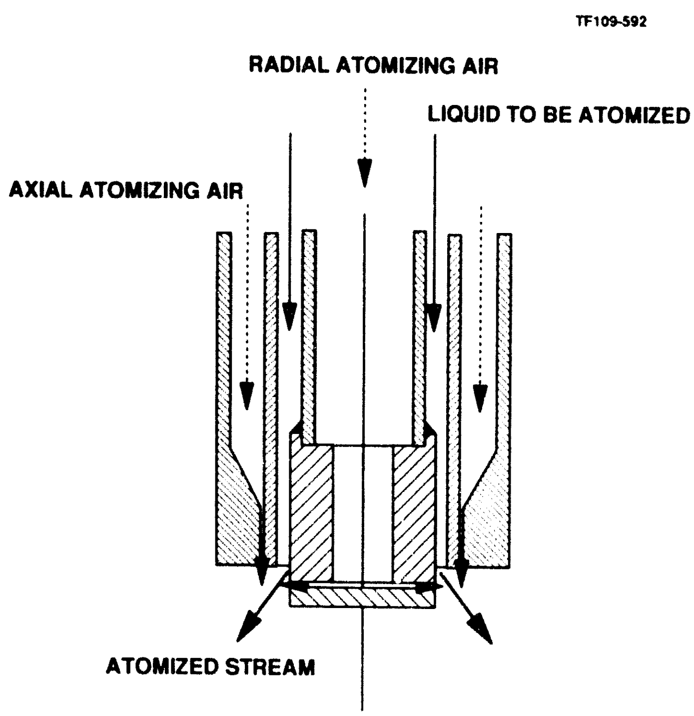

Figure 4. Schematic of Variable Spray Angle (VSA) Atomizer

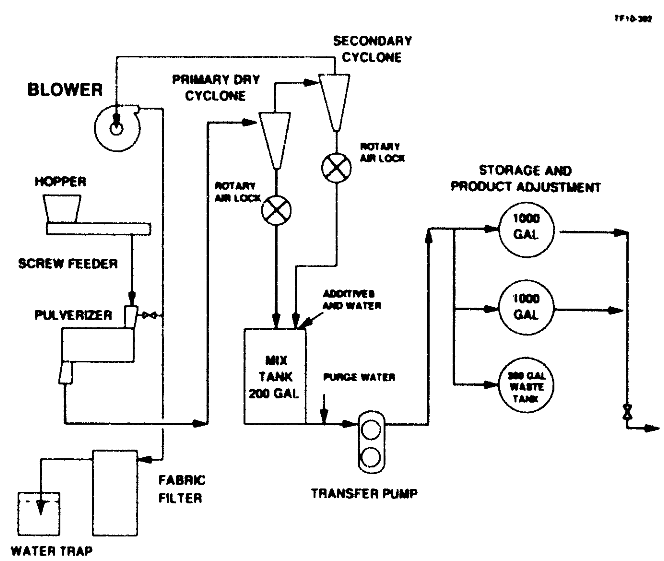

Figure 5. Slurry Production Facility Flow Schematic

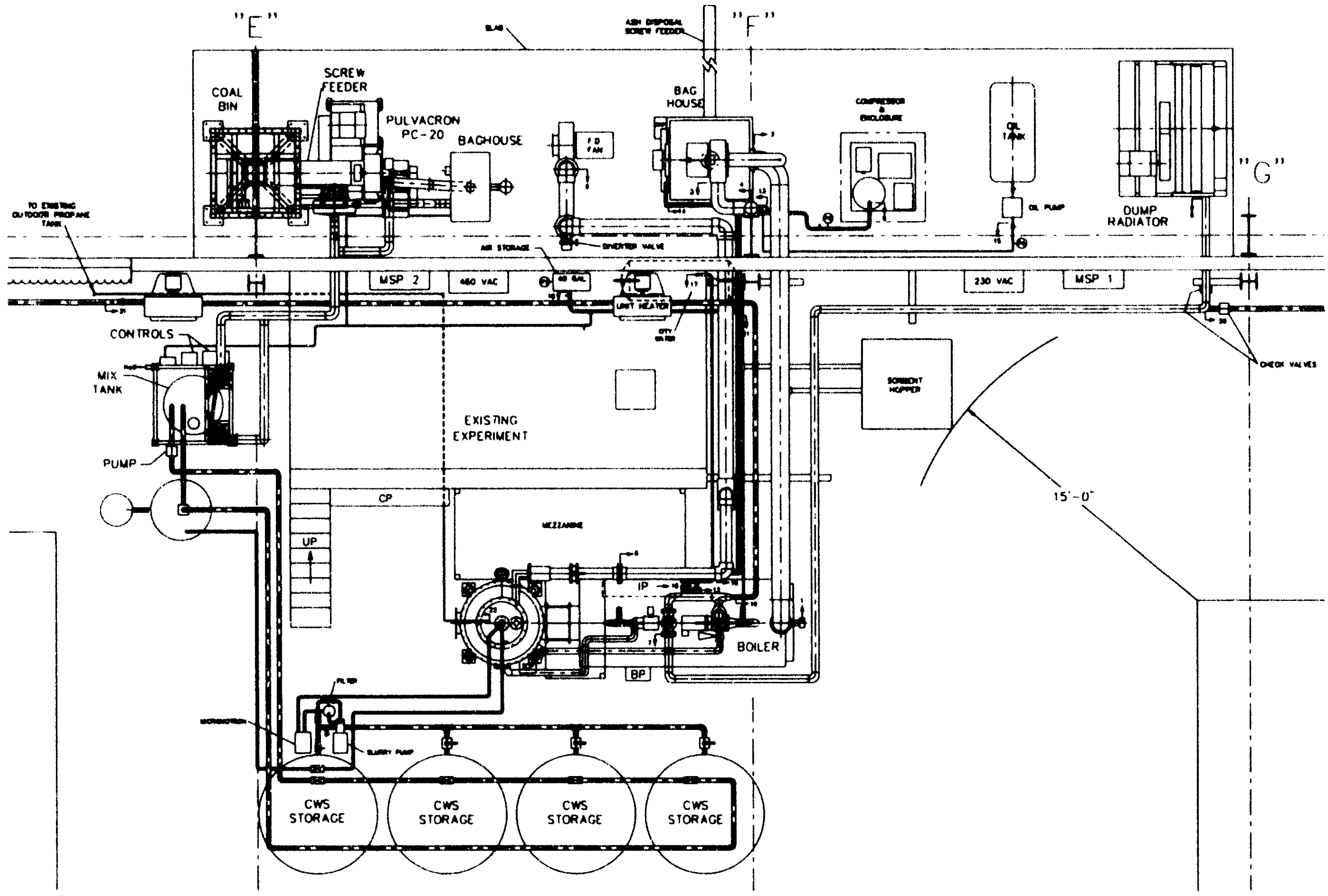

Figure 6. Equipment Configuration at Demonstration Site

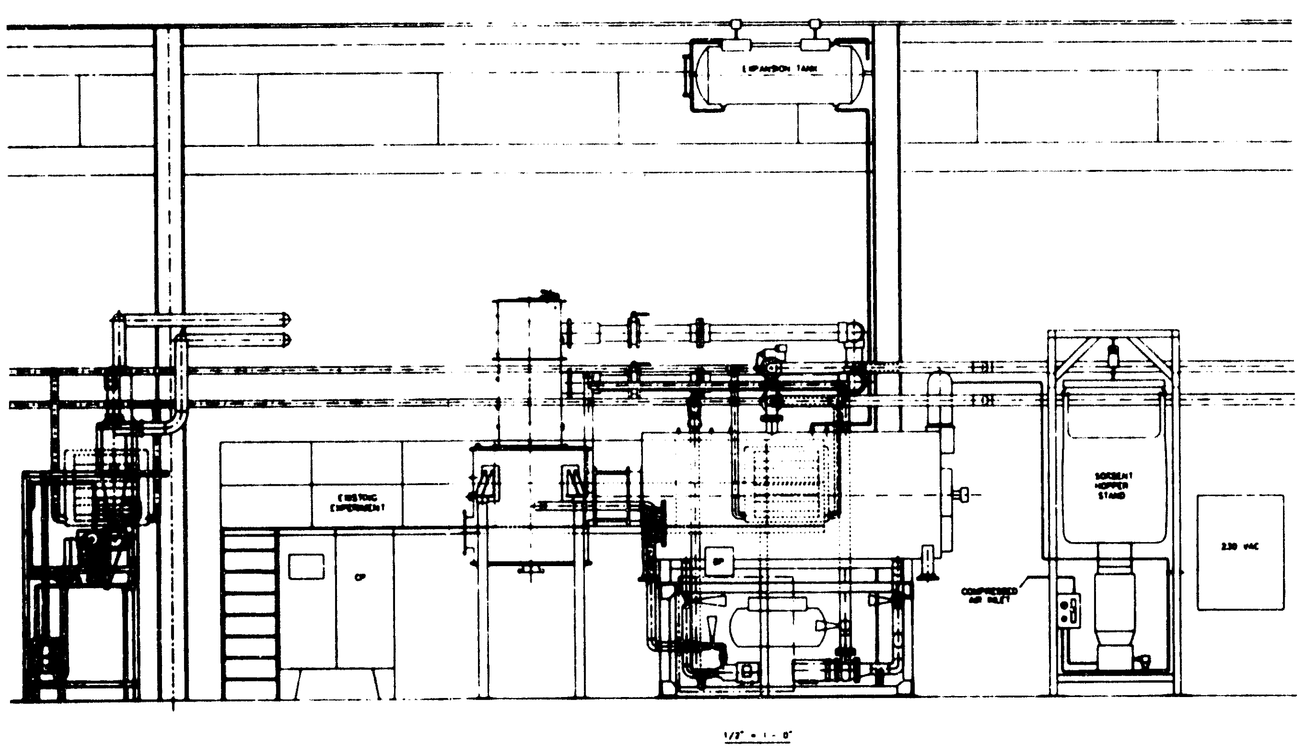

Figure 7. Equipment Configuration at Demonstration Site

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TABLE 1

COAL PROXIMATE AND ULTIMATE ANALYSIS

KENTUCKY HAZARD PRINCE MINE					
Proximate Analysis			Ultimate Analysis		
	As Received	Dry Basis		As Received	Dry Basis
% Moisture	2.69	xxxxx	% Moisture	2.69	xxxxx
% Ash	3.62	3.72	% Carbon	78.91	81.09
% Volatile	35.93	36.92	% Hydrogen	5.25	5.39
% Fixed Carbon	57.76	59.36	% Nitrogen	1.63	1.67
	100.00	100.00	% Sulfur	0.74	0.76
			% Ash	3.62	3.72
Btu/lb (HHV)	14144	14535	% Oxygen (diff.)	7.16	7.37
% Sulfur	0.74	0.76		100.00	100.00
MAF Btu		15097			

ILLINOIS NO. 5 WABASH MINE					
Proximate Analysis			Ultimate Analysis		
	As Received	Dry Basis		As Received	Dry Basis
% Moisture	14.94	xxxxx	% Moisture	14.94	xxxxx
% Ash	6.17	7.25	% Carbon	64.30	75.60
% Volatile	33.25	39.09	% Hydrogen	4.24	4.98
% Fixed Carbon	45.64	53.66	% Nitrogen	1.43	1.68
	100.00	100.00	% Chlorine	0.15	0.18
			% Sulfur	1.36	1.60
Btu/lb (HHV)	11439	13450	% Ash	6.17	7.25
% Sulfur	1.36	1.60	% Oxygen (diff.)	7.41	8.71
MAF Btu		14501		100.00	100.00

ILLINOIS NO. 6 DELTA MINE					
Proximate Analysis			Ultimate Analysis		
	As Received	Dry Basis		As Received	Dry Basis
% Moisture	9.44	xxxxx	% Moisture	9.44	xxxxx
% Ash	10.65	11.76	% Carbon	64.42	71.13
% Volatile	33.14	36.60	% Hydrogen	4.31	4.76
% Fixed Carbon	46.77	51.64	% Nitrogen	1.34	1.48
	100.00	100.00	% Chlorine	0.09	0.10
			% Sulfur	2.84	3.14
Btu/lb (HHV)	11592	12800	% Ash	10.65	11.76
% Sulfur	2.84	3.14	% Oxygen (diff.)	6.91	7.63
MAF Btu		14506		100.00	100.00

TABLE 2

TYPICAL SLURRY PROPERTIES

Coal	Kentucky	Illinois No. 5	Illinois No. 6
Coal Loading	59%	55%	57%
Particle Size (mmd)	30 μm	20 μm	18 μm
Specific Gravity	1.15	1.17	1.20
A23 (dry mass coal)	10,000 ppm	15,000 ppm	15,000 ppm
Flocon	700 ppm	700 ppm	700 ppm
Viscosity at 80 1/sec	200 cP	200 cP	200 cP
Heating Value	8,500 Btu/lb	7,400 Btu/lb	7,300 Btu/lb

TF6-593

TABLE 3

PERFORMANCE GOALS

	Goal	Kentucky	Illinois No. 5	Illinois No. 6
Ignition	Safe and Reliable	30 Successful Starts	10 Successful Starts	30 Successful Starts
Turndown	3:1	4:1	3:1	3:1
Thermal Efficiency (percent)	>80	85 Clean 75 Dirty	85 with Soot Blower	85 with Soot Blower
Combustion Efficiency (percent)	>99	Baghouse Ash Burnout >99	Baghouse Ash Burnout >98	Baghouse Ash Burnout >98
Emissions (lb/mil Btu) NO_x SO_x Particulates	 <0.3 <1.2 <0.02	 0.26 1.03 lb/MMBtu (Compliance) Baghouse Control	 0.30 0.68 Baghouse Control	 0.27 0.80 Baghouse Control

ALTERNATIVE FUELS UTILIZATION SESSION

BNL 60373

CONDENSING ECONOMIZERS FOR SMALL COAL-FIRED EQUIPMENT

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April 1994

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DISCLAIMER

CONDENSING ECONOMIZERS FOR SMALL COAL-FIRED EQUIPMENT

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DEPARTMENT OF APPLIED SCIENCE
BROOKHAVEN NATIONAL LABORATORY UPTON, NEW YORK 11973

Contract No.: AS-295-EECD
Period of Performance: February 1991 - October 1994

OBJECTIVE

Condensing economizers can be used to increase the thermal efficiency of boilers and furnaces. This study focuses on evaluating indirect contact economizers as applied to heating equipment burning coal-water mixtures although the results can be extended to other fuels. In addition to dry gas sensible heat, latent heat is recovered from flue gas water vapor, improving system efficiency markedly. In addition to improving thermal efficiency, condensing economizers can also capture particulates. In tests to date up to 98% total removal has been measured. The primary objectives of this project are to evaluate the most important mechanisms involved in particle capture and to enhance capture in practical systems.

The intent of the work is to contribute to the ongoing program at the Department of Energy/Pittsburgh Energy Technology Center in the development of coal-fired combustion equipment. These results are expected to be most applicable to smaller scale equipment where the low temperature heat from the economizer can be used. However, interest in the use of condensing economizers for industrial and utility applications is increasing and this work certainly is relevant in these sections also. The approach involves determining thermal efficiency improvement and particulate removal efficiency (experimental), and developing models capable of predicting system performance under varied operating conditions (theoretical). Gas temperature and condensation profiles through the economizers have been predicted and overall predicted performance are consistent with test results. Mechanisms for particle removal are discussed in this paper and predicted removal efficiencies as a function of particle diameter are presented.

ACCOMPLISHMENTS AND RESULTS

Introduction

Condensing economizers improve efficiency by recovering both sensible and latent heat from flue gas. The economizers are commonly indirect contact, tubular heat exchangers with flue gas passing around the outside of the tubes and cooling medium, such as water or air, passing through the tubes. Condensing economizers have thus far been applied primarily to gas-fired equipment and to some extent oil- and wood-fired boilers. For small heating equipment condensing boilers are packaged with the condensing heat exchanger as an integral unit. For commercial and industrial scale equipment a condensing economizer may be added onto an existing boiler. Condensing systems with gas-fired units can cool flue gas to about 90 F. Boiler or thermal efficiencies of 95% are possible.[1] On the utility scale, heat exchangers of this type are used in Europe for flue gas reheat in FGD applications.[2] One U.S. utility is currently running a demonstration of a condensing economizer on an oil-fired power plant.[3] At this site the economizer is being used to preheat makeup water and energy savings of about 800 Btu/kWh have been reported.

In addition to improving thermal efficiency, condensing economizers remove particulates from the flue gas. In one field test of a boiler plant fired with No. 6 fuel oil the particulate removal efficiency across the economizer was found to be 70%.[4] Additional saturation of the flue gas by spraying water into the combustion products might enhance particle removal by impacting with the particles or simply increasing the amount of water condensed in the heat exchanger. In some configurations water sprays may be used either upstream of the condensing heat exchanger in a presaturator section or in the heat exchanger itself.

This project was originally planned to provide an evaluation of the feasibility of the use of condensing economizer as the sole particulate collection device on small scale, coal-water slurry fired heating equipment. All of this planned work has been completed and a project report prepared.[5] This work included theoretical and experimental evaluation of heat transfer and particle capture. Effects of temperature conditions, presaturation, direct water sprays and economizer pressure drop were evaluated.

Experimental

A schematic of the experimental arrangement used is shown in Figure 1. The main components of this setup consist of the heating system, water and slurry spray systems, the condensing economizer, and multiple sampling points used for flue gas analysis. Two types of condensing economizers, an air-cooled and a water-cooled unit, were evaluated for thermal and particulate removal performance.

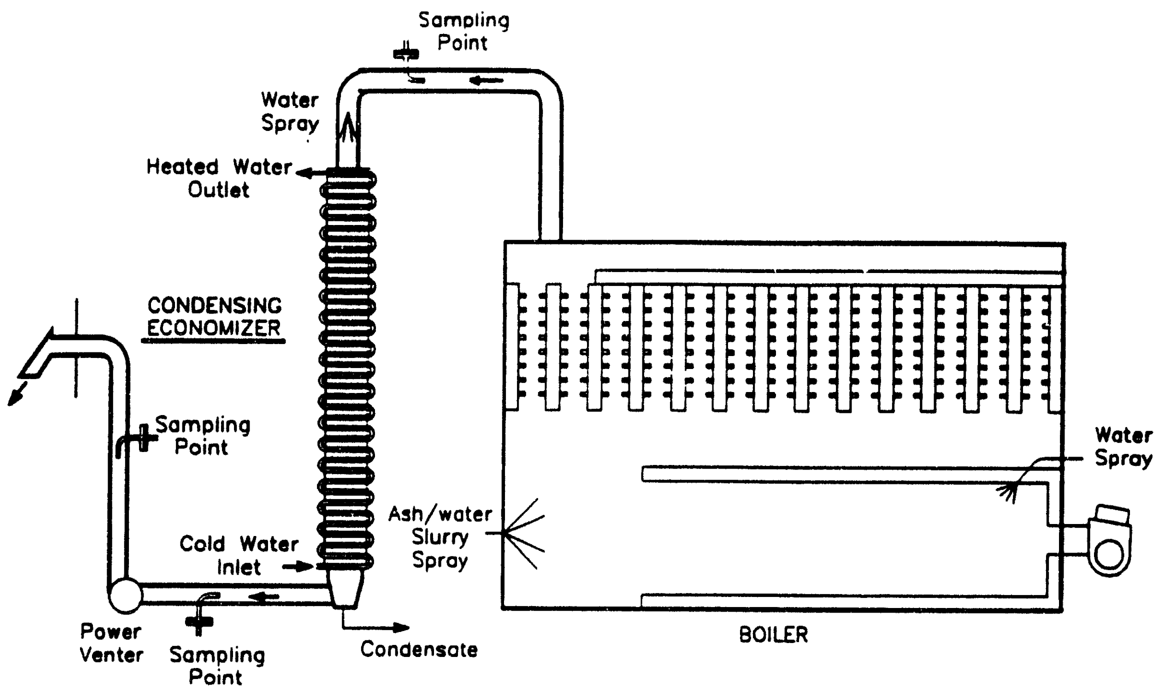

Figure 1. Experimental Arrangement

As part of this study, the measurements and testing were conducted in two ways: (1) firing No. 2 oil with fly ash spray-dried into the flue gas stream to simulate coal-firing conditions with respect to the concentration of fly ash; and (2) with actual coal water slurry firing. Most of the tests were conducted with the oil-fired case. The purpose for these two different experimental setups was to initially demonstrate economizer performance without the added complications of coal-slurry firing, and then to compare and/or validate those results with a few tests consisting of actual coal-slurry firing. In the oil-fired tests, fly ash was introduced into the combustion chamber with a spray assembly that injects an ash/water mixture. The ash was obtained from a precipitator hopper of a coal-fired utility and it was assumed that this provided a representative size distribution for fly ash in the flue gas. The mixture consisted of 10-15% solids (ash) in water. This mixture could then be sprayed with a siphon-type air atomizing nozzle into the combustion chamber through the back end of the boiler, opposite from the burner assembly. Flue gas moisture content was adjusted by spraying water with a siphon nozzle into the flue gas stream at locations upstream of the economizer or directly into the combustion chamber. The air atomized, siphon nozzle provided a low flow rate and a very fine spray which helped to assure that all of the water was vaporized. The moisture content of the flue gas was measured with an EPA-5 train. Samples were taken simultaneously with multiple sampling trains at locations upstream and downstream of the economizer and, in some tests, at the outlet of the induced draft fan.

The locations of the spray points used were selected based on numerous tests in which the water injection rate and the flue gas moisture content were measured. A mass balance on the amount of water input, assuming total evaporation, and the amount measured indicated that in some configurations the spray system was more effective than in other configurations. When the flue gas water content was found to be less than predicted, and therefore not all of the water was evaporated, it was instead collecting on duct walls or on tops of the heat exchanger surfaces. In the configurations used for the particulate tests, a good mass balance for the spray water was realized.

An in-stack, multistage, cascade impactor which adapts to the EPA sampling train was used to measure size distribution of particulate emissions. With simultaneous sampling at the various locations the removal efficiencies with respect to particle size under different operating conditions was determined.

Some of the data was collected with coal-water slurry firing. At the low firing rates at which these studies were performed atomizer pluggage was a particular concern. Several air-atomized nozzles were tested. The most consistent performance was obtained using an "Aero" nozzle supplied by Delavan Inc. Coal water slurry was strained through a 16 mesh screen and then fed to the atomizer using a peristaltic pump.

The boiler used is a sectional cast iron hot water boiler, manufactured by Peerless Industries, Inc., and has a capacity rating of 586 kW (2,000,000 Btu/hr). However, all of the tests, were done at a firing rate of 82 kW (280,000 Btu/hr) or less. These lower firing rates were used simply to match the economizer capacities used. In the oil-fired case, No. 2 fuel oil was burned with a pressure atomized flame retention head burner. At such low firing rates maintaining the desired flue gas temperatures required that the boiler unit be modified such that the combustion area including most of the top section was lined with refractory boards. In addition, most of the boiler heat exchanger sections were blocked with refractory material and only several of the passages remain open. The amount of heat exchanger surface which was effective could be adjusted to trim boiler exit temperature.

Combustion gases leaving the boiler were directed through the condensing economizer and then exhausted outside with an induced draft fan, or a side wall power venter. A bypass system with dampers was set up as part of the flue piping to control the volume of flue gas entering the economizer. Flue gas velocities were measured at the inlet and outlet of the condenser with a standard pitot tube.

The burner arrangement used to fire the coal water slurry includes a direct-fired air preheater which burns kerosene. In some of the coal water slurry tests this burner was used to preheat the combustion air to 120 C (250 F). Under these conditions the oxygen content of the vitiated combustion air is about 19.5%. Strong burner swirl is achieved using axial swirl vanes at the burner head. Typical pressure drop across this head is 750 Pa (3 inches of water). The burner can also directly co-fire No. 2 fuel oil using a pressure atomizer adjacent to the air-atomized slurry nozzle. This was used for initial warm-up of the combustion chamber refractory liner and the boiler itself. During some of the combustion tests with coal water slurry the No. 2 oil was co-fired to assure stable conditions at the economizer. In the experimental work both air- and water- cooled condensing economizers, built by Condensing Heat Exchanger Corp., have been evaluated. These are cross-flow tube type heat exchangers with flue gas passing outside of the Teflon-covered metal tubes. Construction details can be found in reference 5.

Thermal Efficiency Prediction

The method developed by Colburn and Hougen[6] has been used to calculate the latent and sensible heat transfer rates, the water vapor condensation rates and the temperature profiles through the heat exchangers. This general method for evaluating the condensation of a single vapor from a non-condensible gas has been specifically applied by others to flue gas condensing economizers.[7] Predictions of the thermal performance of both the air and water-cooled economizers used in this project to date have been reported earlier.[8,9]

In the case of the air-cooled economizer condensation of water was found to begin relatively late in the economizer. The overall condensation rate could be increased considerably by presaturating the flue gas with water vapor but at some thermal efficiency sacrifice. The water-cooled economizer was designed for higher gas velocities and pressure drop. Condensation rates are considerably higher.

Particulate Removal Prediction

Particle removal is dependent primarily upon the following unit mechanisms: (1) inertial impaction on the tubes, (2) interception, (3) diffusion, (4) particle growth due to nucleation and condensation of water vapor, and (5) thermophoresis. In any practical heat exchanger these are affected by factors including: flue gas temperature and moisture content, heat exchanger surface temperature, excess air, total surface area, gas side pressure drop, and heat exchanger configuration.

For each mechanism discussed above a collection efficiency can be defined. A combined collection efficiency due to all the effects for a single tube can then be found and then used in relationships to evaluate the total collection for the n-rows of the heat exchanger. The predicted collection efficiency, considering four of the listed mechanisms, for both the air- and the water-cooled economizers have been evaluated. For flyash particle resulting from coal combustion, the dominant capture mechanism is inertial impaction. Diffusion is negligible and thermophoresis can only be important for the smallest particles when the difference between the flue gas temperature and the tube surface temperature is very high. For condensation particle growth to occur, the flue gas must be supersaturated somewhere in the boundary layer. Analysis done during this project has shown that this is not likely to occur even when the flue gas contains water upstream of the economizer.

Results

As a result of the importance of inertial impaction in particle capture, anything which leads to increased gas velocity and pressure drop improves total collection efficiency. The water-cooled economizer studied has a smaller minimum flow area than the air-cooled economizer and velocities roughly five times greater. Removal efficiency in the air-cooled economizer was determined to vary from 42% to 66%, while in the water-cooled economizer, removal efficiency was over 90%. Increasing the firing rate and gas flow through the economizers increases pressure drop and removal efficiency. Table 1 provides a summary of results obtained with the water-cooled economizer with a 5" of water pressure drop.

To evaluate effects of the addition of water vapor to the flue gas upstream of the economizer, tests were conducted with flue gas water vapor contents ranging from 10 to 20% (volume). In these tests, the overall particle removal efficiency was nearly independent of flue gas water vapor content. In addition, pre-saturating the gas in this way reduces heat transfer rates in the economizer. The system thermal efficiency penalty is about 1%. Adding water sprays directly within the economizer, in contrast, was found to improve particle removal. This might be used very effectively to obtain high removal efficiency at lower boiler loads where economizer pressure drop is reduced. As with water addition upstream of the economizer, water sprays in the heat exchange tube bank carry a heat transfer penalty.

All of the above results have been with oil-firing and spray-dried flyash. In tests with direct coal-water slurry firing, particle removal efficiencies ranged from 85 to 92% with gas-side pressure drops about 4.6-in. of water. Again with water sprays directly on the tube bank, marked improvements were observed with particle removal efficiencies of about 94%.

Run	13	14
Firing Rate, kW (Btu/hr)	82 (280,046)	82 (280,046)
Particulate concentration at the inlet of economizer, gm/dscm	0.544	0.378
Particulate concentration at the outlet of economizer, gm/dscm	0.01	0.014
Particulate removal efficiency across economizer, %	98	96
Particulate concentration at the outlet of induced draft fan, gm/dscm	0.007	0.006
Overall particulate removal efficiency across system, %	98.6	98
Water vapor content at the inlet of economizer, %	11	10
Water vapor content at the outlet of economizer, %	5	5
Flue gas temperature at the inlet of economizer, C (F)	205 (401)	205 (401)
Flue gas temperature at the outlet of economizer, C (F)	51 (124)	52 (126)

Table 1. Summary of Results of Tests with Water-cooled Condensing Economizer. All Tests with Oil-firing, Spray-dried Flyash, Firing Rate of 82 kW (280,000 Btu/hr). No additional Water Sprays used.

DISCUSSION

Results of the experimental work have shown that inertial capture of particles is the most important mechanism. Specifically, this is supported by 1) the shape of the removal fraction/particle size curves, 2) higher removal efficiency with higher velocity and pressure drop. This is certainly consistent with predictions. However, the actual particulate removal performance of the economizers has consistently been better than predicted. This may be due to inertial impaction of flyash on condensate drops falling from tubes. An estimate of the potential importance of this effect has been made using assumptions about drop size and concentration in the gas phase. Results are shown in Figure 2 and indicate that such impaction could be very important. In future condensing economizer designs, it may be practical to enhance this effect by "seeding" the economizer with small diameter impactors. An evaluation of this concept can be found in Reference 5.

Conclusions

A number of detailed conclusions can be drawn from the studies conducted during this project. Perhaps the most important is that condensing economizers can be used to control particulate emissions from coal water slurry-fired boilers. Particulate removal efficiencies as high as 98% were achieved in this study. For future improvements in the capture of flyash particles enhancing inertial collections through combinations of increased maximum gas velocity in the tube bank, directed water sprays within the heat exchanger and possibly added small diameter impaction sites are suggested.

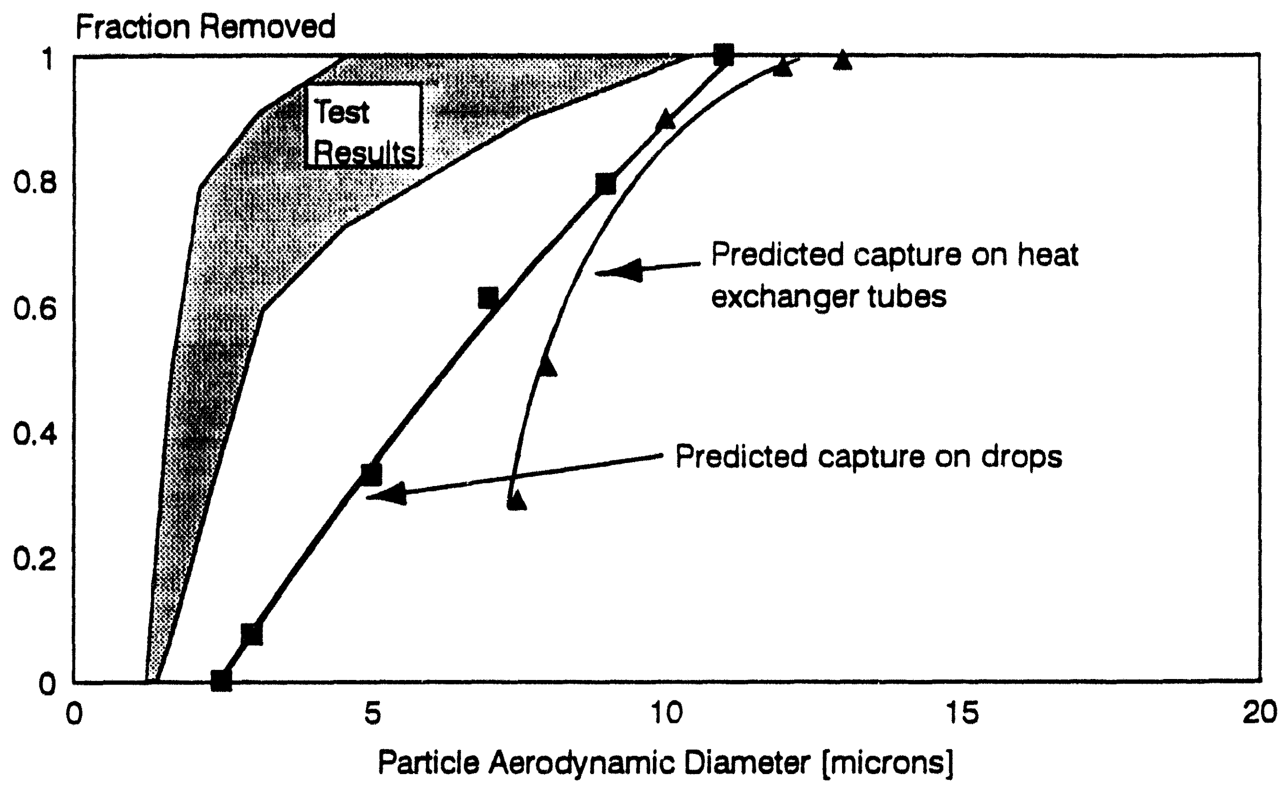

Figure 2. Prediction of particulate capture on condensate drops within the condensing economizer. Comparison with both predicted capture on heat exchanger tubes and observed results.

PLANS

BNL is currently planning to begin a Cooperative Research and Development Agreement project with Babcock and Wilcox Co., Condensing Heat Exchanger Corp., and Consolidated Edison Company of New York. Under this agreement, BNL will continue development studies with DOE support and emphasis on removal of trace pollutants, SO_2 capture, and a two-stage economizer concept. Babcock and Wilcox will also undertake development work at their Alliance Research Center. Consolidated Edison will conduct a demonstration project at their Ravenswood generating station. All groups involved will participate in planning and review of development efforts.

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AN ENVIRONMENTALLY SOUND PROCESS FOR UTILIZING WASTE-TIRE-DERIVED-FUEL (TDF) AND RAILROAD-TIE-DERIVED FUEL (RTDF) IN COAL-FIRED STOKER BOILERS

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ENGINEERING DESIGN CONSIDERATIONS OF INDUSTRIAL BOILER RETROFITS

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INTRODUCTION

The Energy and Environmental Research Corporation (EER) and the Pennsylvania State University are engineering the conversion of an existing heavy fuel oil and natural gas-fired watertube boiler at a U.S. Department of Defense (DOD) facility to fire either micronized coal-water slurry fuel (MCWSF) or dry, micronized coal (DMC). The host boiler is located in building #150 at the Crane Naval Surface Weapons Center in Crane, Indiana. The retrofit is being conducted as part of a program for DOD and the U.S. Department of Energy in which coal-based technologies are being evaluated to determine the technical and economic viability of replacing heavy fuel oil with coal in industrial-sized boilers. Retrofit options currently being evaluated are the direct firing of MCWSF and DMC, and coal precombustion technologies. The status of the evaluations and designs of the MCWSF and DMC direct firing technologies is presented.

HOST BOILER CHARACTERISTICS

The host boiler is a Cleaver-Brooks watertube boiler model D-42-LH installed in 1989 and is used to produce steam for weapons production and heating. It has a design capacity of 20,000 lbs/hr saturated steam at 125 psig and was originally designed to be operated on natural gas, #2 fuel oil and #6 fuel oil. The boiler has fired natural gas and #2 fuel oil. The boiler shares this building with two other boilers; one is a twin of this unit and the other is a Cleaver-Brooks D type with a capacity of 18 million Btu/h. Typically the boilers are operated about nine months of the year on a cyclical basis, each boiler being utilized about 3 months of the year. The annual fuel consumption per boiler is approximately 35,000 MMBtu. The boiler's normal production rate is about 80% of it's maximum continuous rating. If additional steam is required, another boiler is put into service.

The boiler is a two drum, bent tube "D" type boiler. The inside and outside furnace walls, as well as the floor and roof, are of tangent tube construction. The front and rear walls are similarly constructed but are also refractory covered.

The existing boiler controls are relatively simple. A roving operator checks on the boilers in the building once or twice a day. The only existing boiler alarm provides a signal for low-steam pressure.

This watertube boiler is representative of many units in the DOD inventory. For example, there are currently 266 natural gas, #2 fuel oil, and heavy fuel oil boilers in the inventory of the U.S. Army' with capacities ranging from 16 to 60 million Btu/h, which are candidates for conversion to fire coal-based fuels.

RETROFIT APPROACH

Typical concerns with such a conversion include ease of operation, cost of operation, impact on boiler performance, ash deposition and carbon conversion. Several features have been incorporated into the design to address these concerns. The coal is micronized to increase the carbon conversion and reduce the tendency of the ash to settle out in the boiler system. Carbon conversion is further enhanced by preheating the combustion air to 400 °F. To keep the boiler free of ash deposition, a floor blast system and sootblowers in the convective pass will be installed. The air heater is also equipped with sootblowers.

The approach for the retrofit was to utilize presently available state of the art technology. The conversion will include a fuel delivery and fuel handling system, low NO_x burner, FD fan, combustion air preheaters, baghouse, ID fan, ash silo, stack and control system.

A new distributed control system will be added to monitor and control the boiler and new equipment. The system will be complex in design to minimize the operator attention required at the facility.

Figures 1 and 2 illustrate the equipment layout for the MCWSF and DMC systems, respectively. This arrangement will allow the design to be easily modified for future sites and will also reduce the cost of construction. Since the design parameters for both systems are very similar, the combustion air and flue gas equipment will be the same. To further enhance the similarity of the two systems, the coal silo and the MCWSF storage tank will have the same diameter and support configurations. The only parts that will differ are the fuel unloading and storage systems and the burner injection equipment.

COAL DERIVED FUEL

There are two different fuel alternatives being evaluated for the conversion project: MCWSF, and DMC. Both of the fuels will utilize a local Indiana coal. Past experience has shown that a micronized coal flame has characteristics similar to that of an oil flame.

Micronized Coal-Water Slurry Fuel The Micronized Coal-Water Slurry Fuel will be produced off-site and will arrive at the facility in stainless steel tank trucks. The slurry will have a solids loading of 60%, a heating value of approximately 8300 BTU/lb, .5% sulfur as received and an ash content of approximately 3% as received. The coal particles in the slurry will be micronized and have a wide particle size distribution to increase the stability characteristics and reduce the viscosity. By decreasing the viscosity of the MCWSF, a higher degree of atomization can be obtained which promotes increased carbon conversion.

Dry Micronized Coal Coal will arrive at the facility in 20-ton conventional coal trucks. The coal will be 2" x 0" product and have a HHV of 11,898 BTU/lb. The coal will have 5% sulfur, as received and an ash content of 4.3% as received.

FUEL UNLOADING SYSTEM

Micronized Coal-Water Slurry Fuel The MCWSF delivery system will consist of an air operated diaphragm pump to unload the stainless steel tank truck. The system will be sized to unload a 4000 gallon truck in one hour. The unloading circuit will be equipped to automatically flush all of the slurry transport lines. The delivery system will also be capable of unloading the MCWSF storage tank into trucks, if required.

The steel MCWSF storage tank will have a capacity of 28,000 gallons. This size was a requirement of the host site to provide an on-site fuel storage supply of five days. The tank will be cone bottomed and equipped with a roof mounted paddle mixer, baffles to promote better mixing and level sensors. The storage tank will also be insulated and equipped with a heater capable of maintaining the slurry at 40°F. An air blast system will be located at the outlet of the tank to provide a means of breaking up the slurry should settling occur in the discharge cone.

Dry Micronized Coal The dry micronized coal delivery system will consist of an unloading building, coal receiving hopper, screw conveyor, crusher, bucket elevator and coal storage silo. The system will be sized to handle 20 tons/hr or one coal truck per hour. The coal will be delivered to the coal unloading building where the truck will dump into the coal receiving hopper. The unloading building will be equipped with dust collection to minimize fugitive dust. A screw conveyor will then transfer the coal from the hopper to the crusher where the size will be reduced from 2" x 0" to 3/4" x 0". The crusher will discharge into an enclosed bucket elevator which will transport the coal into the coal storage silo. The coal storage silo will have a capacity of 4100 ft^3 to provide the required on-site fuel reserves. The silo will be equipped with a bin vent filter, high level alarms to prevent overfilling and a bin discharger to promote mass flow in the silo. Magnets will be used through out the system to catch any ferrous material that may be entrained in the coal.

FUEL DELIVERY SYSTEM

Micronized Coal-Water Slurry Fuel The Micronized Coal-Water Slurry Fuel system will consist of a progressive cavity pump with a variable speed drive motor, basket strainers, flow sensor, steam heater and piping to the burner front. The MCWSF will flow from the bottom of the MCWSF storage tank through strainers for pump protection, and into the progressive cavity pump. The pump will have a variable speed drive to control slurry flow to match boiler load following requirements. This pump is protected from overpressure by a high pressure switch located on the discharge. After the progressive cavity pump, the MCWSF flows through an indirect steam heater to increase the temperature to 250 °F. The MCWSF then enters strainers to prevent atomizer pluggage, followed by a mass flow meter. This meter will also measure the slurry temperature and density. The MCWSF then flows to the twin fluid atomizer for injection into the boiler. The atomizer is of the internal mix design and manufactured from a wear resistant material. In addition to the system described above, there will be a slurry recirculation loop and flush equipment to prevent settling of the MCWSF.

Dry Micronized Coal The DMC burner system will consist of a weigh belt feeder, coal micronizing mill and the coal delivery piping. Coal from the silo will flow into the weigh belt feeder. The feeder will be equipped with a variable speed drive and will be designed to NFPA 50 psi burst specifications. The feeder will control the flow to the micronizing mill and in turn control the coal feed to the boiler. The micronizing mill will take the coal from 3/4" x 0" to 80% thru 325 mesh. The micronizing mill is equipped with a rotary classifier and provides the primary combustion air to transport the micronized coal to the burner. The mill is protected from tramp metal by magnets and a metal detector with diverter valve at the inlet of the mill.

BURNER

EER will supply a Low NO_x Burner that will fire gas to bring the boiler up to operating temperature and then switch to coal. A sectional view of the burner is shown in figure 3. The burner will fire either DMC or MCWSF depending on the system selected. If MCWSF is selected, EER will utilize a VEER™ Jet atomizer which has been demonstrated on two different boilers with excellent atomization and reduced NO_x operation. EER offers the FlamemastEER™ Burner for industrial and utility wall-fired boilers in North and South America. The unique design of this burner produces a highly stable attached flame with adjustable flame shape. This high degree of control allows the burner performance to be tailored to furnace dimensions for the lowest possible NO_x emissions and excellent combustion efficiency. NO_x emissions are typically reduced by 50 percent without performance penalties such as increased carbon loss or slagging. The FlamemastEER™ is designed for long life and uses an innovative air flow control mechanism that eliminates the complex linkages and gears which have caused problems in other low NO_x burners.

Mechanically, the burner has been designed to minimize the number of moving parts. Those parts which do move slide axially, eliminating complex linkages and gears. The secondary and tertiary swirl control vanes move back and forth within conical passages of the burner. As the swirlers are moved toward the narrow end of the cone more air passes through the vanes increasing the amount of swirl. As the swirler is moved in the opposite direction, the air follows the path of least resistance and by-passes the vanes, resulting in less swirl. The moving parts are located farthest away from the high heat flux environment in order to reduce warpage and binding.

The first US installation was at Penelec's Seward Station Boiler 14 (Sommer et al., 1993). In addition to reducing NO_x emissions, the burners at Seward are capable of cofiring up to 40% of their rated capacity on coal water slurry.

COMBUSTION AIR PREHEATERS

The retrofit will include two combustion air preheaters. The first is a steam coil air preheater designed to heat extremely cold ambient air to 200 °F. This is necessary to prevent the problem of back-end corrosion in the flue gas system. The second combustion air heat exchanger is a heat pipe flue gas heat exchanger that will be located on the roof of the building. The flue gas will leave the boiler at 500 °F and will exit the heat exchanger at 350 °F. Simultaneously, the combustion air will be heated to 400 °F. The flue gas heat exchanger will be equipped with a sootblower to clean the flue gas side of the exchanger and a bypass. At 1/3 load the steam coil air preheater is capable of heating the combustion air to a temperature greater than the boiler exit gas temperature. If the bypass was not provided, the combustion air temperature would be reduced in the air heater.

ASH HANDLING SYSTEM

The ash handling system will consist of a baghouse to collect the particulate matter in the flue gas stream, pneumatic conveying system, ash storage silo and an ash unloading screw conveyer. The pneumatic conveying system will transfer the ash from the baghouse into the ash storage silo. This silo will be sized for seven days storage. The silo will also have a bin vent filter to capture fugitive dust from the pneumatic conveying system and a level sensor to prevent overfilling. The ash screw conveyor will unload the silo into a waiting truck. The screw conveyor will be equipped with water injection nozzles to prevent fugitive dust emissions and heat traced to prevent acidic corrosion and freezing.

SCHEDULE AND FUTURE PLANS

The two design packages will be completed in June, 1994. The decision as to which, if either, conversion system to recommend to DOD will be made after the technology demonstrations (DMC and MCWSF) at Penn State and the economic evaluations of the systems are completed.

CONCLUSIONS

The designs for converting a DOD natural gas/fuel oil-fired boiler to directly fire MCWSF and DMC are nearing completion. The designs include the fuel handling system, a low-NO_x burner package, boiler modifications for ash deposition control, and a fly ash capture, storage, and handling system.

A retrofit option will be recommended to DOD after the designs, economic evaluations, and component/technology demonstrations at Penn State are completed. Using the design approach presented, the proposed arrangement can be standardized for DOD sites by changing equipment size and layout to meet site-specific requirements.

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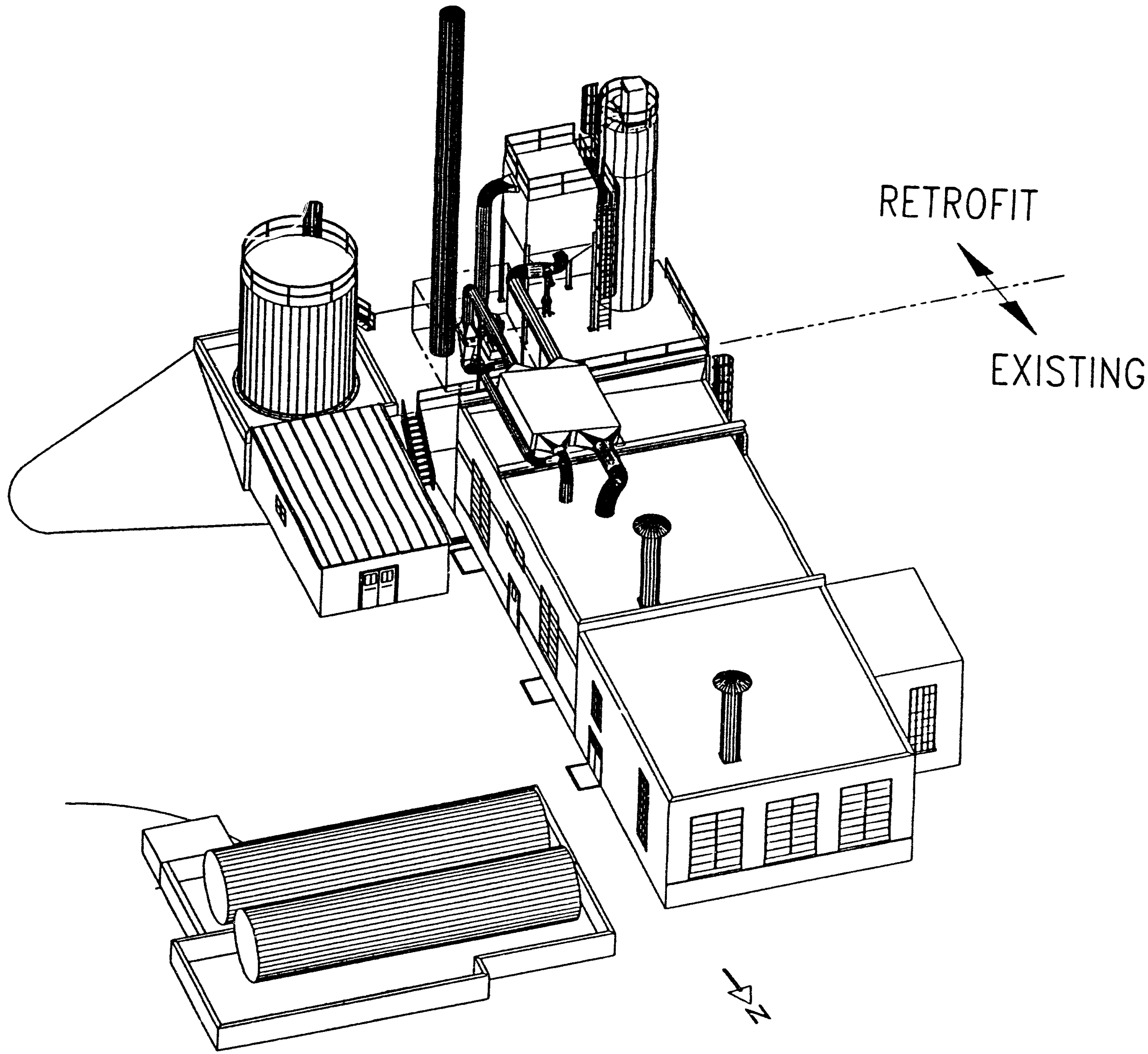

Figure 1. MCWSF Retrofit.

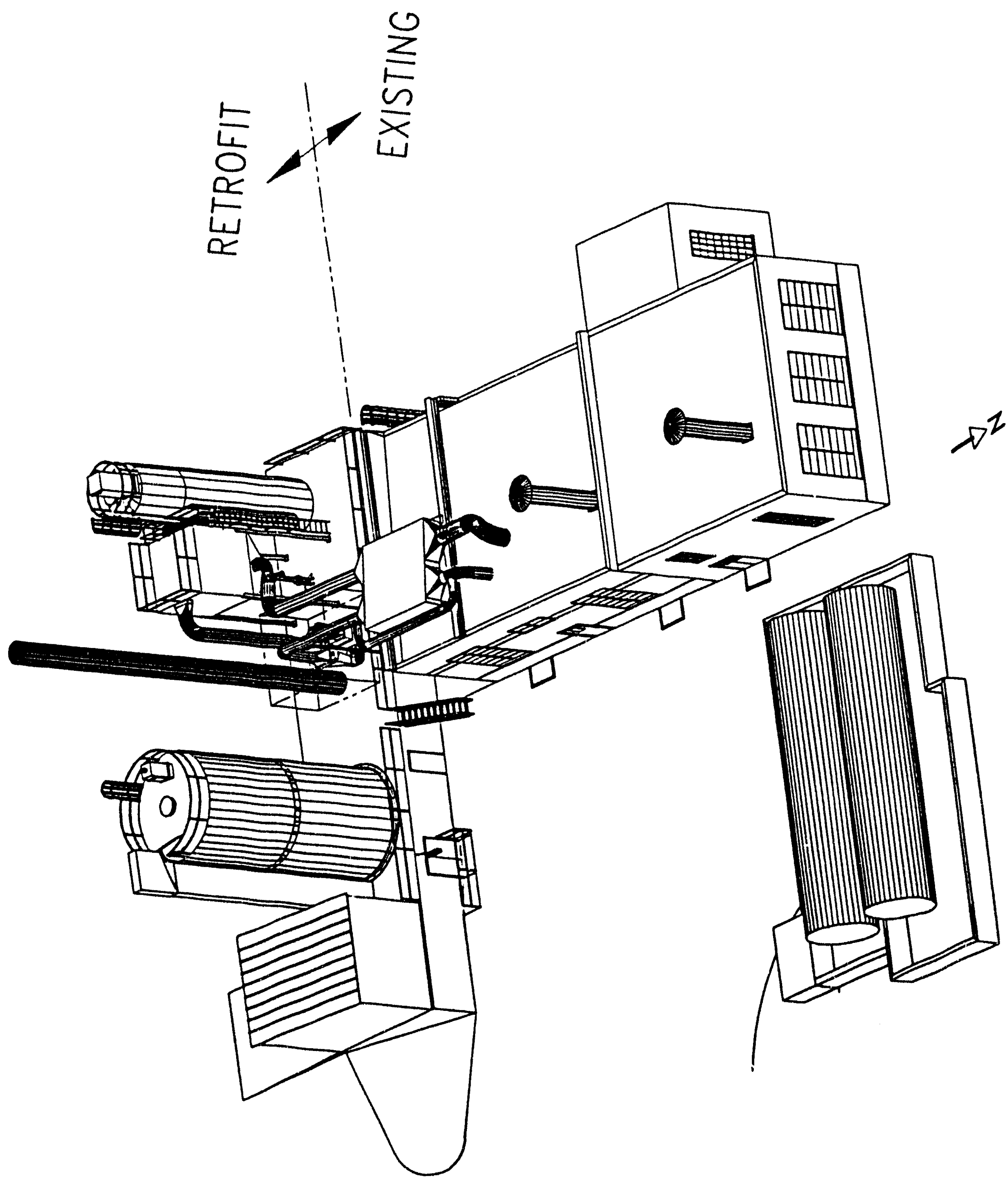

Figure 2. DMC Retrofit.

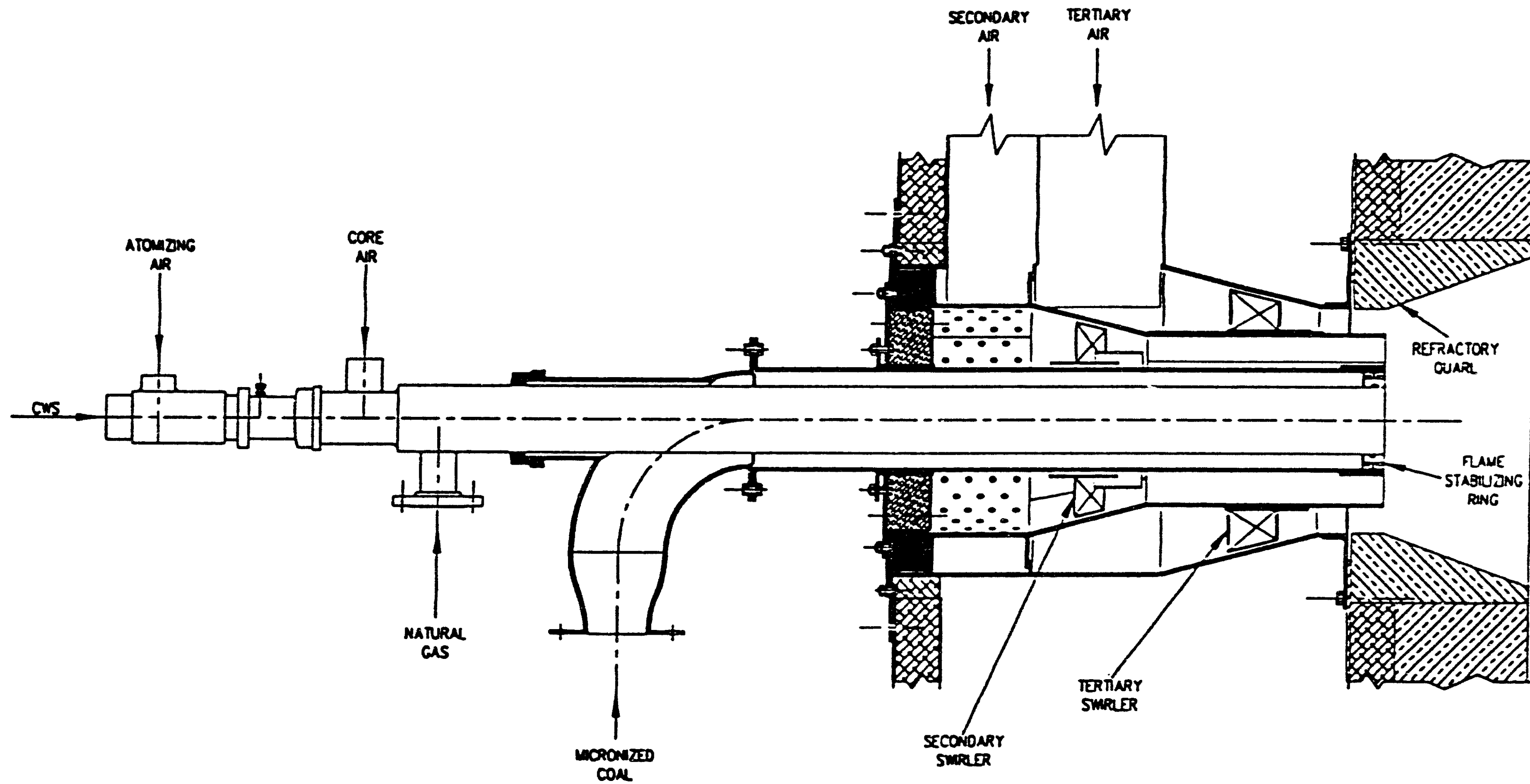

Figure 3. Burner Sectional View.