Project: " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE COAL FIRED COMBUSTION SYSTEM, PHASE 3"

Contract: DE-AC22-91PC91162

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Final Technical Report

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ABSTRACT:

Coal Tech Corp's mission is to develop, license & sell innovative, lowest cost, solid fuel fired power systems & total emission control processes using proprietary and patented technology for domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases. The first phase, "Optimization of First Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor", consisted of three tasks, which are detailed in Appendix "A" of this report. They were implemented in 1992 and 1993 at the first generation, 20 MMBtu/hour, combustor-boiler test site in Williamsport, PA. It consisted of substantial combustor modifications and coal-fired tests designed to improve the combustor's wall cooling, slag and ash management, automating of its operation, and correcting severe deficiencies in the coal feeding to the combustor. The need for these changes was indicated during the prior 900-hour test effort on this combustor that was conducted as part of the DOE Clean Coal Program.

A combination of combustor changes, auxiliary equipment changes, sophisticated multi-dimensional combustion analysis, computer controlled automation, and series of single and double day shift tests totaling about 300 hours, either resolved these operational issues or indicated that further corrective changes were needed in the combustor design. The key result from both analyses and tests was that the combustor must be substantially lengthened to maximize combustion efficiency and sharply increase slag retention in the combustor.

A measure of the success of these modifications was realized in the third phase of this project, consisting of task 5 entitled: "Site Demonstration with the Second Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor". The details of the task 5 effort are contained in Appendix "C". It was implemented between 1994 and 1998 after the entire 20 MMBtu/hr combustor-boiler facility was relocated to Philadelphia, PA in 1994. A new test facility was designed and installed. A substantially longer combustor was fabricated. Although not in the project plan or cost plan, an entire steam turbine-electric power generating plant was designed and the appropriate new and used equipment for continuous operation was specified. Insufficient funds and the lack of a customer for any electric power that the test facility could have generated prevented the installation of the power generating equipment needed for continuous operation.

All other task 5 project measures were met and exceeded. 107 days of testing in task 5, which exceeded the 63 days (about 500 hours) in the test plan, were implemented. Compared to the first generation 20 MMBtu/hr combustor in Williamsport, the 2nd generation combustor has a much higher combustion efficiency, the retention of slag inside the combustor doubled to about 75% of the coal ash, and the ash carryover into the boiler, a major problem in the Williamsport combustor was essentially eliminated.

In addition, the project goals for coal-fired emissions were exceeded in task 5. SO_2 was reduced by 80% to 0.2 lb/MMBtu in a combination of reagent injection in the combustion and post-combustion zones. NO_x was reduced by 93% to 0.07 lb/MMBtu in a combination of

staged combustion in the combustor and post-combustion reagent injection. A baghouse was installed that was rated to 0.03 lb/MMBtu stack particle emissions. The initial particle emission test by EPA Method 5 indicated substantially higher emissions far beyond that indicated by the clear emission plume. These emissions were attributed to steel particles released by wall corrosion in the baghouse, correction of which had no effect of emissions.

The second phase of the project, task 4, was implemented concurrently with phase one from 1992 through 1994. It was entitled: "Economic Evaluation & Commercialization of the Air-Cooled-Slagging Coal Combustor", and it is detailed in Appendix "B" of this report..

--The centerpiece of this task were two 20 MW power plant studies that could have resulted in a commercial installation of the Coal Tech, air-cooled slagging combustor. One was a 20 MW "Greenfield" plant consisting of a combined 5 MW natural gas fired -gas turbine-electric generator and a 15 MW, bottoming steam turbine-generator, fired with Coal Tech's combustor and using coal mine waste fuel. The capital cost was $1,200/kW.

The other study was a 20 MW repowering plant with the Coal Tech combustor and a new steam boiler to be located at an existing power plant in Pennsylvania and fired with coal waste culm. Its capital cost was estimated at $520/kW.

For the first plant, the developer could not secure financing. For the second plant, Coal Tech found an investor for the project, but the power plant owner withdrew the offer of using the site.

--Another part of this task involved evaluating various industrial steam plants at various manufacturing plant in southeast Pennsylvania for installation of the Coal Tech combustor to be used for task 5. While several very promising sites were found, none of the owners agreed to install the coal fired combustion system.

--The third part of this task involved marketing interactions with foreign energy concerns for installation of a slagging combustor system, with emphasis on regions that utilize very high ash coals, specifically India and China. In connection with this effort, several tons of 37% ash, Indian coal was procured and successfully tested during the task 5 effort. However, the marketing effort failed due to the lack of financing for any of the several very promising projects that were identified.

Task 6 was for disassembly of the entire facility. This was not done, and the facility still is operational, for the following reasons:

Although not part of this project, the task 4 effort strongly indicated that even an extremely low cost the combustor system, which can be retrofitted to almost any boiler, could not be fully commercialized without adding **very low cost, total emission control**. Indeed, the lack of total emission control can explain the limited growth in coal utilization in recent decades.

Therefore, after over one-half dozen Coal Tech Corp proposals to DOE over the past 6 years for partial support of this goal of total emission control were all rejected, Coal Tech implemented it with internally financed, minimal funds. It resulted in the invention and development of several patented or patent pending processes. They are:

-NO_x control with post-combustion non-catalytic reduction (SNCR)

-NO_x control with primary post-combustion reburn using coal, oil, gas, or biomass.

-Post-combustion SO_2 reduction
-Combined post-combustion SO_2 and NO_x
-Dioxin/furan reduction for municipal solid waste
-Mercury capture in slag and post-combustion
-A process for carbon dioxide separation and sequestration from coal combustion using the Coal Tech Corp combustor

Most of this work was implemented on the 20 MMBtu/hour Philadelphia facility that Coal Tech has maintained in operating order to this date, March 2004. Some of the NO_x and SO_2 work also was tested on a 50 MW utility boiler, where Coal Tech's extremely low cost Selective Non-Catalytic (SNCR) NOx reduction process recently achieved 0.15 lb/MMBtu emissions, which meets EPA's 2003 standard. Also, Coal Tech's dioxin/furan process was tested on a solid waste municipal incinerator.

It now appears that all this investment is very timely.
-Air pollution problems in Asian countries that burn very high ash coals has resulted in the formation of a massive "brown Cloud" over the Indian Ocean, and it is c ertainly a factor respiratory illnesses that according to the World Health organization are the single major pulmonary illness factor in Asia.
-Mercury deposition on the U.S. from overseas is exceeds the mercury emissions from U.S. coal fired power plants.
- Concern over worldwide greenhouse gas emissions is also increasing. On March 5, 2004 the Wall Street Journal reported that Swiss climatologists have determine that the European heat wave that killed 19,000 people in 2003 was the hottest in 500 years.

Coal Tech air-cooled slagging combustor provides a very low cost solution to all these problems.

Note: The Final Report document contains a brief summary of the work on this project. The details of the work on the 5 tasks of this project are contained in three Appendices A, B, and C.

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1. EXECUTIVE SUMMARY

Overview: Coal Tech Corp's mission is to develop, license & sell innovative, lowest cost, solid fuel fired power systems & total emission control processes using proprietary technology for domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases.

The first phase, "Optimization of First Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor", which is summarized in Appendix "A", invol ved the optimization of the design and operation of the first generation design 20 MMBtu/hour, air-cooled, coal combustor that was attached to an oil/gas design package boiler at an industrial steam plant in Williamsport, PA. The key activity was about 300 hours of coal-fired combustor tests and accompanying analyses that were implemented in a 2-year period in 1992 and 1993. The objective was to identify the modification needed to resolve outstanding performance issues on Coal Tech's first-generation, air-cooled, slagging, coal combustor. The key result was the data needed to design a longer combustor in Phase 3, task 5.

The second phase, ""Economic Evaluation & Commercialization of the Air -Cooled-Slagging Coal Combustor", which is summarized in Append ix 'B", involved the development of coal fired power generating systems suitable for industrial and electric utility applications, and the development of a plan to introduce this combustor technology into the market place. This effort was performed mostly between 1992 and 1994. The key results were the development of a design for a 20 MW combined gas turbine-steam turbine power plant, and a 20 MW repowering steam plant, both of which utilized the Coal Tech combustor. A financier for the latter plant was found, but the site owner backed out. However, the results are even more timely today in 2004 due to the collapse of the massive new power plant construction market that is based on scarce and costly natural gas and due to the increasing concern with global warming and coal emissions, such as mercury. Coal Tech's air -cooled combustor and emission control technology address all these issues.

The third phase, " Site Demonstration with the Second Generation, 20 MMBtu/hr, Air-Cooled, Slagging, Coal Tech Combustor", is summarized in Appendix 'C". It involved the relocation of the entire test facility from Williamsport, PA, to the Arsenal Business Center in Philadelphia, PA. The plan for task 5 was to design a new second generator combustor that incorporated the lessons learned in the test effort with the first generation combustor in Williamsport. It took an entire year, 1994, to find and prepare the Arsenal facility in order to relocate all the equipment. The entire installation was implemented in 1995, followed by the 2 year test effort in 1996 and 1997 during which 107 days of testing, versus the 63 days planned, demonstrated the commercial readiness of the combustor system, as well as its environmental performed, which met and exceeded the most optimistic project goals.

In the years following the completion of this project, 1998 to 2004, Coal Tech continued internally financed R&D on total emission elimination from coal and solid fuels at this Philadelphia facility and at a coal fired power plant and a municipal solid waste incinerator. The work resulted in the invention and development of emission control processes that can totally remove NO_x, SO_2, dioxin/furan, volatile trace metal, and **carbon dioxide** emissions from coal fired power plants that utilize the air-cooled slagging combustor.

This DOE project, its preceding DOE Clean Coal project, and its subsequent internally funded R&D effort nearly completed this two decade long emission control effort and completed the demonstration at a commercial scale of a patented, air-cooled slagging coal, combustor. Its key novel features are:

1) By combusting coal and solid fuels, such as shredded biomass or municipal solid waste, in the combustor and removing within it the bulk of the ash as liquid slag, the combustor can be retrofitted at very low cost to existing coal, solid waste, oil or gas fired boilers and new compact solid fuel boilers.

2) Air cooling decouples the combustor's cooling circuit from the boiler's steam circuit allowing attachment to almost any boiler, an extremely important cost saving feature.

3) Conversion of most of the coal ash into chemically inert slag traps most of the volatile trace metals, including mercury, and converts a disposal problem into a marketable product.

4) The sulfur dioxide and nitrogen oxide is sharply reduced inside the combustor, and the addition of simple, very low cost, post-combustion control process essentially eliminates the emission of these pollutants and the other coal combustion pollutants.

5) The combustor is ideally suited as a core component in a system to produce valuable coal derived gaseous fuels while concentrating carbon dioxide emissions for simpler sequestration in the earth.

Background of the present project: Coal Tech's commercial scale, combustor system development effort began in the mid-1980's with the design and fabrication of the 1st generation, 20 MMBtu/hr, air cooled combustor with partial support from the Commonwealth of Pennsylvania, and the private sector, primarily Coal Tech Corp., and some DOE support. In 1987, the combustor was attached to a 17,500 -steam lb/hour, oil design package boiler at a boiler manufacturing plant in Williamsport, PA, as part of the DOE Clean Coal Round 1 Program. At $1 million in total funds, split equally between DOE and non-federal sources, it was by far the smallest Clean Coal project. The objective of this project was to demonstrate the combustor's operation and environmental emission control performance in 900 hours of operation, including a series of 100-hour round-the-clock tests. This effort was successfully completed in 1991. However, the focus of the work statement was on the 900 hours of operation, which consumed all the project resources and prevented the implementation of important improvements that became apparent during the test effort. The most important of these was the need to lengthen the combustor in order to improve combustion and retain much more of the slag.

Phase 1 of the Present Project: The Clean Coal project showed the need for a substantial additional effort and this was the goal of the present project, which began in 1992. Among the primary areas needing improvement were:

1) The combustor length was inadequate for complete combustion under the fuel rich conditions needed for control of nitrogen oxides and sulfur dioxide emissions within the combustor. As a result a substantial fraction of the combustion and sulfur dioxide reduction occurred in the boiler, downstream of the combustor exit.

2) The reliability of the slag removal system needed vast improvement. Also, a large fraction of the slag drained into the boiler instead of the combustor's slag tap.

3) The steady increase in wall temperatures in the adiabatic exit section of the combustor required its conversion to air-cooling.

4) The solid fuel and reagent feed system capacity and reliability required expansion and greatly increased reliability.

5) Automation of the combustor air-cooling sub-system as well automation of the overall operation of the combustor system to reduce operating costs.

6) Due to the substantial carryover of slag and unburned carbon and ash into the furnace section of the boiler, major slag deposits drained onto the combustor floor and thick ash layers deposited on the boiler's furnace floor and to p of the lower drum between convective tubes .

The plan for implementing these changes was developed in task 1 of the project. Since a key issue was determining the increased combustor length necessary to achieve complete carbon burnout, and complete slag retention inside the combustor, very sophisticated two and three-dimensional coal particle combustion analysis were performed.

The changes to the combustor and test facility were identified in a series on single and double shift duration tests in tasks 2 and 3. A measure of the success of these modifications was realized in task 5 of the project when the entire 20 MMBtu/hr combustor-boiler facility was relocated to Philadelphia and a substantially longer combustor was fabricated. The success of these changes was apparent almost immediately on startup of the task 5 tests in that slag carryover out of the combustor and the ash deposits on the boiler's furnace floor were negligible.

A very important element of the task 3 effort in Williamsport was converting the exit section of the combustor from adiabatic to air-cooled operation. This yielded major benefits in the redesign of the combustor in the task 5 effort. In contrast, another effort in task 2 and 3 to re-entrain ash deposits from the boiler floor proved to be unnecessary in the task 5 effort due to the much improved performance of the new combustor.

Other key improvements made during the task 2 and task 3 test efforts, were automation of the combustor's wall air -cooling systems, redesign of the pneumatic feed system for injecting pulverized coal into the combustor, major improvements to the flame safety system to overcome its propensity for false flame trip that were caused by blinding from the pulverized coal and reagent powder injection, near automation of the slag tap to sharply reduce the need for shutdown to clear the tap of frozen slag, and addressing the mundane problems needed to reliably operate a steam power plant.

Phase 2 of the project: The work of Phase 2, the task 4 economic-study, was divided into two parts. In part one, a nearly one year long effort was devoted to finding a suitable a site in the Greater Delaware Valley region of southeast Pennsylvania to implement the present project's task 5 Site Demonstration task. Several such sites were identified which would have involved the sale of steam or electricity to the site owner. However, after evaluating the options, and reflecting on the problems of running an R&D effort at the Williamsport, PA, site, a stand alone building in Philadelphia was selected, and this proved to be an almost unique choice. The details of this effort are given in Appendix "B" and the first part of Appendix "C" of this report.

The second part of the marketing effort, which is also detailed in Appendix "B", involved responding to a request from a developer of power plants for the cost of a new "Greenfield" power plant rated at 20 MW electric power that used the air-cooled slagging combustor. There existed a potential for licensing of the combustor technology to this developer because he had a contract to sell 20 MW of electricity capacity to a local utility. We judged the probability as low. Instead we were motivated by the desire to develop a prototype design for a power plant based on Coal Tech's u nique, patented, air-cooled, slagging coal combustor. As a result considerable resources were dedicated to this effort. The power plant consisted of a 5 MW commercial gas turbine that was fired with natural gas and used steam injection to achieve the rated power. The turbines exhaust at about 1000^{o}F was used as pre-heated combustion air for the coal-fired, slagging combustor that was attached to a ABB Company D-frame industrial oil design boiler producing superheated steam to drive a nominal 15 MW steam turbine-generator. The power plant efficiency, as computed by Coal Tech and independently by DOE-NETL, was in the low 30% range.

The total plant cost, as developed by the engineering firm sub-contractor and based on quotations from major component manufacturers, was about $1,200/kW. According to this firm, this cost was substantially less than a coal fired fluid bed power plant of equal rating. The developer planned to utilize high ash, coalmine waste to fire the combustor. Based on the results of the 20 MW repowering study, to be summarized next, we judged the 20 MW combined cycle cost obtained by the engineering firm as being far too high. In any case, as we had suspected the developer withdrew his offer to build the plant. Nevertheless, the study proved very worthwhile, as we used the results in the 20 MW repowering study to be summarized next. Furthermore, after the present project ended in 1998, we developed designs for using the combined cycle plant with pyrolysis gas derived either from biomass or coal to fire the gas turbine, and the char to fire the slagging combustor, a function for which it is uniquely suited. **More recently, we used this cycle arrangement to design a combined gas-steam turbine cycle power plant that has in effect zero environmentally intrusive emissions and removes and sequesters in the earth the carbon dioxide.**

The second study, a 20 MW repowering plant, was an outgrowth of our search for a site to install the combustor for long-term operation. Four potential coal-fired electric utility sites in PA, KY, and KS were evaluated and the PA site provided an ideal fit. The power plant had an unused 20 MW steam turbine in need of extensive refurbishing, all the electric generating and transmission capacity, and most importantly, a very large supply of high ash coal culm. Using the same engineering firm, a design for this plant was developed in which two 150 MMBtu/hour air-cooled slagging combustors would be attached to an ABB Company D Frame boiler. The design developed by the engineering firm was estimated to cost over $900/kW. However, Coal Tech used innovative components and arrangements that lowered the cost to only $520/kW. With the help of the engineering firm, we found a power plant developer who was interesting in finance the project. However, the power plant owners were considering (in 1994) shutting the entire power plant by the end of the decade, and since the developer estimated that it would take 4 years to obtain the permits and install the plant, the effort was terminated.

In addition, a number of other site-specific applications where the combustor provided economic advantages were evaluated. They concerned plants that utilized steam and electricity for processes, primarily in the paper industry. The projects ranged in size from small firetube boilers rated at 10 MMBtu/hr to large boilers in the several 100 MMBtu/hr range. In all cases, recovery of invested capital ranged from less than 1 year to several years. The two barrier problems Coal Tech faced in implementing these economically attractive projects was the great reluctance of the hosts to be the first to install the air-cooled combustor, and the insistence that third party financing be provided.

The effort also included overseas marketing, especially to India and China. Their primary use of high ash coals is an ideal fit to Coal Tech's the air -cooled, slagging combustor, which converts at least 75% of the ash into inert slag. This sharply reduces the particulate emissions that are a problem in the combustion of very high ash coals. In addition, Coal Tech's very low cost emission control processes remove the other pollutants. . The barrier problem we encountered was financing the projects.

A major effort at Coal Tech, especially in the past 7 years, has been development of total emission control from coal combustion, including SO_2, NO_x, volatile coal ash trace metals, including mercury, carbon recovery and vitrification of fly ash, dioxins and furans, and the removal and sequestration of carbon dioxide. This has resulted in a series of proprietary combustion and post-combustion processes that meet this goal of total control. This 7 year effort has been totally financed by Coal Tech. DOE declined to participate in the half dozen proposals that were submitted in this period.

Coal Tech's low cost coal combustion and emission control systems are now very timely in part due to the ongoing financial crisis in the electric utility industry, which resulted mostly from the total reliance on natural gas for new gas power plants. Another timely factor is the recognition that atmospheric pollution from particulates and mercury emitted from the inefficient combustion of high ash coals that are used extensively in some countries contributes to atmospheric warming and mercury transport. For example:

--It was recently reported that a massive upper atmosphere particulate laden pollution cloud, 2 miles thick and in extent equal to that of the continental USA, has been found over the Indian Ocean. While Asian government officials this "cloud" to inefficient combustion of dung by India's poor, a far more likely source is inefficient combustion of the very high ash coals used in that region of the World. This combustion also contributes to increasing pulmonary related health problems, which with modern transportation in airplanes can rapidly spread around the globe. In contrast, the Coal Tech air-cooled slagging combustor has burned 37% ash Asian coals and 70% ash biomass char waste from gasifiers

Finally, while the debate on Global Warming continues, despite very strong evidence of its existence, that at the least would warrant some carbon dioxide reduction measures in the USA, which consumes one-quarter of the World's energy, warming effects continue to accumulate. As this editorial review of this projects Final Report is in progress, the March 5, 2004 issue of the Wall Street Journal reports that "Swiss climate researchers said last summer' s head wave, blamed for killing 19,000, was probably the hottest Europe has been in at least 500 years".

In connection with the issue of global warming, some climate researchers in the USA have claimed that between about 800 and 1300, called the Medieval Warm Period, the earth's climate was warmer that today, and it was followed by a Little Ice Age that lasted until about 1700, the dawn of the Industrial revolution. The inference that these researchers draw is that there is no need to worry. Most climatologists dispute that this earlier period was warmer that the current warming. In researching this problem in the past year, I uncovered evidence, (which was apparently overlooked by both parties of the dispute,) that both the warming and subsequent cooling in those eras was caused in part by anthropogenic (human) actions, an incredible conclusion since the world's population at the time was about 5% of current levels. A report on my findings is in preparation.

In any case, the technologies discussed in this report provide a potentially low cost solution to the problem of environmentally intrusive, coal combustion.

2: INTRODUCTION

2.1. Foreword:

Coal is by far the most abundant domestic energy source. Yet in the 4th decade of repeated "energy crises" it continues to be massively underutilized. Instead the U.S . economy has been subjected to repeated international and domestic stresses, including two wars, all of which were caused in part by U.S. reliance on the "clean" fuels, oil and natural gas. During this entire period, the growth in coal use has been relatively modest, and it promises to remain even more modest or even decline because ever more stringent environmental constraints are being added, with reduction of carbon dioxide's "greenhouse" emissions being the most recent and potentially the final "shows topper".

To an objective observer the problem with coal has been the failure to develop low cost energy systems that are **totally** environmentally benign and more importantly are economically competitive with the "clean fuel" based systems.

Instead the coal production and coal use industry have engaged in delaying actions against the introduction of the emission controls necessary to enhance coal use on the argument that they are not economically competitive. This argument is indeed justifiable based on the existing and proposed emission control technologies, which are quite costly because the R&D that developed them placed technical sophistication above low cost. As a result, after three decades of coal R&D opportunity still exists to tap this immense domestic energy source provided low cost environmentally benign coal based systems are developed.

This has motivated Coal Tech Corp's two decade long R&D effort to develop such systems, primarily those based on its unique and very low cost air-cooled, slagging coal combustor and associated emission-control processes. The present project was a key element in solving the combustor's technical issues and in solving part of the emission control issues for coal. Following the completion of this project, Coal Tech devoted for the past 7 years its modest internal resources to develop additional emission controls for nitrogen oxide, sulfur dioxide, volatile trace metals, including mercury, and most important for removing and sequestering the "greenhouse gas" carbon dioxide. Consequently in 2004 this technology is even more timely that ever before. This report will address some of this system's applications that were studied in this project, additional details are contained in Appendix "A", "B", and "C".

2.2. U.S. Energy Policies & Coal R&D Programs

In the mid-1970's, in response to the oil price shocks of that decade, the U.S. government embarked on a massive R&D program to increase coal utilization. The primary focus of the effort in the late 1970's was on conversion of coal to synthetic liquid fuel to replace petroleum. A secondary but still major R&D effort focused on direct coal utilization in advanced coal fired power plants using either direct coal firing, coal gasification, or coal slurry fuels. The synthetic fuels effort terminated and the direct coal utilization R&D effort decreased sharply in the early 1980's as the price of oil collapsed from the artificial levels of the late 1970's.

In response, the focus of U.S. government's coal R&D shifted in the mid-1980's almost totally to direct coal utilization in advanced power and energy systems with primary emphasis on removing the one key barrier to increased coal use, namely, coal's high air emissions of pollutants, primarily SO_2, NO_x, and particulates. The centerpiece of this effort was the Department of Energy's (DOE) Clean Coal Program that began in 1986 and continues to-date, 2004. A number of advanced coal fired power plant systems at the full scale, electric utility level, were successfully implemented through the decade of the 1990's. Many billions of industry and government funds were expended on these projects.

Yet despite these successes, when the electric utility industry was faced with sharply increased demand in the 1990's, over 90% of new power plant construction was natural gas fired. Economic and public policy considerations favored gas fired-combined gas turbine/steam turbine power plants. They were more efficient than the most modern coal fired plants, they were essentially non-polluting, they could be erected in one-half the time of coal power plants, natural gas prices were low, a nationwide pipeline grid was in place, and as an added bonus, natural gas produced much lower "greenhouse gases" than coal. However, in the rush to construct new gas fired power plants, developers appeared to overlook that much of this gas capacity was committed to existing users. As demand increased, gas prices rose sharply and stayed high even as the economy entered recession in around 2000. The result was a financial meltdown of power producers as electricity prices returned to historical norms leaving little or no margin to service debt, much less produce a profit. While the resulting financial meltdown in the power sector in 2001 was almost certainly accelerated by the financial improprieties by certain companies that came to light in 2001, these financial problems would have surfaced eventually. Since industrial users can use gas and oil interchangeably, their prices are coupled. Oil prices increased over the past decade with increasing demand from a shift to larger fuel inefficient cars. Prices were also pressured by political instabilities in key oil producing nations, which included two wars in Iraq. In addition, gas prices would also be pressured by the massive investments in gas exploration and pipeline construction that would be needed to meet the growth in gas use.

These gas supply problems would seem to favor increased coal utilization for electric power as it is in almost limitless supply and offers stable pricing. However, here also, economic, political and public policies have prevented this growth.

Existing coal fired power plants benefit substantially from high prices from gas-fired power because electricity is generally priced at the highest marginal producer. Coal power plants produce by far the lowest cost electricity because they are "grand fathered" and generally exempt from newer and costly emission regulations as long as they make no "substantial" changes to the existing power plants. This has of course resulted in decades long litigation between these producers and the government on the meaning of the word **"substantial"**.

Nevertheless, it has not prevented very low cost emission control technologies, such as "low NO_x" burners" from being widely adopted. However, that has not been the case for the much more costly NO_x, SO_2, volatile trace metals, and very fine particulate emission control technologies. Ironically, it would appear that these costly technologies actually are favored by existing coal power producers because it provides an excuse for maintaining the profitable status quo.

The public's inconsistent position on energy also helps to maintain the status quo. "Clean", but costly, natural gas plants a nd even more costly taxpayer subsidized- "renewable" energy power plants are favored, while "dirty" coal plants are opposed. Yet the experience of California shows the danger of relying primarily on "clean" hydropower and "clean" natural gas power. In 2000, a booming economy, a drought in the hydropower region and a shortage of natural gas, combined to cause electricity prices to soar. While it was determined in the following year that part of the increase was due to market manipulation, electricity prices would still have risen sharply. In fact, if not for coal-fired electricity from neighboring States, the crisis would have been much worse.

The conclusion from all these factors is that "clean" coal fired electricity is essential for a healthy American economy, **provided it can be supplied at modest added costs to current coal based electricity. While coal R&D has delivered "clean" coal, it is quite costly, and it will become even more costly when new controls on emissions of mercury and carbon dioxide sequestration are added.**

2.3. Coal Tech's R&D Approach to Coal Based Power

This project's principal investigator (P.I.), the author of this report, was exposed to the overriding importance of a systems approach to evaluating new energy technologies in the mid-1970's. The Energy R&D Administration (ERDA), the predecessor to DOE, commissioned a comparative system study of existing and advanced coal based, electric power generating technologies all of which were to be fired with coal (Ref. 1). The key result from that study was that some advanced high efficiency energy conversion technologies lost much of this efficiency and, even worse, they lost their cost advantages when they were evaluated as a total system in a power plant.

This problem was due to the inefficiencies and costs that were introduced as multi-step processes and thermodynamic cycles were added to achieve optimum combinations of the coal fuel with the power cycle. For example:

-Using coal to power a combined gas turbine/steam turbine required a gasifier and a gas cleanup system, each of which suffered from inefficiencies and costly components. Interestingly, the study concluded that this power cycle was one of the most economically attractive, even superior to more efficient advanced power cycle, such as the open cycle magnetohydrodynamic topping/steam bottoming cycle, or a steam cycle with full environmental compliance using stack gas scrubbing for SO_2. However, no comparison was made with a steam cycle without SO_2 or NO_x control as no one envisioned in the mid-1970's that these polluters would still be operating three decades later. As a result, outside of subsidized demonstration projects, few, if any, economically stand-alone coal gasification gas/steam turbine power plants have been erected in the U.S. in the past three decades.

-Using a fluid bed boiler to burn coal and to remove sulfur dioxide emissions required replacing much of the steam boiler with a fluid bed boiler, which rendered the existing stock of coal fired boilers useless. This eliminated this technology for low cost retrofit applications.

-Treating coal to remove sulfur at the mine simple shifted the cost from one location to another

The key lesson this author drew from that and similar studies, and one confirmed for essentially all other new technologies, is that for a new technology to replace an existing one, it must be more less costly. Even the jet plane only replaced the piston driven plane because its higher speed resulted in a lower cost to the traveler.

Low cost is extremely difficult to implement in a capital-intensive system such as a coal fired power plant, where the increased efficiency from alternate power cycles is relatively small, while costly environmental emission control is only a long-term indirect benefit to the public in improved health. Therefore, a critical corollary to the lesson of low cost is that as much as possible of the existing power plant components must remain in use. One successful application of the lesson low cost is the "low NOx" burner.

It is this need for low cost that requires maximum reuse of existing equipment that led to the air-cooled, slagging coal combustor. It meets most of these requirements.

1) It can be directly attached to existing coal-fired boilers.

2) Air-cooling eliminates the need for integration into the existing steam loop of the boiler, or the need for an inefficient separate water-steam cooling loop.

3) A substantial fraction of the NO_x and SO_2 is controlled inside the combustor. This reduces the additional post-combustion reduction needed for complete removal.

4) About three-quarters of the ash is removed in the combustor as slag, which allows its use on oil or gas designed boilers as well as much smaller coal design boilers.

4a) The char combustion capability makes this combustor ideally suited for power cycles in which cleaned pyrolysis gas is used to produce clean gas fuels to gas turbines. Since pyrolysis of volatile matter in coal or biomass occurs at substantially lower temperatures than total gasification the efficiency of gas production is higher due to the absence of air dilution or the need for oxygen. Also, materials requirements are much less stringent.

5) Volatile trace metals in the coal ash, including possibly mercury, are trapped in the chemically inert slag removed from the combustor.

6) Suitable fuels include, low to very high ash coals and coal char, shredded biomass, and shredded municipal solid waste fuels, oil, and gas.

7) Finally, the combustor fabrication and installation cost is very low. Almost all other components are essentially identical to those found in current coal fired power plants.

Therefore, the air-cooled, slagging-combustor meets the requirement for a "clean" coal technology that requires only a modest cost increase above current coal combustion systems

In this document only the overall results of the entire project are summarized to enable the reader to obtain an overview of the entire project. The details are contained in Appendices "A", "B", and "C". This approach is more informative because the three phases of this project were distinct work elements.

3. **Technical Approach & Task Description**

3.1. Overall Project Objectives

The primary objective of tasks 1, 2, and 3, as well as task 5 was to perform the final demonstration testing of the 20 MMBtu/hr air-cooled, slagging coal combustor-boiler system. The focus of all the tests was on combustor durability, automatic control of the combustor' s operation, and optimum environmental control of emissions inside the combustor. The goal was to achieve 0.4 lb/ MMBtu of SO_2 emissions, 0.2 lb/MMBtu of NO_x emissions, and 0.02 lb particulates/MMBtu. The first two goals were substantially exceeded in the task 5 efforts. The particulate goal could not be met in tasks 1 through 3 because the Williamsport facility was equipped with a wet centrifugal particle scrubber that could only meet the local regional emission goal of 0.3 lb/MMBtu. However, in task 5 the scrubber was replaced with a fabric filter baghouse that was guaranteed by the supplier to meet the Philadelphia standard of 0.03 lb/MMBtu.

The project objectives for tasks 1, 2, 3, and 5 were to be met by a series of tests of increasingly longer duration, and totaling about 800 hours of total testing. In practice this was substantially exceeded in the combined task 1 through 3 and task 5 testing.

The final objective, task 4, was to define suitable commercial power or steam generating systems to which the use of the air-cooled combustor offers significant technical and economic benefits. In implementing this last objective in task 4 a steam power plant at the 20 MW electric output and a 20 MW electric combined gas turbine-steam generation plant were designed and costed. Furthermore, considerable marketing efforts were implemented that including finding several suitable sites for constructing such a power plant. In one case a potential private sector financier was found for a 20 MW re-powering project.

3.2. Task Description & Brief Summary of Work Done

The following is a summary of the objectives, the planned work, and the actual work for each task: More details are contained in Appendices A, B, and C.

Task 1: Design, Fabricate, and Integrate Components

This task consisted of three sub-tasks. The components necessary to implement the modifications indicated at the start of the project were designed, fabricated, and installed on the 20 MMBtu/hr combustor facility in Williamsport. The goal of these modifications, which is discussed in detail in Appendix "A", was to enable combustor operation in a safe and environmentally compliant manner for a totaling of up to 100 hours.

In addition, sophisticated computer modeling of the coal fired combustion process inside the air-cooled combustor was implemented. The analytical results confirmed the combustor test results in which poor slag removal inside the combustor and high unburned carbon and fly ash carryover out of the combustor strongly indicated that the combustor should be substantially lengthened. The analytical results suggested the amount of lengthening. However, one of the two analytical models, which was more complex and sophisticated, was found by Coal Tech's technical staff to be flawed. Therefore, the decision on the design modifications on the second-generation combustor that was fabricated for use in task 5, was based on test experience. This decision was validated as soon as the task 5 tests began.

The second major modification was the conversion of the exit nozzle of the combustor from adiabatic operation to active air-cooling. This modification was implemented and tested in task 3. The results were successfully incorporated in the second-generation combustor fabricated and tests in task 5. Task 1 was successfully completed in 1992. The summary of this task is in this report, and the details are in Appendix "A"

Task 2: <u>Preliminary Systems Tests</u>

The modified combustor system underwent a series of one-day parametric tests of total duration of 100 hours in which the design changes introduced in task 1 were tested. This task was successfully completed in 1992-1993. The summary of this task is in this report, and the details are in Appendix "A".

Task 3. <u>Proof of Concept Tests</u>

The durability of the combustor was to be determined in a series of tests of between 50 and 100 hours of continuous operation, with a goal of a total test period of 200 hours. A total of 200 hours of combustor operation were implemented. However, as described in Appendix "A", personnel and operational issues, not directly related to the combustor, such as wood chip contaminated pulverized coal supplied by the offsite supplier, prevented round the clock coal-fired operation. However, several round the clock tests were performed, with coal firing in two shifts during the day and third-shift operation at high rates on oil firing. In addition, as noted in the task 1 paragraph above, the exit nozzle air-cooling design was successfully validated.

Task 3 was successfully completed at the end of 1993. At that time the Williamsport test site owner notified Coal Tech that the plant had been sold and we must vacate within 60 days. This turned out to be an **extremely positive** development because it eliminated the original plan to implement task 5 in Williamsport. The original task 5 plan was for performing 100 hour duration coal fired tests, which could have been done with the staff available in Williamsport. However, it would have been performed in a combustor that was too short to be effective because there was no room in the boilerhouse to lengthen the combustor. Furthermore, the project would have ended in early 1995 and the facility would have been disassembled under task 6 and scrapped. This would have eliminated any possibility of developing a commercially viable, air-cooled combustor. It would also have removed any possibility of developing the emission control processes that were implemented with Coal Tech's own resources. The 20 MMBtu/hour combustor-boiler facility in Philadelphia is still operational today in 2004.

The summary of this task is in this report, and the details are in Appendix "A"

Task 4. Economic Evaluation and Commercialization plan.

The objectives of this task were to evaluate the technical and economic potential of the air-cooled, slagging coal combustor in electric utility power applications and in industrial steam process heat applications. To implement this task under realistic commercial systems the studies in this task were performed as much as possible for users of this technology that were identified in a marketing effort. To implement this task Coal Tech performed a marketing effort to identify users who would benefit from this technology, and once identified, analysis of different degrees of depth were performed to demonstrate to them the economic benefit of using this technology. In other words, the goal of this task was to analyze only those applications where a reasonable chance existed that the result could lead to commercial use of the technology after this project was completed.

The major plan for this task was to perform a technical and economics analysis of two different industrial scale steam based cycles using the Coal Tech air-cooled combustor. As a result a 20 MW "Greenfield" power plant consisting of a com bined gas turbine-steam turbine power cycle was designed and costed. The other task was for a 20 MW repowering plant focused on a specific power plant in Pennsylvania was implemented.

As part of this effort several commercialization plans that were developed with partial assistance of a DOE-SBIR sponsored commercialization program, were utilized for the present project. This marketing effort yielded serious interest that justified the two 20 MW power plant studies.

In a parallel effort whose objective was to find a site for the task 5, Site Demonstration effort, potential industrial or electric utility sites were sought out that would be interested in using the combustor system after the completion of this project. While several suitable candidates were identified in the Southeast Pennsylvania region prior to the initiation of task 5, it soon became clear that the funds available for such an effort were insufficient to implement a full commercial installation. Furthermore, in light of the difficulties of operating within the boiler manufacturing site in Williamsport, as described in Appendix "A" of this Final Report, it was decided to implement task 5 in a stand alone site, as described under task 5.

Also, an international marketing effort was launched that succeeded in identifying two potential sites in India for industrial process steam use and for electric power generation. They did not proceed due to lack of financing.

The marketing effort clearly demonstrated the need for implementing a fully commercial scale project in order to market the combustor system. To this end Coal Tech assembled an industrial team and submitted a proposal for a 20 MW steam power plant to be located at a former large manufacturing site in the Greater Philadelphia Valley in response to the DOE Clean Coal Round 3 solicitation. The estimated cost was in the $20 million range. DOE rejected it. This was most unfortunate because in the years **after** the present project was completed in early 1998, Coal Tech invented and developed a series of very low cost processes that could remove all emissions from coal combustion. Had a 20 MW power plant been in operation, the air-cooled combustor system would have been fully commercial by the present time.

Task 5. <u>Conducting a site demonstration</u>.

The details of the work on this task are contained in Appendix 'C".

The overall primary objective of this project was to perform the final testing at a 20 MMBtu/hr commercial scale of an air-cooled, slagging coal combustor for application to industrial steam boilers and power plants. The focus of the test effort was on combustor durability, automatic control of the combustor' s operation, and optimum environmental control of emissions inside the combustor. In connection with the latter, the goal was to achieve 0.4 lb/MMBtu of SO_2 emissions, 0.2 lb/MMBtu of NO_x emissions, and 0.02 lb particulates/MMBtu. Task 5 was the key task in achieving the objectives of this entire project. For example, meeting the particulate goal required the use of a baghouse or electrostatic precipitator to augment the nominal 80% ash retention in the combustor. The Williamsport installation where tasks 1, 2 and 3 were implemented was equipped only with a wet particle scrubber that could not meet this goal, and there was no room for the other two components. Task 5 would meet and greatly exceed the NO_x emission goal, which required only a modest improvement over reductions achieved in task 3 of 0.26 lb/MMBtu. At the end of task 3, SO_2 levels as low as 0.6 lb/MMBtu, equal to 81% reduction in 2% sulfur coals, had been measured with boiler injection of lime. In task 5 it was planned to reach the 0.2 lb/MMBtu goal by combined injection into the combustor and boiler.

The task 5 project objectives were to be met by a series of tests of increasingly longer duration, and totaling about 500 hours of total testing, comprising 63 days of single shift testing. Actually, 107 days of testing were implemented in this period of which 73 were directly on task 5 and 34 test days were on a parallel project, whose results contributed to the goals of task 5.

By the end of task 3 excellent progress had been made in the previous several years in meeting the task 5 combustor performance objectives. Ever since the start of this combustor development effort in 1985, one of the most important objectives had been 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 calcium oxide based reagent injection in the combustor has been 56%, (+/-) 5%. Of this amount a maximum of 11% of the total coal sulfur was trapped in the slag. On the other hand, up to 81% SO_2 reduction has been measured with lime injection in the boiler immediately downstream of the combustor. Task 5 focused on optimizing the combined SO_2 reduction.

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^oF gas temperatures, durability has been one of the key challenges in the development process. Here also the use of computer control has been the means whereby this problem was being solved. Since introduction of computer control at the beginning of this project, the need for frequent refractory liner patching inside the combustor had been eliminated. The task 3 tests had shown combustor durability by operating the combustor continuously on coal for 8 to 10 hours on successive days. It had been planned for task 5 to achieve continuous round-the-clock coal fired operation for up to 100 hours. 100 hour operation would not add to the durability of the combustor, because start and stop operation is much more severe on the combustor wall than continuous operation. Nevertheless, such continuous tests were planned for task 5. However, due to limitations in funding it was not possible to obtain the needed personnel to implement a 100-hour continuous coal fired operation. Instead durability was demonstrated by operating the combustor for many test days without internal refurbishing of the refractory lines.

Task 6: Decommission the test facility

There was a task 6 to decommission the test facility. However, Coal Tech Corp has at its own expense continued to maintain and operate the facility in Philadelphia since 1998 end of testing on this project. During that time Coal Tech Corp made major advances in:

Post-combustion control of NO_x with development of an novel low cost Selective Non Catalytic Reduction (SNCR) process

Post combustion "Reburn" NOx reduction process using biomass, oil, or coal as the rebrun fuel,

Post-combustion SO_2.reduction process

Post combustion combined SO2/NOx reduction process

Combustion and post combustion dioxin/furan reduction process

Volatile trace metal-in-slag in the combustor capture process, that includes mercury,

Post combustion mercury reduction process

Coal gasification & carbon dioxide separation and sequestration processes, and

Combustion NOx reduction process for gas turbines

All this work was implemented on a minimal internal budget.

The facility is still operational in May 2004.

3.3: Summary of Project Results & Discussion

This section presents the highlights of the project results. The details of the well over 100 test days that were implemented in this project over a 6 period, including a 2 year interval between the first group of tests in Williamsport and the second group in Philadelphia cover such a wide range of operating conditions that it was necessary to divide the Final Report into three sections. The analytical task 4 was also quite extensive. Therefore, the details on the 5 project tasks are given in the three appendices.

Appendix "A" covers the tests in the firs t-generation combustor in Williamsport, PA that were implemented as tasks 1, 2, and 3.

Appendix "B" covers the power plant designs and economic analysis and marketing effort that utilized Coal Tech's air -cooled, slagging combustor technology that was implemented as task 4.

Appendix "C" covers the second -generation combustor tests in Philadelphia, PA that was implemented as task 5.

Therefore, this section begins with a description of the air-cooled combustor technology, followed by key project results.

3.3.1. 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 reagent powder for SO_2 control is 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.

The first generation combustor tested in Williamsport was first designed and fabricated in 1986. It was installed in 1987 in the boilerhouse of a boiler manufacturing plant in Williamsport, PA, and tested for about 900 hours as part of the DOE Clean Coal Round 1 project, and several other project, as well as in tasks 1, 2 and 3 of the present project. Based on these test results, a new and longer combustor with similar design features as the first ones, and as shown in figure T, was fabricated and installed in the Philadelphia facility. It main new features were greater axial length and an air-cooled exit nozzle, instead of the previous adiabatic exit nozzle. It was tested in the task 5 effort.

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

The 20 MMBtu/hr combustor was installed on a 17,500 lb./hr steam boiler. Figure 2 shows a side view drawing of the combustor attached to the boiler. The coal is pulverized off-site, and it was delivered to the site in a tanker truck in Williamsport and in 1 tons supersacks in task 5. 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 can be refilled without combustor shutdown. A wet particulate scrubber was used in Williamsport and a dry fabric filter baghouse 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 gas measurements, including O_2, CO_2, CO, SO_2, NO_x, HC. Gas samples are taken in the stack above the boiler, prior to the wet particle scrubber.

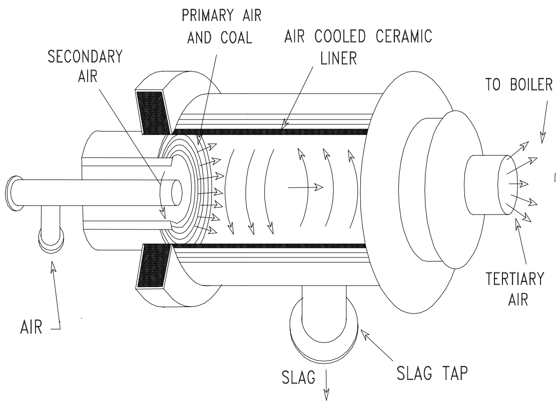


Figure 1 Coal Tech's 20 MMBtu/hr Combustor

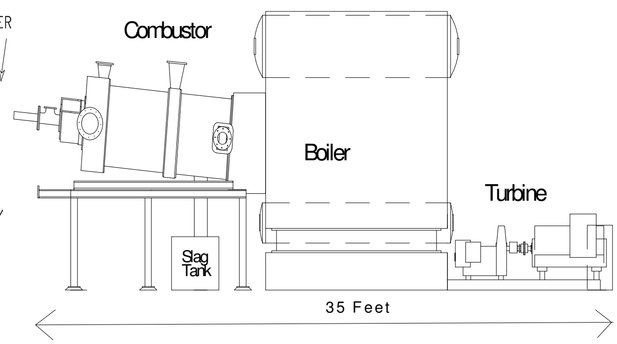


Figure 2: The 2nd Generation 20 MMBtu/hr Combustor-Boiler

3.3.3. Summary of the test effort in the first generation combustor- (1992 –1993)

Task 1: <u>Design, Fabricate, Integrate Components</u>

The planned combustor modifications in task 1 were completed in late 1992. A series of two shakedown tests was performed to test the operability of these modifications. No major modifications to the combustor were made in this task. All the changes were improvements in overall combustor-boiler operation, maintenance and repair of components, and addition of diagnostics. In addition, during shakedown tests of these modifications the need for additional improvements or modifications became apparent, and these were implemented. The major improvements focused on coal and reagent storage to allow multi-day continuous coal fired operation, modifications to the injection of coal and reagent into the combustor to optimize combustion uniformity, real time control of ash deposition in the boiler, improved combustor wall cooling, expanded computer control and diagnostics, and refurbishment of the scrubber and combustor temperature measurements.

One modification was delayed until the latter part of task 2, namely, installation of active cooling of the combustor exit nozzle. The nozzle was designed originally for heat sink operation which limited the continuous run time at high thermal input to at most 16 hours, compared to present project objective of 100 hours of continuous operation. Analytical modeling of a method to cool the part of the exit nozzle that protrudes through the boiler's refractory wall was performed. The implementation of this modification was deferred until late in the task 2 testing in order to obtain additional exit nozzle performance data. These tests were performed in early

1993. They showed that exit nozzle cooling was required over its entire length. A more complex design was developed to accomplish this and its installation was completed early in second quarter of 1993.

As part of the automation of the combustor' s operation, additional combustor performance observables and diagnostics were converted from manual to computer control and recording. This included water-cooling circuits, steam flow, wall temperatures, coal flow, oil flow, and reagent flow. In addition, the computer was programmed to control combustor heatup, steady state, and cooldown. Due to the presence of technical specialists at all the tests, complete automation, which would require only a push button start, was not introduced due to cost considerations. Only the major control functions are included in the process control software. They are being upgraded as additional performance data is accumulated.

Another task 1 activity was the fabrication and installation of an automatic slag breaker. This was completed and successfully tested early in the task 2. This device is needed to prevent blockage of the slag tap, which requires termination of coal firing. Another automation step was the addition of a slag tank water level control and an improved slag removal procedure from the tank.

One goal of the tests was to determine the interaction of various components in the combustor. For example, when the number of coal and reagent injection points in the combustor was increased to improve uniformity of air/solids mixing, the flame safety reliability decreased causing combustor shutdowns. To improve flame safety reliability, an integrated flame safety system was designed and installed

In the analytical part of task 1, two-dimensional combustor modeling with the Brigham Young University (BYU) combustion code was implemented. The results were used in combination with the test results through to end of task 3 to specify the length of the second-generation combustor. Additional work involving the 2 dimensional FLUENT combustion code led to discrepancies in the combustion chemistry. At the time, no satisfactory explanation was found for this either Coal Tech or the code developers. Re-examination of the graphical results as this final report was being prepared in May 2003 clearly indicates that the problem was due to either the use of too coarse a computational grid or incorrect carbon-oxygen reaction rates. The new conclusion was based on the observation that 1-micron coal particles were completely consumed soon after injection into the combustor, while 3-micron particles managed to transit one-half dozen feet in the 3000^{o}F combustion zone, which is impossible. The lesson from this exercise is not to take the results of complex computer modeling at face value without comparing them to experimental data. Even when the results do agree one should make sure that this is not due to modeling assumptions.

Figure 3 shows a typical result of the coal particle combustion, as obtained by the FLUENT code. If the particle track, for the specified coal particle size distribution, leaves the combustor exit nozzle, (one the right in the figure) it means that combustion is incomplete, and a longer combustor length is necessary. These results were compared to the measured carbon conversion based on solids sampling in the particle scrubber to determine the degree of carbon conversion and combustion efficiency for a specific set of operating conditions.

(see Appendix "A" for details on the combustor modeling.

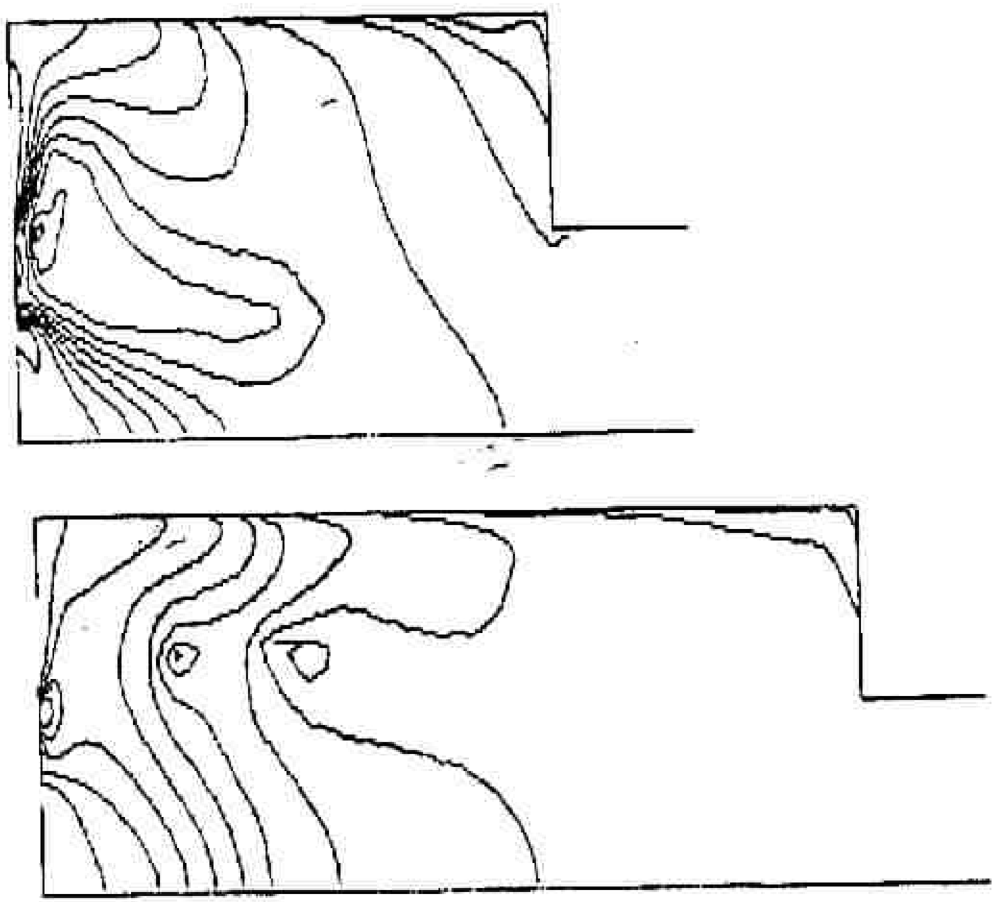
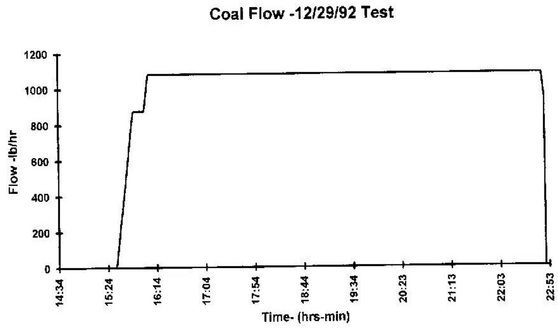


Figure 3: Gas Temperature Profiles for the FUEL LEAN Conditions in the Combustor for Two Combustor Length/Diameter Rations: L/D=1.5 (Top Graph) and for L/D=2.5 (Bottom Graph)

Task 2. Preliminary Systems Tests

Six tests were planned and completed in this task. The first two were parametric tests of nominal one shift, (8 hour) duration on coal. The objective of these tests was to evaluate the performance of the components that were added to allow continuous coal fired operation at high thermal input. The first test showed that doubling the number of coal and reagent injection points produced more uniform mixing and improved combustion efficiency. The test also showed the importance of proper placement of the flame safety system to prevent false combustor shutdown. In the second test, steady coal fired operation was maintained for almost 8 hours until the 4 ton coal bin was empty. The remaining tests were planned to be each at one optimum condition, with increasingly longer coal fired periods.

The third test was performed on December 29, 1993 when the combustor was on line for about 11 hours, including 4 hours for startup and shutdown, from 7 AM to 11 PM. It was on coal for 8 hours until the 4-ton coal bin was empty. Total fuel heat input was 14 MMBtu/hr, 94% due to coal with the balance natural gas. Figure 4 shows the coal flow rate for this test, which as shown in the figure was constant throughout



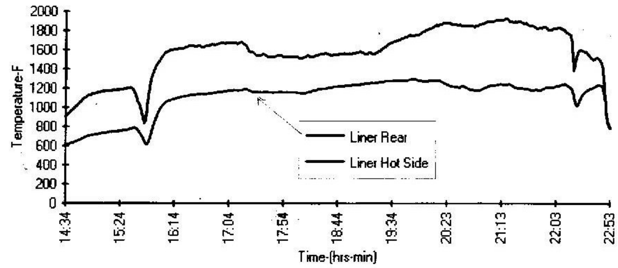
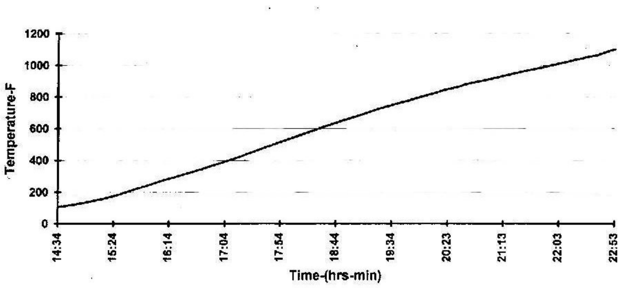


Figure 4: Coal Flow –12/29/1992 Test

Figure 5: Combustor Wall Temperature Top Curve-Liner Hot side

Figure 5 shows the wall temperatures in the combustor liner at two radial locations, near the hot refractory liner-slag interface, and in the rear of the liner at the air-cooled metal section. The combustor' s air-cooling was controlled with the computer using manual inputs to change the cooling air flow as the wall temperature changed. One notes that this procedure had a very slow response time. This is due to the transient heat transfer relaxation time of the liner. This relaxation time is a function of the thermal conductivity of the liner and the temperature difference across the liner. One notes that the wall temperature fluctuated over a range of several 100 degrees Fahrenheit. This is too wide a range for effective control of the wall temperature and for combustor durability. This problem was solved early in the task 3 tests in July 1993 with the addition of another cooling stream to the combustor. With this new procedure, it was possible to maintain the hot-side liner temperature at 2000^{o}F, in a range of less than 50F, (see below)

Thermocouples embedded in the adiabatic, heat sink exit nozzle of the combustor showed that its temperature increased with time. Figure 6 shows this exit nozzle wall temperature for the same test as figure 4 and 5, December 29,1992. Extrapolation of this data showed that the heat sink design allowed a maximum of about 16 hours high thermal input operation before active cooling was required. Active air-cooling was added to the exit nozzle in March/April 1993. This lowered the wall temperature at this location by almost a factor of two from 1100^{o}F to 500-600^{o}F. More importantly, the wall temperature leveled out at this lower value after only a few hours of coal-fired operation at steady thermal input. This is shown in figure 7 for a test in task 3 on 7/15/1993. Exit nozzle cooling is also discussed under task 3.



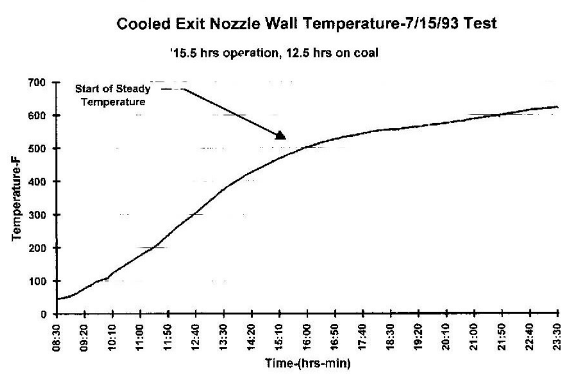


Figure 6: Adiabatic Exit Nozzle Wall –12/29/92

Figure 7: Air-Cooled Nozzle Wall-7/15/93 Test

The fourth test was performed over a two day period in subfreezing and snow conditions. The combustor operated on oil while ice was removed from the outdoor coal feed system and the scrubber water drainage system.

Subsequent to this test, four days of testing were performing with No.6 oil for another project. The objectives of these tests were to evaluate the combustor' s operation with the difficult to burn No.6 fuel and to study SO_2 control with reagent injection in the combustor. A very high combustion gas temperature was reached after optimum oil atomization conditions were achieved. As a result extremely high wall heat transfer conditions developed in the combustor and exit nozzle. The very high wall heat transfer rates in these oil tests provided the performance data needed to finalize the actively cooled exit nozzle design for the combustor. The exit nozzle cooling system was designed and installed in the period between February and April 1993.

A. Status of Combustor Test Results at the end of task 2

A.1 Combustor Operation

A major part of the test effort was to develop a database on combustor performance and durability. As these factors were uncovered, modifications to the combustor design, operation and computer control are made. In addition, information was accumulated on how significant improvement and simplifications in the design and durability of the combustor could be implemented in future combustor designs.

A.2. The Combustor' s Environmental Performance

A. 2.1. Stack Particle & NO_x Emissions:

In the prior DOE Clean Coal Project (Ref. 2) tests with staged combustion (i.e. fuel rich operation inside the combustor) were performed during which NO_x levels at the boiler outlet that were reduced by over 60% from the un-staged, excess air values. This corresponds to about 184 ppm, normalized to 3% oxygen, or 69 ppm at gas turbine outlet conditions, namely 15% oxygen. Additional NO_x reductions of 5 to 18 % were obtained in the scrubber outlet discharging to atmosphere. Minimum emissions levels were obtained at a combustor stoichiometric ratio in the range of 0.7. No significant changes were measured in the task 2 or 3 tests.

A.2.2. SO_2 Emissions:

Sulfur capture by injected calcium oxide based reagents in the combustor is a non-equilibrium process. The gas residence time in the combustor is short, typically about 100 to 200 milliseconds. It was hypothesized (Ref. 3) that the sulfur capture reaction takes place during calcination and particle heatup in the injection and mixing zone of the combustor Furthermore, the reaction is controlled by the CaO particle temperature, which in this zone is lower than the gas temperature. To prevent the reacted $CaSO_4$ or CaS particle from dissociating as it heats up to the final 3000°F combustion gas temperature, it is removed from the combustor before reaching this temperature, either by impinging on the slag or by exiting rapidly through the combustor' s exit nozzle. Since the start of the 20 MMBtu/hr combustor test effort in the late 1980's, a significant part of the effort was devoted to creating the conditions in the combustor under which all these processes can proceed.

Sulfur capture is also dependent on combustor operation conditions with solid feed uniformity, combustor stoichiometry, combustion gas temperature, combustor gas residence time, and slag residence time of the combustor wall being key variables. A theory to fully explain all these effects has not yet been developed. *(Note added: May 2003: This statement was made in 1994. It is still valid today.)* Others (e.g. Ref. 4) have also observed this non-equilibrium effect with variability in SO_2 reduction data with combustor reagent injection. This author believes that these differences are due to variable operating conditions.

The following is a summary of status of SO_2 reduction results in the 20 MMBtu/hr-combustor at the end of tasks 2 and 3.

--Initial results showed considerable variability for the reasons given above. After further major improvements in combustor performance were achieved, especially in the area of feed uniformity, limestone injection yielded reductions of 56% at a Ca/S ratio of 2. Calcium hydrate injection in the combustor yielded SO_2 reductions in the range of 85% for a 1.5% sulfur coal at Ca/S ratios somewhat greater than 3. Calcium hydrate (lime) injection immediately downstream of the combustor exit nozzle into the furnace section of the boiler yielded SO_2 reduction of 80% at a Ca/S mol ration of somewhat greater than 4. The level of these reductions was a function of the coal sulfur content because as sulfur content increased, more reagent mass flow was required to maintain the Ca/S ratio, and soon a limit was reached on the amount that could be fed into the combustor with the equipment on hand. While the main controlling parameters were identified at the time of these two tasks, it was recognized that further tests would be needed until all the governing parameters were identified. Appendix "A" contains more details on the sulfur dioxide control tests.

As of the present date, May 2003, this issue is not as important as Coal Tech has developed post-combustion SO_2 control processes that can remove most of the remaining SO_2.

A. 2.3. Air Toxics- Dioxins/Furans

The emissions of organic micro-pollutants from fossil fuel combustion sources are a matter of increasing importance. In 1990, the authors performed a series of tests on refuse derived fuel (RDF) combustion in the 20 MMBtu/hr combustor for ENEL, the Italian National Electric Utility (Ref.5). As part of this test effort, the magnitude of organic micro-pollutants were measured in the boiler furnace and in the stack, upstream of the scrubber. Although not part of any DOE sponsored test effort, the results are of sufficient interest to be summarized here. The RDF was co-fired with coal, in various ratios up to 33% by weight of RDF. To provide a baseline for these tests, the stack micro-pollutants were also measured with only coal firing. Three classes of organics were measured: Dioxin and Furans, (PCDD,PCDF, {Polychlorodi-benzodioxins/ Polychlorodibenzofurans}) and PAH (Polycyclic Aromatic Hydrocarbons). The dioxins compounds range from the tetra dioxins (TCDD), to the octacongeners (OCDD). The former are 1000 times more toxic than the latter. The samples were analyzed by ENEL and the results are reported in reference 5. The average level of PCDD's for coal only firing, as measured at the stack, was 22.5 ng/Nm^3, and the PCDF levels at the stack was 7 ng/Nm^3, both at 7%O2. For the co-fired RDF-coal case, the corresponding levels were 1457 ng/Nm^3 and 28 ng/Nm^3. However, due to a temperature limitation with the probe, it was necessary to operate the combustor at high excess air conditions in the final burnup stage in the boiler. As a result, the CO level in the stack approached 1000 ppm, which was about 10 times greater than under normal coal firing. It is thus probable that the level of these emissions could be reduced under optimum final burnup conditions. In addition, the method of feeding the RDF into the combustor resulted in considerable feed non-uniformities. This also could have adversely affected the level of these emissions.

Subsequent to these tests in 1993, a small Phase 1 DOE-SBIR project (Ref. 6) was implemented whose objective was to utilize a surrogate source of dioxins that would be co-injected with coal into the 20 MMBtu/hour air-cooled combustor at a constant feed rate in order to determine the impact of uniform feed on dioxin/furan emissions. For this purpose calcium chloride was used as the surrogate chlorine source, and the chlorine level was much greater that in the RDF tests. The result showed that uniform feed did indeed sharply reduce the dioxin formation, which now was only slightly (less that 50%) higher than with coal only. Injection of lime (calcium hydrate) lowered the dioxins by about 30%. For the follow-on Phase II DOE-SBIR effort, Coal Tech proposed using polyvinyl chloride pellets to actually duplicate a primary dioxin/furan source in municipal solid waste. However, the DOE-SBIR Program office declined to support the project.

March 2004*: On September 10, 2001, Coal Tech implemented a pair of tests on a 90 MMBtu/hr solid waste municipal incinerator with lime injection into the combustion flame zone of the incinerator. However, due to the extreme non-uniformity of the gas temperature in the mass burn flame zone, the dioxin/furan emissions continuously changed, a fact that was not known until 1 month after the test, which is the time it takes to analyze the data.. Therefore, the short duration (1-1/4 hours) [instead of the planned normal 4 hours] and the failure of the stack testing technician to adjust the stack sampling probe to account for the shorter than prescribed by EPA Protocol 5 for particulates and dioxin/furans, the result was inconclusive. However, a second test on that day of 2 hours duration, where again the stack probe traverse was not adjusted for the shorter test time, Coal Tech's specialized injectors reduced the stack temperature upstream of the particle collector. This resulted in at least a 30% dioxin/furan reduction.*

The conclusion from the methodology and results in these various brief tests was that the combination of uniform combustion, which is now readily obtained in the air-cooled combustor, combined with stack gas temperature conditioning using Coal Tech's special injectors, should eliminate dioxin/furan emissions from chlorinated hydrocarbon combustion. Since the 20 MMBtu/hr combustor-boiler facility is still operational in Philadelphia at this time, March 2004, this conclusion can be readily verified for interested parties.

The final two of the six planned tests in task 2 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, which replaced the prior adiabatic design. In the final task 2 test in May, 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, as shown in figure 6. Figure 7 shows this same result with the air-cooled exit nozzle for a test in task 3 on July 15, 1993, which was fired for an even longer period.

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 test in task 2, 200 pounds of fly ash, supplied by an independent power producing company, was vitrified. The fly ash had a 30% carbon content. Vitrification would have enabled that company to recover the heat content of the carbon while converting the ash to slag, and avoiding the high cost of shipping the wetted fly ash to a landfill several 100 miles away. No carbon was found in the slag and the carbon in the stack was such that the effective carbon content of the original ash of 30% was reduced to 4.5% . The company elected not to proceed with this application.

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 was installed with the original coal storage and feed system in 1987, remained unreliable. This was a "commercial" system, yet it was totally unsuitable for pulverized coal fee ding. . In fact, a considerable amount of problems were encountered with "commercial" components in the entire 20 MMBtu/hr combustor development effort, including the scrubber, which corroded rapidly and had an ineffective stack gas cooling spray system, the flame safety system that kept tripping for no clear cut reason, a variable speed drive controller that failed on its first use, and the ultimate flaw-the high pressure fan that shook so badly that its noise level exceeded 115 db (equal to an artillery barrage), and it nearly shook itself to pieces when first delivered in 1987. In that case, after several failed attempts by manufacturers representatives to identify the problem, the present author by trial and error identified the problem at being caused by restriction of the inlet by the inlet particle filter. That was most likely the reason it was no detected in the factory, as it was tested without the filter. In the end, the fan had to be returned at which time it was discovered that it was operation on the wrong side of the fan curve. In any case, after 5 years of struggling to continuously improve the coal feeder, at the beginning of task

3, a new feeder of different design was acquired, and it performed flawlessly throughout the task 3 tests and task 5.

2) In a slagging combustor operation, the slag tap obviously must remain open at all times. During the preceding Clean Coal project (Ref. 2), 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 an 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 8 from 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, as shown in figure 5.

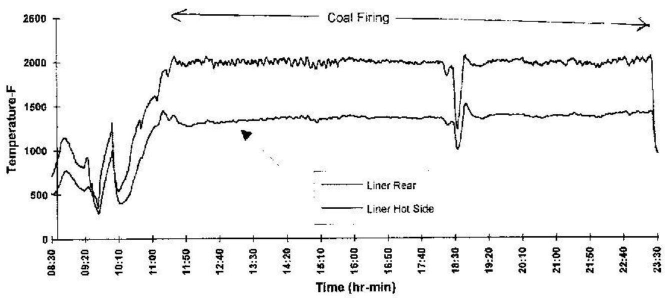


Figure 8. Combustor Wall Temperature –Top: Liner hot side. Bottom: Liner Rear, 7/15/1993

4) A major part of the task 3 effort was devoted to achieving very uniform and reliable coal, reagent, 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 was not been obtained. Axially directed injection had about

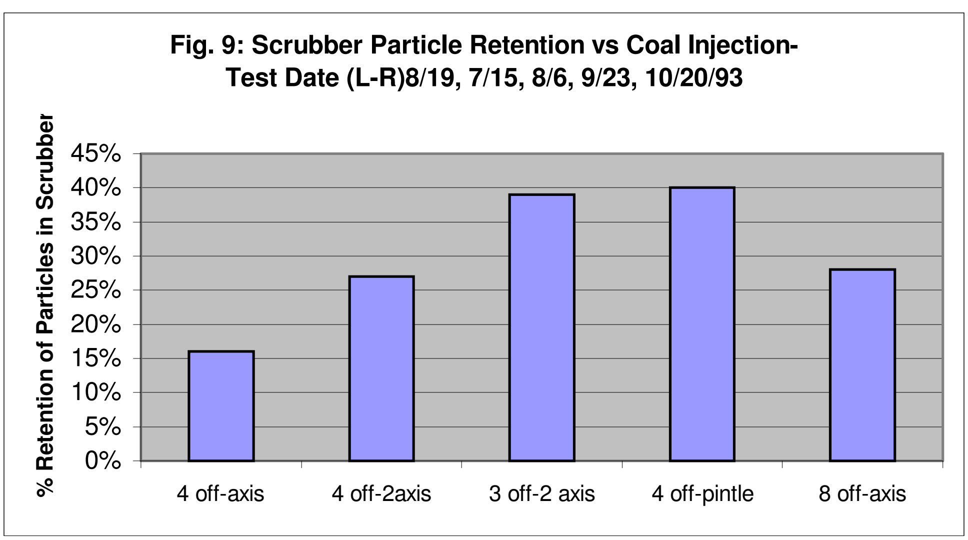


Fig. 9: Scrubber Particle Retention vs Coal Injection-Test Date (L-R)8/19, 7/15, 8/6, 9/23, 10/20/93

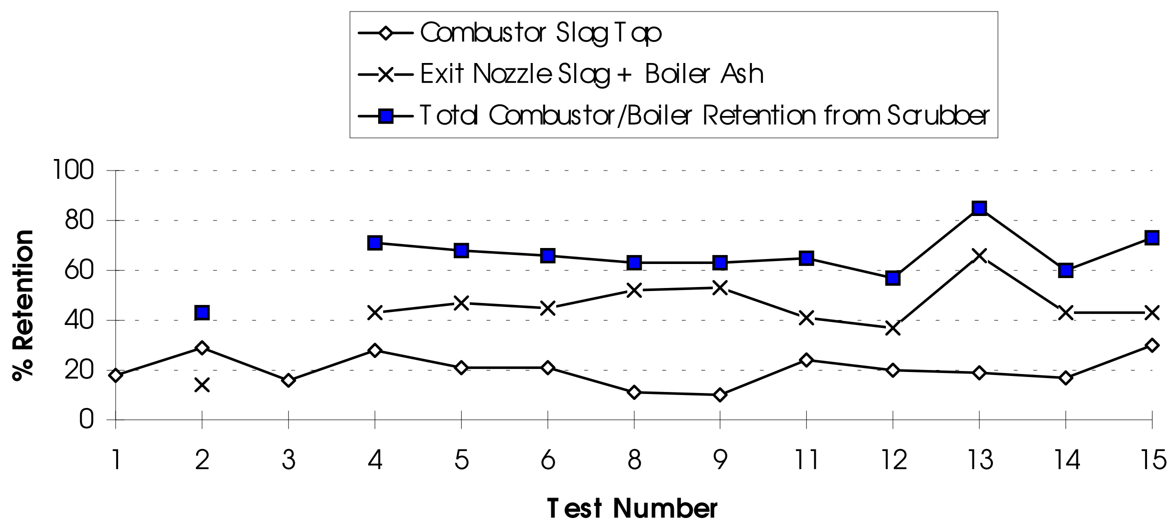
twice the ash-carryover to the boiler than off axis injection. Figure 9 is a bar graph that shows scrubber solids retention for 5 tests with different coal injection locations and methods.

With the final 8 injectors test (10/20/93), 25% of the solids reported to the scrubber. This was much lower than the 40% with 4 off axis + axial pintle (9/23/93) and the 39% with 3 off axis+2 axial injectors (7/15/93). It was about the same as the 27% with 4 off axis+2 axial (7/15/93) and higher that the 16% with 4 off axial injectors ((8/19/93). However, these earlier four tests were at substantially coal feed rates.

(Note added May 2003: The task 5 tests showed that combustor length was much more important to particle retention in the combustor that the injection method.

Figure 10 is a mass balance of the slag and ash distribution that was removed from the slag tap, the exit nozzle slag and boiler ash combined, and the ash collected in the scrubber. The slag contained essentially no carbon, while the boiler ash and scrubber ash had unburned carbon. This has been removed from the data shown. The tests took place between August and October 1993.

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



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 sulfur dioxide reagent 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 the 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 as with the coal in the daytime. 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. The wall temperature at one location in the exit nozzle was measured and after thermal equilibrium was reached after about 8 hours of operation, the nozzle wall temperature remained nearly constant at about 600°F 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 feature in task 3 was the development and use of an about 10 feet long 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. This provided information on the combustion and related reaction processes in the combustor and furnace section of the boiler. 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 furnace section of the boiler immediately downstream of the combustor exit to achieve fuel lean conditions. A detailed explanation of the results of these boiler probe measurements can be found in Appendix “A”, beginning on page 67. Here only a brief summary, focused on the SO_2 results, will be given.

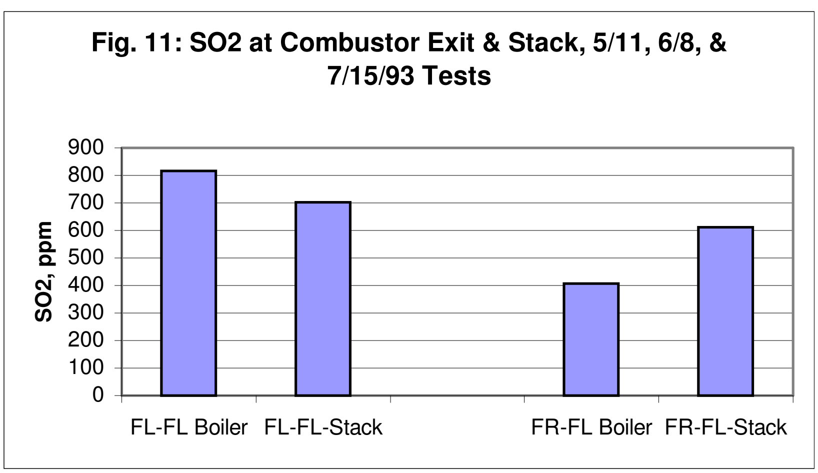
The O_2 results from the boiler gas probe and the stack gas probes were essentially identical in the FL-FL test and FR-FL tests. This indicated that effective mixing between the first stage (i.e. combustor) exhaust and the second stage (i.e. final combustion) air was occurring immediately at the combustor exit nozzle exhaust. However, due to the generally high excess air operation conditions in the furnace, O_2 was not a sensitive measure of combustion efficiency.

This was shown by the CO measurements. In the FL-FL test, the CO level increased by 67% from the boiler probe to the stack probe, namely, the absolute level of CO increased from 36 ppmv to 60 ppmv. Since in this case more than enough combustion air was introduced into the combustor, the increase in CO was due to incomplete combustion of char particles carried out of the combustor into the boiler. These particles burn in the immediate combustor exhaust zone but rapid gas cooling freezes the reaction in the remainder of the furnace section of the boiler. This prevents this CO from further reaction to form CO_2. It should be emphasized that the CO by itself cannot be used to determine the amount of unburned char from which one measures the combustion efficiency. To determine the combustion efficiency, the amount of unburned char was estimated from a mass balance of the carbon in the slag and the carbon in the solids removed in the wet particle scrubber. This yielded an overall combustion efficiency in the FL-FL cases between 87 to 97%.

(Note: According to boiler designation practice, the furnace section of a boiler is the region between the primary combustion zone and the convective heating zone. In the furnace section, heat transfer from the combustion gas to the boiler wall occurs primarily by radiation.)

In contrast, in the FR-FL case, the reverse condition takes place with the two CO results in that the CO at the exit nozzle decreased by about 50% to 53 ppmv in the stack. In this case, the CO gas leaving the combustor is converted to CO_2 by reacting with the additional air introduced near the combustor gas exhaust in the boiler. In the FR-FL cases, the combustion efficiency as determined from the stack gases and scrubber ash analysis, ranged from 83% to 93%. Therefore, despite the decrease in CO at the stack, the unburned char carried was actually somewhat greater in the FR-FL case, which would be anticipated because the unburned char increased as the combustor stoichiometry decreased. Further details are in Appendix “A”

Figure 11 shows the SO_2 results for the two tests conditions FL-FL and FR-FL. In the

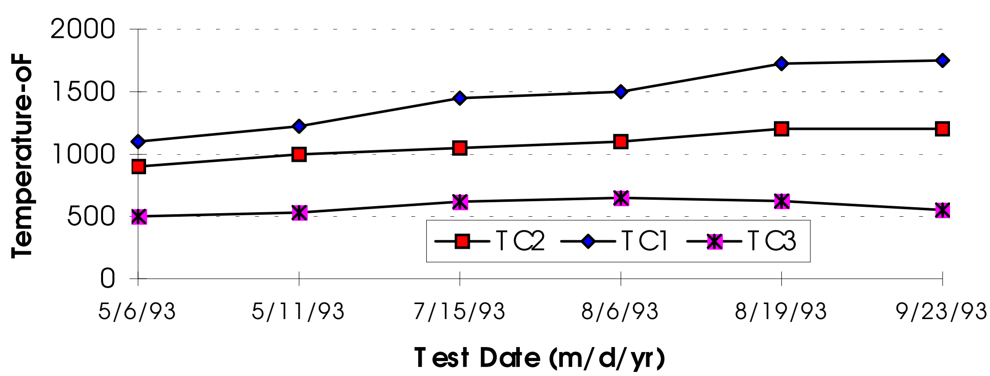


former case, the SO_2 level decreases toward the stack, while latter case it increases. From the CO results, it was hypothesized that the char carried over into the boiler continued to burn and evolve SO_2. This SO_2 reacted with the smaller CaO particles leaving the combustor, which in the FL-Fl lean 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. in the fuel rich case (FR-FL), 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 11 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, 52% in the FR-FL test and 58% in the FL-FL test.

(***Note Added in April 2003: The above analysis was performed in 1993. Based on subsequent task 5 testing, this dead burning assumption is highly questionable. More probably, the swirling combustion gases drive CaO particles into the colder gas regions immediately outside the hot cylindrical gas flow exiting the combustor. This probably accounted for the lesser reaction in the exhaust region, and not dead burning. This hypothesis is very interesting because it may explain why in SO_2 tests in the task 5 combustor conducted under other projects, the SO_2 level was generally higher in the stack than immediately downstream of the combustor exit, or near the colder regions nearer to the boiler furnace wall.)***

In conclusion, the significance of these probe tests was that a diagnostic tool had been developed that allowed determination of the combustion and environmental performance under all stoichiometric operating conditions. This probe was used in many of the subsequent tests. However, due to resignation of the individual that performed these calculations in January 1994, much of the task 3 test data collected between August and December 1993 was not analyzed. An analysis was performed of the carbon in some of the samples of the solids removed in the particle scrubber for these tests, which provided a measure of the combustion efficiency. In general the results were in the same general range, and they did not change the overall conclusion of the task 2 and 3 tests that the first-generation combustor used in Williamsport was

Figure 12: Exit Nozzle Wall Temperatures since Installation of Air Cooling in April 1993 (TC 1,2,3 at Three Different Radii -See fig.22)



too short to effect high combustion efficiencies, especially under fuel rich conditions.

As was shown in connection with figure 7, active air-cooling reduced by about 50% the exit nozzle' s refractory wall temperatures compared to the prior adiabatic nozzle. Figure 12 shows the average temperature measurement at the three radial locations corresponding to TC 1, 2 and 3 as a function of the test date after since the installation of the cooling tubes in the exit nozzle. Note that with increasing operating time the innermost temperature, TC 1 (Top graph) gradually increased from 1100^{o}F to 1800^{o}F. This indicated that the inner wall material was melting due to slag action. This was confirmed by internal measurement between tests and by accurate measurement after disassembly of the combustor. It was determined that the entire alumina section that had been inserted inside the fused refractory liner had dissolved in the slag. The fused refractory remained intact with the exception of the usual radial and longitudinal cracks due to thermal cycling.

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 was adequate for the air-cooled combustor liner because material loss there can be replaced with slag. However, the exit nozzle cooling used for task 3 was 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. An actively fully air-cooled design was used in task 5.

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 had been patched several times. The combustor's refractory wall was extensively patched 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 8), a series of tests were performed 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^{O}F to 1300^{O}F. The effectiveness of replenishment was confirmed after the completion of the task 3 tests when the refractory inside the combustor was removed during disassembly of the Williamsport facility. 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 the original liner refractory 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 provided 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 was 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^{O}F to as high as 620^{O}F. The latter value indicated 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^{o}F to 450^{o}F. This was 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 was performed with coal having a 44% through 200 mesh and 35% through 100 mesh. Normal coal sizes in all previous tests had been 70 to 80% through 200 mesh. 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.

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.

3.3.4. Task 4. Economic Evaluation & Commercialization Plan

Overview of the Effort in Task 4:

The details of the effort on this task are contained in Appendix "B" of this Final Report.

This effort was performed mostly between 1992 and 1994. However, the results are even more timely in 2004 due to increased pressure on reducing coal emissions. The work was divided into two parts.

In part one, a nearly one year long effort, from late 1993 to late 1994, was implemented to find a suitable a site in the Greater Delaware Valley of Southeast Pennsylvania to implement the present project's task 5 Site Demonstration task. Several such sites were identified which would have involved the sale of steam or electricity to the site owner. However, after evaluating the options, and reflecting on the problems of running an R&D effort at the Williamsport, PA, site, a stand alone building in Philadelphia was selected, and this proved to be an almost unique choice. The details of the task 5 effort are given in Appendix "C" of this report.

The second part of the marketing effort involved finding an electric utility site to install a 20 MW electric power plant using the air-cooled slagging combustor. The scale was selected because it allowed the use air-cooled combustors in the 100 MMBtu/hr range, which was a reasonable scale-up from the present 20 MMBtu/hour-combustor. Two 20 MWe power plant designs were developed. One was a steam repowering plant using coalmine waste, and the other was a "Greenfield" combined gas turbine -steam turbine power plant using natural gas for the gas turbine and coalmine waste for the steam plant. Investors were found for both plants, but with the low electricity prices prevailing during the mid-1990's and the competition from "cheap" natural gas power plants, these projects did not proceed. However, this work is now in 2004 very timely because natural gas costs 2 to 3 times more than in the mid-1990's.

A key result of these two power plant studies was the recognition of the critical importance of innovative designs for the balance of power plant in order to achieve capital costs that are competitive with gas fired power plants.

In addition, a number of other site-specific applications where the combustor provided economical advantages were evaluated. The study focused on plants that utilized steam and electricity for processes, primarily in the paper industry. The projects ranged in size from small firetube boilers rated at 10 MMBtu/hr to large boilers in the several 100 MMBtu/hr range. In all cases, the time for recovery of invested capital ranged from less than 1 year to several years. The two barrier problems Coal Tech faced in implementing these economically attractive projects was the great reluctance of the hosts to be the first to install the air-cooled combustor, and the insistence that third party financing be provided by Coal Tech.

The task 4 effort also included overseas marketing, especially to India and China. Their primary use of high ash coals is an ideal fit to Coal Tech's the air-cooled, slagging combustor, which converts at least 75% of the ash into inert slag, thereby sharply reducing the particulate emissions that are a problem in the combustion of very high ash coals. In addition, Coal Tech's very low cost emission control processes remove the other pollutants. The problem in implementing these projects was financing.

A major effort at Coal Tech, especially in the past 7 years, has been development of total emission control from coal combustion, including SO_2, NO_x, volatile coal ash trace metals, including mercury, carbon recovery and vitrification of fly ash, dioxins and furans, and the removal and sequestration of carbon dioxide. This has resulted in a series of proprietary combustion and post-combustion processes that meet this goal of total control. The effort of the past 7 years has been totally financed by Coal Tech. DOE has declined to participate by declining Coal Tech's over one-half dozen solicited proposals that were submitted in this period.

Coal Tech's low cost coal combustion and emission control systems are now very timely in part due to the ongoing financial crisis in the electric utility industry, which resulted mostly from the industry's total reliance on natural gas for new power plants. Interestingly this "crisis" was mostly caused by the industry's refusal to address the problem of coal emission control. Instead of insisting that R&D focus on low cost emission control processes, the industry focused on delaying tactics. This caused uncertainties just as demand for power exploded, and rather than risk investing in coal power plants, the industry turned on natural gas fired power plants. The problems for coal are now even worse because atmospheric pollution from particulates and mercury emitted from the inefficient combustion of high ash coals that are used extensively in Asia add to atmospheric warming and mercury transport. Also, it contributes to increasing pulmonary related health problems, which with modern transportation in airplanes can rapidly spread around the globe. The Coal Tech air-cooled slagging combustor has burned 70% ash Asian coals and 70% ash biomass char waste from gasifiers. It is therefore a solution to both domestic and foreign coal utilization.

Selected Result from the Task 4 Effort: (Details are in Appendix 'B")

Economic Recovery of Carbon in Fly Ash: 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 limestone. 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. At the time the 80 MW plant operators had to ship wetted down fly ash several 100 miles to an out-of-state landfill. **Result**: As Coal Tech encountered numerous times in its marketing effort, the plant owners preferred to continue with the "proven" but very costly ash disposal method rather than further exploring our very low cost solution.

Steam for a Paper Manufacturing Plant: 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. **Result**: See comment under fly ash application above.

20 MW Coal Fired Power Plant Repowering: This was one of the two major applications that were evaluated in task 4. It involved the repowering of an existing 20 MW steam turbine generator in a coal fired utility power plant in Pennsylvania 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, an ABB Company D-frame boiler that had about one-half the volume of an equally rated conventional coal fired 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. Two 150 MMBtu/hour air-cooled slagging combustors would be attached to an ABB Company D Frame boiler. The existing turbine-generator, feedwater heating, and power transmission system would be refurbished.

The engineering firm, H-R International, developed the overall design. They estimated the cost at somewhat more than $900/kW. However, Coal Tech noticed several discrepancies in the cost estimated. For example, the vendor quotation for this baghouse was twice that of the vendor quote for the baghouse in the 20 MW combined cycle plant (see below) even though its gas flow rate much greater. Also, more innovative components and arrangements, such as eliminating the costly coal storage bins and leaving the coal on the ground, as was done for the other boiler at this power plant, lowered the cost to only $520/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 was to be 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%.

However, the power plant owners were considering (in 1994) shutting the entire power plant by the end of the decade, and since the developer estimated that it would take 4 years to obtain the permits and install the plant, the effort was terminated. The plant is still in operation in 2004. Ironically, a peaking gas turbine power plant was installed at the site just as demand for electricity began to decline with the economic recession. Had our project proceeded, the profits during the power crisis of the late nineties would have been astounding. Furthermore, as the company satisfied its power needs by purchase from another utility, there was no need for 100% reliability for our plant during the initial demonstration period.

20 MW Combined Gas Turbine-Steam Turbine Power Plant: **The technical and economic analysis for this power plant was the primary effort in task 4**. In was initiated in 1992 in response to a request from a developer of power plants for the cost of a new "Greenfield" power plant rated at 20 MW electric power that used the air -cooled slagging combustor. In responding to this request, Coal Tech retained an engineering firm with experience in developing small power plant projects, H-R International, to assist in the design and cost effort. There existed a potential for the licensing of the combustor technology to this developer because he had a contract to sell 20 MW of electricity capacity to a local utility. However, we judged the probability as low. Instead we were motivated by the desire to develop a prototype design for a power plant based on Coal Tech's unique, patented, air-cooled, slagging coal combustor. As a result considerable resources were dedicated to this effort. The power plant consisted of a 5 MW commercial gas turbine that was fired with natural gas and used steam injection to achieve the rated power. The turbines exhaust at about 1000^{o}F was used as pre-heated combustion air for the coal-fired, slagging combustor that was attached to a ABB Company D-frame industrial oil design boiler producing superheated steam to drive a nominal 15 MW steam turbine-generator. The power plant efficiency, as computed by Coal Tech and independently by DOE-NETL, was in the low 30% range.

Figure 13 shows the elevation and figure 14 the plan view of the 20 MW combined Cycle power plant. Details are in Appendix "B".

The total plant cost, as developed by the engineering firm and based on quotations from major component manufacturers, was about $1,200/kW. According to H-R, this cost was substantially less than a coal fired fluid bed power plant of equal rating. The developer planned to utilize high ash, coalmine waste to fire the combustor. Based on the results of the 20 MW repowering study, summarized above, we judged the 20 MW combined cycle cost obtained by the engineering firm as being far too high. In any case, as we had suspected the developer withdrew his offer to build the plant. Nevertheless, the study proved very worthwhile, as we used the results in the 20 MW repowering study described above. Furthermore, after the present project ended in 1998, we developed designs for using the combined cycle plant with pyrolysis gas derived either from biomass or coal to fire the gas turbine, and the char to fire the slagging combustor.

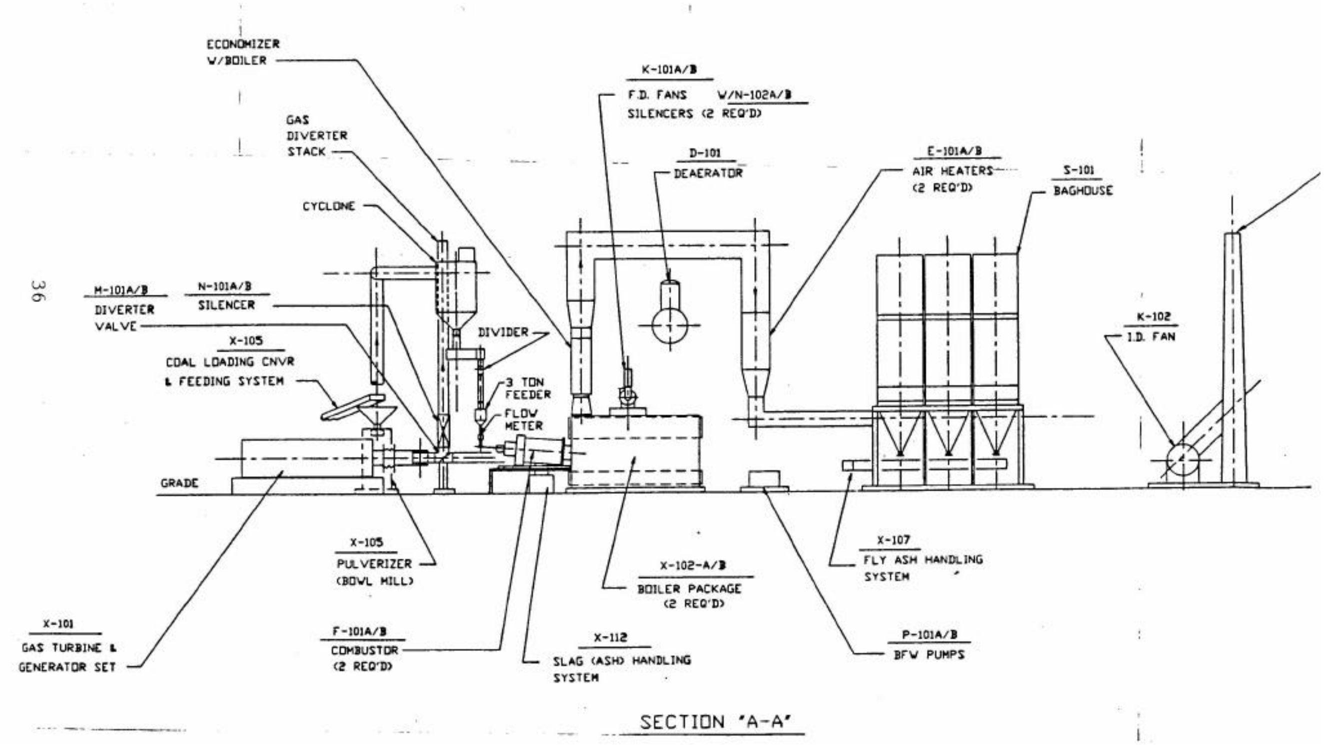


Figure 13: Elevation View of 20 MW Combined Cycle Plant-with Major Equipment Arrangement

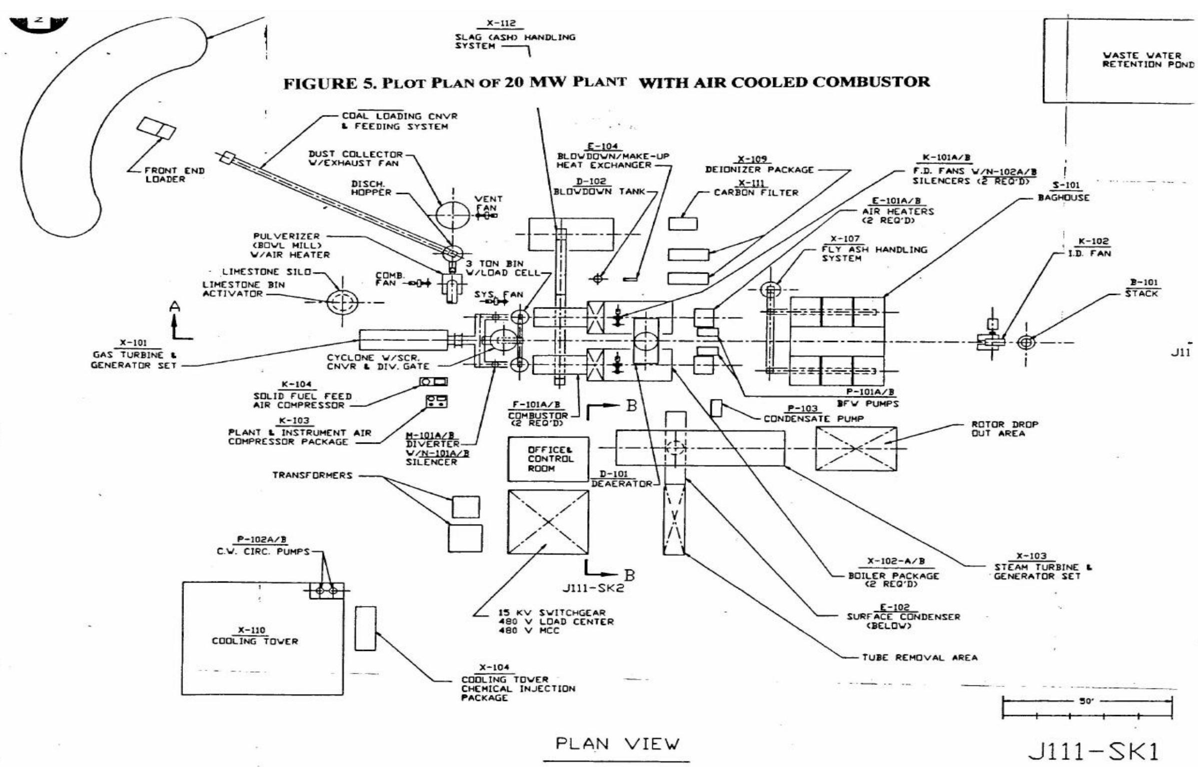


Figure 14 Plot Plan of 20 MW Combined Cycle Power Plant

Other Task 4 Application Studies:

As part of the site selection effort for task 5 well over a dozen users of process steam and electricity were evaluated for relocation of the combustor-boiler facility from Williamsport to Southeast Pennsylvania. They included paper manufacturing plants, a hospital that still burns anthracite coal by PA law, a university, and several large industrial parks. After a search that took a large part of 1994, we decided to install the facility at a stand-alone site at the Arsenal Industrial Center in North Philadelphia. In the first place, none of the site owners were interested to convert to coal, even though the energy cost would be substantially lower. In addition, there was the usual concern with "new" technology. Finally, after examining the operating procedures at all these boiler sites, and recalling the problems we experienced in implementing our 7 year R&D effort in Williamsport, a boiler manufacturing plant, we opted for the stand alone site. Details of the evaluation of these sites are contained in Appendix "B".

3.3.5. Task 5: " Site Demonstration with the Second Generation, 20 MMBtu/hr, Air-Cooled, Slagging, Coal Tech Combustor"

<u>a) Overview of the Testing in the Second Generation Combustor-Boiler:</u>

The objective of task 5, which was the third phase and final phase of this project, was to utilize the results of the previous four tasks and implement a commercially ready demonstration of the air-cooled combustor technology. The details of the task 5 effort are in Appendix "C".

Task 5 involved the relocation of the entire test facility from Williamsport, PA, to the Arsenal Business Center, a former U.S. Army facility in Philadelphia, PA. The plan for task 5 was to design a new second generator combustor that incorporated the lessons learned in the test effort with the first generation combustor in Williamsport. An additional part of the task 5 plan was to add the other components needed to convert the 20 MMBtu/hr combustor-boiler facility into a continuously operating steam generating plant or electric power generating plant. To implement this would require a steam or electricity host, and beginning in November 1993, a search, which took one year, was implemented to find an industrial host site that would meet the requirements for installation of the new facility and for utilizing the energy production. After several negotiations for a site did not result in an agreement, a lengthy negotiation for the Arsenal site was completed in the late Fall of 1994, and modifications for a small electric power generation facility were initiated that winter.

Also, in the first half of 1994, the second-generation, 20 MMBtu/hr-combustor was designed, and after a lengthy search, an apparently acceptable fabricator was selected that summer. Unfortunately, the fabricator slipped far behind schedule so that it was not completed until late spring 1995. In addition, while considerable innovation was used in designing and selecting equipment for a 500 kW electric power plant, it became clear that there were insufficient funds to procure and install the power plant. As a result the facility remained a test site, as opposed to a continuously operating power plant. This was not surprising as the original Coal Tech cost proposal requested twice as much funds as were finally allocated. Nevertheless, by using considerable innovation, we came very close to implementing the entire effort with the reduced allocated funds. The limiting factor was the inability to negotiate a suitable contract for sale of electric power in order to defray the operating costs.

A major innovation in this project was the drastic reduction from the Williamsport operation by a factor of 2 to 3 in personnel for installation and operation of the facility, and a factor of 2 to 3 reduction in electricity and water consumption, as well as a factor of 3 reduction in gas and oil for daily startup and shutdown of the combustor. The original plan required 500 hours of testing in 100 hour, or more, continuous blocks. This was not possible with the personnel resources available. Instead a total of 63 single shift tests were planned, which equaled in time to 500 hours of testing. However, due to the cost saving measures in personnel and utility use, a total of 108 test days were implemented from the beginning of 1996 to the first quarter of 1998 when testing on this project ended.

The success of these changes in the design of the second-generation combustor was apparent almost immediately on startup of the task 5 tests. The combustion efficiency even under fuel rich conditions in the combustor was substantially improved. More importantly, slag carryover out of the combustor into the boiler, which had been a major problem in the first generation combustor, was now negligible. Also, ash deposits on the boiler furnace floor, another major problem in the first generation combustor, were very minimal.

In view of the immediate success in operating the new combustor, the focus in the task 5 testing shifted toward combustion and post-combustion emission control for NO_x and SO_2. While some of the SO_2 and NO_x control work was implemented in task 5, the bulk of this work, especially the very valuable, low cost post combustion work, was implemented solely at Coal Tech expense in the 6 years after the project testing ended.

A major breakthrough was achieved in the combination of staged combustion inside the combustor with post-combustion injection of ammonia-based reagent in a process known as Selective Non-Catalytic Reduction (SNCR). It resulted in an incredible peak 93% NO_x reduction, from an initial 1 lb/MMBtu to a final 0.07 lb/MMBtu. Similarly, high reductions in SO_2 were achieved in both task 5 and in the Coal Tech funded testing afterward.

In addition, tests were performed on 100 MW and 37 MW coal fired electric utility boilers with Coal Tech's SNCR process that resulted in 40% NO_x reduction in the latter boiler. .

After this project ended, a series of proposals to DOE to expand the combustion and post-combustion emission reductions by including biomass combustion and post combustion reburn, and other reduction processes, such as reduction of trace mercury released during coal combustion, submitted in the period between 1998 and 2002, were all rejected. Consequently, by using innovation and great ingenuity, Coal Tech was able to develop almost all its emission control processes on the 20 MMBtu/hr-combustor, and on a utility boiler and a municipal incinerator, with its own internal resources. All this emission control work was not part of this project. It was very successful, and a number of patents were either granted or are pending. The most recent is a low cost process for the removal and sequestration of the carbon dioxide that is based on Coal Tech's air-cooled, slagging combustor. It can be retrofitted to most existing coal fired boiler. Also, two novel mercury capture processes were invented, one of which utilizes the air-cooled combustor..

A very important benefit of the move to Philadelphia was that it enabled Coal Tech to maintain the 20 MMBtu/hr facility **at its own expense** for the past 7 years by paying for rent and utilities as well as performing emissions control testing. The cost of accomplishing this in Williamsport, had the site not been sold, would have been prohibitive. The wisdom of that maintaining the facility is shown by a May 2003 Wall Street Journal front-page story on the discovery of a massive pollution cloud over the Indian Ocean that is 2 miles thick and about 2000 miles across. While Indian government officials have attributed the source of this cloud as being due to combustion of dung by India's poor, it is almost certainly a result of inefficient combustion of the high ash Indian coals, whose 1999 consumption outnumbered dung combustion by a factor of 3. Furthermore, as this coal combustion contains high (about 40% on average) ash while dung contains less than 1% ash, it will be easy to verify the source by random particulate sampling in the cloud. Once proven, it will be found that the very much lowest cost method of reducing this pollution is by retrofitting Indian coals furnaces and boilers with air-cooled slagging combustor, which can be attached to almost any boiler. As proof, we cite a test conducted in January 1977, as part of task 5 in which several tons of 37% ash, Indian coal was burned with high combustion efficiency and over 75% conversion of the coal ash into slag.

In conclusion, the effort expended on this project as well as the subsequent Coal Tech work on emission control from coal combustion has resulted in the development on a solid fuel combustion system that is unique in its capability of achieving total emission control (including mercury and carbon dioxide) from coal combustion in essentially all types of coal in worldwide use. Details on this task 5 effort are in Appendix 'C". Here selected key details are presented.

b) <u>The Task 5 Test Site Modifications & Permitting</u>

The task 5 test site is a 3000 square foot building (No. 238) in the Arsenal Business Center, 5301 Tacony Street, Philadelphia, PA 19137. The site is within 100 feet of a tidal stream that drains to the Delaware River about 1000 feet away. It is on the former Frankford Army Munitions Arsenal, which opened in 1816 and was closed by DOD in the late 1970's. The building consists of two rooms, a small room about 20 x 30 feet and a larger room 70 ft. x 30 ft. with a 27 ft. ceiling. The larger room is ideal for the 20 MMBtu/hr combustor-boiler installation that includes compressors, fans, control panel, computer cabinet, 550 gallon-oil storage tanks, and there is also room for a steam-turbine generator. Figure 15 shows a plot plan and elevation view of the installation including all the components needed for a 500 kW continuously operating power plant. The components listed in this figure were the ones that were originally planned. As this work progressed substantial modifications were made to accommodate permit requirements, site characteristics, landlord actions, and cost objectives. They are:

<u>Concrete Pad for Outdoor Equipment</u>: A concrete pavement with a spill containment barrier was designed for the 15 ft. wide, dirt outdoor alley adjacent to the building (see top of figure 15). A 2 foot deep x 3.5 ft wide x 24 ft long concrete pit (top right in figure 15) was to be placed at the open end of the alley for installation of a screw feeder and elevator (shown in figure 15) but then replaced by a conveyor belt (not-shown). A 25 ton load, coal dump truck would

back into the driveway and drop the coal onto this conveyor for delivery by means of the conveyor to the top of the 25 ton raw coal bin.

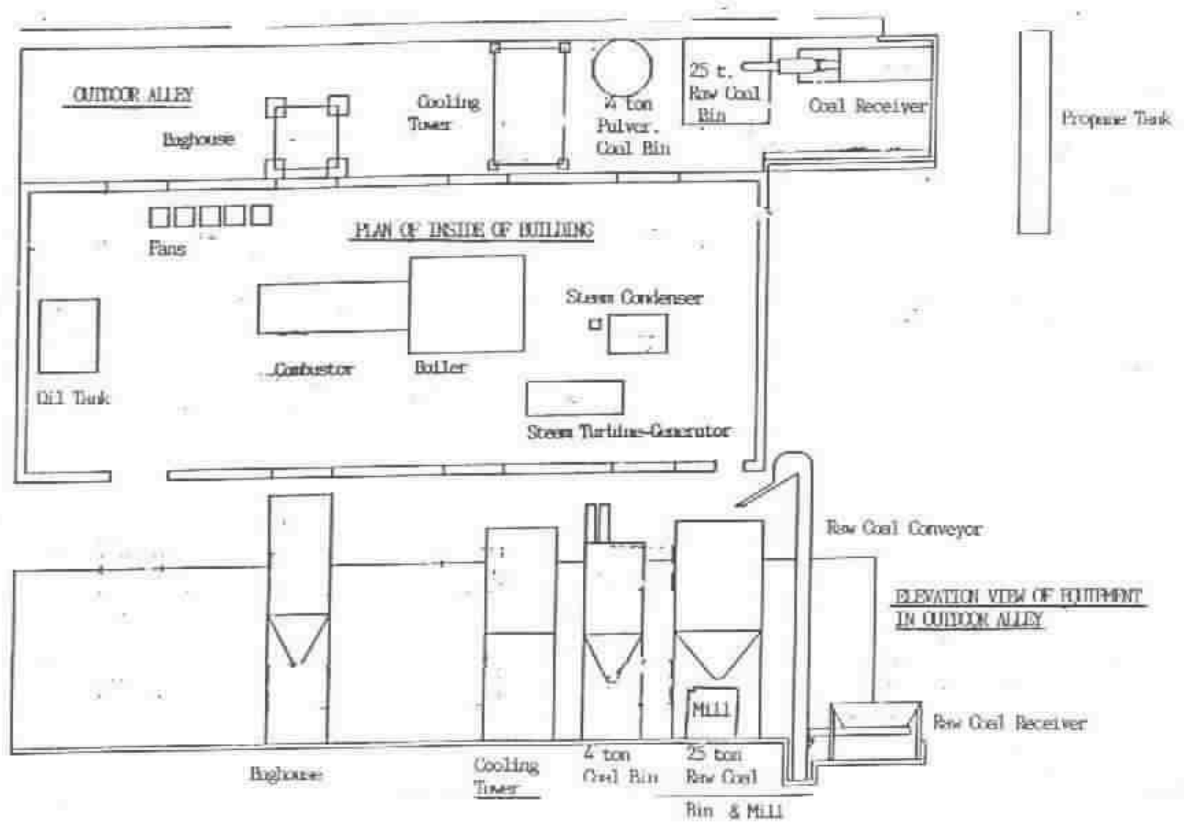


Figure 15: Plan (top) & Elevation (Bottom) Sketch of the Original 500 kW Power Plant for task 5

Propane Fuel Supply: The building has a propane tank with 1840-gallon (165 MMBtu) capacity. In Williamsport 3 MMBtu/hr was required for pilot gas ignition of the combustor. This was sharply reduced after the new combustor became operational which saved well over $10,000 in propane costs during the project. A series of concrete filled steel poles and a fence was installed to prevent the coal and oil truck from hitting the propane tank.

No. 2 Oil Tank: The heatup and cool down of the combustor occurs with gas and oil firing. In Williamsport, a 3000 gallon- No.2 oil tank was used. Initially, a 1000-gallon, aboveground, No.2 oil tank was to be installed at the Arsenal site. However, due to City regulations this tank would have cost well over $20,000 installed. Accordingly, all the test data from 1992 to 1993 were re-evaluated, and it was determined that two 175-gallon domestic oil tanks would have adequate capacity for heatup and cool down with one week intervals between refueling, at a total cost of several $100, plus a few days of Coal Tech installation.

In practice by improving the startup and shutdown procedure, the oil consumption for start up and shutdown was reduced by a factor of more than 3 from that used in Williamsport. After the present project ended, we developed an operating procedure that **reduced the oil required by a factor of 10,** and capacity of the small oil tanks is sufficient for several weeks of regular use. **We keep repeating all these "little" cost savings to emphasize our thesis that coal fired power plants are way over-designed and over-costed.**

Furthermore, the above discussion may seem trivial within the context of the goals of the present project. However, this simple step was of major importance, not only for the present project, but also for future commercial use. In India, the use of oil is limited to 1.5% of the total energy consumption, and the original oil consumption in Williamsport was about 5%.

Enlarged Equipment Door: A design for opening the main door in the building from 8 ft x 10 ft to 12 ft x 14 ft was prepared in August and submitted to the landlord on August 30th. It included a steel roll up door to replace the small, dilapidated wooden door. This item then became the primary source of delay in the project for 5 months because the landlord insisted on doing the work by his maintenance staff at a **cost that was 43% higher than three bids obtained by Coal Tech from outside vendors**. After much haggling, the landlord finally accepted our lower bid to install the doors by his crew of "experts".

Immediately after signing the lease in July 1994, we requested a telephone line. This would have required running an overhead line from an adjacent building about 75 feet away. The landlord insisted that a 75-foot long trench be dug for the line because an overhead line would impair the "historic beauty" of the site. (**A visit to the site will quickly disabuse the visitor to its "historic beauty"**.). Despite the lease (and the **DOE contract) requirement** for three competitive bids, the landlord's agent provided us with a single quote for an underground line at the outrageous price of **$3800.** However, when Coal Tech found a means of running a line through the existing underground service tunnels that runs under the entire site, the Philadelphia Installation Office of Bell of PA (Verizon) suddenly obtaining approval from the landlord to install an overhead phone line between the two buildings. The total cost was about **$240**.

It may appear that these trivial points do not belong in a technical report. However, R&D requires money, and failure to attend to such trivial points, diverts limited funds in useless directions. We should also note that one outcome of the all these delays is that the landlord agreed to refund the many thousands of dollars in base rent from August 1 to December 31, 1994. Also, we did not lose any project schedule because the combustor fabricators badly slipped their delivery of the combustor from July 1994 to March 1995, as described below.

Permitting: Permits were obtained from the City and State for a business operating license, emission permit for coal firing, transport of oversize boiler through State roads, sewage discharge permits, and solid waste permit for the coal ash and slag.

c) **Design & Installation of the 20 MMBtu/hr Combustor-Boiler**

The design of the equipment was based on the results of tests in the 20 MMBtu/hr air cooled combustor in Williamsport, PA, and on the site specific combustor applications studies for power plants in the 1 to 20 MW range that were performed for task 4 and other non-project studies.

It was originally planned to install the 20 MMBtu/hr combustor/boiler at the new site with an atmospheric back pressure turbine to generate about 500 kW of power from the 17,500 lb/hr, 250 psig boiler. Sale of this power would partially defray the cost of more extensive durability tests on the combustor/boiler system. However, due to the inability to sell the power at a price that would defray operating costs, it was decided to eliminate the power generation step and proceed to commercial introduction of the technology.

To meet the particle emission standard for Philadelphia, a baghouse was required in place of the wet particle scrubber that was used in Williamsport. The latter's best performance resulted in a particle emission of 0.26 lb/MMBtu, which was below the Williamsport standard of 0.4 lb/MMBtu. The Philadelphia standard is 0.06 lb/MMBtu. The manufacturer of the baghouse has stated that particle emissions of less than 0.03 lb/MMBtu can be readily achieved under the operating conditions existing in the present facility.

As noted above, figure 1 is a side view drawing of the 20 MMBtu/hr combustor/boiler installation in Philadelphia. PA. Its total size is such that it can be shipped by tractor trailer to any site. Figure 15 shows a plan and side view of the Philadelphia facility. It includes provision for a 25 ton raw coal delivery and storage area, a low cost coal mill, a 4 ton pulverized coal storage bin, sorbent storage bins, pneumatic coal and sorbent delivery, a boiler, the combustor and its auxiliary subsystems, specifically, water cooling, oil, gas, combustion air, cooling air, compressed air, slag removal, and the stack system, including the baghouse, and induced draft fan. The entire system is controlled by programmable logic controllers (PLC) and computer process control. Performance parameters are measured and recorded on a computer. Combustion gases, O_2, CO, NO_x, and SO_2, are measured in the boiler radiant furnace section, boiler stack outlet, and baghouse outlet.

d) Novel Features and Operating Experience of the Test Facility.

The facility was designed to include the major features that will be incorporated in Coal Tech future commercial power plants in the 1 to 20 MWe range. Therefore, the primary design objective was to minimize capital, operating and maintenance costs.

Capital cost was minimized by factory assembly of its major subsystems. Oil/gas designed boilers are compatible with the air cooled, coal combustor. These boilers are factory assembled for thermal ratings of up to 200 MMBtu/hr. Air-cooled combustors can be fabricated up to 150 MMBtu/hr. The combustor's auxiliary subsystems are assembled in modules and attached to the combustor support structure. Therefore, the combustor and boiler can be shipped from the factory in two modules.

Another important capital cost saving results from the fuel flexibility and rapid shift among the various fuels. This sharply reduces the need for on site fuel storage.

Air-cooling operation was much improved in the present combustor to the point where gas and oil fuel consumption for heatup and cooldown of the combustor was reduced by about a factor of two from the quantities used in the Williamsport combustor, and by a factor of 10 after the project ended. Another major result of the improved air-cooling was a factor of two reduction in the cooling fan power requirement. In addition, the quantity of compressed air flow required to operate the facility was sharply reduced. Finally, the use of a baghouse in place of the wet particle scrubber sharply reduced the induced stack fan power. As a result, the total power used in the Philadelphia plant was **reduced to one-third of the level required in the first generation Williamsport facility.**

The improved combustor operation reduced the combustion gas temperature at the boiler outlet an average of 100^{o}F to 150^{o}F for identical coal firing and sootblowing conditions in the previous combustor. Additional cooling of the stack gases was added to allow the use of substantially lower cost bags for the baghouse and to further reduce the stack fan power.

The combustor is a higher maintenance component than the boiler. It is, therefore, essential to minimize downtime when it requires refurbishment. Consequently, the current combustor design allows its removal from all its auxiliary sub-systems and from the boiler in less than 1 day.

A high maintenance item has been the combustor's slag tap assembly, primarily during the initial tests. Subsequent modifications were made which have sharply reduced maintenance.

The relay controlled system used in the previous combustor system was replaced with programmable logic controllers (PLC). The PLC assure that the combustor's fuel supply and the boiler's steam supply operate with all safety interlocks functioning. The previous computer process control software was upgraded to account for the changes in the design of the present combustor. As the test effort proceeded, it was found that the combustor could be controlled with a much simpler procedure than was used for the previous combustor, and the software was changed accordingly.

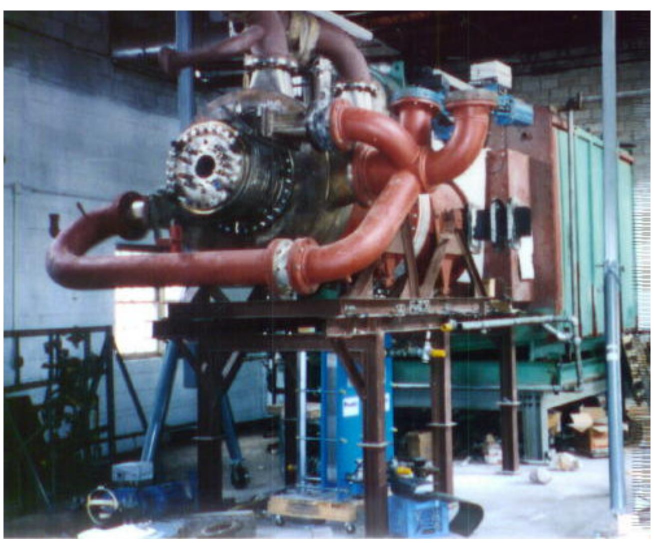


Fig.16: Combustor-Boiler in 1995

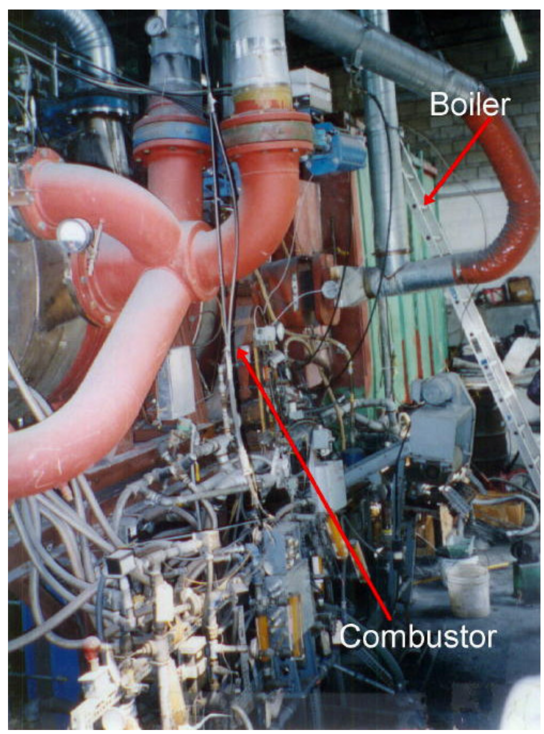


Fig. 17. Combustor after final assembly

Figures 16 and 17 show the 20 MMBtu/hr combustor attached to the 17,500 lb/hr boiler during initial installation and after final assembly.

With these improvements, the personnel needed to operate the facility was reduced from an average of six in the Williamsport facility to two or three, depending on the specific test objectives. Based on this experience, it is anticipated that a fully commercial plant can be operated with substantially fewer personnel than are used in a conventional coal fired plant.

e) 20 MMBtu/hr Combustor Operation in the Philadelphia Facility:

As soon as the present combustor was placed into operation, its exhibited performance was far superior to the earlier unit. Areas of improvement include combustion efficiency, slag retention, wall materials durability, and length of heatup and cooldown.

Slag retention, which is a key measure of slagging combustor performance, improved substantially. In the earlier 20 MMBtu/hr combustor, only one-half to two-thirds of the injected coal ash and sorbent minerals was converted to slag in the combustor. The balance of the ash and sorbent was blown out of the combustor as dry fly ash. Furthermore, over one-half of the slag formed in the combustor flowed out of the exit nozzle to the boiler floor, thus limiting the run time of the combustor. Although provision has been made to remove slag carryover from the combustor to the boiler by installing a combustor/boiler transition section, in the operations to date, the amount of slag carried over from the combustor to the boiler ranged from 0% to 5% of the total slag. Slag retention was also substantially better than before, averaging two-thirds of the injected mineral matter, which includes coal ash and sorbents.

Combustor refractory liner durability is another major performance parameter. Chemical reactions between the liquid slag and the combustor refractory wall can rapidly deplete the latter. However, by control of the combustor wall temperature, a layer of frozen slag can form on the combustor's refractory wall, which maintains the integrity of the wall. Much progress had been made in perfecting this wall replenishment technique in the earlier 20 MMBtu/hr combustor. Replenishment of the refractory liner by injection of fly ash with the coal and sorbent proved to be very effective in the earlier combustor. In the present combustor, the combustor wall replenishment procedure has been further improved. Consequently, it has not been necessary to reline the combustor wall with refractory, except for occasional patches caused by the many startups and shutdowns. Note that in the utility scale B&W slagging combustors, the entire refractory is relined annually during schedule shutdowns. There are no shutdowns in between. to date.

The cooling and combustion air distribution and control scheme was substantially modified for the present combustor in order to simplify the combustion and combustor wall cooling process. The new scheme has proven to be much simpler to control, and the need for the previous complicated computer control has been eliminated.

To minimize nitrogen oxide emissions it is necessary to operate the combustor under fuel rich conditions. Final combustion occurs in the furnace section of the boiler where the CO and H_2 rich combustor gas exhaust is mixed with additional air to complete combustion. Optimum NO_x reduction occurs at about 70% stoichiometric air/fuel ratio in the combustor. [Ref.2]. However, operation of the earlier 20 MMBtu/hr combustor at this condition resulted substantially reduced combustion efficiency [Ref. 2].

The three methods of measuring combustion efficiency in the slagging combustor are based on carbon in the slag, CO in the stack gases, and carbon in the stack fly ash. Under fuel rich conditions, significant amounts of carbon in the slag indicates poor combustion inside the combustor. In the present combustor, combustion efficiency, based on carbon in the slag, has been over 99% in almost all the tests including at fuel rich operation as low as 75% stoichiometric air/fuel ratio. Since carbon monoxide is an air pollutant, it is essential that it be minimized in the combustion process. The CO concentration in the stack was generally in the 200 ppm range, which corresponds to better than 99% combustion efficiency.

Both these measurements of combustion efficiency do not account for unburned carbon that is carried over to the stack baghouse. Due to the difficulty in obtaining real time sampling of the baghouse fly ash, the carbon content in the fly ash was determined from random grab samples taken from all the ash collected on the day of testing. The carbon content of the ash ranged from 20% to 50% (dry basis). Since on average about one-third of mineral matter injected reported to the baghouse, one can compute the conversion of the solid carbon in the coal to CO_2 and CO in the combustor from the amount of unburned carbon in the baghouse fly ash. This yielded a carbon conversion greater than 90% for most of the tests. In several tests small quantities of fly ash in the stack were collected in a filter. Analysis of the carbon content in one of these tests yielded a carbon conversion of 94%.

The stoichiometric ratio in the combustor (SR1) ranged from fuel rich to fuel lean ($0.75<SR1<1.1$). Final combustion air was added at the combustor outlet into the boiler, which yielded a stoichiometric ratio in the boiler furnace (SR2) in the range from 1.3 to 1.8. Several bituminous coals were tested having higher heating values (HHV) in the range of 12,000 to 13,700 Btu/lb, ash contents in the 11% to 15% range, and sulfur contents in the range from 1.18% to 3.7%. The bulk of the tests were performed with 3+% sulfur coal.

f) Sample SO_2 Results from Task 5

The initial test effort in the first year of task 5 operation was focused on overall combustor performance, with lesser emphasis on SO_2 and NO_x control. Subsequently, the tests focused on SO_2 control and excellent results have been achieved, especially in low sulfur coal. All this work is detailed in Appendix 'C" of this Final Report. Limestone and hydrated lime were injected into the combustor for slag conditioning and sulfur removal. Previous results in the 20 MMBtu/hr combustor in Williamsport showed that limestone was much less effective than calcium hydrate for sulfur capture. With calcium hydrate injection into the previous combustor, excellent sulfur capture results were achieved, where a maximum reduction in the 85% range was measured.

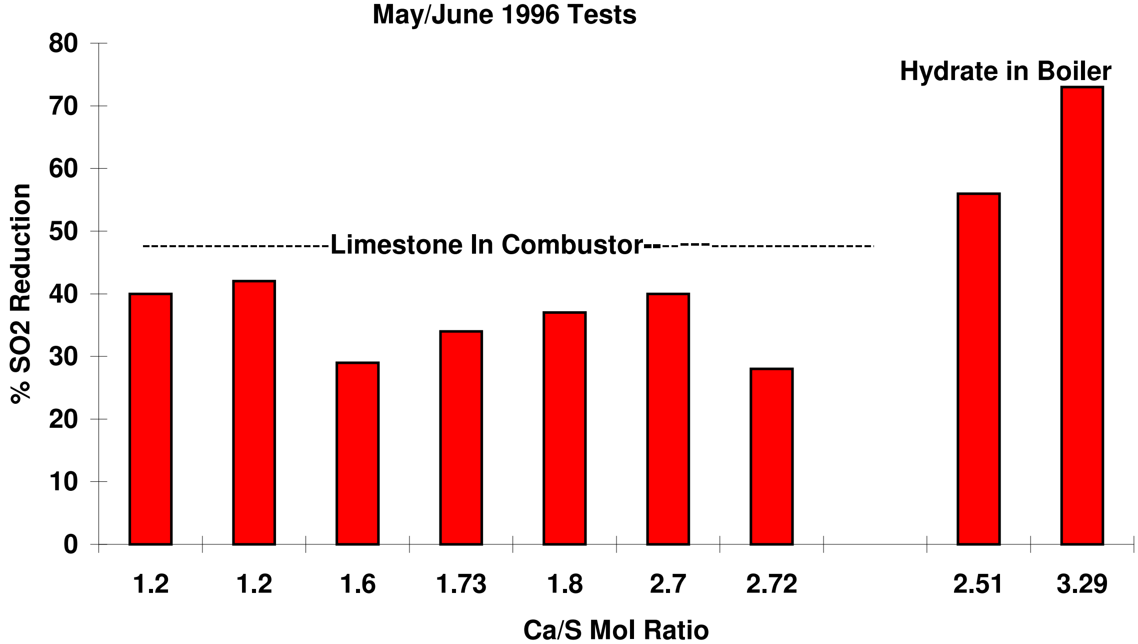
The degree of sulfur capture in the present combustor was found to be very sensitive to combustion conditions, the method and quantity of sorbent injection, and the mineral matter injection rate. In tests at high slag mass flow rates firing 3+% sulfur coal, SO_2 reductions measured in the end wall of the boiler furnace and in the boiler gas outlet at the stack were in the range of 60% to 75% at Ca/S mol ratios of under 3. Similar reductions were measured with injection of calcium hydrate into the boiler furnace near the combustor gas inlet to the boiler. In this case, the Ca/S mol ratios were in the range of 3.5 to 4.9. However, in the latter case, a substantial amount of the hydrate fell to the floor of the boiler furnace. Therefore, the Ca/S mol ratio is not an accurate measure of calcium utilization in this case.

In other tests with 1.5% sulfur coal, the SO_2 reductions were substantially higher. Reductions in the range of 75% to as high as 95% were measured. When expressed in lb/MMBtu, SO_2 emissions as low as 0.22 lb/MMBtu were measured. This is well below the 0.5 lb/MMBtu SO_2 emission standard for Philadelphia, and it near the 0.2 lb/MMBtu that is one of the current test objectives. The reductions were higher at the end wall of the boiler furnace than in the stack at the outlet of the boiler. However, no conclusive explanation for this behavior has been found. See more details on this issue in Appendix 'C".

One interesting result has been finding relatively high sulfur concentrations (10% to 20%) in the slag in several of the tests. With high slag mass flow rates, as obtained with high ash coals or by injecting additional ash, it may be possible to encapsulate all the coal sulfur in the slag. Tests in which additional metal oxide powder was injected into the combustor at up to 40% injected mineral mass flow rates were implemented under a parallel project whose objective was to maximize sulfur capture and retention in the slag drained from the combustor. Those results are given in the final report on that project, [Ref. 7].

Figure 18 shows on set of SO2 reduction results that were obtained in task 5 tests, where as had been previously determined limestone injection in the combustor was about 1/3 as effective in reduction than calcium hydrate. On the other hand calcium hydrate injection at the outlet of the combustor in the boiler was very effective even with inefficient mixing. Injection in the combustor was more effective than limestone, but since the small (7 micron mean) size particles blew out of the combustor, the capture effectiveness was not as high as in the furnace section of the boiler. Much more details are in Appendix 'C".

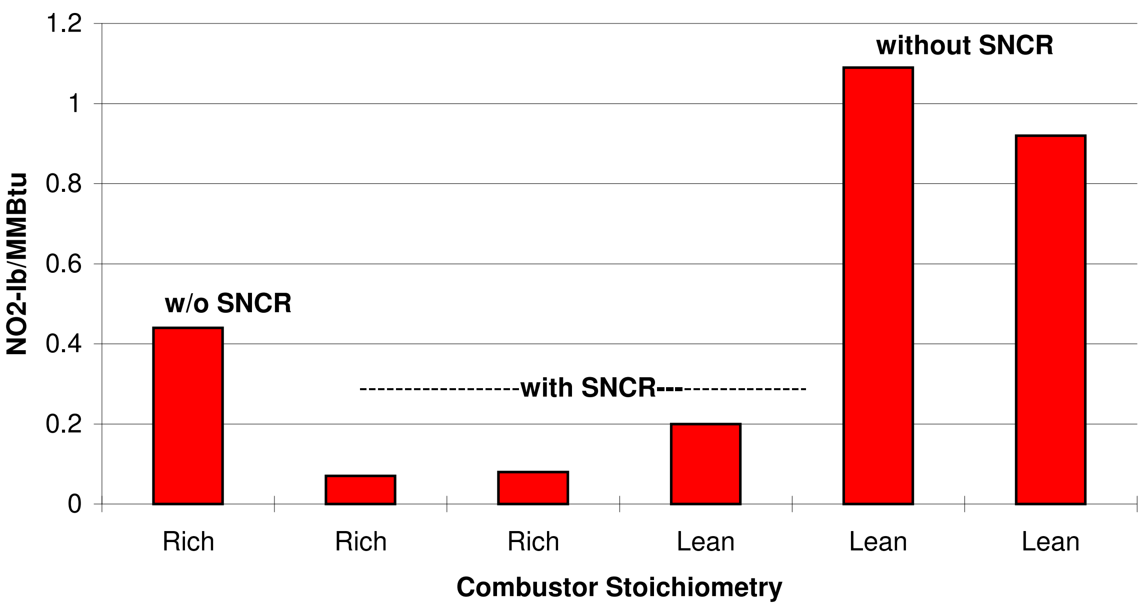
Fig. 18: SO2 Reduction vs Ca/S Mol Ratio of Sorbent Injection
May/June 1996 Tests



g) Key NO_x Results with Staged Combustion & SNCR Post Combustion.

NO_x reduction with staged combustion (i.e. fuel rich operation in the combustor) was the sole focus of all NOx reduction tests since the very first tests conducted under this P.I.'s direction in a 1 MMBtu/hr air-cooled, slagging combustor prior to forming Coal Tech in 1981, and in subsequent years, including a 7 MMBtu/hr combustor in the mid-1980's and then the 20 MMBtu/hr air-cooled , slagging combustor in Williamsport and Philadelphia from 1986 through 1996. However, in the last year of testing in early 1997, the post-combustion Selective Non-Catalytic Reduction (SNCR) reagent injection into the post-combustion gas flow train. SNCR was combined with and without staged combustion in the first test series of 1997. Incredible the best reduction was obtained in this series of initial Figure 19 shows the results obtained in these tests of January 7th. The greatest percentage reduction was obtained under fuel lean conditions in the combustor, with over 80% reduction to 0.2 lb/MMBtu. **However, under fuel rich conditions in the combustor with SNCR injection at the combustor outlet, a value of NO_x as low as 0.07 lb/MMBtu was been measured**. In all the tests, when the injection ceased

Figure 19: NOx Emissions from 20 MMBtu/hr Combustor-Boiler w./w.o. Staged Combustion & w./w.o./ SNCR- January 7, 1997 Test



the NO_x level returned to the prior non-injection value. Various methods of injection were tested in order to optimize this process. A considerable amount of information on this NO_x control process has been accumulated in these tests and in subsequent tests in February 1997. Some of these data were reported at the DOE NOx Control Conference in Pittsburgh on May 15, 1997.

The results in figure 19 are typical of the results obtained in numerous test conditions with SNCR injection under fuel rich and fuel lean conditions in the combustor. In general during each test day multiple SNCR post-combustion injection tests were performed with recovery to no injection. To repeat, 'fuel rich" means staged combustion in which the combustor was operated at various levels below a stoichiometric ratio of 1, which is called "staged combustion", while "fuel lean" means excess air operation in the combustor. The "fuel rich" results in figure 19 shows that the NO_x reduction level achieved by staged combustion in the combustor is augmented by SNCR injection to approximately the same degree as SNCR without staged combustion. **Note that the NO_x level shown in figure 19 is 50% of that required by EPA under the 2003 rules.**

Since the description on these data may not always align with the graph, the following elaboration is given. The first and last two of the six columns represent the fuel rich and fuel lean NO_x emissions, reported as NO_2, as measured without SNCR injection downstream of the combustor. The middle three columns show the result for rich and lean combustor conditions with SNCR injection downstream. Note that the reductions are proportional to the initial NO_x levels. Therefore, to achieve the lowest NO_x levels, 0.07 lb/MMBtu in this case, fuel rich staged combustion is advantageous. However, this condition may result in increased unburned carbon in the fly ash as well as potential increased corrosion of boiler tubes due to sulfur compounds in the gases. Therefore, quite a number of tests were performed with only limited fuel rich conditions, namely SR1 of about 0.9, compared to the very fuel rich operation of SR1 of 0.65 that was practiced before this SNCR process was used, as shown in figure 19.

The NO_x reduction achieved with this process varied according to the quantity of reagent and the method of injection. Numerous graphs similar to the one in figure 13 were obtained from the NO_x control tests in January and February.

<u>The significance of the new NOx results is that the second of the three emission goals of this project were now achieved</u>. The first one, SO_2 emissions below 0.4 lb/MMBtu was achieved earlier in the project. SO_2 levels as low as 0.2 lb/MMBtu were measured at the stack in coal with 1.3 to 1.7 % sulfur. <u>The NOx emission goal of 0.2 lb/MMBtu was achieved in the 1st quarter of 1997.</u> The particulate goal was 0.02 lb/MMBtu. However, due to limited funds only one set of tests were performed on particulates by contracting with an outside stack testing company. Unfortunately, there was a problem with the attachment of the bags to the baghouse support structure and some modest gas blowby around the bag supports resulted in high particulate readings, as discussed with the February 1997 tests. However, this is at worst a manufacturing defect in the construction of that bag support plate. It is not a deficiency in baghouse operation. Also, it is essential to stress that by removing about ¾ of the coal ash in the combustor, the particle loading on the baghouse is sharply reduced.

Further details on these NO_x tests are in Appendix "C"

h) The 37% Ash Indian Coal Tests- 1st Q. 1997 & Its Impact on Mercury Capture

As early as 1989, Coal Tech performed tests in the Williamsport 20 MMBtu/hr combustor in which coal fly ash was injected into the combustor with coal to achieve over 50% ash content in the mixture. However, due to the small ash particle size, (<10 microns), much of the ash was blown out of the combustor. The highest ash content in coal that was tested had about 15% ash. In the fall of 1996 a substantial number of tests were performed in which an artificial ash was injected into the combustor. These tests were performed for a parallel sulfur-in -slag project, and for a few tests in the present project, as reported above. But these tests had specific objectives and they may not represent actual conditions of combustion of high ash coal. The high ash coals are widely used in certain European and in much of Asia.

At the DOE Clean Coal Conference on January 9th, the P.I. learned from DOE-FETC personnel that several tons on 37% ash, 0.4% sulfur, 8100 Btu/lb Indian pulverized coal were stored at a DOE warehouse in Pittsburgh. It was shipped to Philadelphia. On January 23rd and 28th tests on this coal were performed. The results were excellent, far exceeding expectations. Excellent slagging was achieved and the ash deposits on the combustor wall substantially reduced the wall heat transfer.

In view of the excellent results with this coal, the second test on the 28th was performed under the parallel sulfur-in-slag project. Gypsum was injected to determine the suitability of high ash flow rates on retention of sulfur in the slag. As observed previously, the calcium sulfate greatly increased the slag viscosity. As a result, slag removal from the slag tank nearly ceased late in the test. After draining the slag tank at the end of the test, slag was found to have filled the slag removal duct beneath the combustor. It was very easy to break it apart and remove it. In this test the sulfur level frozen in the slag reached 20%, of the injected sulfur, which was the highest level reached in any of the many tests in the first and the second 20 MMBtu/hr combustors.

Coal fly ash injection tests were conducted in the Williamsport combustor in around 1990 under a Phase 1 & 2 DOE-SBIR project [Ref. 8] in which it was found that the amount of volatile trace metals retained in the slag increased with increasing slag mass flow rate up to 500 lb/hr. Measurements with lead and arsenic indicated at slag mass flow rates of 1000 lb/hr almost all the metal would be retained in the slag. This has major implication for mercury retention in slag. Mercury emission increase with ash content and India and China burn 160% of the U.S. coal consumption and their ash levels are up to 4 times higher than U.S. coal ashes. This means that they emit between 3 to 6 times more mercury into the atmosphere than the U.S.

In addition, in the late 1990's Coal Tech developed techniques for generating over 1000-lb/hr slag flow with 70% ash-biomass char in the combustor. This meant that co-firing this biomass with coal would provide a powerful and low cost means for retaining mercury in slag with low ash U.S. coals. When combined with the non-equilibrium initial coal combustion in the air-cooled combustor, which inhibits the evolution of volatile compounds such as sulfur and mercury, these methods could remove mercury from coal at a cost that would be at least 100 times lower that in current post-combustion processes. DOE rejected in 2002 and 2003 two proposals by Coal Tech to tests this process, as well as a low cost post-combustion process for mercury removal.

i) Post Combustion NOx Reduction with "Reburn".

After completion of this project, Coal Tech internally funded work on the use of "reburn" in the post-combustion zone to reduce NOx. No.2 oil and shredded and fine biomass powder was used as the reburn fuel in the 20 MMBtu/hr combustor. About 50% NO_x reduction was achieved. Proposals to DOE to expand this work to include coal as the reburn fuel were rejected.

j) Combined Post-combustion NO_x and SO_2 Reduction

Also in the late 1990's Coal Tech combined its SNCR process with SO2 reduction by adding a second reagent powder. This required considerable development to prepare the mixture. In an extensive test effort in the 20 MMBtu/hr combustor, reductions of 80% were achieved for both NOx and SO2.

Several brief tests on this process were also implemented on a 50 MW coal fired utility boiler. The SNCR NOx results obtained with SNCR on this boiler of 40% were duplicated. However, feeding difficulties of the reagent liquid resulted in only limited SO2 reductions. As Coal Tech financed these tests with very limited funds and they were not continued. However, there is no doubt that the results in the small combustor –boiler can be repeated in large boilers.

k) SNCR Post Combustion NO_x Control in a 37 MW & 100 MW Electric Utility Boiler:

Coal Tech's SNCR post combustion process is readily adaptable to large boilers. In June 1997, a brief one-day NO_x control test on the 100 MW-boiler was performed. With only one injector, a 25% NO_x reduction was measured.

This test revealed that the process was effective, but that the injectors would have to be modified somewhat. Coal Tech process is so low in cost and so simple to implement that the entire test on one boiler, including driving to the plant, installing the injection equipment, performing the test, removing the equipment and driving home can be done in one day. Coal Tech was responsible for the entire cost of the test, including providing all the personnel for installation of the test equipment, operating the equipment, and providing the personnel and equipment for tests of ammonia slip at the stack. Due to Coal Tech resource limitations this precluded extended test periods and the installation of sufficient injectors to duplicate the high NO_x reduction measured in the 20 MMBtu/hr-combustor.

To maximize the results within these resource limitations, a second test was planned for early August. Since the plant had a smaller 37 MW boiler, it was decided to include this boiler in the test effort, and add a second test day. Its smaller size allowed a greater impact on NO_x reduction with fewer injectors. From our decades long experience with test operations, we were certain that there would be problems that would limit the planned test objectives. Accordingly, we had hoped to implement a third series test on these boilers. However, two substantial unexpected expenses prevented this.

First at the insistence of the regulatory authorities we were required to measure trace pollutants, especially ammonia slip, during the injection process. Since these were short duration tests, we would have preferred to defer ammonia slip tests until more test data had been gathered. This testing required retaining an outside stack gas-testing firm for this purpose at considerable expense, which added substantially to the cost of the test.

Note added March 2004: This requirement made absolutely no sense because the 37 MW boiler emitted 1 lb/MMBtu of NO_x continuously, which was far worse than the few milligrams of ammonia slip during the several hours of testing. As a result of this "decision"

and the refusal of the utility to pay for any part of the tests, we could not afford any more tests. As a result we shifted to another utility, which has a 50 MW boiler, and performed a series of tests in 1999, 2000 and late 2003, again at our expense but with the help of the power plant staff. These tests resulted in a major breakthrough in that late* last year Coal Tech SNCR process reduced NO_x by nearly 50% to 0.15 lb/MMBtu, the EPA 2003 limit. *Furthermore, the* process operating cost is under $500/ton of NO_x removed, *and* the capital cost is a few dollars per kilowatt. *Had either the utility invested in 1997 the few 1000 dollars for ammonia slip tests, or DOE selected our solicited NO_x proposals, this technology would have been fully commercial before 2000 and could have reduced by now several additional million tons of NO_x annually. The moral is the elementary school rhyme: "For want of a nail, the horse was lost, for want of a horse, the war was lost".

Secondly, one of the boilers had a common stack with a second identically rated boiler. We suggested that one could simply deduct the NO_x reduction achieved by the injection process, and attribute it all to the test boiler. This was unacceptable to the utility personnel. We agreed to bring Coal Tech's portable NO_x instrument to measure the NO_x on the test boiler outlet. However, two days before the scheduled test, the instrument broke down and there was not time to repair it. Since all the test arrangements had been made, the only option was to purchase another instrument from the suppliers stock for almost $5000. The utility had promised to pay for half the cost of the instrument, but as this had only been a verbal promise, it was not kept. The expense incurred for these two items equaled our budget for one series of tests, and it precluded a third series of tests.

In addition, without the help of the plant operators, we hired 3 technicians from our old Williamsport contractor to assist in the tests. This was in addition, to four Coal Tech personnel. The reason for all these people was the need to mix the reagent with water in 55-gallon drums, which required mixing a new batch about every 10 minutes at each of the two-injector locations. In the event, this method of mixing was totally unsatisfactory and poor results were obtained.

The first day of testing on August 6, 1997 was on the 100 MW boiler. This boiler is equipped with low NO_x burners and overfire air. In the June test, the baseline NO_x emission was about 0.3 lb/MMBtu. On the day of the August test, the NO_x level was 0.44 lb/MMBtu. The ash deposits on the furnace wall and boiler tubes were relatively high and it was necessary to perform soot blowing before and during the test. One injector was placed at the same location as in the previous test and another one was placed on the opposite boiler wall. As anticipated, problems developed immediately. The 115 Volt outlets that were used to power the small pumps blew the circuit breakers, and no one could find the circuit breakers. Consequently, a search was made for working 115 V. outlets. After a brief period, these circuit breakers also blew. As a result of all the delays incurred, the test periods were greatly reduced. Meanwhile our costly stack test crew had to restart sampling after every breakdown. Three test conditions were implemented and the maximum reduction measured was 24% at one of the test conditions. This was about the same as had been achieved in the previous test with one injector. The injectors were then moved to a different location in the boiler for the final condition. Here the NO_x reduction was substantially lower.

These results were very puzzling. However, two factors were highly suspect.

One was the rapid pace of the tests and the high heat in the building meant that the mixing of the reagent with the water in the 55 gallon was hurried and incomplete. This meant that the reagent injection was non-uniform

The other factor was the observation of severe distortion in the compressed air pipe in the injector assembly. This meant that the injection mechanism was overheating which means that the reagent dispersal was deficient.

Both these factors were corrected in subsequent tests. The first one that of proper mixing was partially corrected on the next day. The second one of proper cooling of the injectors was corrected in subsequent tests performed on a 50 MW coal fired utility boiler several years after the present project ended. In that later test 40% NOx reduction was obtained. However, in one test on the 50 MW boiler where the injector cooling circuit was blocked, the NO_x reduction was minimal, which proved injector cooling is critical to proper injector functioning.

Nevertheless, the 37 MW and 100 MW tests results provided information on the required number of injectors that are needed to cover the combustion gas flow path. Due to the interruptions listed above, the measurements of trace gas ammonia slip in the stack showed wide variations. They, therefore, provided only qualitative guidance on the magnitude of trace pollutant emissions of ammonia slip, and the expense incurred for this measurement was wasted.

On the second day, the tests were performed on the 37 MW boiler. It used a very high ash coalmine waste and had no NO_x control. The uncontrolled NO_x emission levels were 1 lb/MMBtu. A brown pollution plume was visible from the stack of this plant as a result of the high NO_x. Here again due to boiler operational issues on the parallel 37 MW boiler, the test duration was less than planned originally. The stack gases were sampled at the outlet of the stack particulate control equipment at a point where the gas ducting enters the common stack to both 37 MW boilers. On comparing the NO_x results measured with the Coal Tech instrument at the duct leading from the test boiler to the common stack with the utility's NO_x instruments at the top of the stack, it was found that the NO_x values were nearly identical. It was concluded that the exhaust gases from both boilers, which entered the stack on opposite sides, mixed completely at the base of the stack so that the measurement at the base was not necessary. In hindsight, it was not necessary for Coal Tech to waste nearly $5000 and purchase the replacement NO_x instrument.

The best NO_x reduction obtained at one of the test conditions in the 37 MW boiler was 40%. Of greater importance, the utilization of the reagent was 75% for that test condition. Furthermore, the ammonia slip in the stack was below 10 ppm. This was a very significant result in that the cost of operating Coal Tech's NO_x control process is far less than other post combustion SNCR NO_x control processes that achieve almost the same nominal one-third reduction and that are now on the market.

The utility's staff refused to participate in any further tests for which they would have had to incur the expense of the test, which would have been minimal. In early 1998, Coal Tech offered to install the SNCR system on the highly polluting 37 MW boiler at a cost that was less than one-half of the lowest cost alternative SNCR on the market. The offer was rejected on the grounds that we could not implement it at that low cost. Instead the power plant continued to pollute the atmosphere. Interestingly, at one of its largest power plants, this utility installed a SCR NOx controls system that conservatively costs at least a factor of 10 more than Coal Tech's process.

As noted above, Coal Tech did successfully demonstrate this process at its own expense on a 50 MW coal fired boiler in 1999, 2000 and 2003. As noted in the March 2004 note above, the tests in 2003 resulted in nearly 50% NO_x reduction to 0.15 lb/MMBtu, which is EPA's 2003 emission limit.

Note March 2004: A summary of the results of these NOx tests as well as Coal Tech's SO2, dioxin/furan, volatile trace metal emission control processes can be found in Ref.9, "Proceedings of the 19th International Conference of Solid Waste Technology", Philadelphia, PA March 21-23, 2004, published in the Journal of Solid Waste Technology & Management"

Over the next several years, Coal Tech submitted about one-half dozen proposals to DOE for demonstrating its post-combustion processes on utility boilers, including the SNCR and reburn processes for NO_x control, and its combined NO_x/SO_2 process. All were rejected in favor of other projects that cost 5 to 20 times more than Coal Tech's proposals.

Table 1 is a summary of the test results on the 37 MW and 100 MW boilers

Table 1:
Results from Coal Tech's SNCR Test on a 37 MW Coal Fired Electric Utility Boiler

Test Day	# Injectors	NOx, lb/MMBtu	% NOx Reduction	NH3 Slip, ppm
8/7/97	0.	1.07	0	0
8/7/97	1	0.6	40	8.7
8/7/97	1	0.6	40	7.6

t) Final Tests on the 20 MMBtu/he Combustor-Boiler: 4th Quarter 1997 to 2003

The above tests were the last ones on the present project. A total of 73 test days had been performed compared to the 63 days originally planned for task 5.

Testing on the parallel sulfur-to-slag project continued for another 6-month period until March 31, 1998, by which time a total of 34 tests days had been implemented on coal firing. This brought the total number of test days to 108.

In the following 5 years over 100 days of testing was implemented on this combustor, which led to the development of Coal Tech proprietary, patented and patent pending, NO_x and SO_2 post combustion emission control processes. They include SNCR and 'Reburn" NO_x control as well as SO_2 control, and combined SO_2 and NO_x control, all of which are patented.. All these tests were implemented with oil and/or biomass firing with the injection of compounds that duplicated the NO_x and SO_2 emissions released during coal combustion. Since these tests were performed mostly with oil, the slag, which had replaced much of the refractory liner of the combustor, melted. It will be necessary to reline the combustor with refractory to return to coal firing. This can be readily implemented without removal of the combustor from the boiler.

In addition, processes were invented for the total removal of volatile trace metal, such as mercury, that are released during coal combustion. Also, more recently, a process has been invented for converting removing the carbon dioxide from the combustion gas stream and sequestering it in the earth. Coal Tech has financed all this work of the past 7 years. As noted above, the NO_x and SO_2 processes have been tested on a 50 MMBtu/hr coal fired utility boiler.

Only the mercury capture and the carbon dioxide sequestration processes remain to be tested. With these final steps, the air-cooled slagging, cyclone combustor is capable of coal combustion with the total removal of all gas, liquid, and solid pollutants that result from coal combustion.

Further details on task 5 are given in Appendix "C"

4: CONCLUSIONS TO THE ENTIRE PROJECT

Conclusions to the three phases of this project are given at the end of Appendices "A", "B", and "C". Since task 5 was the most important task of this project, its conclusions are repeated in this overall conclusion section.

This section presents some general insights that the author gained in preparing of this Final Project Report in May 2003, as well as further insights and comments gained in the editorial review of this report in March 2004..

(a) Status of the Air-Cooled Slagging Combustor at the End of Task 5

At the end of the task 5 testing in 1998, the work statement for this project had been completed and in some key areas, such as emission control, substantially exceeded. Most all the key technical issues on the operation of the combustor and its internal emission controls for SO_2 and NO_x had been resolved. **Two key issues remained**.

a.1)-*Long duration (1000's of hours), continuous operation of the combustor*. This required the installation of a complete electric power generation system, with power sales to a user, for which a design and equipment specification had been developed. While Coal Tech had proposed this task in the original proposal in 1990, no funds were available for this purpose. And it was beyond available project resources.

a.II)-*Near zero emissions from coal combustion,* including NO_x, SO_2, dioxin/furans, volatile trace metals in ash, and sequestration of carbon dioxide. This was not in the project work statement. From assessment of the coal utilization market in the early to mid-1990's, Coal Tech's P.I. reached the conclusion that without zero emissions, coal use would not increase significantly, and it might very well decrease. As there was no follow-contract for this project, and when Coal Tech's over one-half dozen proposals to DOE were all declined, internal resources were used in the following years to accomplish this task. At present (March 2004), only Coal Tech's inventions of a mercury emission control process and of a carbon dioxide removal and sequestration process remain to be experimentally demonstrated. All of these processes have either been patented or have patents pending.

Even without the last two tasks of mercury control and carbon dioxide emission control, the air-cooled cyclone combustor is today (March 2004) the lowest cost, totally environmentally friendly, coal combustion system, ready for the domestic and international energy market.

(b) ***General Observations:*** This final report is based in large part of the technical reports that were written contemporaneously with the effort on this project, which deals with Tasks 1 though 5, and covers the 6 years from 1992 through early 1998. The 6-year interval before the preparation of this Report has enabled the author to approach this work with a new and hopefully more objective point of view. One unexpected aspect of the current review was how much was accomplished during this project. It is now very clear that within the constraints of the modest resources that were available, the task 5 effort was especially very successful. Key results were:

- The second-generation design of the combustor solved the major problem of slag retention in the combustor, with essentially no outflow of slag into the boiler.
-Concurrently this greatly improved the combustion efficiency in that the extensive unburned carbon laden ash deposits on the boiler's furnace floor essentially disappeared.
-Almost all the steps necessary to complete the development of the air-cooled combustor for commercial use were implemented. The one item that was missing was long period operation, namely in the 2000 hour per year range and up. For that additional funds were needed and a users of steam and or electricity.
-In retrospect the most surprising result was how close we came to building a complete electric generation power plant, considering that we implemented task 5 within the budget that we had originally proposed for only the first four tasks. Our original proposal for task 5 was for a sum equal to the value of the final total contract. As it was, we could have implemented the power plant task with additional funds of about one-half more than the funds that in the proposal for implementing tasks 1 though 4.

(c) ***Electric Power Generation as a Marketing Tool:*** One intriguing idea that occurred to this author in reviewing task 5 is that we should have focused on the power generation part of the plant instead of the coal part of the plant. This would have entailed purchasing the very old 600 kW Elliot steam turbine-electric generator, a very low cost new atmospheric plate condenser, and a water spray-cooling tower. Instead we focusing more on the raw coal storage and pulverization part of the plant and when its costs began to balloon out of proportion to the benefit we simply abandoned the power plant option.

Even without an outside revenue-producing customer for the electricity, we could have used up to 40% of the power for more flexible operation of the combustor. We could have purchased an electric furnace to melt scrap metals, instead of trying to develop a novel new furnace.

What motivated this idea was Coal Tech's experience in marketing the combustor. A considerable number of potential customers visited the site or contacted Coal Tech to this day, 2004. In all cases the barrier was the lack of any commercial sales, and no one wanted to be the first. With the addition of the electric generator, revenue from electricity would have been obtained and this would have assured customers of the commercial potential.

(d) ***Moving Task 5 to Philadelphia:*** The totally unanticipated event in this project was the closing of the Williamsport test site, which necessitated the move to Philadelphia. More than any other aspect of this project, it prevented the air-cooled combustor technology from premature termination. Had task 5 been implemented in Williamsport, it is almost certain that it would have been implemented with minor changes to the first generation combustor. As such we would have focused on continuous round-the-clock operation in increments of 100 hours. It was written into the work statement and it was an issue desired by potential customers. However, the first-generation combustor had severe design deficiencies, as is amply documented in this Final Report. Therefore, on a technical basis the work would have been a dead-end.

It would have also been a dead-end from a policy standpoint. As there was no follow-on to this project, all the equipment would have been scrapped, as indeed was contained in task 6 of this project. Coal Tech was in no position to finance continued work on this technology with its internal resources. On the other hand the move to Philadelphia enabled Coal Tech Corp to keep the facility operational to this day (March 2004) because the internal resources required were far lower, mainly rent. More importantly, it enabled us to develop new or improved, very low cost emission control processes for post-combustion SNCR and reburn for NOx, post-combustion SO_2, dioxins and furans for municipal waste, mercury control, and more recently carbon dioxide sequestration. Most importantly, it has made the air-cooled combustor technology available for markets in Asia and the U.S. that are now coming into focus.

(e) ***Slagging Combustor Market***: As is evident from this report, the preferred markets for the slagging combustor are users of high ash coals, which are located in Asia, primarily India, China, and Indonesia, among others. The reason for this is that coal extraction costs are low while revenue from exporting low ash coals is high, leaving the high ash coals for domestic use.

Conventional pulverized coal fired boiler are very inefficient when burning high ash coals. While the B&W slagging combustor can burn such coals efficiently, as a wall-burning device this can only be accomplished under high excess air, which results in very high NO_x production. An even more important disadvantage of the B&W slagging combustor is that it is water cooled, and as such it must be constructed as an integral part of the water-steam loop of the boiler. This eliminates its use in all existing boilers. A major R&D effort has been expended by another firm in the past several decades on developing a slagging combustor whose water-cooling circuit is separate from the boiler water-steam loop. However, this involves efficiency losses because the cooling water is low grade heat.

Coal Tech has recognized the major advantage of the air-cooled combustor for the high ash coal market because it can be retrofitted to almost any boiler or furnace. This was the motivation for burning the 37% ash Indian coal in task 5. Throughout the decade of the 1990's, Coal Tech had attempted to market this combustor to Indian companies, and to a lesser extent to Chinese companies. However, there was no financial incentive for these companies to switch to this technology as long as existing methods were profitable, even under inefficient combustion conditions. Similarly, there was little regulatory pressure to sharply reduce the air pollution resulting from this type of combustion, especially from foreign governments.

However, the air-cooled combustor market may change in the near future.

On May 2003, the Wall Street Journal carried a front-page story about a massive "Brown Cloud" over the Indian Ocean that is 2 miles thick with an area equal to that of the continental U.S.A. Indian environmental officials prevailed on the U.N. to cut off funding for further study of the "cloud" on grounds that it was caused by India's poor burning animal dung for cooking and stopping that would result in starvation. However, the 'cloud' is almost certainly due to inefficient combustion of the high ash (40%) Indian coals. Coal is used primarily for electricity production whose high cost places it out of reach of India's poor. According to India's Tata Energy Research Institute (TERI), New Delhi, India, the fuel consumption of animal dung in 1999 was **106.9** million metric tons (MMT) compared to over **300** MMT of coal**.**

The source of the 'cloud' can be readily verified. Biomass, including dung, firewood, and crop residue, with the exception of rice, have at most several percent ash. If biomass were the primary source of the Indian Ocean cloud, particles sampled inside the cloud would consist exclusively of black unburned carbon particles. On the other hand, if inefficient combustion of high ash Indian coal were the source, then gray ash particles would substantially exceed the black carbon in the samples.

The 1983 annual report of the World Health Organization (WHO) stated that **respiratory diseases were the main cause of death in developing countries**. Since that time, India's coal consumption has grown by about 300%, while dung consumption has increased by only 50% (TERI). China's coal consumption has also grown dramatically during this period. China also has an air pollution problem. Interestingly, whatever the origin of the SARS virus, it is a respiratory disease. Also, the results of a study by a California physician, Dr. Hightower, that was released last year found elevated levels of mercury in Californians that consumed more than the average number of fish. Mercury in coal ash is emitted during combustion, and the world winds blow from the East in Asia to the West in America.

As proven by the results of the 37% ash Indian coal test, Coal Tech's air-cooled combustor offers a low cost solution to this emission problem. Replacing all the coal burners on power plant boilers and other furnaces with this combustor would remove over 75% of the ash as chemically inert slag, which would also trap part of the mercury. In the process, all the carbon would be burned. We estimate that the cost saving from the recovered carbon energy exceeds the cost of these combustors.

Today, March 11, 2004, the Wall Street Journal reported that coal is even in greater demand in Asia due to the booming mainland economies in China and India. The price of Australian export coal has skyrocketed to $50/metric ton from $20/ton, just two years ago. All this coal is adding to world pollution and increased carbon dioxide emissions.

(f) ***Comments on DOE's Reviews of this Project***:

Program reviews were held regularly in the early years of this project, none were held after the results of task 5 were complete. There was also one visit by DOE technical personnel to the Philadelphia site in the early phases of the test effort, at which Coal Tech was commended for the good cost to benefit ratio of its R&D programs. However, there was no review at the end of the project.

There was an extensive set of detailed questions submitted to Coal Tech late in the Task 5 effort on the status of the project to which we provided a detailed response in one of the Technical Quarterly Reports, and which is also contained in Appendix "C" of this Final Report.

One possibly reason for the lack of interest at that time was that after a decade of low natural gas prices and a literal stampede by power plant developers to erect natural gas fired power plants, there seemed no future in coal based technologies, especially a niche technology like the air-cooled slagging combustor. This of course changed drastically in 2001 when the price of natural gas exploded while the price of electricity collapsed. The resultant financial collapse in the utility sector demonstrated the folly of relying on a fuel that was in relatively limited supply and focusing only on the "low capital" cost of gas fired power plants.

g) **Comment on Contradictory Government Policies on Energy R&D**

The development of Coal Tech's combustor and emission control technologies has been made possibly by government support and impacted by the government's procurement and tax policies. It may therefore be of interest to share some comments on this subject.

As stated in this report, in the process of implementing the commercialization task, No. 4, it became clear that low cost was insufficient to market the air-cooled combustor. It had to be accompanied by **low cost, total emission controls** from coal combustion. The air-cooled combustor by itself could not accomplish this objective. Accordingly beginning in 1997, Coal Tech initiated a post-combustion emission control R&D effort, beginning with the post-combustion SNCR process. It was almost immediately very successful, as reported herein. The combined stage combustion-SNCR reduced NOx by as much as 93% to 0.07 lb/MMBtu.

However, our requests for DOE support were unsuccessful in that over one-half dozen proposals on emission control between 1997 and 2003 were **all** rejected. Oour bids ranged from 5% to 20% of the value of the contracts that were generally awarded.

We believe that **a key factor in these decisions was the government's solicitation policy that awards a point score for technical sophistication and team composition, but not for cost. This favors large and sophisticated teams. This in turn has generally resulted in large and costly commercial products and processes**. This may explain the decades long delaying actions by the coal fired utility industry in implementing the most stringent emission controls.

The procurement policy has another counterproductive result in that as technologies move from prototype development stage to full-scale commercial demonstration, small companies tend to fall by the wayside due to the government's policy of "one -size fits all" cost sharing requirement, a requirement that is far easier for large companies to meet than small ones.

Another policy that inhibits R&D in new technologies is a regulation by the Internal Revenue Service that the R&D Tax Credit cannot be applied to unrelated revenue. This means that in the early years of developing new technologies, when revenues are slim to non-existent and financial need is greatest, **the R&D Tax Credits are useless**.

In Coal Tech's case the wisdom of ignoring "sound business practices" of shutting down, and instead continuing with the development of emission control processes with internal resources may soon be vindicated. During the past 6 years processes for the removal of the emissions of NO_x, SO_2, dioxins/furans were developed and tested. As reported herein, one of these extremely low cost NO_x processes, the SNCR Process, achieved the EPA 2003 emissions target of 0.15 lb/MMBtu in a coal fired utility boiler. The process is essentially commercially ready. Patents for low cost removal of this and the other pollutants from coal combustion, including volatile trace metals such as mercury, and even carbon dioxide have either been granted or are pending. The conclusion is that in a fundamental endeavor as energy persistence pays, especially if it can be implemented at low cost, which in turn should lead to low costs solutions. For that this P.I. wishes to thank DOE personnel for their previous support.

ACKNOWLEDGMENTS

A project of a 5-plus year extent, involving test operations in the pre-existing 20 MMBtu/hr combustor-boiler facility in Williamsport, PA in 1992 and 1993, and construction of the second generation 20 MMBtu/hr combustor, erection of the test facility, and testing from 1994 to 1998 involved many organizations and individuals. The contributions of the following individuals and organizations are especially cited and acknowledged by the P.I.:

Tasks 1 through 3: Dr. Ed Fleming-implementation of test effort; Mr. Ben Borck-computer control design and test; the late Mr. Dave Alexander, the indispensable electronic technician and his staff at Lyco; the technicians from DePasqualle; staff members from the host facility-Tampella-Keeler; Dr. Charles Marston and Dr. Scott Brewster-computer modeling,

Task 4: Staff members of H-R International

Task 5: Mr. Karl Peng-design of the 2nd combustor and its installation, Mr. Bob Frain-design, installation and test operation, Mr. Ben Borck-computer control and test, Cherry Hill Equipment- facility installation; Arsenal maintenance staff-facility construction, Mr. Bob O'Connor of ELI - stack gas sampling, Alpha-Omega facility layout; and others who contributed to this project.

This project was supported in part by the DOE-Advanced Combustion Technology Program at the National Energy Technology Laboratory (NETL) in Pittsburgh, PA. The P.I. wishes to acknowledge the technical program managers from DOE who filled that function throughout this project, including Mr. Cliff Smith, Mr. Andy Karasch, and Mr. Arun Bose. He also wishes to cite the important DOE support in the early years of this technology development in the Clean Coal phase of this combustor's development, primarily Mr. Arthur Baldwin. Other DOE individuals in the Pittsburgh Office and in the DOE Headquarter offices, especially the SBIR Office were of very great help and support.

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Project: " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE ,
COAL FIRED COMBUSTION SYSTEM,PHASE 3"

Contract: DE-AC22-91PC91162

Contract Period of Performance: 9/30/91 to 9/30/99

Final Technical Report

Appendix A

"Optimization of First Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor"

Project Tasks 1, 2 and 3

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ABSTRACT :Appendix A

Coal Tech Corp's mission is to develop, license & sell innovative, lowest cost, solid fuel fired power systems & total emission control processes using proprietary technology for domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases. The first phase, "Optimization of First Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor", which is summarized in this Appendix "A", involved the optimization of the design and operation of the first generation design coal combustor that was attached to an oil/gas design package boiler at an industrial steam plant in Williamsport, PA. At the start of the present project in 1992, the combustor had completed a five-year test effort as part of the DOE Clean Coal Program that demonstrated the technical feasibility of operating an air-cooled slagging coal combustor at a commercial scale. Air-cooling allows retrofitting the combustor for coal and solid fuel operation on existing oil or gas fired boilers and new compact coal and solid fuel boilers.

The Clean Coal Project, which included about 900 hours of combustor operation revealed the need for certain improvements prior to commercial use, and this was the primary objective of the present project. Among the primary area needing improvement were:

1) The combustor length was inadequate to effect complete combustion under the fuel rich conditions needed for control of nitrogen oxide and sulfur dioxide emissions within the combustor. As a result a substantial fraction of the combustion and sulfur dioxide reduction occurred in the boiler, downstream of the combustor exit.

2) The reliability of the slag removal system needed improvement. Also, a large fraction of the slag drained into the boiler instead of the combustor's slag tap.

3) The steady increase in wall temperatures in the adiabatic exit section of the combustor indicated a need for conversion to air-cooling.

4) The solid fuel and reagent feed system capacity and reliability required expansion and increased reliability.

5) Automation of the combustor air-cooling sub-system as well automation of the overall operation of the combustor system was necessary in order to reduce operating costs.

6) Due to the substantial carryover of slag and unburned carbon and ash into the furnace section of the boiler, major slag deposits drained onto the combustor floor and thick ash layers deposited on the boiler's furnace floor.

The need for most of these improvements was recognized in the course of the testing under the previous the Clean Coal project. However, the work statement for that project required up to 1000 hours of operation, including a number of 100 hour round-the clock tests, and as a result no time or resources were available for implementing major changes in operating procedures.

The plan for implementing these changes was developed in task 1 of the project. Since a key issue was determining the increased combustor length needed to achieve complete carbon burnout, and complete slag retention inside the combustor, very sophisticated two and

three-dimensional coal particle combustion analyses were performed. One of these analytical models, developed at Brigham Young University, was generally successful in offering guidance as to the proper combustor and post-combustion processes to implement. On the other hand another even more complex model, called FLUENT, predicted solutions that were clearly at variance with experimental observations, and the reason for this variance was not determined either by Coal Tech or the developer of the model.

While the modifications to the combustor and its auxiliary sub-systems were developed and implemented in task 1, some of them, such as the conversion of the exit nozzle to air-cooling were delayed until later in tasks 2 and 3.

Most of these changes were successfully tested in series on single and double shift duration tests in tasks 2 and 3. However, the final success of these modifications was only realized in task 5 of the project when the entire 20 MMBtu/hr combustor-boiler facility was relocated to Philadelphia and a substantially longer combustor was fabricated. The success of these changes was apparent almost immediately on startup of the task 5 tests because slag carryover out of the combustor and ash deposits on the boiler's furnace floor were both negligible.

One important aspect of this project is that a very substantial part of the effort had to be devoted to components that were "commercially" available. For example, after suffering with a "commercial" coal feeder throughout the Clean Coal project and early into the task 2 test effort, it was finally determined that its design was defective and it was replaced with a a commercial unit of totally different design.

In addition, a very time consuming effort was made to convert the exit section of the combustor from adiabatic to air-cooled operation by inserting pipes into the combustor-boiler wall. This effort yielded major benefits in the redesign of the combustor during the task 5 effort.

On the other hand, another effort in task 2 and 3 to re-entrain ash deposits from the boiler floor in order to remove them in the stack scrubber proved to be unnecessary with the new 2nd generation combustor in the task 5 effort.

In conclusion, the work on tasks 1 through 3 was successful in laying the groundwork for the successful implementation of the more extensive task 5 test effort.

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A-1. EXECUTIVE SUMMARY for Appendix "A".

Coal Tech Corp's mission is to develop, license & sell innovative, lowest cost, solid fuel fired power systems & total emission control processes using proprietary technology for domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases. The first phase, "Optimization of First Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor", which is summarized in this Appendix "A", involved the optimization of the design and operation of the first generation design coal combustor that was attached to an oil/gas design package boiler at an industrial steam plant in Williamsport, PA.

This project was the final, decade long, demonstration at a commercial scale of a patented, air-cooled slagging coal, combustor. Its key novel features are:

1) By combusting coal and solid fuels, such as shredded biomass or municipal solid waste, in the combustor and removing within it the bulk of the ash as liquid slag, the combustor can be retrofitted at very low cost to existing oil or gas fired boilers and compact solid fuel boilers.

2) Air cooling decouples the combustor's cooling circuit from the boiler's steam circuit allowing attachment to almost any boiler.

3) Conversion of most of the coal ash into chemically inert slag traps most of the volatile trace metals and converts a disposal problem into a marketable product.

4) The sulfur dioxide and nitrogen oxides are sharply reduced inside the combustor. Therefore, the addition of simple post-combustion control process essentially eliminate the emission of these pollutants.

5) The combustor is ideally suited as a core component in a system to produce coal gas while concentrating carbon dioxide emissions for simpler removal and sequestration in the earth.

The commercial scale, combustor system development effort began in the mid-1980s with the design and fabrication of the 1st generation, 20 MMBtu/hr, air-cooled combustor with 50% support from Commonwealth of Pennsylvania, and private sector, primarily Coal Tech Corp., and 50% from DOE. In 1987, the combustor was installation on a 17,500 steam lb/hour, oil design package boiler at a boiler manufacturing company in Williamsport, PA, as part of a DOE Clean Coal Project. The objective of this project was to demonstrate the combustor's operation and environmental emission control performance in 900 hours of operation, including a series of 100-hour round-the-clock tests. This effort was successfully completed in 1991. However, the focus of the work statement on the 900 hours of operation consumed all the project resources and prevented the implementation of important improvements, especially the need to lengthen the combustor that became apparent as the test effort proceeded. Nevertheless, major potential technical barrier problems were overcome, the most serious of which was the total failure at the start of the test effort of the refractory liner material, which resulted in damage to the metal cooling components.

The need for a substantial additional effort was clearly indicated and this was the goal of the present project, which began in 1992. Among the primary area needing improvement were:

1) The combustor length was inadequate to effect complete combustion under the fuel rich conditions needed for control of nitrogen oxide and sulfur dioxide emissions within the combustor. As a result a substantial fraction of the combustion and sulfur dioxide reduction occurred in the boiler, downstream of the combustor exit.

2) The reliability of the slag removal system needed improvement. Also, a large fraction of the slag drained into the boiler instead of the combustor's slag tap.

3) The steady increase in wall temperatures in the adiabatic exit section of the combustor indicated that conversion to air-cooling was required.

4) The solid fuel and reagent feed system capacity and reliability required expansion and increased reliability.

5) Automation of the combustor air-cooling sub-system as well automation of the overall operation of the combustor system was necessary to reduce operating costs.

6) Due to the substantial carryover of slag and unburned carbon and ash into the furnace section of the boiler, major slag deposits drained onto the combustor floor and thick ash layers deposited on the boiler's furnace floor.

The plan for implementing these changes was developed in task 1 of the project. Since a key issue was determining the increased combustor length achieve complete carbon burnout, and complete slag retention inside the combustor, very sophisticated two and three-dimensional coal particle combustion analyses were performed. One of these analytical models, developed at Brigham Young University, was generally successful in offering guidance as to the proper combustor and post-combustion processes to implement. On the other hand another even more complex model, called FLUENT, predicted solutions that were clearly at variance with experimental observations, and the reason for this variance was not determined at the time either by Coal Tech or the developer of the model. However, during the preparation of the present report, the P.I. noticed that the problem may have been caused by the use of too coarse a grid in the analysis, as described herein.

While the modifications to the combustor and its auxiliary sub-systems were developed and implemented in task 1, some of them, such as the conversion of the exit nozzle to air-cooling were delayed until later in tasks 2 and 3..

The changes were successfully tested in a series on single and double shift duration tests in tasks 2 and 3. However, the final success of these modifications was only realized in task 5 of the project when the entire 20 MMBtu/hr combustor-boiler facility was relocated to Philadelphia and a substantially longer combustor was fabricated. The success of all previous these changes was apparent almost immediately on startup of the task 5 tests in that slag carryover out of the combustor and the ash deposits on the boiler's furnace floor were negligible.

One important aspect of this project is that a very substantial part of the effort had to be devoted to components that were "commercially" available. For example, after suffering with a "commercial" coal feeder throughout the Clean Coal project and early in the task 2 test effort, it was finally determined, after numerous time-consuming improvements that were made, that its design was defective and it was replaced with another vendor's commercial unit of totally different design.

In addition, a very time consuming effort was made to convert the exit section of the combustor from adiabatic to air-cooled operation by inserting pipes into the combustor-boiler wall. This effort yielded major benefits in the redesign of the combustor in the task 5 effort.

On the other hand, the effort in task 2 and 3 to re-entrain ash deposits from the boiler floor was not needed in the task 5 effort due to new combustors greatly improved slag retention.

Other key improvements made during the task 2 and task 3 test efforts, were automation of the combustor's wall air -cooling systems, redesign of the pneumatic feed system for injecting pulverized coal into the combustor, major improvements to the flame safety system to overcome its propensity for false flame trip that were caused by blinding from the pulverized coal and reagent powder injection, near automation of the slag tap to sharply reduce the need for shutdown to clear the tap of frozen slag, and addressing the mundane problems needed to reliably operate a steam power plant.

The last named item of "mundane problems" is generally not recognize d in planning a new technology demonstration project but it proved to be a time consuming task that substantially interfered with the implementation of the project's test plan.

For example, the boiler house's water inlet pipes were almost totally blocked with internal deposits to the point were they had to be replaced, the plant air compressor was inadequate in that it was shared with the manufacturing section to the point where a diesel powered compressor had to be finally rented for all tests, the pulverized coal supplier delivered coal loaded with tramp materials that continuously plugged the pneumatic coal feed lines, which necessitated the eventual use of another supplier, the boiler feedwater pump failed several times and had to be replaced each time, the relay control system used for both the Clean Coal project and tasks 2 and 3 tests on this project proved to be unreliably and caused numerous shutdowns, the high pressure fan used for the air cooling and combustion air had a major design defect that required its return to the factory early in the Clean Coal project, variable speed control for the coal feeder was initially defective, the induced draft stack fan regularly went out of balance from ash deposits passing the wet particle scrubber, which necessitated frequent bearing replacement, the motor on the primary air fan failed, the inlet to the wet particle scrubber rapidly plugged with ash due to a poor cooling spray design, and the boiler feed water level control failed necessitating manual feedwater operation in some of the tests. This list is not exhaustive of all the operational problems.

All the above items were 'commercial" equipment that had nothing to do with the combustor. However, they are obviously vital to the operation of the combustor. Therefore, an important element of the present project was to replace all the unreliable components with simpler and more reliable equipment. For example, the relay controls for the combustor were replaced for the task 5, 2nd generation combustor installation with programmable logic controls (PLC), which operated reliable throughout the task 5 effort and to date in 2004. The coal feed auger was replaced with a much more reliable design, the wet particle scrubber was replaced with a fabric filter baghouse, and the high-pressure fan was replaced with a lower pressure fan consuming only one-half the power.

All these and other improvements bore fruit in the 2nd generation combustor test operation in task 5. A measure of the success is that the number of operators was reduced from 7 or more in Williamsport to 2 or 3 in Philadelphia. That labor saving alone enabled doubling the original planned task 5 tests within the original budget. Even more important, it enabled Coal Tech with its meager internal resources to continue the development of its post-combustion emission control development between 1998 and to-date, 2004, by sole use of internal resources. This latter internal effort resulted in the development of a complete suite of coal combustion emission control processes that are extremely low in cost, and can be applied to almost all coal fired boilers and furnaces.

At the time of submission of this Final Report, March 2004, the air-cooled combustor and its associated emission control processes have been developed to the point where they can be installed in new or retrofitted to existing coal fired, power plants to produce zero emissions of CO_2, SO_2, NO_x, dioxins, furans, and volatile trace metals, including mercury.

In conclusion, the work on tasks 1 through 3, as summarized in this Appendix “A” was successful in laying the groundwork for the successful implementation of the more extensive task 5 test effort

A-2: INTRODUCTION

A-2.1. U.S. Energy Policies & Coal R&D Programs

In the mid-1970's, in response to the oil price shocks of that decade, the U.S. government embarked on a massive R&D program to increase coal utilization. The primary focus of the effort in the late 1970's was on conversion of coal to synthetic liquid fuel to replace petroleum. A secondary but still major R&D effort focused on direct coal utilization in advanced coal fired power plants using either direct coal firing, coal gasification, or coal slurry fuels. The synthetic fuels effort terminated and the direct coal utilization R&D effort decreased sharply in the early 1980's as the price of oil collapsed from the artificial levels of the late 1970's. In response, the focus of U.S. government's coal R&D shifted in the mid-1980's almost totally to direct coal utilization in advanced power and energy systems with primary emphasis on removing the one key barrier to increased coal use, namely, coal's high air emissions of pollutants, primarily SO_2, NO_x, and particulates. The centerpiece of this effort was the Department of Energy's (DOE) Clean Coal Program. A number of advanced coal fired power plant systems at the full scale, electric utility level, were successfully implemented through the decade of the 1990's. Many billions of industry and government funds were expended on these projects.

Yet despite these successes, when the electric utility industry was faced with sharply increased demand in the 1990's, over 90% of new power plant construction was natural gas fired. Economic and public policy considerations favored gas fired-combined gas turbine/steam turbine power plants. They were more efficient than the most modern coal fired plants, they were essentially non-polluting, they could be erected in one-half the time of coal power plants, natural gas prices were low, a nationwide pipeline grid was in place, and as an added bonus, natural gas produced much lower "greenhouse gases" than coal. However, in the rush to construct new gas fired power plants, developers appeared to overlook that much of this gas capacity was committed to existing users. As demand increased, gas prices rose sharply and stayed high even as the economy entered recession in around 2000. The result was a financial meltdown of power producers as electricity prices returned to historical norms, while gas prices stayed high, leaving little or no margin to service debt, much less produce a profit. While the resulting financial meltdown in the power sector in 2001 was almost certainly accelerated by financial improprieties by certain companies that came to light in 2001, these legitimate financial problems would have surfaced eventually. Since industrial users can use gas and oil interchangeably, their prices are coupled. Oil prices increased over the past decade with increasing demand from a shift to larger fuel inefficient cars. One can always count on the U.S. auto manufacturers to ruin a "good thing", low oil prices. Prices were also pressured by political instabilities in key oil producing nations, which included the war in Iraq. In any case, natural gas prices would also be pressured by the massive investments in gas exploration and pipeline construction that would be needed to meet the growth in gas use.

These gas supply problems would seem to favor increased coal utilization for electric power as it is in almost limitless supply and offers stable pricing. However, here also, economic, political and public policies have prevented this growth.

Existing coal fired power benefit substantially from high prices from gas-fired power because electricity is generally priced at the highest marginal producer. Coal power plants produce by far the lowest cost electricity because they are "grand fathered" and generally exempt from newer and costly emission regulations as long as they make no "substantial" changes to the existing power plants. This has of course resulted in decades long litigation between these producers and the government on the meaning of the word "substantial". However, it has not prevented very low cost emission control technologies, such as "low NO_x" burners" from being widely adopted. However, that has not been the case for the much more costly NO_x, SO_2, volatile trace metals, and very fine particulate emission control technologies, which are in far less commercial use. Ironically, it would appear that these costly technologies favor existing coal power producers because it provides an excuse to delay their installation and it maintains the profitable status quo.

The public's inconsistent position on energy also maintains the status quo. "Clean", but costly, natural gas plants and even more costly taxpayer subsidized- "renewable" energy are favored, while "dirty" coal plants are opposed. Yet the experience of California shows the danger of relying primarily on "clean" hydropower and "clean" natural gas power. In 2000, a booming economy, a drought in the hydropower region and a shortage of natural gas, and a defective deregulation policy, all combined to cause electricity prices to soar in California. While it was determined in the following year that part of the increase was due to market manipulation, electricity prices would still have risen sharply. In fact, if not for coal-fired electricity from neighboring States, the crisis would have been much worse.

The conclusion from all these factors is that "clean" coal fired electricity is essential for a healthy American economy, **provided it can be supplied at modest added cost to current coal based electricity. While coal R&D has delivered "clean" coal, it is quite costly, and it will become even more costly when new controls on emissions of mercury and carbon dioxide sequestration are added.**

A-2.2. Coal Tech's R&D Approach to Coal Based Power

This project's principal investigator (P.I.), the author of this report, was exposed to the overriding importance of a systems approach to evaluating new energy technologies in the mid-1970's. The Energy R&D Administration (ERDA), the predecessor to DOE, commissioned a comparative system study of existing and advanced coal based, electric power generating technologies all of which were to be fired with coal, (Ref. A-1). The key result from that study was that some advanced high efficiency energy conversion technologies lost much of this efficiency and, even worse, they lost their cost advantages when they were evaluated as a total system in a power plant.

This problem was due to the inefficiencies and costs that were introduced as multi-step processes and thermodynamic cycles were added to achieve optimum combinations of the coal within the power cycle. For example:

-Using coal to power a combined gas turbine/steam turbine required a gasifier and a gas cleanup system, each of which suffered from inefficiencies and costly components. Interestingly, the study concluded that this power cycle was one of the most economically attractive, even superior to more efficient advanced power cycle, such as the open cycle magnetohydrodynamic topping/steam bottoming cycle, or a steam cycle with full environmental compliance using stack gas scrubbing for SO_2. However, no comparison was made with a steam cycle without SO_2 or NO_x control as no one envisioned in the mid-1970's that these polluters would still be operating three decades later. As a result, outside of subsidized demonstration projects, few, if any, economically stand-alone coal gasification gas/steam turbine power plants have been erected in the U.S. in the past three decades.

-Using a fluid bed boiler to burn coal and to remove sulfur dioxide emissions required replacing much of the steam boiler with a fluid bed boiler, which rendered the existing stock of coal fired boilers useless. This eliminated this technology for low cost retrofit applications.

-Treating coal to remove sulfur at the mine simple shifted the cost from one location to another

The key lesson this author drew from that and similar studies, and one confirmed for essentially all other new technologies, is that for a new technology to replace an existing one, it much be more less costly. Even the jet plane only replaced the piston driven plane because its higher speed resulted in a lower cost to the traveler.

Low cost is extremely difficult to implement in a capital-intensive system such as a coal fired power plant, where the increased efficiency from alternate power cycles is relatively small, while costly environmental emission control is only a long-term indirect benefit to the public in improved health. Therefore, a critical corollary to the lesson of low cost is that as much as possible of the existing power plant components must remain in use. One successful application of the lesson of low cost is the "low NO_x" burner.

It is this need for low cost that requires maximum reuse of existing equipment that led to the air-cooled, slagging coal combustor. It meets most of these requirements

1) It can be directly attached to existing coal-fired boilers.

2) Air-cooling eliminates the need for integration into the existing steam loop of the boiler, or the need for an inefficient separate water-steam cooling loop.

3) A substantial fraction of the NO_x and SO_2 is controlled inside the combustor. This reduces the additional post-combustion reduction needed for complete removal.

4) About three-quarters of the ash is removed in the combustor as slag, which allows its use on oil or gas designed boilers as well as much smaller coal design boilers.

4a) The char combustion capability makes this combustor ideally suited for power cycles in which cleaned pyrolysis gas is used to produce clean gas fuels to gas turbines. Since pyrolysis of volatile matter in coal or biomass occurs at substantially lower temperatures than total gasification the efficiency of gas production is higher due to the absence of air dilution or the need for oxygen. Also, materials requirements are much less stringent.

5) Volatile trace metals in the coal ash, including possibly mercury, are trapped in the chemically inert slag removed from the combustor.

6) Suitable fuels include, low to very high ash coals and coal char, shredded biomass, and shredded municipal solid waste fuels, oil, and gas.

7) Finally, the combustor fabrication and installation cost is very low. Almost all other components are essentially identical to those found in current coal fired power plants.

Therefore, the air-cooled, slagging-combustor meets the requirement for a "clean" coal technology that requires only a modest cost increase above current coal combustion systems.

The benefits of air-cooling were first recognized almost 3 decades ago during the initial development of a 1 MMBtu/hour air-cooled, coal combustor for use as a heat source for a packed bed regenerative heat exchanger (Ref. A-2). In the late 1970's it was decided to apply the combustor to retrofit of oil fired boilers due to its capability of removing most of the ash as slag in the combustor. However, the first step was to demonstrate that by using staged combustion, NO_x one of the key coal combustion pollutants, could be controlled within the combustor. This was accomplished in tests in the 1 MMBtu/hr combustor where NOx was reduced by about two-thirds, (Ref. A-3). The next step was to determine the feasibility of reducing SO_2 in the combustor with limestone injection. This was accomplished in tests in a 7 MMBtu/hour-water cooled, slagging combustor where over 50% reduction was measured (Ref. A-3.1.)

This set the stage for demonstrating the air-cooled combustor technology at a commercial scale of 20 MMBtu/hour. The first generation design of the present air-cooled, slagging coal combustor was implemented in the mid-1980's primarily with private sector and State government funds. In 1986, DOE co-sponsored this effort by selecting this project as part of the Clean Coal Round 1 Projects (Ref. A-4). The central feature of this project was the installation of the combustor on a 17,500 lb/hr, oil design package boiler at a boiler manufacturing plant in Williamsport, PA, and the implementation of 900 hours of test operations including several 100 hours, round-the clock tests.

This Clean Coal effort was successfully completed in 1991. However, the focus of the work statement on the 900 hours of operation consumed all the project resources and prevented the implementation of important improvements, especially the need to lengthen the combustor that became apparent as the test effort proceeded. Nevertheless, major potential technical barrier problems were overcome, the most serious of which was the total failure at the start of the test effort of the refractory lines material, which resulted in damage to the metal cooling components.

The need for a substantial additional effort was clearly indicated and this was the goal of the present project, which began in 1992. Among the primary area needing improvement were:

1) The combustor length was inadequate for effect complete combustion under the fuel rich conditions needed for control of nitrogen oxide and sulfur dioxide emissions within the combustor. As a result a substantial fraction of the combustion and sulfur dioxide reduction occurred in the boiler, downstream of the combustor exit.

2) The reliability of the slag removal system needed improvement. Also, a large fraction of the slag drained into the boiler instead of the combustor's slag tap.

3) The steady increase in wall temperatures in the adiabatic exit section of the combustor indicated a need for conversion to air-cooling.

4) The solid fuel and reagent feed system capacity and reliability required expansion and increased reliability.

5) Automation of the combustor air-cooling sub-system as well automation of the overall operation of the combustor system was necessary in order to reduce operating costs.

6) Due to the substantial carryover of slag and unburned carbon and ash into the furnace section of the boiler, major slag deposits drained onto the combustor floor and thick ash layers deposited on the boiler's furnace floor.

The balance of Appendix "A" discusses the work that was implemented under tasks 1, 2 and 3 of the present project in order to correct the above one-half dozen technical issues. They were addressed analytically and experimentally in the Williamsport combustor-boiler installation. This work provided the technical basis for the task 5 effort for the design, fabrication and testing of an improved 2nd generation combustor at Coal Tech's Philadelphia, PA site. The task 5 effort is described in Appendix 'C". Also, a commercialization task, No.4, was implemented, which has considerable bearing on the non-technical issues discussed in this Introduction. This work is discussed in Appendix 'B".

A-3. Results & Discussion for Project Tasks 1, 2, and 3

A-3.1. Objectives of Tasks 1, 2 and 3

The primary objective of tasks 1, 2, and 3, as well as task 5 was to perform the final demonstration testing of the 20 MMBtu/hr air-cooled, slagging coal combustor-boiler system. The focus of all the tests was on combustor durability, automatic control of the combustor' s operation, and optimum environmental control of emissions inside the combustor. The goal was to achieve 0.4 lb/ MMBtu of SO_2 emissions, 0.2 lb/MMBtu of NO_x emissions, and 0.02 lb particulates/MMBtu. The first two goals were substantially exceeded in the task 5 efforts. The particulate goal could not be met in tasks 1 through 3 because the Williamsport facility was equipped with a wet centrifugal particle scrubber that could only meet the local regional emission goal of 0.3 lb/MMBtu. However, in task 5 the scrubber was replaced with a fabric filter baghouse that was guaranteed by the supplier to meet the Philadelphia standard of 0.03 lb/MMBtu.

The objectives of these three tasks as well as task 5 were to be met by a series of tests of increasingly longer duration, and totaling about 800 hours of total testing. In practice this was substantially exceeded in the combined task 1 through 3 and task 5 testing.

The final objective, task 4, was to define suitable commercial power or steam generating systems to which the use of the air-cooled combustor offers significant technical and economic benefits. In implementing this last objective in task 4 a steam power plant at the 20 MW electric output and a 20 MW electric combined gas turbine-steam generation plant were designed and costed. Furthermore, considerable marketing efforts were implemented that including finding several suitable sites for constructing such a power plant. In one case a potential private sector financier was found for a 20 MW re-powering project.

A-3.2: **Technical Approach to Tasks 1, 2 and 3 & Task Description**

Task 1: Design, Fabricate, and Integrate Components

This task consisted of three sub-tasks. The components necessary to implement the modifications indicated at the start of the project were designed, fabricated, and installed on the 20 MMBtu/hr combustor facility in Williamsport. The goal of these modifications, to be described in the next section was to enable combustor operation in a safe and environmentally compliant manner for a totaling of up to 100 hours. This task was successfully completed.

Task 2: Preliminary Systems Tests

The modified combustor system underwent a series of one-day parametric tests of total duration of 100 hours in which the design changes introduced in task 1. This task was successfully completed.

Task 3. Proof of Concept Tests

The durability of the combustor was to be determined in a series of tests of between 50 and 100 hours of continuous operation, with a goal of a total test period of 200 hours. A total of 200 hours of combustor operation were implemented. However, as described below, personnel and operational issues, not directly related to the combustor, such as wood chip contaminated pulverized coal supplied by the off-site supplier prevented round the clock operation.

Task 4. An economic evaluation and commercialization plan is discussed in Appendix 'B".

Task 5. Conducting a site demonstration is discussed in Appendix 'C".

There was a task 6 to decommission the test facility. However, Coal Tech Corp has at its own expense continued to maintain and operate the facility in Philadelphia since the 1998 end of testing on this project. During that time Coal Tech Corp made major advanced in post-combustion control of NO_x and SO_2 some of which is summarized in Appendix 'C".

A-3.3: **Results & Discussion of Task 1,2, and 3.**

Task 1.1. Design, Procure & Install Modifications to 20 MMBtu/hr Combustor & Boiler.

The work on this task was implemented in 1992. A detailed report was prepared and submitted to DOE on the design modifications that were planned for the 20 MMBtu/hr test facility. This section briefly summarizes the work. One notes that many of them are unrelated to the combustor but are essential for combustor operation.

Coal Feed: Pulsations in the pneumatic coal feed system were a serious problem in flame stability. After much trial and error, a series of dampers were installed to correct the problem.

Coal Storage: Since the on-site coal bin only had a 4 ton capacity, a 20 ton tanker truck remained on site for longer duration tests.

Coal & Reagent Powder Injection: The number of injection ports in the combustor was doubled to increase the total coal feed rate and SO_2 reduction capacity. Also, improvements were made in the entire feed process.

Slag Flow Control: Injection capacity was added for fly ash injection and metal oxide injection in order to replenish the combustor's refractory lining during long term operation. This method was used in a parallel project with mixed results, (Ref. A-5).

Control of Ash Deposits on the Boiler Floor: The slag retention inside the 1st generation combustor in Williamsport was very poor and most of the slag flowed out of the combustor exit nozzle instead of into the slag tap. Also, substantial ash deposited on the floor of the boiler. An air lance was installed on the boiler floor to re-entrain the ash into the exhaust gas to the stack. Results were mixed.

However, booth the slag flow problem into the boiler and the heavy boiler floor ash deposits were essentially eliminated in the longer 2nd generation combustor and this lance was not used there.

Air Pre-heat: Due to the high levels of unburned carbon in the stack gases designs were developed to pre-heat the combustion air from 400°F to as high as 1800°F. The later range was eliminated as it would have required 25% of the total heat input. The lower level was also eliminated because in the 2nd generation longer combustor, the unburned carbon levels were lower both as a result of longer residence times and as a result of less need for very fuel rich operation to control NO_x emissions.

Slag Tap Operation: Maintaining an open slag tap by preventing slag from freezing therein was one of the major challenges of both this project and the previous Clean Coal project. Solving this problem consumed a substantial amount of time. Both local heat input and mechanical clearing were used. One test where operations continued with a plugged slag tap resulted in almost a one-foot thick slag layer of the floor of the combustor after several hours of operation. In the end an automatic mechanical device proved to be the most reliable means of clearing the slag during combustor operation. Also, considerable attention must be given to slag flow properties and slag mass flow rates.

Combustor Wall Cooling: A number of improvements in the air-cooling were made to allow automatic control of the combustor wall temperature within a very narrow range. This also included an improved wall temperature monitoring system. Multiple methods were developed to achieve control of the wall temperature.

Active Cooling of the Combustor Exit Nozzle: A major change was in the total replacement of the adiabatic combustor exit nozzle with an air-cooled design. As this had to be implemented from inside the boiler, it proved to be a very arduous and time-consuming task. In the end it was extremely important as it provided the basis for the air-cooled exit nozzle design that was used in the 2nd generation combustor.

Computer Control: This extremely important feature was implemented in the 2nd generation combustor for task 5. The entire relay control system was replaced with Programmable Logic Controllers (PLC) and a computer software program was purchased and programmed to monitor and control the combustor operation. The latter proved mainly useful in data collection. An advanced version of this costly program was also purchased but it proved too cumbersome to use and was never placed in service.

Particle Scrubber & Induced stack fan: The original scrubber metal corroded to the point where most of it had to be replaced with improved steel. Also, the inlet cooling design supplied by the manufacturer was totally inadequate, and it was redesigned. The bearings of the induced fan failed rather frequently due to imbalances caused by ash deposition on fan wheel. It was concluded that while web scrubbers are very cheap they are not very reliable.

Facility Maintenance: The building water inlet pipe had to be replaced as it was nearly shut due to corrosion. The boiler feedwater pumped failed on several occasions thereby requiring regular replacement. In the task 5 effort the city water pressure was high enough to allow dispensing with a feedwater pump. A rental air compressor was used for the tests because the plant compressed air was unreliable.

Flame Safety: A major problem was the frequent false flameouts that caused combustor shutdown. Most of them were the result of 'blinding" of the flame sensor by injected coal powder. After considerable effort, including installation of dual sensors, and adding a third sensor based on a totally different sensing method, this problem was mostly solved.

Task 1.2: Combustor Modeling

a) Combustor Modeling with the FLUENT Code:

Modeling of the combustion process in the combustor was important because the deficiencies of the first 20 MMBtu/hr design were clearly apparent in that its length was inadequate. Before embarking on the costly task of lengthening the combustor and adding an air cooled exit section, modeling was absolutely essential.

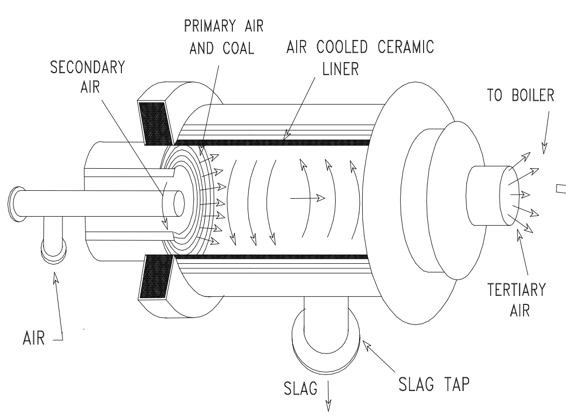
However, as will be shown the FLUENT code had serious deficiencies that were never resolved with the company that developed the code. As a result the design of the 2nd generation combustor that was used for the task 5 testing was performed on the basis of test results in the Clean Coal project (Ref. A-4) and tasks 1, 2 and 3 of the present project. Also, analyses that were developed by Coal Tech prior to these projects were used.

Nevertheless, the FLUENT results are presented because they do show the methodology that was used to analyze the combustor, and also as a note of caution in relying on complex computer results without means for checking said results by simple calculations or experiment. We should note that the cost for this effort was relatively high.

Determining Optimum Combustor Length: The first part of the modeling effort was with a solid particle combustion code, FLUENT. It was available only under very costly license payments. However, at the time it was considered the most advanced model for this application. This work was divided into two equal elements. The first element was completed prior to the task 2 tests, while the second part was completed after said tests. For simplicity the relevant task 2 results are presented in the task 2 section of this report.

The following applies to the first set of calculations. In view of the problems with the results, only a general description indicating the nature of the results is presented.

Figure 1, a sketch of the Coal Tech's 20 MMBtu/hr air-cooled cyclone combustor, and figure 2, a sketch of its attachment to the boiler. The figures are shown to clarify the analysis.



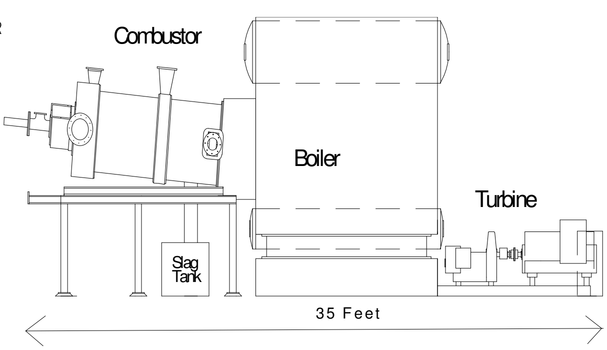


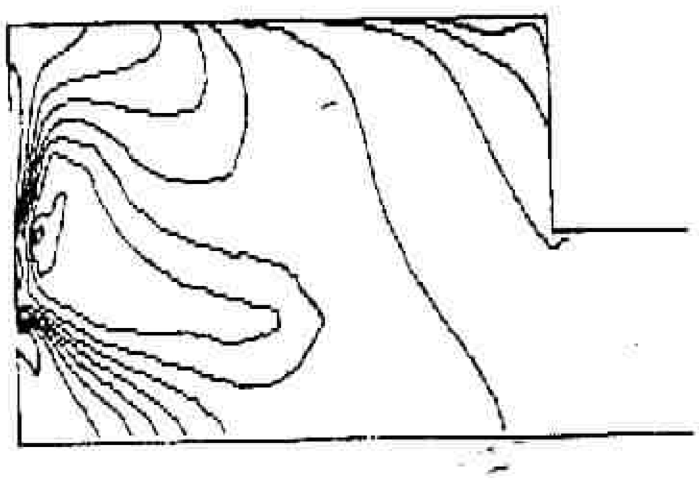
Figure 1 Coal Tech's 20 MMBtu/hr Combustor   Figure 2: The 2nd Generation 20 MMBtu/hr Combustor-Boiler

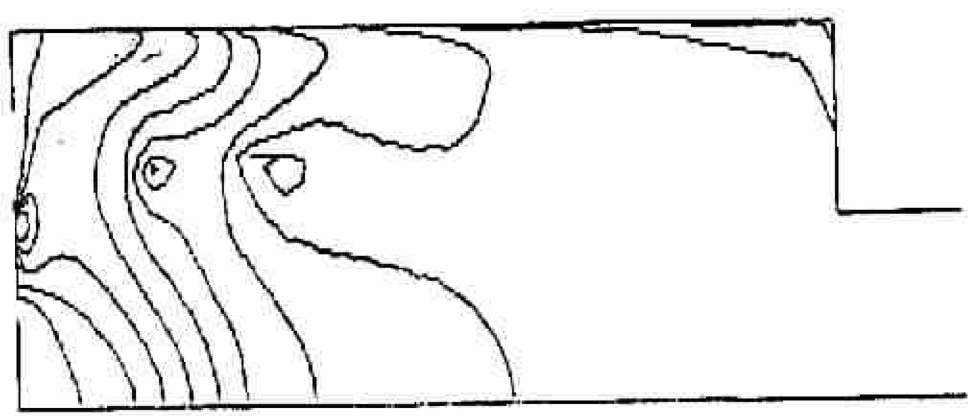
A detailed set of input conditions for the FLUENT modeling was prepared. A fuel rich case (stoichiometric ratio [SR]=0.75) and a fuel lean case (SR=1.1) were analyzed for a typical set of conditions existing in the 20 MMBtu/hr-combustor. In addition, two different combustor length/diameter ratios of 1.5 and 2.5 were analyzed. The objective was to evaluate the impact of combustor length on coal burnout.

The initial results were presented in the form of equal temperature lines on an axial cross-sectional slice of the combustor in figure 1. For the fuel lean case and L/D of 2.5 the temperature lines were concentrated at the injection of the combustor length, (the extreme left side in figure 1), which indicated that the combustor length was excessive. These temperature profiles in the combustor for the FUEL LEAN case from the FLUENT code are the shown in figure 3A for the two combustor lengths, L/D=1.5 and L/D=2.5. Note that this result would indicate that the latter combustor is too long. This also seems to be confirmed by the particle trajectory analysis, where disappearance of the tracks indicates that the particle is totally burned up, as seems to be indicated by figure 3B that shows the tracks of the large 44-micron particles. These particle tracks also thin out and disappear inside the L/D=2.5 combustor, while they fill the L/D=1.5 combustor.

However as was shown from the combustor tests in tasks 2 and 3, the L/D=1.5 combustor was clearly too short. The problems with the FLUENT code were recognized immediately as these results became available. However, the most probable cause was never isolated until April 2003, as is explained below.

Figure 3A: Gas Temperature Profiles for the FLUENT FUEL LEAN Case for L/D=1.5 (Top Graph) and for L/D=2.5 (Bottom Graph)





The pulverized coal particle sizes were divided into 7 discrete groups, namely, 1, 3, 6, 16,32, 44, and 99 microns. The weight percentage of the coal particles was distributed according the pulverized coal used in the combustor tests. Graphical results of the particle tracks were divided into two groups.

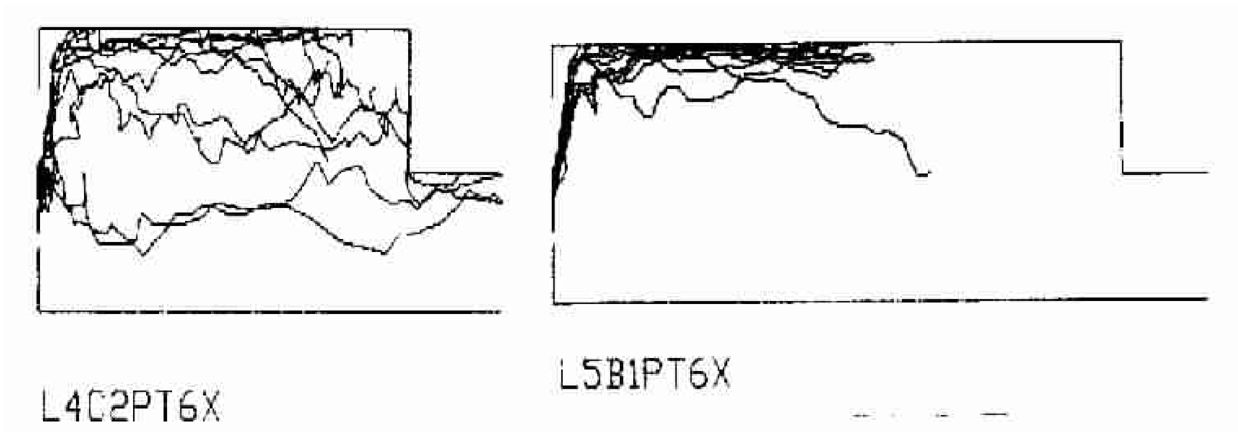


Figure 3B: Group 6 (44 ì) 10 ParticleT racks in the20 MMBtu/hr Combustor for Fuel Lean Conditions. The left figure is for L/D=1.5, the right figure is for L/D=2.5. Particle injection is at left and combustor exit is at right,)see Fig. 1).

In one group each particle size was divided into 10 samples, which were tracked from the combustor inlet, (left side of figure 1) to the exit nozzle outlet (right side of figure). Figure 3B shows sample results for the 10 samples in the 44 micron group. The letters and numbers under the figure have the following meaning: L is fuel lean; 4 or 5 is the computer run number; C2 or B1 is a calculation code; PT means particle track; 6 is the specific particle size which applies to 44 micron particles, and X means that 10 particles at this size were tracked.

The particle trajectories indicate that L/D of 2.5 was too long in that the particles are consumed in about one-half the combustor length, while for L/D of 1.5 almost all the particles are consumed by the combustor exit nozzle outlet.

NOTE ADDED IN APRIL 2003: As will be described below, there was something very wrong with the FLUENT code results that was never resolved by Coal Tech or the company that developed the code. However, in preparing the final report the present author noticed something very strange, namely for the fuel lean particle results, and L/D=1.5, the particle trajectories for Group 1 particles (1 micron), all terminated about one-half the axial length of the combustor. On the other hand all the particle tracks for Group 2 (3 microns) exited the combustor. This is shown in figure 4, where the ten 1 micron particle tracks (Group 1) in the combustor are shown on the left, and the 3 micron particle tracks (Group 2) are shown on the right. There is no way that 3 micron particles can survive the entire combustor length at 3000°F temperatures.

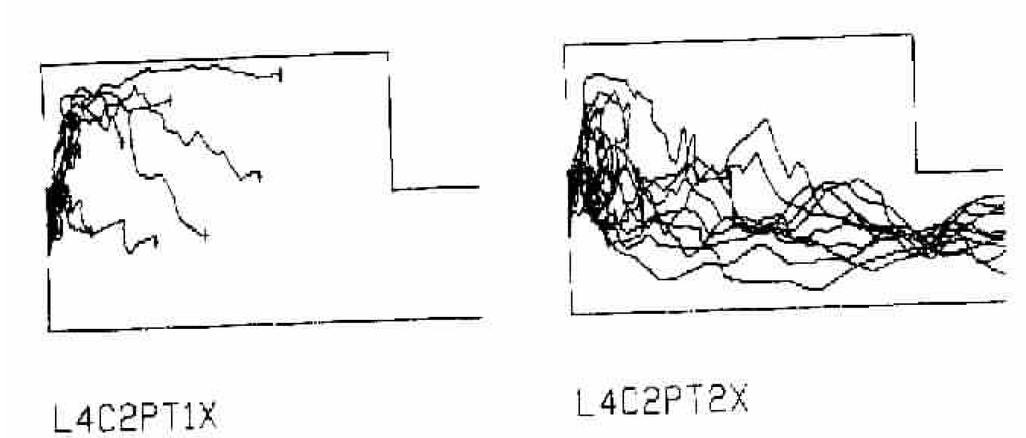


Figure 4: Group 1 (1 micron) 10 Particle Tracks on Left & Group 2 (3micron) Tracks on Right.

The same incomprehensible pattern was observed in the particle tracks for 6 micron particles. While the 16 micron particle tracks had 7 of 10 tracks exiting, the 6 micron particle tracks had 8 of 10 tracks exiting the combustor! Now there is no way that 3 micron particles can survive for a distance of several feet in the 3000+^{o}F combustion gases. In fact they should all be consumed within a few milliseconds (i.e. several inches) after injection in the combustor (see Ref. A-6).

As will be shown in the next sub-section directly below, the combustion gas analysis indicated that a substantial fraction of the solid carbon was not burned. Now at the time of the original analysis in 1992, the Coal Tech analysts assumed that the missing carbon solids were among the largest particles and since there were not enough of them to0 account for the measured unburned carbon, they concluded that the FLUENT code defective for some unknown reason. However, on further review in 2003 it appeared from an examination of the particle tracks that the discrepancy lay in the defects in FLUENT where the bulk of the smaller particles that were not consumed inside the combustor.

There are two probable explanations for this. One is that the grid size was somehow such, (possibly too coarse?) so as to "miss" these smaller particles. The other explanation is that the gas surface reaction of the carbon with oxygen used by the FLUENT model was in error.

If that had been recognized in 1992, it might have enabled the code developers to solve the problem.

This development should not be surprising. The present author has experienced numerous times in his career situations where a solution lay in front of his eyes for days and even weeks until it suddenly became clear. The reaction generally was that it was so obvious it should have be seen right away. END OF NOTE 1-2003

It had been originally planned to use the 3-Dimnesional FLUENT code and Brigham Young (BYU) 2D Mixing code to scope the effects of various injection geometries on performance, including fuel/air/reagent powder mixing. This would include multi-port injection, swirl velocity, and injector locations. In addition, commercial design issues such as L/D and exit nozzle ID effects were to be evaluated in terms of performance.

A key element in this type of modeling was to verify, wherever possible, the model predictions against experimental data. Once this was done and a reasonable confidence level established, the model predictions, based on combustor design or operational changes outside the realm of direct experimental verification, would be somewhat believable.

As noted, the plan had been to use the 3D-FLUENT code. However, owing to input complexity and cost limitations the FLUENT 2D code was used instead of the originally planned 3D version. Four cases were modeled using the commercially available 2D version of the FLUENT code. The results for the first two cases contained tabularized and graphical output of key process variables for both fuel-lean and fuel-rich cases at a combustor length/diameter (L/D) ratio of 1.5; these were coded L4C2 and R1C1 respectively. The final two cases presented the output for the fuel-lean (L5B1) and fuel-rich (R2B1) cases for an L/D = 2.5.

Before any modeling results can be confidently utilized in predicting operational performance as a function, for example, of combustor design changes, the reliability or reasonableness of the model' s predictions must be verified against experimental data and other standards. As part of this evaluation, the model output directly yielded combustor exit gas mass fractions and temperatures. The mass fraction output was then converted to the more common unit of volume (or mole) percent, shown in Table 1.

Table 1. FLUENT Output For Key Variables At The Combustor Exit.

	Vol % in POC (c)					Effective Stoichiometry(a)	C/H Mole Ratio (b)	Exit Gas Temp, F
Case	CO	CO_2	H_2O	H_2	O_2			
L4C2	0.4	5.1	4.2	4.6	12.9	>2	0.31	3515
R1C1	7.8	6.4	8.7	1.7	5.3	@ 1	0.68	3902
L5B1	0.8	3.6	3.5	8.2	13.4	@ 1.8	0.19	4030
R2B1	3.9	2.9	4.7	8.3	12.3	@ 1.4	0.26	4130

(a) Based on remaining O_2 when all H_2 and CO are converted to final products.
(b) C/H Mole Ratio = $(CO + CO_2)/[2 * (H_2 + H_2O)]$.
(c) Balance assumed to be N_2.

The specified coal input was 30% volatile matter (VM) and 42% non-volatile matter or fixed carbon (FC), the remaining 28% being ash by default. VM is represented by propane, which has a C/H mole ratio of 0.375. Evaluation of Coal Tech coal (PC#7) yielded a C/H mole ratio of 0.358 for the VM, reasonably close to the propane value. The resulting coal composition, by weight, was thus 66.6% carbon, 5.4% hydrogen, and 28% ash. Of the total carbon, 37% is in the VM while 63% is FC. Thus using propane as the VM and with FC = 42%, the input C/H mole ratio used by FLUENT was calculated to be 1.03. [It should be noted that the correct value for the non-volatile matter should have been 58%, resulting in 12% ash. The non-volatile matter value was incorrectly specified as 42% due to a computational error.]

By the Ideal Gas Law and Dalton' s Law of Partial Pressures, if species are conserved and if all carbon and hydrogen are converted to gaseous species, the input C/H mole ratio, besides equaling the output C/H mole ratio, also equals the volume ratio of all carbon containing gaseous species, vs. all hydrogen containing gaseous species, when all species are suitably corrected for the number of atoms per molecule. This approach ignores the small contribution (< 5%) of coal moisture to hydrogen mole input.

As can be seen from Table 1, the model derived product stream C/H mole ratios vary from a low of 0.19 to a high of 0.68. Besides being highly variable for a fixed fuel C/H mole ratio input, these ratios are all well below the expected value of 1.03. This result strongly suggests that insufficient carbon is reporting to the gas phase for some unknown reason. Assuming 100% hydrogen conservation, the carbon shortfall derived from comparison of the C/H ratio in the exit POC' s to the input ratio, as a percent of total coal carbon input, is 70% in L4C2, 34% in R1C1, 82% in L5B1, and 75% in R2B1. When the POC C/H ratio is below 0.375 (true in all but one case) then the gas phase carbon shortfall must also include carbon "lost" from the VM as well as the FC. For example, if unburned char were the only source of lost carbon, then the maximum "missing" gas phase carbon would be 63% of total carbon.

Based on input coal flow and composition and combustion air flow, the inverse equivalence ratios (i.e. the fractions of theoretical combustion air or SR' s) were 1.40 and 0.91 for the fuelean and fuel-rich cases respectively. [Using the correct non-volatile value of 58% would have yielded the target values of 1.16 and 0.75 respectively.]

From Table 1, surprisingly, there is significant predicted H_2 in the presence of excess O_2 in all cases, and high CO in the presence of O_2 in the nominally fuel-rich cases. In any case, by converting all H_2 and CO to H_2O and CO_2, the remaining O_2 can be used to estimate the effective stoichiometry. As can be seen from Table 1, the fuel-lean cases have effective inverse equivalence ratios of about 1.8 to 2.0, compared to the input value of 1.40. Similarly, the fuel-rich cases have SR @ 1.0 to 1.4, compared to the input value of 0.91. Again, this apparent excess in combustion air would be in-line with the predicted C/H ratios if carbon were somehow lost in the "book keeping" calculations, resulting in a carbon deficiency in the gas phase.

Based on various output parameters for the seven coal particle sizes used, the coal particle properties were evaluated. Of special interest were the ratio of the particle mass vs. its initial mass, and the char mass itself. In all four cases, particles having diameters of 32 microns or less appear to be completely burned out at or before the combustor exit. This accounts for about 87% of the total coal carbon input. The 44-micron particle properties were not part of the output at the combustor exit. However, they were available at several upstream locations. By comparison with the 32-micron particles, it seems that the 44 micron particles would also be nearly or fully burned out at or before the exit, thus raising total carbon conversion to 89%. Unfortunately, no output is available for the 99-micron particles; however, these account for only about 11% of the total carbon.

Based on the above, the lack of complete or near-complete coal or char particle burnout does not appear to be the cause of the discrepancy between the POC and input C/H mole ratios. By inference, the problem seems to be associated with species "book keeping" in the gas phase.

With stoichiometry and product gas composition off the mark, it is not surprising that exit gas temperatures are also unusual. As seen in Table 1, fuel-lean temperatures are 3515°F and 4030°F while for the fuel-rich cases the values are 3902°F and 4130°F. Based on Coal Tech calculations, at SR = 1 the adiabatic flame temperature, neglecting species dissociation, is about 4000°F, in fairly good agreement with 3902°F. For effective SR = 1.4, the calculated adiabatic flame temperature does not exceed about 3200°F and for SR @ 2 it is well below 3000°F. At the correct input SR values of 1.40 and 0.91 the adiabatic flame temperatures are around 3200°F and 3900°F respectively.

Of some interest, but of secondary importance in the present context, is the value calculated for the equilibrium constant of the water gas shift reaction, namely

$$H_2O + CO = CO_2 + H_2$$

with

$$K_p = (P_{CO2}*P_{H2})/(P_{H2O}*P_{CO})$$

where P_X = partial pressure of species X.

Based on the derived species concentrations in the product gas the calculated equilibrium constants were: 14.0 (for case L4C2), 0.16 (R1C1), 10.5 (L5B1), and 1.3 (R2B1). For homogeneous gas phase reaction, attainment of the equilibrium gas composition is a strong function of reaction temperature. The actual gas composition, however, is not greatly affected by temperature since the equilibrium constant (K_p) of the shift reaction goes from 0.51 at 1300°K (1881°F) to 0.21 at 2100°K (3321°F). However, the kinetic rates of the shift reaction and its reverse are highly temperature dependent due to the relatively high activation energies involved, namely > 50 kcal/mole. Thus, at the predicted high exit gas temperatures, Kp values of 0.2 or less are expected.

In summary, **the FLUENT modeling predictions of product composition are in significant disagreement with input fuel and air flows, as well as fuel input composition, in terms of stoichiometry and C/H mole ratio. Incidental to this, the product gas temperatures and shift reaction equilibria also appear to be incorrect.** Only for case R1C1 are the output parameters in "ball park" agreement with expected values. Globally, these results might be accounted for if fuel carbon was somehow prevented from reporting to the gas phase.

FLUENT devoted some time to address the situation, suggesting that the problem may have been due to a lack of convergence, possibly related to grid size selection. However, the source of the problem was not found. Based on information available, as well as the painstaking efforts to assure data input integrity, we do not believe that the source of error is incorrect interpretation of the results or faulty input. From our contacts at the time with others in in the university and other technical communities, it appeared that problems with the combustion aspects of the FLUENT model have assailed users other than Coal Tech.

At FLUENT' s request, copies of the output were sento them for evaluation. However, no satisfactory explanation was ever advanced by them and their model was no use. The particle track calculations are also useless because the length of combustor needed for complete burnup of each particle size depends on a correct calculation of the combustion rate of each particle.

The above discussion on the combustion analysis results shown in Table 1 was written over a decade ago at the time the work was implemented.

NOTE 2 ADDED IN APRIL 2003. As stated in the above note of April 2003, neither Coal Tech nor FLUENT personnel noted the discrepancy within the particle trajectories at the time. It is now clear that the two probable explanations for the lack of accounting for the unburned carbon was almost certainly due to erroneous reaction rates between solid carbon and gaseous oxidizers or errors in the grid size. In any case, the problem with the FLUENT code was never resolved.

However, it offers a timely lesson not to take complex computer calculations at face value without checking. By coincidence also in 2003, this Principal Investigator was working with a colleague who had a copy of the NASA Lewis Thermodynamic Equilibrium Code, which was developed several decades ago, in performing a series of solid-gas reactions, which produced gas temperatures that were far too high for a combustion type reaction. The P.I. then used a freshman college chemistry text that had the heats of formation for the species of interest, from which he verified that indeed the NASA code results were in error. To test this further we ran the simple methane oxidation reaction and it also produced strange results. Since we had no further use for the Code we did not resolve this issue, especially since this work was performed at Coal Tech Corp expenses.

A similar strange computer result was obtained with one of the BYU codes that was used to model the gas temperature distribution in the furnace section of 17,500 lb/hr boiler. Here also the initial results were totally at variance with our gas temperature measurements in the furnace section. In that case the error was the result of leaving out the particle radiation term from the computer analysis.

This issue leads to another issue in which it appears that this P.I. has had differences of opinion in his approach to technical analysis with others. One of the early contracts that Coal Tech Corp received from DOE in the early 1980's was to perform an analysis of the combustion process and sulfur capture reaction with calcium oxide in a slagging cyclone coal combustor (Ref. A-6). The P.I. performed the entire analysis with simple computer calculations and hand calculator calculations that separated the different steps in the various processes and reactions. In subsequent experimental testing much of this analysis was validated. However, at the time, the review of the final report on this project was quite negative. END OF NOTE 2

b) Combustor Modeling Results from the BYU CODE

Prior to this project, the BYU 2D code was used to model the 20 MMBtu/hr-combustor. Subsequent evaluation of operating data as well as improvements in the BYU code enabled a more rigorous modeling effort. For example, one deficiency in the earlier modeling was the use of a high air-preheat temperature in lieu of natural gas (NG) co-firing with the coal. This resulted in effective stoichiometries well above the desired values. However, for the present project, NG could be included as a premixed part of the primary air stream.

A second shortcoming of the prior results was the incorrect specification of swirl air tangential velocity, resulting in ultra-high swirl numbers. Velocity probe measurements performed by pitot tubes and cold flow in the combustor have shown that swirl velocity decays rapidly between swirl air injection and the front entrance plane to the combustor (left in figure 1). Thus both of the above problems were corrected for the next series of model simulations.

Globally, the present effort was aimed at modeling two base cases: one fuel-lean (FL) and one fuel-rich (FR). If these simulations were satisfactory, in terms of reasonable agreement with measured test data, two additional cases were to be performed: Other cases considered were FR with a longer combustor (i.e. a higher L/D) and a smaller exit nozzle diameter (END), and possibly FL with the same L/D and END as for the FR case, or some other case.

A new provision of the BYU 2D model was to allow the reaction chamber to have an axial wall temperature profile. It was then also possible for coal particles, whose trajectories go to the wall, to either be captured (with 100 % burnout assumed) or to rebound back into the gas stream or re-circulation zone as a function of wall temperature.

Based on experimental observation, both the FR and FL base cases have identical axial wall temperature profiles. These profiles have three zones: the heat-up zone having an increasing wall temperature, the main combustion zone which has a fixed wall temperature, and the exit nozzle zone having its own constant wall temperature.

In the model it was assumed, based on observations of slag deposits on the combustor wall and temperature measurements of the combustor wall, that the combustor wall temperature rises from 250^{o}F (394^{o}K) at 0" (0.00 m) to 2500^{o}F (1644^{o}K) at 15" (0.38 m). This rise is not linear but takes the polynomial form:

$$T_w = ((0.113571*X) - (0.003571*X^2) + 0.1) * T_f$$

where T_w = wall temperature in ^{o}F, X = axial combustor length in inches, and T_f = final wall temperature in F, namely 2500^{o}F for both the FR and FL cases.

From 15" (0.38 m) to 48" (1.2195 m) the combustor wall is roughly isothermal at 2500^{o}F (1644^{o}K). From 48" (1.2195 m) to the end of the simulation at 84" (2.134 m), the wall is at the exit nozzle surface temperature of 2600^{o}F (1700^{o}K).

In the previous simulations all particles impacting the wall were assumed to be captured with 100 % burnout. For the new simulations the coal/ash particle wall capture was represented as a function of axial wall temperature. Namely, if the wall temperature was below 2200^{o}F (1477^{o}K) the particles were assumed to rebound back into the gas stream or into the re-circulation zone and continue to react. If the wall temperature was equal to or greater than 2200^{o}F (1477^{o}K) then the particles were assumed to stick and undergo 100 % burnout. The reason for this approach was to try to accommodate experimental evidence indicating that about the first foot of the combustor wall had essentially no slag covering, meaning coal particles would bounce off. The 2200^{o}F (1477^{o}K) threshold value is related to experimental slag T250' s (the slag temperature at which its viscosity is 250 poise) as well as reported slag softening and melting data.

Another of the model' s improvements was the calculation of wall radiative heat transfer. Previously, heat loss was simply mathematically subtracted at the desired level of 10 %. With the new code, heat loss should be available from the solution of the energy equations. In addition, this should allow the determination of wall heat flux.

In the absence of the FLUENT code, this BYU code was then used to model the combustor and also the furnace section of the boiler.

c) Thermal Analysis of the Exit Nozzle:

The third area of modeling was the combustor's exit nozzle, sho wn on the right side of figure 2, 3 and 4. The initial exit nozzle in the 1st generation combustor operated nearly adiabatically. This required the use of a special high temperature, very costly, cast refractory for the inner wall of the nozzle to withstand the very high temperatures in the nozzle. It was very prone to failure by thermal shock and it had to be replaced once during the Clean Coal project. It was totally unsuitable for cycling temperature operation as practiced during the entire test effort on this combustor.

To eliminate this material required the use of active wall cooling. The plan that was implemented was to remove this material and then insert cooling tubes around the exit nozzle and measure the thermal load. To obtain information of the type of cooling necessary, a 2 dimensional numerical heat transfer analysis was performed. The present multi-layer ceramic material nozzle geometry was analyzed in polar coordinates. Temperature profiles were computed for various numbers of cooling tubes, located at a specified radial distance from the nozzle axis. If too few tubes were placed axially at a given radius around the circumference, then the refractory temperature between cooling tubes would increases. This calculation was continued until a number of cooling tubes was obtained that resulted in equal temperature lines at the cooling tube radius, which indicated that the latter number of cooling tubes would be effective in cooling the entire exit nozzle. In the analysis, the inner wall of the nozzle was 3000^{o}F and the cooling tube cylinder was 500^{o}F.

Although exit nozzle wall temperatures were measured in prior tests, these thermocouples failed very rapidly. As a result, good thermal profiles were not obtained. These measurements were made with newly installed, removable thermocouples in the exit nozzle wall during the task 1 shakedown tests and task 2 systems tests. These results were then used to install an active exit nozzle cooling system for the task 3 tests.

Task 1.3. Component Installation and Shakedown Tests.

All the components that were needed to proceed with task 2 tests were installed. To tests their operability a series of two 1-day hot combustion shakedown tests were performed in July and August 1992. These tests were preceded by cold flow tests of new components.

The results will be presented in historical order to show the development of the project. Where pertinent, comments based on later results will be added. These comments are based on the status in April 2003, the time that this Final Report was prepared. If it is a major change, the date April 2003 will be noted.

Shakedown Test No.1. The purpose of this first hot flow test was to verify the performance of the new coal and reagent injection system, which could not be safely tested with coal under cold flow conditions. The hot flow test was also used for a demonstration of a flame detector in which a manufacturer' s representative brought a sample unit to the test site. Both the feed injection and IR detector performed very well under coal fired conditions, and the new flame detector was purchased. The new feed system caused a very dramatic improvement in the heat release inside the combustor. The wall heat transfer increased significantly which indicated that much more of the combustor volume was being utilized. A test of the slag grit removal system showed the need for a high performance water pump, which was procured and installed and tested in the second shakedown test in August.

The hot flow coal test yielded an unexpected result. Soon after startup on coal, the coal flow became intermittent. It was discovered that small wooden twigs were inside the powdered coal. To allow the test to continue, a screen located at the auger outlet was removed. This caused a total cutoff of the coal flow and the combustor was shutdown. It was found that all the coal feed lines to the combustor had plugged. The lines were cleared and the combustor was restarted with a technician stationed to remove twigs as they left the coal feed auger. This worked for about one hour. Soon thereafter a major concentration of twigs caused a coal flow cutoff. An attempt to restart rapidly on coal caused several coal pre ignitions in the boiler, and it was decided to stop the test.

Problems with tramp material had been encountered several times during the combustor test operations in the past 5 years, but not in the past 2 or 3 years. A simple screen was designed and tested in the second shakedown test in August. This point is noted to show how almost trivial non-combustor issues can interfere with a test effort.

Another test implemented during the hot flow operation was ash re-entrainment in the boiler. An air injection tube was placed inside the boiler and it was fully operational throughout the hot flow test operation. Post-test inspection revealed that there were no ash deposits on the boiler floor near the ash probe. As a result a more elaborate probe was designed and tested in the August test.

Shakedown Test No.2   The purpose of this test was to test those components that had not been tested in the first test, and to test the corrections made as a result of the first test.

This test is described in somewhat more detail in this Final Report because it shows the methodology hat was used in this project.

Introduction:

This combustor test (DP2) was conducted on 8/27/92. There were two general goals: (1) shakedown of newly installed or refurbished equipment; and (2) further development of the operating database, especially in the areas of combustor wall temperature and SO_2 control.

Specific hardware evaluations included the effects of the upgraded Boiler-Ash-Re-entrainment-Lance (BARL) on boiler floor ash deposits, the effects of steam or water spray injection into the combustor cooling air passages on wall temperatures and other process variables, as well as the performance of new exit nozzle thermocouples (TC' s) and combustor cooling water flow and temperature sensors. In addition, a newly purchased flame detector was to be evaluated prior to integration into the flame safety system.

Test Results

COAL FEED: A coal screen was used to remove the wood chips and twigs that were found in the coal during the first test. The tramp material screen performed as per design, although a technician had to periodically manually remove wood twigs and chips from the screen. Coal firing continued for nearly six hours until the 4-ton coal bin was empty. A new coal supply was ordered and it appeared to be free of chips.

NEW FLAME DETECTOR: The evaluation of the detector was inconclusive because at high coal and reagent injection rates the detector view port into the combustor blocked out most of the light, which caused the detector to operate erratically.

MULTI POINT INJECTION: The entire test was performed with a new expanded multi-point coal and calcium hydrate injection. Visual inspection from the boiler end wall indicated that combustion was not as effective as in the previous run. A significant part of the present test was performed with no reagent injection in order to validate the prior SO_2 capture results. Without reagent injection, slagging was very poor, which in turn reduced combustion efficiency inside the fuel rich combustor. Also, the combustor was overcooled with the new cooling approach, which also resulted in poorer combustion.

SLAG TANK WATER LEVEL AND SLAG GRIT REMOVAL: An automatic slag tank water level control and the slag grit removal system were tested. The inlet filter to the water re-circulation pump, which draws water from the slag tank plugged frequently. Another filter was used in subsequent tests. The grit removal system worked well. However, as much of the combustion took place at the downstream end of the combustor and exit nozzle, little slag (about 100 lbs) and negligible grit was collected during the test. This of course was one reason for lengthening the combustor for task 5.

STEAM INJECTION: The combustor wall temperature, as measured by the sole high temperature thermocouple in operation, registered readings at the upper end of the safe temperature range. Several different steam injection locations were tested until one location was found that caused the combustor wall temperature to decrease within minutes by up to 400^{o}F. Post-test analysis resolved this discrepancy of injection location. It was determined that due to high backpressure, only about one-half as much steam was injected into the location that had no effect versus injection that resulted in the high temperature drop.

WATER DROPLET INJECTION: A water droplet injection system also resulted lowering the wall temperature by 200 to 300^oF.

COMBUSTION EFFICIENCY. As noted, very little slag was collected in the slag tap during the run (about 180 lbs). This may have resulted from overcooling the combustor with combined steam injection and water droplet injection. Post test analysis of the various flows and temperatures confirmed this overcooling effect. As a result a significant part of the combustion took place in the downstream end of the combustor, the exit nozzle, and the boiler. The entire test was performed under fuel rich combustor conditions.

SO_2 REMOVAL: Since the combustor was operating for checkout purposes, it was decided to continue verification of prior very high SO_2 reduction results. For this purpose, the combustor was operated with and without calcium hydrate injection. However, without injection, the slag flow was very low. This in turn affects the combustion efficiency.

This was the first test where SO_2 at the boiler outlet was measured with and without calcium hydrate injection. The range of readings was 50 ppm to 330 ppm, with and without the reagent. When corrected for quenching of SO_2 molecules by the other gases, the corresponding numbers were 70 ppm and 467 ppm. This represents a peak reduction of **85%** at a Ca/S of 4. Based on the coal sulfur (1.54%S), these numbers represent 11% and 74% of the coal sulfur, i.e. **the peak reduction was 89%.** The reagent injection was cutoff and restarted several times during the test. With all the other changes, especially in droplet and steam injection, both of which were done manually in response to changes in combustor wall temperatures, the peak SO_2 reduction was not achieved each time. In some cases it was as low as 47%.

BOILER ASH BLOWING. The new ash blowing system was in operation throughout the test. Post test inspection revealed no significant ash deposits on the right side of the furnace floor where the pipes were located. There were small ash deposits on the other side of the floor. As the boiler had been cleaned prior to this test, all accumulated material was removed and weighed. The total mineral matter solids injected with the coal and lime was about 630 lbs. Of that amount, about 181 lbs was collected in the slag tank, about 59 lbs of slag was collected at the outlet of the exit nozzle, about 29 lbs was collected on the boiler floor, 10 to 20 lbs was collected under the lower boiler drum underneath the convective section, and 32 lbs was collected at the base of the stack. This means that the scrubber collected about 50% of the total solids. This provides further confirmation that the combustor was overcooled. In such a case most of the combustion takes place in the downstream end of the combustion and exit nozzle. This allows significant escape of ash particles.

COMBUSTOR COOLING WATER FLOW & TEMPERATURE SENSORS. The various combustor cooling water flows and temperatures were measured both manually and with electronic flowmeters and thermocouples. The thermocouples were incorrectly connected with reverse polarity.

EXIT NOZZLE THERMOCOUPLES. One of the two newly installed exit nozzle thermocouples (TC's) performed well. The other gave erroneous readings and an effort will be made to correct it before or during the next test. Based on the correct readings, the exit nozzle temperature went from ambient to about 525 F during the heatup on oil. With steady coal operation the temperature rose to nearly 800 F.

Although an asymptotic approach of the exit nozzle temperature to some equilibrium value over time might have been expected, the data obtained in this test DP2 were best represented as a straight line. An extrapolation of this data to longer operating times indicated that the exit nozzle temperature will become excessive during long duration testing. This clearly indicated the need for active exit nozzle wall cooling.

COMBUSTOR WALL TEMPERATURE CONTROL. Considerable effort was expended in analyzing the effect of various combustor wall-cooling methods that were used in this test and their impact on combustor performance. A model was developed for analyzing them and it was used to design the automatic cooling method for subsequent tests. The details were reported in the Quarterly Technical Report for the period ending December 31, 1992.

OVERAL ASSESSMENT OF THE 2ND TEST

Visual impressions during this test DP2 suggested that combustor operation was gradually deteriorating as the test progressed, resulting in poor combustor slag retention/rejection and, possibly, reduced combustion efficiency. The combustor slag rejection was only 29 % of total solids input. Post-test evaluation of several key combustor variables was correlated with the combustor database that was obtained from several years operating experience. A computer program had been designed to relate measured variables against criteria uniquely related to a dozen or so operating conditions, which would allow future incorporation of these measurables into the control program that would allow real-time diagnosis of operating conditions. At the time of this test, the program indicated that combustor operation had indeed gradually slipped from "Normal" to "Poor" partway through test DP2, with the operating condition changing from "Combustor Operational Parameters Normal" to "Poor Combustor Volume Utilization With Downstream Combustion. Possible High Solids Carryover." This deterioration in combustor operation was likely due to excessive direct plus indirect combustor steam injection, which pushed the combustion zone downstream, away from the burner.

Post-test inspection of the Liner-Near-Surface thermocouples showed that about 20%of the original combustor refractory liner was gone. This test took place soon after a test effort, which involved injection of fly ash with the coal into the combustor. The fly ash replenished the liner and it appeared that some of this liner slag had re-melted. This effect was observed many times in the Task 5 testing, and it is one of the benefits of using a high ash coal in this combustor.

This test result shows some of the issues that had to be addressed in operating this combustor. Since the purpose of these two shakedown tests was to determine the impact of the modifications in equipment and operating procedures, the overall result was satisfactory. The project was therefore judged ready to proceed to task 2.

Task 2. Preliminary Systems Tests

Prior to initiating the task 2 tests a test plan was prepared and submitted to DOE for review in September 1992. This plan reflected new results obtained in the previous 6 months of the task 1 effort. The first task 2 tests were planned for October 1992.

The test plan consisted of two groups of tests. The first group consisted of three 1-day tests with nominally 8 hours of coal-fired operation. The objective of these tests was to optimize the performance of the combustor with the modifications installed in task 1. Key test objectives were further evaluation of multi-point injection, optimizing wall cooling, optimizing SO_2 reduction, slag flow and measuring slag desulfurization. The tests were to be performed at part and full thermal input to the boiler.

The second group of three tests was also to be each of one day duration, but the time on coal firing will be increased to two shifts

A) Combustor Operation and Maintenance Results of the 1st Three Task 2 Tests:

Three of the 6 planned tests in task 2 were perform October 8, November 11, and December 29, 1992.

Test No.1 October 8. Frequent combustor trips by the flame safety system required termination of the test after several hours of coal fired operation. Important results are:

Post-test observation showed that the new multi-point injection system operated without plugging of any of the coal or limestone lines. The new coal supply was free of any tramp material. However, post test observation of the four outer coal injection ports revealed that several of them plugged sometime during the test. This could have been caused by either agglomerated coal clumps or very fine tramp material that passed the coal filter screen. Therefore, it decided to eliminate the new multi-point injection from future tests and to return to original 4-point coal injection for the balance of the task 2 and task 3 tests. However, it was re-introduced in task 5 and operated successfully once a feed augmentation component was added.

The ash blowing system in the boiler and convective section was effective in removing fly ash from the boiler floor. Only larger char type particles were found on the boiler floor at the entrance of the convective tube section. As will be reported in the test results section, this char material was due to the combustion inefficiencies that resulted from the use of a high viscosity coal ash with lime co-injection. Lime yielded poor slag flow on the combustor wall, which in turn reduced the char burnout under the fuel rich conditions used in this test.

Test No.2. November 11: The new flame detector had to be repaired after the previous test. Also, internal combustor inspection after the previous test revealed that a previous small water leak through a hairline crack inside the combustor had increased over the level observed in the past. The crack was resealed with a welder to the point where a small residual leak remains. This leak is smaller than the magnitude observed in combustor operation over the past two years. The weld crack developed due to improper re-assembly of the combustor in 1988. It was rewelded at that time, but it reopened during operation with inadequate cooling water in early 1990. At that time the crack was rewelded, but a small residual leak remained. A heat transfer analysis was performed that indicated that this section of the combustor could be cooled with air. However, this was never implemented because the cause of the leak was excessive pressure in the water-cooling loop. This was permanently prevented in the task 5 re-design with a totally new method of water-cooling this section of the combustor. Nevertheless, in future designs, air cooling will be used.

The test on November 11 consisted of a 3 hour heatup period on oil and gas followed by coal firing without interruption for nearly 6 hours until the 4 ton coal bin was almost empty.

The results of the test are discussed in the next sub-section.. ***One key result concerns the impact of coal ash fusion temperature on slag behavior and wall durability.*** To increase sulfur retention in the coal, a high (15%) ash content coal was used in the first three tests in task 2. It was observed in all three tests that combustion efficiency and slagging behavior was poor compared to prior tests. In both the October and November tests, lime was used as a SO_2 reagent. It has a finer particle size distribution compared to limestone. Therefore, with lime the calcium content of the slag was reduced compared to limestone. This in turn yielded a higher viscosity in the slag. This conclusion was verified in the next test, discussed below, where coarser limestone was used, and the slagging effectiveness in the combustor improved. Another effect of the poorer slagging was increased loss of wall material because slag replenishment was less effective.

In late November a combustor test was performed under another contract using No.2 and No.6 fuel oil. During part of this test fly ash was injected to replenish the combustor wall. This was effective in reducing the wall heat flux. Post-test inspection revealed that the slag layer formed was only loosely bonded to the combustor wall. Post-test analysis of the slag revealed that its CaO content was in a range yielding low slag viscosity. It is therefore concluded that the use of oil to replenish the slag layer on the combustor wall is less effective that coal.

During this oil fired test the slag tap blocked to the point where it could not be reopened with a mechanical breaker. In retrospect this should not have been surprising as the oil melted all the slag that had accumulated on the combustor wall. Post-test inspection revealed that most of the ceramic inserts in the slag tap had worn away. Since the slag tap had not been refurbished in the past two years of operation, it was decided to replace all the ceramic inserts in the slag tap. At the same time, the loose slag deposits lining the combustor wall were removed. The inside of the combustor was relined with ceramic cement, which was placed on the remaining ceramic base in the combustor. This was the first time that the ceramic liner had been refurbished since computer control operation was initiated in 1990. The reason the liner was refurbished at this time was to allow implementing a long duration combustor test. The use of coal ash refurbishing of the liner would have required another short duration test.

<u>Test No. 3. December 29:</u> The test began at 7 AM. The gas pilot burner failed to ignite. This had not occurred in 5 years of operation with probably over 1000 ignitions. After checking out the electronics, a technician was sent inside the combustor. He found that the igniter insulator tip was coated with No. 6 oil from the previous oil fired tests, and the oil shorted out the ignition spark. This oil deposit was the result of a brief 10 minute period in the November test when too much No.6 oil was injected into the combustor as a result of a defective oil flow meter. The igniter rod was removed from the combustor and the ceramic insulator sleeves were cleaned. It was not possible to re-insert the

igniter rod because the ceramic sleeves could not be aligned with the sleeve support metal bushings. The insulators were replaced with smaller diameter ceramic tubes and the igniter rod was reinstalled. However, it was not possible to align the igniter rod tip from inside the combustor so that the spark would strike at the gas nozzle exit. Five hours were consumed in this process..

Rather than abort the test, the pilot burner was manually ignited with a small torch inserted through an access port. On turning on the scrubber vessel prior to coal firing, it was found that the water drain underneath the vessel was frozen solid. After it was cleared, coal firing began before 3 PM. It continued at a steady 1080 lb/hr, 15+ MMBtu/hr , until 11 PM when the 4 ton coal bin was nearly empty. There were no flameouts during the test.

The test had several objectives.

- To test the computer wall cooling control with the refurbished combustor wall.
- To test the automatic slag breaker over extended periods.
- To test combustion efficiency and sulfur capture under stoichiometric conditions in the combustor.
- To test the effectiveness of simultaneous limestone injection for fluxing high viscosity coal slag and lime injection for sulfur capture.
- To test combustor durability.

The test results are discussed in the next sub-section.. Key results were:

The combustor was maintained at a fixed wall conditions using the air and water cooling capacity installed this year. Post test inspection revealed that the refurbished liner performed satisfactorily. The slag tap breaker functioned throughout the test. Limestone was more effective that calcium hydrate in fluxing the coal ash. However, even with the limestone and near stoichiometric conditions inside the combustor, the combustion performance was poor compared to a lower viscosity coal, as discussed in the next sub-section. Therefore, the following tests were performed with a coal whose ash yielded a lower viscosity. Overall the combustor operation was excellent. This test was also the first one in which a new test staffing procedure was implemented. The engineering test personnel were on duty from 7 AM to 11 PM. The four technicians were divided into two 8 hour shift periods. This procedure worked well. With the addition of one more test engineer, multi-day continuous coal tests could be performed.

One final point of interest is that the scrubber vessel again plugged the stack gas flow at the end of the test. Examination of the scrubber internals on the following day revealed no blockages in any air ducts. However, there were considerable sludge deposits inside the horizontal water drainage pipes under the scrubber vessel. This problem was last encountered in winter operation during the Clean Coal project. At that time it was corrected by re-piping the water drainage pipes. Since few tests were performed during very cold weather since that time, this blockage problem had not recurred. As a result of the experience in this test, the water drainage pipes were rerouted to eliminate all remaining horizontal sections. In general these operational problems with the scrubber were one factor in the decision to eliminate it for task 5. The other one was that it could not meet Philadelphia emission standards.

In conclusion, the key results of these tests were that once steady state conditions under coal fired operation were established, the computer control system maintained the combustor at a steady operating condition. A major new result was that the viscosity of the coal has a major impact on combustion efficiency, slagging behavior inside the combustor, and slag retention in the combustor. While difficulty in burning high slag viscosity coals was encountered early in the DOE Clean Coal Project in 1987, it appeared at the time that with limestone fluxing this problem could be controlled. Therefore, the present result was unexpected, and it could limit the coal flexibility of the combustor

NOTE ADDED IN APRIL 2003: The problem with the high viscosity coal was almost certainly due to the short axial length of the combustor in Williamsport. With the longer combustor used for task 5 no such problems with slagging were encountered even when operating with a 37% ash Indian coal.

Summary of Performance Results in the 1st Three Task 2 tests.:

This section contains a summary description of the combustor' s performance in the three tests discussed in the previous sub-section. A considerable body of performance data was collected during these three runs, and not all the material is presented here. It can be found in the early 1993 Quarterly Technical Reports. .

Test No.1 (DP3) (Oct.8,1992)

The major goal of this test was to run at three parametric conditions with Ca/S = 1, 2, & 3, and at one wall replenishment condition with an alumina/hydrate mix at Ca/S = 4. The new multi-port injection was used with and without steam and/or water spray injection for wall cooling. Also for this test, a new higher capacity auger was used in the coal feeder. A high ash coal was used.

Additional test goals were to assess the performance of a new stack gas scrubber venturi section; testing of a new finer mesh screening system to capture tramp material in the coal; evaluation of the new Convective Ash Re-entrainment Lance (CARL); re-testing of the new flame detector with proper sensitivity and alignment; and re-evaluation of computer sensors for measuring combustor cooling water flow and temperature.

i) General Results: Partway through the test there were repeated flameouts for no apparent reason. This limited coal run time to about 2 hrs with fuel heat input = 15 MMBtu/hr, 85 % due to coal, balance natural gas. Combustor air averaged 78 % of theoretical air (SR1 = 0.78), while second stage air (SR2) averaged 1.40. Consumables: 2100 lbs coal & 100 lbs lime.

At the beginning of the test, the slag tap burners had to be shut off due to a malfunction. Post test checkout showed that one or more of the burners was slagged over. In addition, the small hydrate eductor periodically blocked with hydrate agglomerates. These burners were a continuing source of difficulty and late in the task 5 tests they were eliminated.

ii) Equipment Performance: Lack of extensive operating time at steady conditions prevented achievement of many technical goals. However, a fairly extensive evaluation of equipment performance was allowed. Namely: the output of the computer sensors for combustor cooling water temperature yielded temperatures in agreement with dial thermometers; two of the three computer sensors for combustor cooling water flow performed correctly, agreeing with other in-line meters; one was completely defective and was removed, after the test, for replacement; the convective ash re-entrainment lance appeared to perform adequately; the fine mesh coal screen blinded almost immediately, requiring reinstallation of the coarser mesh screen; the new flame detector provided a steady signal and appeared ready to be incorporated into the flame safety system. In addition, the new scrubber venturi section worked well, providing the requisite pressure drop to the cyclone, and the coal auger ran with no problems.

iii) Technical Results: Owing to wall cooling requirements, initial direct and indirect combustor steam injection was high, resulting in poor combustor slagging and carbon utilization as in test DP2. Due to this type of operation and the repeated flameouts, combustor tap slag rejection was only 16 %. Planned efforts to replace the cooling steam with air did not materialize due to the onset of repeated flameouts. Based on limited run time, the reduction in stack SO_2 at Ca/S = 1.0 was about 29 % at SR1 = 0.73; at Ca/S = 1.9, the reduction in stack SO_2 was around 37 % at SR1 = 0.89.

Test No.2 (DP4) Nov. 11,1992

The major goal of this test was to run almost exclusively at the nominally optimum condition of SR1 = 0.7 at 16 MMBtu/hr and with hydrate Ca/S = 3, after obtaining "baseline" data with no reagent injection. Owing to the negative effects of excessive water and/or steam injection in the preceding two runs, a more conservative approach to wall cooling was planned.. This test also used the high ash coal of test DP3.

i) General Results: Prior to the test a water leak was discovered in one of the burner cooling circuits. Since the leak was small the test continued. Early in the test, the new lime feed system partially plugged. As a result injection was shifted to other ports in the combustor. Due to the lack of lime injection during the period of feed system changeover, there was slag buildup in the exit nozzle, resulting in roughly 2/3' s closure. However, upon restoration of lime injection, the exit nozzle opened. The new mechanical slag breaker plunger worked well in a semi-automatic mode.

Total coal run time was about 5.5 hrs with average fuel heat input = 14 MMBtu/hr, 93 % due to coal, balance NG. Combustor air averaged 74 % of theoretical air (SR1 = 0.74), while second stage air (SR2) averaged 1.44. Consumables: @ 3 tons of coal & 275 lbs of hydrate.

ii) Combustor Slagging: Although higher than in test DP3, measured combustor slag rejection averaged only 28 %. However, 41 % of the operating time was with no lime injection, which would be expected to lead to poor slagging of the un-fluxed refractory coal ash. This low combustor slag value was qualitatively confirmed by post-test inspection of the boiler indicating considerable fly ash carryover.

Based on measured scrubber solids, the average boiler solids retention was about 45 %, by difference, with the scrubber accounting for around 27 % of the total solids on average. This poor slagging performance occurred even with combustor water or steam injection off, i.e. with robust thermal conditions. In fact, other operating variables suggested that these conditions were too robust, possibly leading to excessive liner loss with wall thermocouple burnout.

It should be noted that after test DP4 an attempt was made under another project (Test OIL1) to replenish the combustor wall with fly ash during oil firing. Based on an evaluation of experimental slagging performance, it was believed that fly ash was a better candidate for wall replenishment than a mix of highly refractory materials such as alumina & hydrate.

As expected, wall replenishment (vs material removal via heavy slagging) was favored by relatively low wall temperatures, i.e. below about 1800^{o}F. Net combustor slag rejection was 37 % of the total combustor solids input while the scrubber accounted for an additional 14 %. The remaining 49 %, corresponding to about 170 lbs, was divided among combustor wall inventory, exit nozzle slag, and boiler deposits.

A major result of the OIL1 coal ash replenishment test was that although the fly ash slag melted easily, having a relatively low T250 of around 2200 to 2300^{o}F due to the presence of 20% or more CaO, if it were allowed to freeze, it was essentially unbreakable by the slag tap plunger. This problem, which was exacerbated by non-functioning slag tap burners, resulted in a plugged slag tap at the end of test OIL1.

A key result of this test was the confirmation that while lime is an excellent reagent for sulfur capture, the particles are too small to be retained in the combustor so that they are not useful to condition the slag for effective slag flow. This was confirmed many times in the task 5 tests, but was not yet fully confirmed during the task 2 tests. It was planned to test the high ash coal one more time but with injection of coarse limestone. If this course of action did not work, the plan was to return to a lower ash coal having a lower T250.

iii) Technical Results: To avoid excessive wall cooling via combustor steam and/or cooling tube water injection, initial efforts were directed at maintaining wall temperature by air cooling alone. However, even with maximum cooling air, it was eventually necessary to introduce some cooling tube water droplets toward the end of the test. Prior to this, however, there was evidence of wall overheating, possibly leading to wall thermocouple and liner loss. As noted above, this indication was confirmed by post-test inspection. In any case, the resulting high temperature operation resulted in good combustion efficiency as derived from measured slag carbon (99.99 % carbon utilization) and as estimated from product gas composition (96 %).

With lime at a Ca/S of 2, the reduction in stack SO_2 averaged 18 (+/-) 7 % at average SR1 = 0.74 (+/-) 0.10. With no lime, up to 89 % of the coal sulfur was measured as SO_2 in the stack. Statistical analysis of project test results suggested that the efficiency of hydrate sulfur capture may increase at lower temperatures. This could be a deadburning effect and is in qualitative agreement with Clean Coal results showing increased sulfur capture efficiency with lime at higher SR1, in contrast to limestone.

Test No.3 (DP5) Dec.29,1992

For this test, key process performance variables were identified in order of importance as follows: (1) combustion or fuel utilization efficiency; (2) combustor slag rejection; (3) sulfur oxide reduction; and (4) nitrogen oxide reduction, with items (3) and (4) being nearly equivalent. Based on earlier results with lime, as well as the historical data base, key variables (1), (2), and (3) were optimized under near-stoichiometric or fuel-lean conditions while variable (4) was optimized under fuel-rich conditions. Thus, globally optimum conditions, which involve some degree of trade-off among key performance variables, were redefined as near-stoichiometric, namely SR1 @ 0.9 - 1.0. In addition, the term "baseline" was assigned to this nominally optimum condition whereas it previously was used to describe a condition with no reagent injection.

Besides an extended duration run at nominally optimum baseline conditions, another major goal of the test was to evaluate the fluxing ability of limestone on the refractory coal ash. This was the first test with dual injection; limestone primarily for ash fluxing and lime mainly for sulfur capture. In addition, this was the first test after the combustor liner was patched with 1 to 2" of alumina mortar and the slag tap refractories and burners were completely refurbished.

i) General Results: Owing to a malfunction in the gas pilot ignition system, the test start was delayed almost 5 hrs. In spite of this, a continuous coal run for 7.5 hrs was obtained with consumption of an entire bin of coal. The semi-automated plunger system worked well and the entire coal run progressed essentially trouble-free.

For the entire test the limestone injection rate was 75 PPH while the hydrate was injected at 40 to 50 PPH. Hydrate flow was limited by the small size of the four injector ports. Fuel heat input was steady at @ 14 MMBtu/hr, 94 % due to coal, balance gas. Combustor air averaged 88 (+/-) 3 % of theoretical air (SR1 = 0.88), while second stage air (SR2) averaged 1.25 (+/-) 0.03. Consumables were: 4 tons of coal, 550 lbs of limestone, and 350 lbs hydrate. In addition, combustor wall cooling was maintained by cooling air with some water injection toward the end of the test. All process measurables indicated normal or near-normal thermal operation.

ii) Technical Results: During the test, visual observation suggested a fairly high carryover of solids into the boiler but no exit nozzle buildup. Measured combustor slag rejection averaged 36 %, which, although an improvement over the 28 % obtained in test DP4, is still low by historical standards.

Slag and scrubber sample chemical analyses were not available prior to the next test. Therefore, it was concluded that the limestone, although more effective in fluxing the refractory coal ash than hydrate, still did not result in acceptable slagging. For the next test a coal having a lower ash T250 was used.

At a Ca/S of 2, of which about half was due to lime and half due to limestone, the reduction in stack SO_2 averaged 37 (+/-) 4 % at average SR1 = 0.88 (+/-) 0.03. With cooling water injection toward the end of the test, the measured SO_2 reduction increased to 45 %, probably reflecting the previously noted enhancement of sulfur capture by limestone with combustor steam injection.

B) Results of the Second Set of Tests

Test No 4 (DP6)-Operational Description.

A 16 hours coal fired operation test was planned for Wednesday, January 27, with test preparation on Tuesday. On Thursday, the 21st, the regular local supplier of pulverized coal informed us that his pulverizer had broken down and he would not be able to deliver the coal in time for the test. We arranged for another supplier near Pittsburgh to deliver 7 tons of coal on the morning of the 27th. The 4 tons coal bin was filled immediately on arrival of the truck, and the truck was to remain on site to refill the bin in the afternoon.

On 1/26/93, the pre-test equipment check-out indicated that the scrubber cyclone was full of rust flakes, some of which were large enough to block the water drain lines. This required re-piping of the scrubber drain. Borescope examination of the combustor interior showed that the slag tap was fully open and that the combustor walls were in good condition

Due to the below freezing ambient temperatures, the installation of the outside reagent injection bin was delayed until Wednesday morning. The slag tap burner, which had failed to ignite in the December test, was tested on Tuesday and it operated satisfactorily. As the main gas pilot igniter was not yet repaired due to the delay in receipt of insulator parts, it was planned to use the slag tap burner to ignite the main pilot gas.

After installing the reagent bin on Wednesday morning, the test began with pilot gas, followed by oil burner heatup. On switching to coal, it was found that the feed auger would not rotate below about 50% of full feed rate. It was also noted that the entire horizontal coal feed line between the outside auger discharge and the inlet pipe to the boilerhouse was frozen solid with ice. This had not been encountered in prior freezing winter operation. However, the method of pneumatic feeding had been changed in the past two years in order to install screens to remove tramp material and to achieve uniform coal feed. The new system is more susceptible to water leakage. A torch was used to melt the ice in the feed pipe.

Upon start-up at around 0900 hrs on 1/27/93, the boiler gas sampling probe was found to have an internal cooling water leak, thus rendering it unusable for the test.

When coal firing resumed it was noted at the auger outlet that this coal contained some fiber type tramp material, which was fine enough to pass through the tramp screen. This eventually led to blockage of several of the coal feed lines at high coal feed rates.

During initial coal firing it was noted that no visible steam plume emerged from the scrubber exhaust stack, while smoke emerged from the closed off regular stack. In December, the boiler manufacturer's personnel began modifications on the other boiler in the boilerhouse for a series of coal fired tests in February and March. This required using Coal Tech' s scrubber to meet emission standards. To this end, ducting was installed from the other stack to our scrubber, and two plates were installed to cut off the gas exhaust flow from either boiler. These cutoff plates were in the proper position for the late December test. However, when smoke emerged from the regular stack and after it was ascertained that the scrubber water drain lines were not frozen, that position of the cutoff plates were rechecked. We found that since the December test someone had installed the plate on our stack and removed the plate from the other stack. It was necessary to shutdown the combustor and change the plates.

Another problem encountered was a water seal failure of the boiler feed pump. This was the second seal failure of this pump since it was installed the previous summer. It was, therefore, necessary to manually refill the boiler periodically to prevent he pump from flooding the boilerhouse floor.

Another problem was the failure of the controller to the boiler steam blowoff valve on the roof of the boilerhouse. This was caused by freezing. During the modification of the other boiler a rented boiler was installed in early December. As a result, this part of the steam blowoff system was disconnected and the condensate inside the blowoff pipes froze. This problem was discovered when the boiler tripped the combustor due to too high steam pressure. The valve was operated manually for the balance of the test. With the exception of the shutdown to change the stack cutoff plate, or boiler trips caused by the first encounter with the feed pump and steam blowoff valve problems, the combustor remained on oil firing during all these events. When coal firing resumed it was found that the feed auger rotated intermittently. The coal was removed from the lower bin and no obstructions were found. Since it was evening by then it was decided to resume coal firing the following day.

On resumption of coal firing on the following day, the 28th, the problem with the auger recurred. It was initially attributed to a failure of the auger motor, but it was found to have been caused by warpage of the auger shaft. This was most probably caused by water penetration in the auger bearings, which froze, causing the auger to warp. The smaller capacity auger was installed and coal firing resumed. This screw was also bent but to a lesser degree, allowing its temporary use. Steady-state coal operation was achieved at about 1400 hrs, however, the coal flow was limited to about 650 lb/hr due to feed pipe blockage by the fiber tramp material. This required No. 2 oil co-firing to achieve the desired heat input. Control of the coal flow became progressively worse, resulting in eductor choking, which lead to periods of nearly zero flow and then surges of excessively high flow. This caused termination of the test after about 3.5 hrs of near steady-state operation. Post-test examination found that 2 of the 4 coal injection ports were blocked by the fiber like tramp material. To correct for fiber tramp material, it was planned to use 6 point injection in the next test and to continue with this method until the remaining coal supply in the bin was consumed and hope that the problem does not recur with a fresh supply of coal. (*NOTE ADDED in April 2003. This problem with pulverized coal contamination never occurred with the pulverized coal supplier in Pittsburgh during the task 5 testing. It would thus appear that much of this tramp material was retained on the walls of the 4 ton bin from the previous supplier's coal.*)

One final note is that the scrubber fan motor slowed down periodically. On post test inspection it was found that one of the 3 phase motor coils had an internal short that required disassembly of the motor to repair it.

The test concluded with 1 to 2 two tons of coal consumed, almost all of it one the second day of operation. However, the combustor remained operational on oil for most of the two days.

The conclusion reached at that time (early 1993) was that operation in subfreezing weather of a system containing water lines and rotating components exposed to the elements is very difficult to implement due to startup from a cold condition. Nevertheless, it is necessary to perform tests under these conditions in order to determine the nature of the problems likely to be encountered. It will be noted that all the problems encountered were not due to the combustor. These tests are considerable importance because they identify the factors that need to be considered in the design of all auxiliary components for a commercial combustor.

2003 COMMENT

The conclusions reached on **April 2003, with the benefit of hindsight**, aret:

1) The combustor was clearly too short and the task 2 effort should have been terminated after the planned modifications, especially after the actively cooled exit nozzle, had been tested, and work on the 2nd generation combustor should have been initiated.

2) **The entire facility should have been relocated after task 2 to Philadelphia because quite a number of operational problems were caused by the inability of the key personnel to live in Williamsport during the entire project period.** Not only does this result in better control and direction in between tests, but it also allows operation and implementation with far less personnel. In Williamsport, over 7 people operated the combustor, while in Philadelphia it required only 3, and much more progress was made. Furthermore, after this project was finished, Coal Tech conducted an internally funded emission control development program over the following 5 years where major progress was made at a very small fraction of the funds expended in Williamsport, which proves that hand-on presence of the key personnel is the most important factor in effective R&D..

3) Sharing the facility with another organization is not conducive to running a R&D or technically complex development effort.

4) Developing a new technology, the air-cooled coal combustor in this case, requires extremely careful attention to the quality and reliability of auxiliary components, even though said components are "commercial".

It was indeed fortunate that the boiler manufacturer sold the entire facility to a **supermarket chain** at the end of 1993, which required the relocation of the entire combustor-boiler facility. The move to Philadelphia saved the project. Looking back none of the progress made in the decade since then, which was far greater than that of the previous 6 years in Williamsport, would have been possible had we remained there. In fact it is almost certain that the facility would have been scrapped in 1995, when task 5 was originally scheduled for completion. END OF 2003 COMMENT

Test No.5 (DP6) Test Results And Discussion:

Test DP6 was conducted at an average heat input of about 14 MMBtu/hr, with 52 % due to coal, the balance being No. 2 oil and NG. Combustor air averaged 105 $\pm$ 12 % of theoretical air, i.e. SR1 = 1.05, while second stage SR2 averaged 1.58 $\pm$ 0.18. For the entire test the limestone injection rate was 60 lb/hr while the hydrate was injected at 0 to 60 lb/hr. In addition, combustor wall cooling was maintained only by the cooling air. Process measurables indicated near-normal thermal operation associated with low combustor heat release and possible exit nozzle solids deposition.

Prior to detailed data analysis, slagging and combustion efficiency were perceived to be somewhat lower than normal during the high ash coal tests DP3, 4, and 5. These observations were attributed to the high coal ash T-250 of 2649 F. Injection of limestone (LS) to flux this refractory ash in test DP5 was partly successful, resulting in a reasonable slag tap rejection rate. However, this did not sufficiently reduce the slag viscosity, and it required frequent slag breaker operation. **It was later determined that the efficacy of LS (limestone)fluxing in test DP5 was somewhat offset by the dissolving of combustor wall alumina cement into the slag**.

In any case, as an experimental convenience, it was decided to return to a lower ash coal having a lower T-250. Test DP6 thus utilized a high volatile (VM = 37 %), low ash (6 %) Pittsburgh coal having a lower ash T-250 (2481^{o}F) than the high ash (15.7 %) coal used in the previous three tests. As noted, use of the Pittsburgh coal, instead of the usual coal was necessitated by a lengthy breakdown at the coal pulverization facility of the original supplier. However, the Pittsburgh coal resembled the desired local coal, which has a T-250 of 2438 F.

During the test, visual observation indicated fairly good slagging. This was confirmed by post-test weighing of rejected slag, including nozzle deposits, yielding a 43 % rejection of slag in the slag tap and exit nozzle into the boiler floor. In addition, the new Pittsburgh coal appeared to burn more efficiently, with less cinder carryover into the boiler than the high ash coal used previously.

However, a comprehensive review of project test data indicated that combustion efficiency and slagging were largely independent of coal type (provided that some level of slag conditioning was implemented) and that variations in these process observables were mainly associated with (calculated) flame temperature. This was determined from a plot of the slag retention in the combustor versus the calculated combustion flame temperature, and in a plot of the combustion efficiency versus flame temperature. Within considerable scatter, the trend is clearly apparent that as the calculated flame temperature increased from 2700^{o}F to 3500^{o}F, the combustion efficiency increased from the low 80% range to the 95% range, and the slag retention increased from the 20% range to the 40% range.

This relationship was the same for the previous, low T-250 coal, the high T-250 coal, and the low ash Pittsburgh seam. It should be added that the flame temperature itself depends mainly on SR1 and the amount of direct and indirect combustor steam injection. In other words, much of the problems were mainly due to operation at very fuel rich conditions. Note that in task 5, operation was generally at modest fuel rich conditions, and no impact of coal type on slagging was observed, as long as limestone fluxing was used.

At Ca/S mol ratios of 3.9, 1.7, and 0 with lime resulted in reductions in stack SO_2 of 17%, 23%, and 0 % respectively. These reductions were less than those typically obtained with lime injection. *The reason for this was believed to be due to sorbent deadburning caused by excessive use of auxiliary No. 2 oil. Work done in the Clean Coal project showed that oil firing rates accounting for more than about 10 % of the total fuel heat input lead to very poor SO_2 reduction, especially with limestone. This was attributed to increased deadburning since the sorbents are injected in a zone near the oil flame.*

In addition, since limestone was injected simultaneously with the lime, the corresponding limestone Ca/S ratios were 2.8, 2.6, and 2.0, resulting in overall Ca/S ratios of 6.7, 4.4, and 2.0. Data analysis indicates, however, that the bulk of the SO_2 reductions measured under the conditions of this project are due primarily to lime, with limestone making about a factor of three less contribution. However, it should be noted that previous work has shown that there is a range of operating conditions where limestone is also effective as a sorbent, namely at low SR1 and high combustor steam injection.

<u>Evaluation of Slag & Scrubber Data from Test No. 4 (DP5), (December 29, 1992</u>

During the test, visual observation suggested a fairly high carryover of solids into the boiler was observed with no exit nozzle buildup. Measured combustor slag rejection averaged 36 %, which, although an improvement over the 28 % obtained in test DP5, appears to be low by historical standards. A comprehensive review of all test results to date, including Clean Coal and Fly Ash melting data, and totaling 74 complete data sets, showed that the historical average combustor slag tap rejection is 42 $\pm$ 16 % with a low of 8 % and a high of 76 %. Statistical analysis of the data further indicated that increased slag T-250 had no effect or, unexpectedly, a slight positive effect on slag rejection. SR1 was confirmed as the key parameter with slag rejection increasing at higher SR1. Increased fuel heat input and swirl air pressure also made a positive contribution to slag rejection. A simple linear regression model of slag rejection vs SR1, heat input, and swirl pressure predicted a 40 % slag rejection at the conditions of test DP5, in good agreement with the measured value of 36 %. Hence the above statement that the DP5 value of 36 % slag rejection is low by historical standards is incorrect. The confusion arises when the tap rejected slag is compared to "best condition" slag values which also include exit nozzle deposits and combustor inventory; these values, as reported under the Clean Coal project, averaged 72 % with a range of 55 to 90 %.]

NOTE ADDED APRIL 2003: The above discussion applies to the 1st generation combustor used in these tests. After the tests in the 2nd generation combustor in task5 it was 100% clear that the first combustor was too short. Therefore, the comments here are mainly of historical interest.

Prior to evaluation of slag and scrubber samples, it was tentatively concluded that the limestone, although more effective in fluxing the refractory coal ash than lime, still did not result in acceptable slagging. (*April 2003- Not correct, limestone is effective.*) This conclusion was to some extent based on the relatively viscous nature of the rejected slag, requiring frequent use of the slag breaker. However, slag chemical analysis strongly suggests that this observation may have been due to excess alumina in the slag arising from its dissolving from the combustor wall patch material during the test. (*April 2003- The adverse impact of alumina was confirmed in tests in the 2nd generation combustor on another project*.) For the next test it was therefore planned to return to a coal having a lower ash T250. The analysis of slag and scrubber chemical compositions, presented below in detail, confirmed this initial view

Slag Composition for Task No. 4 (DP5),December 29, 1992

Analysis of slag samples obtained early in the test revealed two significant findings. One was that the slag CaO content corresponded to over 90 % retention efficiency of CaO from injected limestone (LS). Analysis of the preceding test DP4 slag data indicated that the hydrate-CaO retention was only 17 %. This result confirmed Coal Tech's view that the fine lime (avg. diam. = 7 microns) is mainly carried out of the combustor while the coarse limestone (avg diam = 70 microns) mostly remains in the combustor, provided the walls are in a slagging mode.

Another important finding was that the initially rejected slag was roughly 28 % alumina from the wall repair mortar. This occurred even though the combustor had been operating in a relatively mild thermal mode with key operating indicators normal. However, post-test borescope inspection of the combustor interior showed no excessive wear. Since the applied patch thickness was up to 2 inches, it is believed that the high slag alumina resulted from the washing-off of excess coating during initial coal operation and that no significant deterioration of the combustor walls occurred.

Related to the above, slag T250 was reduced from the unfluxed value of about 2600^{o}F by improved combustor reagent retention. However, the amount of reduction was somewhat offset by the wall alumina wash, resulting in a net T250 of 2332^{o}F.

Wall Cooling with Water Injection for Task No. 4 (DP5),December 29, 1992

In order to avoid overheating, water droplets were injected into the combustor wall cooling circuit toward the end of the test. This injection coincided with an increase in the reduction of stack SO_2 from about 35 to 45 %. As noted above, this result probably reflects the previously discovered enhancement of limestone sulfur capture by combustor steam injection.

However, as also previously reported, wall cooling water injection appeared to negatively affect combustion efficiency and slagging. Namely, based on stack gas species and fuel and air flow measurements, the estimated overall combustion efficiency averaged 89 % with no water injection but fell to 71 % at 150 lb/hr of water. More accurately, overall combustion efficiency as determined from scrubber solids content fell from 93 % to 89 %. Similarly, combustor/boiler solids retention averaged 73 % with no water but was 54 % with water injection.

Although effective in controlling wall temperature, water injection must be balanced against combustion efficiency deterioration. Operationally, this may not be harmful to the combustor since testing indicated that steam injection may be more effective in controlling combustor temperature than water tube injection, without having as serious a negative side-effect on combustion and slagging efficiencies.

Solids Mass Balance for Task No. 4 (DP5),December 29, 1992

Post-test removal and weighing of all boiler solids, as well as scrubber solids determinations, allowed the performance of a mass balance. Total combustor slag was 36 % (21 % rejected through the tap and 15 % in the exit nozzle). Boiler deposits amounted to 33 % of the total solids, with 25 % in the boiler, 2 % in the convective section, and 6 % at the base of the stack.

Chemical analysis of solids collected from the stack base indicated that these deposits were agglomerates of partially burned coal plus CaO from carried over reagent, mainly lime. The sulfur content in the stack solids corresponded to about 13 % of the coal sulfur. This is probably mostly unreleased sulfur since the loss on ignition (LOI) of 64 % corresponds to only 20 % fuel utilization. This is in line with stack SO_2 measurements in test DP4, with no reagent injection, showing that 11 to 16 % of the coal sulfur was not reporting to the gas phase. Alternatively, the deposit CaO, which arises mainly from lime carryover, can also account for some of the sulfur since the deposit Ca/S = 3.

Assuming negligible emissions to atmosphere, the amount of scrubber solids was calculated by difference to be 31 % of the total solids input. Analysis of several scrubber samples obtained during the test yielded an average scrubber solids of 32 %, in excellent agreement with the calculated value. This result incidentally proves that the scrubber was not blocked off during DP5 by the plate as was the case at the start of test DP6 in late January.

Based on test data from DP4 and DP5, the varying reagent effects on solids partitioning can be evaluated. As shown on Table 1, the unfluxed refractory coal ash was poorly slagged, leading to low combustor slag and high scrubber solids. The use of lime significantly improved combustor slagging but because of its high carryover this fluxing effect was mainly reflected in significantly increased boiler deposits. It should be noted that these deposits were mostly floor agglomerates and not tube deposits.

With limestone injection, combustor slagging was only slightly improved over the lime case, with boiler deposits being essentially the same as in the unfluxed case. It should be noted that the fluxing efficiency of limestone as reflected in improved combustor slag rejection, was probably somewhat off-set by the high amounts of alumina patch washed off the combustor walls.

In summary, both lime and limestone injection lead to generally improved slagging with the highly refractory ash coal, resulting in measured slag tap rejections in line with historical values. The limestone (LS) was somewhat superior since it was better retained in the slag due to its coarse particle size. However, the slag conditioning efficacy of injected LS may have been off-set by alumina wall patch wash-off. Thus, it is concluded that highly refractory ash coals may be suitable for use on the present combustor with proper slag conditioning. However, for experimental convenience, future testing will involve a return to lower ash fusion coals.

Table 2. Sorbent Effects on Solids Partitioning With Refractory Ash Coal.

Percent of Total (Permanent) Solids Input

	No Flux	Lime	Limestone
Combustor Slag	23 (a)	33 (a)	36
Boiler Deposits (b)	36	50	37 (c)
Scrubber Solids	41	17	27

(a) estimated.
(b) by difference.
(c) measured value is 33 %.

As part of required environmental monitoring, slag samples were subjected to the TCLP Leachate Analysis. As can be seen on Table 3, all tested species were well below environmental standards or even below the detectability limit.

Table 3. Results of Slag TCLP Leachate Analysis.

Species	Measured (mg/l)	Standard (b) (mg/l)
Pb	<0.02	5.0
Cd	0.005	1.0
Cr	0.038	5.0
As	<0.04	5.0
Sulfide	<1.0	14.4 (c)
TOX (a)	0.413	50.0 (d)

(a) Total Organic Halogens.
(b) 40 CFR, Part 261 et al., March 29, 1990.
(c) CS2 limit.
(d) Personal communication, Pa DER.

20 MMBtu/hr Combustor Test with No.6 Oil

As part of its effort to extend the applications of the air cooled combustor, Coal Tech performed in the winter of 1992-1993 a series of test for ENEL, the Italian National Electric Utility, on the effectiveness of reagent injection into the air cooled combustor to reduce the SO_2 emissions from the combustion of No.6 fuel oil. These tests were funded by ENEL. Selected results from these oil tests are included in this report because they directly relate to the implementation of the present project's objectives.

A separate No.6 oil feed system was constructed to heat and pump the oil to the oil burner. This oil must be heated to flow and to properly atomize. A preliminary checkout of this system was performed in November 1992. In this test about 100 gallons of No.6 oil were burned.

Due to various conflicting schedule requirements between the test site owner's plan to operate the other boiler, and other commitments by ENEL personnel, the only open date for the oil tests was in early February. A dozen parametric conditions were tested over a 3 day period. Stack gas sampling and particulate sampling were performed for each test condition. The results were reported in a Coal Tech report to ENEL, and copies must be obtained from that organization. . For present purposes, the significance of these results is their applicability to the present coal fired tests in the combustor.

Due to its very high viscosity at ambient conditions, No.6 oil is much more difficult to burn than No.2 oil. Proper atomization is critical for efficient combustion. With poor atomization, caused primarily by too high an oil viscosity, extensive unburned carbon deposits formed at the upstream end of the combustor. After considerable adjustment, reasonably good atomization and combustion was obtained. At that time, it was noted that the wall heat transfer and wall temperatures were considerably higher than for coal fired operation. Also slag flowed out of the slag tap. Since this ceased for a period of time, it was assumed that this slag was from inventory built up from the previous coal test. However, on the second day of testing, substantial slag flow resumed, and the wall heat transfer rate remained high despite attempts to lower it with wall cooling water injection. In addition, the outlet of the exit nozzle become covered with a frozen slag layer to the point where it was almost completely blocked. At that time, combustion gases were observed escaping from fissures in the refractory exit nozzle-boiler wall into the furnace section of the boiler. It was therefore necessary to shutoff the combustor and break off this slag layer with a long pipe inserted through the end wall of the boiler. Inspection of the exit nozzle from a viewport at the rear of the boiler indicated apparent loss of exit nozzle refractory on the inside of the nozzle wall. Also, several fissures in the refractory wall of the boiler radiated from the internal diameter of the exit nozzle. Steam injection into the combustor was effective in lowering the gas temperature and heat transfer rate.

Post test internal inspection after the boiler cooled down confirmed this material loss. While the fissures were not unexpected in view of the exit nozzle blockage with slag, the material loss on the inside of the exit nozzle was unexpected. This material, a fused very high temperature refractory, had been successfully used in the previous five years of combustor operation. Prior material loss in the exit nozzle had been limited to the interfaces between the exit nozzle ceramic sections. This loss was due primarily to thermal shock from the extensive thermal cycling of the combustor. The No.6 oil test was the first time in which wall material loss resulted in a significant increase of the internal diameter of the exit nozzle.

Post test analysis of the wall heat transfer rate in the combustor and exit nozzle showed that it had been significantly above normal conditions, especially in the early part of the test. Also, the analysis showed that the combustion temperature was substantially higher than the normal range.

The above results led to the following conclusion concerning the combustor wall design and operation.

1) The combustion gas temperature must be maintained below the level at which the wall heat transfer exceeds the wall cooling capacity. *(April 2003. In retrospect this is obvious. However, as we had no prior experience with No.6 oil, it was not so obvious at the time*.) Lowering the gas temperature is the most direct method of reducing the wall heat transfer. The computer was designed to compute the combustor's wall heat transfer, and this information was used to adjust the wall heat transfer rate. The latter was accomplished by either reducing the thermal input, by adjusting the combustor stoichiometry, or by injection water or steam into the combustor. As a result of the oil tests the control software was modified to add the computer gas temperature as an additional wall heat transfer control step.

2) The wall heat transfer rate was at the time monitored in real time. However, reduction of excessive heat transfer had to be performed manually. It was planned to upgrade the software and add additional automatic controllers to have the computer control the wall heat transfer.

3) A mechanical device must be used to break any slag layer that forms in a manner that can close the exit nozzle. This was subsequently accomplished by inserting an actively cooled lance through the end wall of the boiler. (*April 2003: Subsequent to the end of the present project, another method was invented that will obviate the need for such a lance*.)

4) Finally, and **most importantly**, the No. 6 oil tests showed that we could not continue to operate the exit nozzle in the adiabatic mode for continuous and extended periods at high thermal inputs. Furthermore, the oil tests showed that cooling of the exit nozzle must occur in relatively close proximity to the inner diameter of the nozzle, and it must extend over most of the length of the nozzle. The significance of this result is that the method of air-cooling the exit nozzle that was analyzed in task 1 was inadequate. In the task 1 analysis, the position of the cooling tubes was too far from the inner diameter of the nozzle, and only the downstream half of the nozzle, namely the section that penetrates the refractory front wall, was to be cooled.

As a result of the oil test results, a new wall cooling design for the exit nozzle was analyzed. This consisted of a series of air cooling tubes that were placed around the exit nozzle at about double the radius of the inner nozzle opening. Also the entire length of the nozzle was cooled. This design was implemented in March and April of 1993, and its key features are summarized in the next sub-section.

Since it was necessary to refurbish the combustor refractory, and since the objective of the remaining task 2 and task 3.2 tests were longer duration operation, it was decided to add the exit nozzle cooling as well as other delayed additions to the refurbishment. This had the effect of advancing the task 3.1 modifications and refurbishments prior to completing the task 2 tests. With these refurbishments, it was possible to proceed to the task 3.2 longer duration tests after the completion of the next task 2 test. The next section will describe these modifications.

Task 3: Combustor & Boiler Modifications for the Proof of Concept Tests
a) Addition of Exit Nozzle Cooling System and other Task 3.1 Refurbishments.

Refurbishment work was delayed until the mid-March because the site owner used the other boiler for test purposes, which not only prevented any work inside our boiler during that time, but also could have resulted in damage to our combustor, and interfered with our next test, as explained below. The primary effort was the installation of the new exit nozzle cooling. The following modifications were made.

1) The combustor's liner and exit nozzle refractory were completely refurbished after the completion of the No.6 oil test. An alumina ceramic cement was used for the combustor wall refurbishment, while a combination of alumina plastic refractory and cement of the same material as the exit nozzle fused refractory was used in the exit nozzle. This effort was at the expense of the oil project funds.

2) The slag tap refractory block was also replaced as part of this effort. It became damaged when overheating warped the mechanical slag tap breaker causing it to impact the ceramic block.

3) A great deal of time and expense was expended in the installation of the new exit nozzle cooling system, which would allow round the clock coal-fired operation. The analytical model briefly described in the above Task 1 "Combustor Modification" section was used to analyze the proper placement of the cooling tubes.

This system consisted of several parts. Eleven holes were drilled from inside the boiler through the refractory front wall of the boiler, to a depth equal to the axial length of the exit nozzle. The holes were drilled at a radius equal to twice that of the inner radius of the nozzle. An annular stainless steel tube assembly was placed into each of these holes, and connected to a tube assembly that was placed parallel to the inner refractory wall of the boiler. This assembly was in turn was connected to a plenum chamber that supplied the cooling air to the tubes inside the exit nozzle. This arrangement is figure 5, where the left figure is a photograph of the exit nozzle viewed from inside the boiler furnace box showing the metal cooling tubes protruding from the front refractory wall of the boiler and connecting to the cooling air plenum pipes. The exit nozzle outlet plane is in the center. The right photo shows the front boiler wall after all these metal pipes have been covered with refractory. Note the four pipe elbows at 45% degree to the vertical and horizontal, which were used to introduce final combustion air.

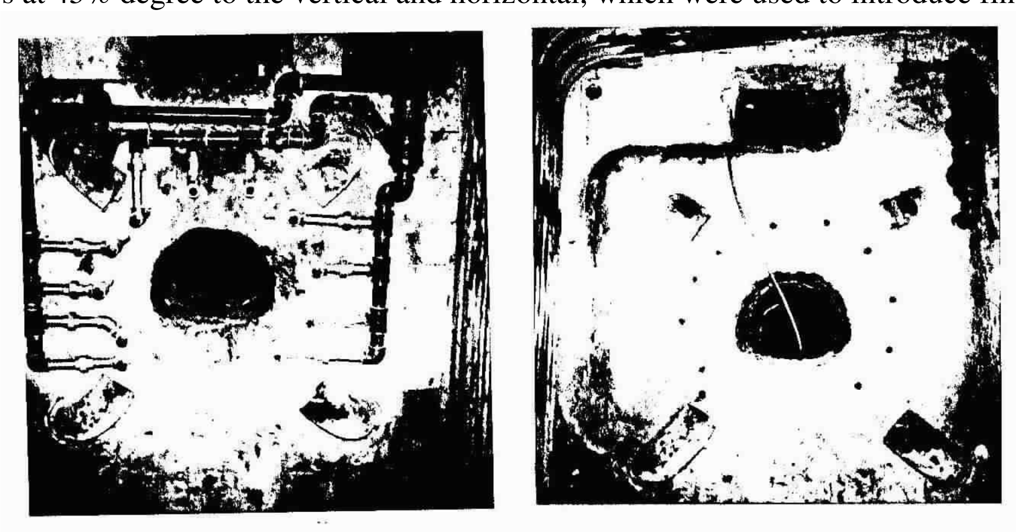


Figure 5: Exit Nozzle Air Cooling Assembly. (See text above)

4) The site owner used the adjacent boiler for a test that required the use of our scrubber. At that time we shut off the water lines to our combustor. During one of the site owner's tests it was found that substantial water flowed into the combustor. After several days of searching for the cause of the leak it was found to have been due to a leaking water valve upstream of the combustor cooling circuit. During normal combustor operation this valve would be normally open but all water valves to the combustor were shut off for the site owner's test. As a result of this leak, all other water valves were checked and the seals were replaced for any leaking valve. This incident is documented to show that even routine items such water valves used to control city water pressure require regular maintenance checks for proper operation.

5) A new opening was installed in the rear wall of the boiler to allow insertion of a slag breaker pipe during combustor operation in order to break any slag that could partially cover the exit nozzle. As noted, the exit nozzle closure during the No. 6 oil test was a major factor in damaging the exit nozzle refractory. This port was also used to insert a gas-sampling probe for SO_2 measurements at the exit of the combustor. It also allowed the measurement of the gas temperature distribution inside the furnace section of the boiler with a suction pyrometer. This allowed the collection of data on combustion efficiency and SO_2 and NO_x control inside the furnace section of the boiler.

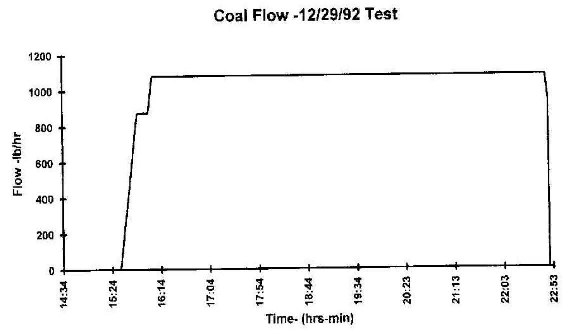
The dimensions of the furnace section of the boiler are determined primarily by the volume required to complete combustion of gas, liquid, or solid fuels. *Since the boiler is a major cost component in any new or repowered plant, the smaller the furnace volume the lower the boiler costs.* It is anticipated that with over three-fourths of the combustion occurring inside the cyclone combustor, only a small furnace volume will be required to complete combustion. Measurement of the gas and temperature conditions inside the furnace section of the boiler will provide the design data for the furnace section in future commercial boilers..

Completion of the Task 2 Tests

Following the completion of the combustor and boiler modification described in the last sub-section, the last two of the six planned tests in task 2 were completed.

The following is a brief summary of test work to that point. The task 2 test plan called for one day tests, each of up to 16 hours duration, with emphasis on the following four areas: Computer automation of the combustor, combustor and boiler durability, SO_2 control, and operation under conditions that will exist in commercial applications. Following the completion of the first two tests and a review of the results, the primary test emphasis for the remaining four tests was placed on durability under optimum combustor operating conditions.

The first of the last four tests was performed on December 29, 1992 when the combustor was on line for about 11 hours, including 4 hours for startup and shutdown, from 7 AM to 11 PM. It was on coal for 8 hours until the 4 ton coal bin was empty. Total fuel heat input was 14 MMBtu/hr, 94% due to coal with the balance natural gas. Figure 6 shows the coal flow rate for this test. Figure 7 shows the wall temperatures in the combustor liner at two radial locations, near the hot refractory liner-slag interface, and in the rear of the liner at the air-cooled metal section. The combustor's air-cooling was controlled with the computer, using manual inputs to change the cooling air flow as the wall temperature changed. One notes that this procedure had a very slow response time. This is due to the transient heat transfer relaxation time of the liner. This relaxation time is a function of the thermal conductivity of the liner and the temperature difference across the liner. One notes that the wall temperature fluctuated over a range of several 100 degrees Fahrenheit. This is too wide a range for effective control of the wall temperature and for combustor durability. This problem was solved early in the task 3 tests in July 1993, with the addition of another cooling stream to the combustor. With this new procedure, it was possible to maintain the hot-side liner temperature at 2000^{o}F, in a range of less than 50F.



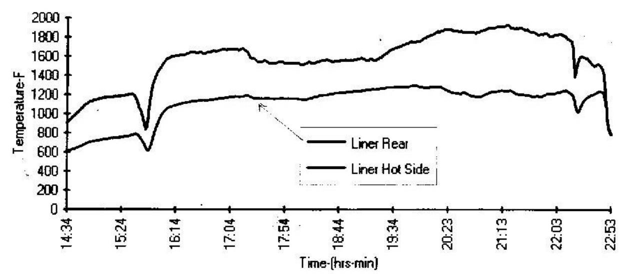
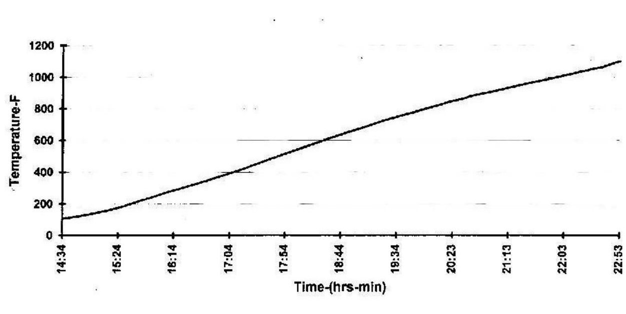


Figure 6: Coal Flow –12/29/1992 Test

Figure 7: Combustor Wall Temperature Top Curve-Liner Hot side

Figure 8 shows the temperature in the refractory front wall of the boiler through which the combustor exit nozzle passes for the December 29,1992 test. The measurement was taken at a point about 10 inches from the inner diameter of the combustor exit nozzle. The reason for the continuous temperature increase is that this section of the exit nozzle operates nearly adiabatic with no cooling. As described in the previous, sub-section, active air-cooling was added to the exit nozzle in March/April 1993. This lowered the wall temperature at this location by almost a factor of two from 1100^{o}F to 500-600^{o}F. More importantly, the wall temperature leveled out at this lower value after only a few hours of coal-fired operation at steady thermal input. Exit nozzle cooling will be discussed below.



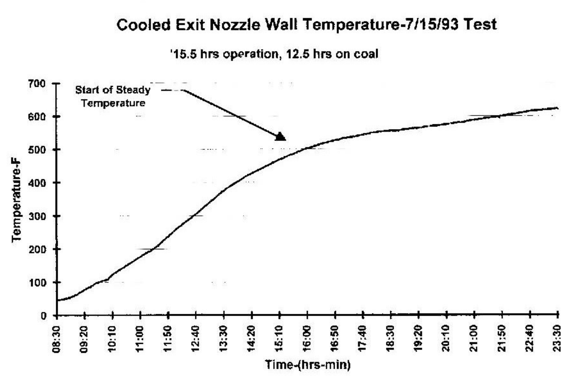


Figure 8: Adiabatic Exit Nozzle Wall –12/29/92

Figure 9: Air-Cooled Nozzle Wall-7/15/93 Test

The second of the last four tests was performed at the end of January during subfreezing and snow conditions. The difficulties experienced due to the weather for this 2-day test were discussed above. Total heat input was about 14 MMBtu/hr, with 52% due to coal and the balance being No.2 oil and gas. Subsequent to this test several minor modifications were made to the coal feed lines and the scrubber water lines, which should eliminate this problem in future operations under freezing conditions.

In February, a three-day test with a total operating time of about 30 hours was performed under another project, as discussed above. The test objective was to evaluate sulfur control in number 6-oil combustion. The No.6 oil's very high heat release rate caused the wall temperature to exceed the design conditions which resulted in melting of the refractory material in the combustor wall and exit nozzle wall. This required the installation of actively cooling of the exit nozzle, which was discussed in the previous sub-section.

The third of the last four tests was performed after the completion of the above work on May 6, 1993. Despite pre-test checks, which showed satisfactory operation of the coal feed auger, the auger jammed at the beginning of the coal fired period and it could not be restarted. Rather than stop the test, the entire test was performed with No.2 oil and gas firing at a total heat input of 12.9 MMBtu/hr, with 81% being oil and the balance natural gas. The reason for this decision was that there were key test objectives that could be implemented with oil. The most important one was to verify the thermal performance of the new exit nozzle The test duration extended for a period of about 12 hours. The new exit nozzle cooling system performed as per design. The air cooling resulted in a 50% reduction in the peak temperature reached in the test.

A second objective of this test was to determine the effectiveness of ash vitrification of a high (30%) carbon content fly ash. As described in the task 4 discussion of this report, (Appendix 'B') Coal Tech proposed using the combustor to vitrify high carbon content, fly ash to an independent power generation producer in upstate New York. At the time the high carbon content of the fly ash at that power plant requires costly landfill disposal by adding about 30% water to the fly ash and shipping it several 100 miles in open coal cars to a landfill. The fly ash production rate of the plant was 6 tons/hour. This will require a 100 MMBtu/hr combustor to vitrify it. To determine the combustion characteristics of this **30% carbon content fly ash**, 200 pounds of this ash was supplied by the company for a brief trial injection test of several hours duration. The ash slagged with no difficulty. The injection rates varied from about 130 to 180 lb/hr. This provided an additional heat input between 0.6 to 0.9 MMBtu/hr. Oil and gas was used as the auxiliary fuel at a heat input of 12.9 MMBtu/hr.

Post-test chemical analysis of the slag showed no detectable carbon in the slag. At an ash injection rate of 150 lb/hr, an average of 28% of the injected ash was captured in the scrubber water. The carbon content of the scrubber solids was 20%. Since the scrubber solids represent only 28% of the injected rate, the **reduction in carbon content of the original fly ash was from 30% to 4.5%.** The thermal efficiency of conversion was not measured due to the low ash injection rate. A proposal was submitted to the company to perform a test to measure the conversion efficiency and the thermal efficiency of the process using about 3000 lbs of ash. In addition, a budgetary estimate was submitted for a 6-ton/hr, vitrification capacity combustion system. The Company chose not to proceed. We encountered this type of extreme caution to move from the known to the unknown on many occasions in marketing this technology. No one wanted the first commercial application.

This was the last straw with this "commercial" coal feed system on which countless hours and considerable funds had been expended in the previous 6 years. We ordered a coal feeder based on a totally different feed mechanism, and since its introduction in the Spring of 1993 it has performed flawlessly through 1998. However, this P.I. rarely throws anything out and in 1999, the old feeder was used to feed biomass into the combustor (of course with an additional modification.) However, in this new "application" it performed flawlessly.

While awaiting delivery of the new auger, one more test was performed using the old auger. Its flights were ground down, and after it still jammed, the operating procedure was changed and the auger was started **prior** to introducing the coal.

On May 11th, combustor operation began at 9 AM. Coal firing began at 11:30 AM and continued until 11 PM when the coal bin was empty. With the exception of two flameouts caused by operational errors, coal firing continued with no interruption until the last two hours. At that time, the old coal feed auger jammed several times, which caused flameouts. The combustor was rapidly restarted each time. The average coal feed rate was about 750 lb/hr, and the stoichiometric ratio in the combustor was about 1.1, i.e. fuel lean. The total heat input was about 13.6 MMBtu/hr with 83% coal and the balance natural gas.

A significant result of the May 11 test was that air-cooling of the exit nozzle continued to be effective. The nozzle wall temperature leveled out at about one-half of the values obtained with the un-cooled exit nozzle temperature at this location in the December test (figure 8). The total run time was about 11 hours in the December test and 14 hours in the May 11 test. At about 10 hours into fuel firing, the temperature began to level off in the May 6 test. In contrast in the December test, (Fig.8), it continued to rise to the end of the test.

A better proof of the effectiveness of exit nozzle cooling is contained in figure 9, which shows the exit nozzle temperature at the same location as in the other cases. This 15.5 hours duration test, with 12.5 hours on coal, was performed on July 15,1993. For the first 55% of the test time, the total heat input was 14.7 MMBtu/hr, with 92% coal and the balance natural gas. For the balance of the test, it was 13 MMBtu/hr, with 88% coal. Note that in this test, the temperature is also about one-half that of the December test. Furthermore, the leveling off of the exit nozzle temperature is clearly visible at 16:00 hours, which was 8 hours after startup. For the following 8 hours, the temperature increase is only 100^{o}F. In the December test (figure 8), where the total heat input of 14 MMBtu/hr was about the same as in the July 15 test, the temperature increased by 300^{o}F over the final 3 hours, beginning at the same 8 hours after startup. <u>This is rate of increase is 8 times greater than in the July test</u>. The exit nozzle air-cooling was controlled manually. Further details on the July test are reported below.

Finally, the mechanical device for clearing slag blockage in the exit nozzle was successfully used almost a dozen times in the May 11 test to clear slag from the exit nozzle outlet while the combustor was at operating conditions.

Another very interesting result of the 5/11/93 test was the gas sampling data obtained with the probe that was inserted into the boiler. The probe tip was within 2 feet of the main combustor exit nozzle. General results were as follows:

- The combustor operated fuel lean so that all combustion was expected to be complete in the combustor.
- The NO_x concentration at the exit nozzle was about 96% of its value at the base of the stack, which is the normal sampling location. This showed that little thermal NO_x was forming in the boiler section.
- The SO_2 reduction was 19% at the exit nozzle and 48% at the base of the stack. This is the first confirmation that the calcined CaO continues to react substantially in the furnace and convective sections of the boiler. We had suspected that this was the case due to the low sulfur

concentrations in the slag, but the absence of sampling directly at the exit nozzle prevented its confirmation.

- The oxygen concentration at the exit nozzle was on average 92% of its value at the stack. Since the combustor ran at slightly excess air conditions, this oxygen result shows that there was some unburned coal/char particles that escaped from the combustor and continue to burn in the furnace. Large (about 1 mm) partially burned char particles are generally found in the rear viewport on the boiler.
- The O_2 results are also confirmed by the CO results. The CO level in the stack was 61% of its value at the combustor exit. This shows that char particle combustion continues in the furnace.

Task 2 Tests: Conclusions: The primary objective of these task 2 tests was to achieve operating conditions that would allow continuous operation of the combustor. By the time of the last test in task 2, this has been achieved. The combustor could have remained on line through the night if additional trained personnel had been available and the coal bin had been refilled. These longer duration tests were planned as part of task 3, which involved round the clock operation.

The second objective of combustor automation was also achieved. The results showed that computer automation of all the cooling streams is essential to maintain a constant combustor wall temperature. Air-cooling control alone does not have a rapid enough response time to wall temperature changes, as was shown in the December test, (see figure 7). Computer control of all the wall temperature-cooling streams was added in the task 3 effort.

The third objective of operation under potential commercial application conditions was also achieved. Steam injection, which is needed for the combined cycle application using a steam-injected gas turbine, was tested in several of the task 2 tests. Also, the brief test of ash vitrification of high carbon content fly ash indicated the suitability of the combustor for this application.

The final objective of SO_2 control was de-emphasized in the task 2 tests. However, by placing a gas probe within 2 feet of the 3000^{o}F combustor exit nozzle outlet on the last test, the diagnostic system was now in place to optimize SO_2 control in future tests. In fact it was used in that task 5 tests in the 2nd generation combustor in Philadelphia.

One final note of interest is that most of the factors that limited the test time in the task 2 tests were failures in the auxiliary equipment, all of which were "commercial" products. We conclude that an integral part of the test effort is to identify reliable products and operating procedures for the auxiliary equipment.

Task 3. Proof of Concept Tests

Task 3.1 Combustor Refurbishment

As reported in the previous sub-sections, the changes needed to proceed with the task 3.2 tests were mostly completed in March and April 1993 prior to the final two task 2 tests. The more important changes, such as the air-cooled exit nozzle, and the new coal feeder, were described in the previous sub-section.

In addition, changes and modifications were necessary due to normal wear of equipment or due to external factors. An example of the former is the replacement of the housing of the stack scrubber fan. The housing experienced substantial material loss due to corrosion since its acquisition in 1988. This occurred due to its exposure to the elements and to the erosive action of the particulate laden stream. As such it is a function of both time of operation, which in this case is over 1000 hours, and years in service, which is in this case is 5 years. Examples of external factors are repair or replacement of such components as the boiler feedwater pump, fresh water booster pump, and the air compressor. The facility owner provided these plant services. In the course of operation it was found that sharing this equipment with other users on the site did interfere with proper operation of the combustor. Some of these were noted above. For example, the coal and reagent feed into the combustor were conveyed by compressed air. When the plant' s fabricating shops suddenly utilize a considerable number of compressed air driven tools, the compressed air line pressure substantially decreased for a short period. This lowered the feed transport air velocity, which could cause the solid particles to settle in the feed lines. On quite a few occasions, complete blockage of one or more feed lines was observed, which was partly caused by the compressed air pressure fluctuations. This in turn produces combustion pulsations. To prevent this, it was decided to use a rented air compressor dedicated solely to the combustor test.

Task 3.2 Proof of Concept Tests

The primary objective of the Task 3 tests was extended duration operation under computer control. An integral part of this effort was the attention paid to auxiliary components and sub-systems, which were "commercial" but which failed to perform to reliable standards. Much of this was discussed above. One such component was replacement of the coal feeder with a unit similar to the one used to feed the limestone, lime and ash. As described above, the original feeder had several major drawbacks.

1) It was very prone to jamming, especially in freezing temperature.

2) When jammed, it was very difficult to free.

3) Its turning resistance was high. Therefore, its minimum starting position is at 20% of full feed load. This has several adverse effects on the combustor performance, with the most important one being that it causes flooding and plugging of the slag tap.

The new auger was delivered at the end of June 1993 and its performance was far superior to the previous one. It was used successfully in four combustor tests in July and August with a total of 37.5 hours of operation and no problems.

One short duration test, designed to test several modifications was performed on June 8th before the new auger arrived. Its objective was to determine the effectiveness of the new automatic combustor wall temperature control system and the new flame detector system. The following are highlights of the results:

a) The most important result was verification of the effectiveness of the new computer controlled combustor wall temperature system. The wall temperature was maintained at an essentially constant value within about 50°F at 2000°F. Here again several flameouts occurred due to minor problems with the old coal feed auger. A more convincing demonstration of this control is shown in figure 9 (above), which shows the combustor wall temperature for the test of July 15, 1993. In this 15.5 hour combustor test, with 12.5 hours on coal, the wall temperature remained within 50°F for the entire coal fired period. The same result was achieved in the 27 hour combustor test of August 6,1993.

b) Another test objective was to test a combined IR and UV flame detector system. The combined system was more reliable than the dual UV detectors used previously. For example, once the UV system signaled a flameout, while the IR detector maintained combustion. Due to the location of the two of the three flame sensor ports they were subject to blinding by injected coal and reagent powder. It was anticipated that the IR detector would be less sensitive to blinding. However, this was not the case. To correct this problem a second UV detector was placed in a field of view where it is not subject to injected powder blinding.

The new feeder was installed on July 7, 1993. It was used in a combustor test on July 8 and its performance was excellent. Feeding ramped up linearly from zero. Feeding was very uniform, and it appeared that blinding of the flame detectors was greatly reduced.

The new feeder was used in three long duration combustor tests, with total operating times of 15.5 hours, 27 hours, and 27.5 hours, of which 12.5 hours, 13 hours, and 12 hours were with coal. Once combustor heatup was achieved, several hours after startup, a heat input in the range of 13 to 15 MMBtu/hr was maintained throughout the tests. In the latter two tests, overnight operation was on oil and gas, with shift back to coal on the following morning. In all these tests, combustor shutdown was pre-planned and no refurbishment of combustor internal parts occurred between tests. Since the cooling system had been added to the exit nozzle in April 1993, the combustor logged about 100 hours of operation in which the exit nozzle temperature distribution was maintained in a narrow range with no visible deterioration of the exit nozzle wall refractory. In addition, with the introduction of accurate combustor wall temperature control in early July, the wall temperature was also maintained in the desired narrow temperature range. This method of wall temperature control is a critical element in combustor durability where slag replenishment of the refractory wall is used to maintain wall integrity. More details of these three tests are given below.

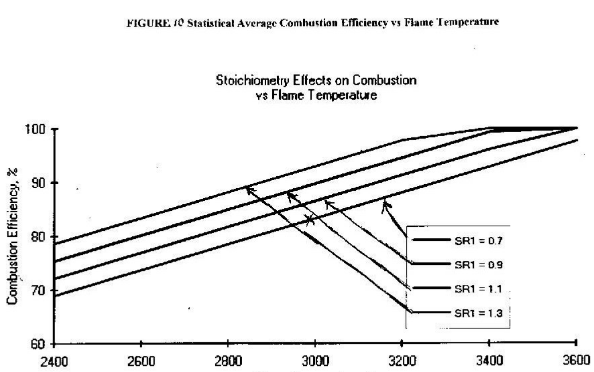
d) Another result of the test was the insight it provided on the proper operation of the slag tap: Proper operation of the slag tap is one of the more important aspects of slagging combustor operation. In the course of operating the combustor, it was determined that plugging of the slag tap is influenced by the design of the slag tap as well as by combustor operation. Some of these factors, such as flooding resulting from char buildup on the walls, were discussed above. In the course of operating this combustor over the past several years it was determined that a combination of slag tap heating and a mechanical device to break loose frozen slag in the tap was sufficient to maintain an open tap, provided appropriate combustor operating procedures are followed. Continuous improvements in the slag tap operational procedure have been implemented during the present test effort with the objective of fully automating the operation of the tap clearance procedure. Following the experience with slag flooding in the June 8 combustor test, the design of the mechanical breaker was substantially modified to increase its durability and reliability. In addition, additional heat was added to the slag tap section. These changes substantially improved the reliability of the slag tap operation. A brief one-day combustor test of the modified slag tap system was performed in early July.

In conclusion, the improvements made in the combustor system in the previous months resulted in much more reliable operation of the combustor.

Task 1, 2, and 3 Combustion & Environmental Performance Summary

The primary emphasis in these tests was been on combustor durability and automatic computer control. To meet these objectives no attempt was made to achieve operation of the combustor under conditions of optimum combustion efficiency, slag retention, SO_2 and NO_x control. Nevertheless, during combustor operation, data on these performance parameters was obtained. Some of this work was summarized above. The following is a summary of all the data obtained in the task 1, 2 and 3 tests to the end of June 1993 in graphical form. These data give the statistical average of the performance results.

Figure 10 shows the statistical average combustion efficiency for all the tests as deduced from stack gas and the scrubber solids data. It is plotted as a function of computed combustion flame temperature. These test were performed with thermal inputs in the 12 to 15 MMBtu/hr range. Due to wall heat transfer considerations, the combustor stoichiometry in these tests was set to achieve flame temperatures in the range of 3000^{o}F to 3200^{o}F. The result shows that at these temperatures, combustion efficiency is in the range of 83% to 98%, depending on stoichiometry. To achieve 99% efficiency requires an extrapolated 3400^{o}F to 3600^{o}F temperature, which is too high for the present air-cooled combustor wall cooling capacity. This would also require substantial air pre-heat for fuel rich operation.



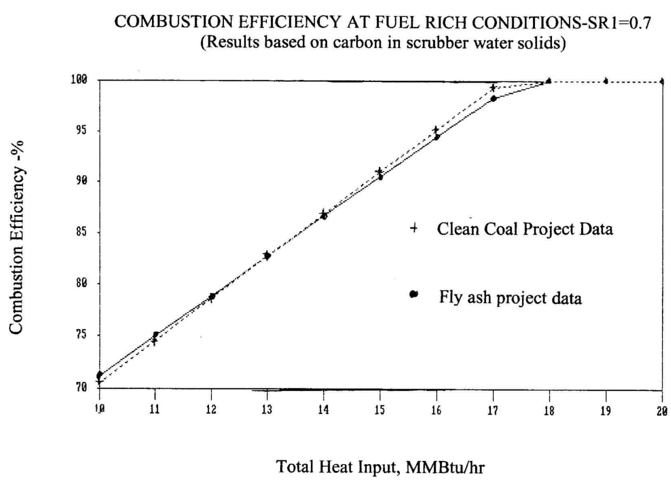
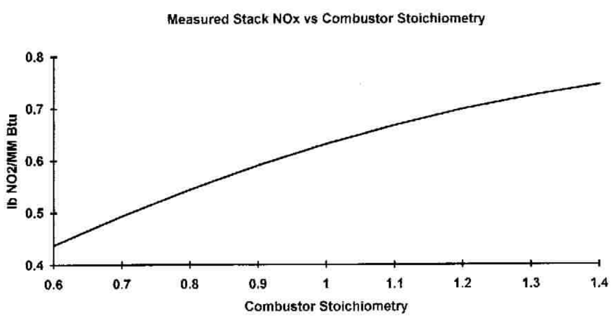


Fig. 10: Statistical Ave. Combustion Eff. vs Flame Temp. **Fig. 11: Comb. Efficiency @ Fuel Rich, SR1=0.7,**

This combustion efficiency result must be qualified. In the first place, all this data was obtained under different fuel injection conditions and with the old coal feeder, which as noted in the previous sections, was prone to breakdowns. As a result, in many of the tests, one or more coal feed lines became blocked during unscheduled coal feed shutdowns, which adversely affected coal-air mixing uniformity. (*April 2003: Also as noted in several places in this Appendix "A", this combustor* *was too short and this was a major factor in the lower combustion efficiency than in the second, longer combustor of task 5.*)

Figure 11 shows the combustion efficiency obtained in tests between 1988 and 1992 in this 1st generation, short-combustor as a function of total heat input and at a stoichiometric ratio (SR) of 0.7, i.e. very fuel rich. One notes that in the 12 to 15 MMBtu/hr range, the combustion efficiency increases from 79% to 90%. This is consistent with the curve for SR=0.7 in figure 10, which shows a flame temperature of 3000^{o}F to 3300^{o}F is required for this efficiency. This is in the range of operating conditions for the combustor. Figure 11 shows that to achieve 99% efficiency, a heat input above 16 MMBtu/hr is required. Therefore, the current combustion efficiency data is consistent with the prior results. .



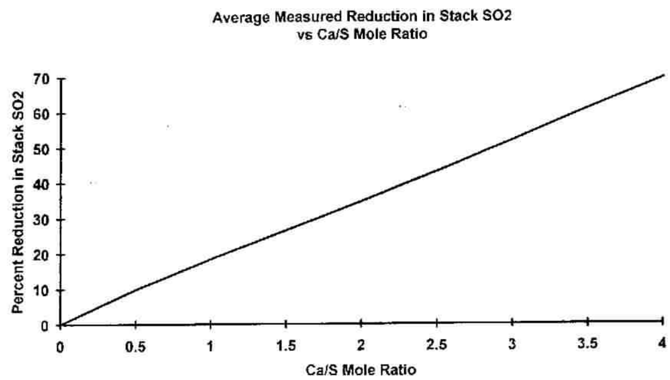


Fig. 12: Statistical Ave.NOx vs Combustor Stoichiometry **Fig.13: Statis. Ave. SO2 vs Combustor Stoichiometry**

Figure 12 shows the statistically averaged NO_x reduction for the task 1, 2 and 3 tests. The maximum reduction to about 0.5 lb/MMBtu at SR=0.7 is less than the best previously reported value for this combustor to a value of 0.26 lb/MMBtu. As noted, these tests were not optimized.

Figure 13 shows the statistically averaged SO_2 reductions for these tests as a function of Ca/S mol ratio. At a Ca/S ratio of 3 to 4 where most of the tests were performed, the SO_2 reduction ranges from 50% to 70%. However, the reagent was a mixture of limestone, whose primary function was to control slag melting temperature, and lime (calcium hydrate). The latter accounted for the bulk of the sulfur capture. Prior data in this combustor showed that lime was over 3 times more effective than limestone as sulfur capture material. Therefore, based on the calcium content of the lime, the capture efficiency was substantially higher. Again because the data was not obtained under optimized conditions, this refinement of relative capture effectiveness is not shown. Note that limestone and lime flows were about equal in mass flow rate.

Task 3.2: Additional Details on Task 3 Tests in Chronological Order

Test DP 10- July 8, 1993

The first test, coded DP 10, was performed on July 8,1993. The objectives were to test the new coal feeder that was installed to replace the feeder that had been in use since 1987, to test the new mechanical slag breaker, and to test a new slag burner that was added to increase the thermal input to the slag tap.

The original test plan had been to perform a durability test with 16 hours of operation. However, the test took place during a heat wave in which daily peak temperatures were in the high 90' s most of the week. Rather than indefinitely postpone the test, it was decided to operate the combustor for a sufficiently long period to achieve the three test objectives. Thus if needed modifications could be immediately implemented without further schedule slippage. In view of the heat, test operations began at 6 AM instead of 7 AM. Combustor ignition was after 7 AM and the test was terminated at 2 PM after all the test objectives had been met.

Based on a trial test performed by the feeder manufacturer using a 30-gallon drum filled with our test coal, a discharge nozzle was supplied that differed from the one used with the old feeder. The new feeder produced a more uniform discharge, and it operated properly until the end of the test. However, the next test showed that short duration pulsed feed still occurred which resulted in a pulsed flame.

Further improvements in the operation of the slag breaker were tested to assure reliable and repetitive operation was achieved. A tradeoff had to be made been sufficient force against too much force which could damage combustor components. A damper was added to achieve this balance. The new breaker operated effectively in keeping the slag tap open and in reopening it after its closure with frozen slag.

The chamber immediately underneath the slag tap had been heated with two gas burners. For this test, a third burner was added because the two burners were adequate in maintaining the slag in this chamber in a molten or near molten state, but inadequate to remelt frozen slag inside the slag tap slag chamber. In the July 8th test, all three burner were operated throughout the test. However, the three burners could not reopen a frozen slag tap. After much additional manipulation in the task 5 test effort, the slag tap burners were eventually removed. Instead a combination of judicious use of the breaker and test operations were used to keep the slag tap open.

In conclusion, the first two test objectives were successfully realized, while the third one, namely, the third slag tap burner, was not capable of reopening a frozen slag tap. Nevertheless, all three burners remained in use until late in the task 5 effort.

Test DP 11- July 15, 1993 Test

The objective of this test was combustor durability under computer-controlled operation. In order to achieve continuous operation it was essential that the combustor and exit nozzle wall temperatures remain constant within a few percent throughout the operating time. Accordingly, the primary objective of DP 11 test was to test the new auxiliary temperature control system that underwent its initial test on July 8th. Refilling the 4 ton bin from a tanker trailer is essential in order to operate the combustor for extended periods. This was attempted in two prior tests but it was not implemented because the coal flow rate was too low to empty to 4 ton coal bin during the period of coal firing.

Test DP 11 began at 7 AM and by a little after 8 AM heatup began on gas and oil. After a delay, mainly caused by a trip of the plant compressor, coal firing began at 11 AM. At about 2 PM, the 4 ton coal bin was refilled by the tanker that was parked outside the boiler house. Coal firing continued until combustor shutdown at 11:30 PM when the coal bin was empty. The following discussion focuses on the key observations during the test.

Post test inspection revealed extensive ash deposits on the floor of the combustor and boiler of about 1 foot in thickness. It is certain that this was due to the pulsations of the coal feed. To correct this several procedures that have been used successfully in the past were added to the new feeder. They included:

Vibrators were added to the lower coal bin and to the tramp material screen.

The coal discharge chute was centered to prevent uneven discharge of the coal into the pneumatic eductor.

Inserts were placed on the inside of the lower coal bin opposite the vibrators. This improves distribution of the coal inside the feeder.

An improved upper level indicator was installed in the lower feeder bin. This allows the rotary valve between the lower small feeder bin and the upper 4 ton bin to shut off, which eliminated excessive packing of the coal in the lower bin.

The July 15th test was the first opportunity to test wall temperature control by computer controlled auxiliary cooling, and it was very successful. Figure 14 shows the hot ceramic liner temperature for the entire 11.5 hours of coal-fired operation. The temperature is constant within 50 degrees for the entire period. The brief dip at 18:30 hours was due to an inadvertent manual shutdown and does not impact the constant temperature result.

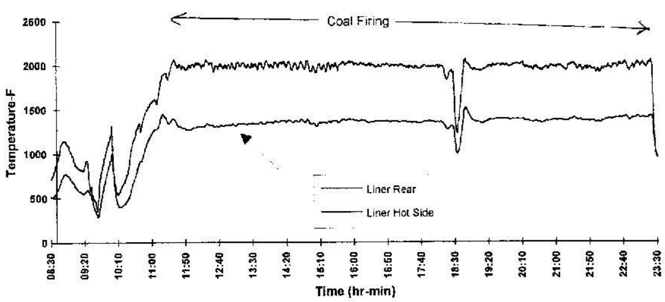


Figure 14. Combustor Wall Temperature –Top: Liner hot side. Bottom : Liner Rear, 7/15/1993

In view of the success of this method, the next step that could be implemented was complete computer control. This was accomplished by using a differential pressure transducer to signal the computer the auxiliary cooling being injected into the combustor. By comparing this signal with the combustor wall temperature, the computer can adjust the auxiliary cooling flow valve to maintain the wall temperature at a constant value.

After the test, a 1-foot thick layer of ash was measured on the boiler furnace floor. A total of 1760 lbs of ash was removed from the floor of the boiler, 25 lbs from the base of the stack, and 25 lbs from beneath the convective section. Most of this material had accumulated during the July 15 test. Of the 1760 lbs, between 500 and 700 lbs represents slag had accumulated at the boiler outlet side of the exit nozzle. Samples were submitted for analysis. However, it was almost certain that much of the remaining material has a very high carbon content and represents unburned char. It is most probably due to the multi-second pulsations that were noted throughout the test, and which were due to he periodic nature of the coal feed auger's rotation that produced this non-uniformity. At the time it was anticipated that with improved uniformity, the amount of ash deposits, as well as the exit nozzle slag would decrease substantially. (*April 2003: While that did result in some improvements, the major improvement was due to the longer 2nd generation combustor, which resulted in full combustion inside the slagging combustor, and no substantial ash deposits were found on the floor of the boiler*.)

A number of maintenance items required attention after the July 15 test. One was the boiler low water level alarm did not trip the combustor. Another was the delay in repair after almost 4 months of the boiler feedwater pump. This delay was due to the pump manufacturers failure to replace the pump, which was purchased less than 1 year earlier. Instead the manufacturer sent a series of incorrect parts. The pump was finally repaired in early August. In the meantime, we used the high-pressure city water pump to operate the boiler. Another item was the numerous flame safety alarms, which were found to be due to a weak UV detector tube. Another item was the need to add a trip circuit that would shut off the coal and reagent during a flameout without requiring a manual shutoff. These items, none of which affected the test schedule, were all resolved by the end of September..

Test DP 12 - August 5-6,1993

The first two multi-day continuous operation combustor tests were performed in August. Due to operational safety concerns on overnight coal fired operation, it was decided to implement these initial tests with oil firing at near the planned heat input during the overnight shift with resumption of coal firing on the following morning.

The first of the two tests, DP 12, was performed on August 5 and 6. The test had two major objectives. One was to achieve continuous operation in excess of 24 hours at a high thermal input. The second was to suppress the coal feed induced combustion fluctuations observed on the July 15 test. Prior to the test, the bin level indicator was replaced, and bin vibrators were installed on the lower bin. This substantially improved feed uniformity in the test. However, after several hours of coal-fired operation, the flame pulsations returned. Combustion continued for 27 hours. Operation began at 8 AM, with coal firing beginning at about 11 AM and it continued to 9:30 PM. At that time, combustor operation shifted to oil firing at about the same thermal input of 13 to 15 MMBtu/hr. At 7 AM the following day, coal firing resumed until 10 AM. We had to shut down because the combustor was drawing too much compressed air. This interfered with the operation of the manufacturing operation, which required compressed air for power tools. Otherwise the test could have continued on coal firing.

Since the combustor performance was similar to the previous runs, the data curves for coal, flow, steam, flow combustor wall and exit nozzle temperatures are not shown.

During the oil-fired period, the combustor wall temperature was deliberately lowered to below slagging conditions to prevent accumulation of frozen slag in the slag tap during this period. Also during this test, the 4 ton coal bin was refilled by a tanker while coal fired operation was in progress.

The air-cooled exit nozzle wall temperature stabilized at 16:00 hours at about 550^{o}F and slowly crept up to a little over 600^{o}F when the test stopped near noon of the next day. This result duplicated previous exit nozzle test results.

Test DP 13 - August 18-19, 1993

In order to be independent of the manufacturing plant' s air compressor and to evaluate the impact of reduced air flow from this compressor on the cause of coal flow blockage in test DP 12, a rented compressor was used for the next continuous two-day test on August 18 and 19.

For this test, four coal feed lines were used, as opposed to 6 feed lines in the previous tests because it was assumed that a constant air pressure would eliminate feed line blockage.

Test DP 13 had three major objectives: To perform a second continuous two day test, to improve combustion efficiency and slag retention by using different coal injection, and to increase the thermal input to the 17 to 19 MMBtu/hr range versus the 13 to 15 MMBtu/hr range of the previous test. To improve the compressed air distribution, all the pressurized air lines were re-piped to a central manifold which allowed better control of individual air lines to the combustor.

All the equipment that was exposed to a roof water leak on the 18th was cleaned by the morning of the 19th and combustor heatup resumed before 8 AM on the 19th. After completion of heatup, coal firing was initiated at 9:50 AM. It was soon determined that with only the 4 central injectors, the maximum coal feed rate was limited to 750 lb/hr, compared to 1000 lb/hr with the 6 point injection used in the prior test. This limitation was determined from the observation of coal backflow to the inlet of the coal feed eductor. This result showed that variable compressor pressure was not a factor in the prior fuel fluctuations and flame pulsations because the rented compressors capacity was 3 times the maximum compressed air usage.

When a burst of compressed air was momentarily applied to the one coal feed line that was most susceptible to plugging, the maximum coal feed rate increased. It was found that to maintain the 750 lb/hr coal feed rate it was necessary to use the compressed air clearing operation every 5 to 15 minutes. Since each operation resulted in the release of a burst of unburned coal into the boiler, it was decided to lower the coal feed rate to 500 lb/hr and eliminate this step. However, even at this lower rate, periodic puffs of unburned coal were released. This was attributed to the cyclic action of blockage of the line, followed by clearing of the coal feed line by the coal transport air from the eductor.

The test could have been stopped and the two swirl cage coal injectors could have been added to increase the coal feed to 1000 lb/hr, as had been done in the August 5/6 test. However, this would have resulted in repeating the low slag retention results of the previous test. Instead it was decided to augment the lower coal flow rate with 3 MMBtu/hr of gas and with No.2 oil in order to achieve a 17 to 19 MMBtu/hr thermal input to the combustor. This would provide continuous operating data on the combustor and exit nozzle cooling at higher thermal input.

Combustor operation with this three fuel mixture continued until 20:45 hours on the 19th. Computer data recording began at 15:00 hours after all the above fuel feed variations had been tested and the specific fuel levels had been finalized. The data will be shown below.

At 20:45 hours, the combustor was briefly shutdown in order to determine which coal lines were plugged. As suspected, the two lower lines of the 4 lines were plugged. However, only the section at the outlet of the flow splitter was blocked. The rest of the 4-foot long tube from the flow splitter to the combustor was clear. In previous combustor tests, where compressed air clearing of these tubes was not used, post test observation revealed that the entire tube was blocked, and it had been assumed that blockage began at outlet of the tubes into the combustor and propagated back to the flow splitter. The present result clearly showed that the blockage was at the flow splitter and any corrective action must focus on this device.

At 22:00 hours gas and oil firing at 13.5 to 14 MMBtu/hr resumed and continued throughout the night.

At the low coal flow rate of 500 lb/hr, the slag flow is less than 50 lb/hr. As a result of the low slag flow rate, the slag accumulated in the tap and the slag breaker kept getting stuck in the slag. While is was possible to remove it, the continuous operation of the breaker every few minutes caused it to distort. It was therefore decided on resumption of coal firing on the following day to limit the coal flow even further to 200 lb/hr where little slag would accumulate in the combustor. To reach the desired 19+ MMBtu/hr thermal input, the oil flow rate was increased. To limit the flow of slag, the combustor wall temperature was maintained at or below the slag melting temperature.

The test was terminated at 11:30 AM on the 20th. The combustor had been on line for 27.5 hours with one scheduled interruption for 1-1/2 hours to inspect the coal feed tubes the previous evening. In addition, there were several brief flameouts on the morning of the 20th, which were caused by a combination of a wiring problem in the flame sensor circuits and by the low combustion temperature resulting from the planned low wall temperature.

Another important result of this test is that the combustor and exit wall temperatures were maintained at fairly constant temperature throughout the two-day test, about the same as in the previous tests.

This second test also demonstrated the importance of maintaining a proper equipment maintenance schedule because a series of breakdowns were experienced that affected the test. None of these breakdowns were caused by the combustor. Some of them were involved the facilities, such as the leaking roof, the failure of the upper coal bin alarm to sound which resulted in overfilling of the 4 ton coal bin, and operational problems with the wet particle scrubber. The leaking roof problem was solved when the entire roof was replaced at the end of August. The overfilling of the coal bin problem was solved by assigning a technician to monitor the air pressure in the coal bin during refilling. This allowed a manual shutdown during refilling in the event of a failure of both the over pressure alarm and upper level indicator, such as had occurred during this test.

The scrubber operational problems were due to several factors. Poor performance was traced to a poor design by the manufacturer of the inlet gas cooling water spray, whose function was to decrease the stack gas temperature from 500°-600°F to 200°-250°F. The cooling spray was an integral part of the purchased scrubber. Prior to the September test, we installed our own designed water spray assembly, which substantially improved the stack gas cooling to the 140°-150°F temperature range. The other problem was caused by blockage of the scrubber water drain by sludge material. This was corrected in subsequent tests by increasing the outlet diameter of the drainpipe. The final problem was scrubber fan vibration, which was caused by deposits of minute ash particles that adhered to the fan wheel. The solution for the task 5 tests in Philadelphia was to replace the wet scrubber with a fabric filter baghouse. It has been necessary to clean and re balance the fan after about 5 to 10 days of testing, with washing of the wheel after each test. This fan problem would not allow safe operation of the scrubber on coal continuously in multi-day tests.

Test DP 14- September 23, 1993

The primary test objective was testing of a new dual pneumatic coal feed system, which was designed to achieve coal feed at rates of up to 1200-1400 lb/hr. With 2 MMBtu/hr pilot gas, this yield a 17.5 to 20 MMBtu/hr thermal input to the combustor.

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A sub-set of this objective was to test a pneumatic coal feed augmentation method to prevent blockage of the coal feed lines at the outlet of the coal flow splitter.

Another objective was to test the above noted atomizing water spray instead of the original manufacturer's water spray for cooling the stack gases prior to entry into the scrubber.

Another objective was to test the effectiveness of placing one of the flame safety detectors at the rear wall of the boiler. This was required because its usual location, the oil burner port was used in this test for another coal feed pipe.

The final objective was to test a slag grit suction system that had been installed in the slag tank in order to remove this grit, which regularly caused the slag conveyor to jam.

The key element driving the test plan was the new coal feed system. Based on operating experience, a test of several hours duration was deemed sufficient to allow the determination of the effectiveness of the new coal feed method. Also, since the objective was to evaluate the peak coal feed rate, the test plan called for coal feed rates in the 1100 to 1200 lb/hr range. This was higher than the 1050 lb/hr peak injection rates that had been achieved in previous tests with 6 point coal injection in prior tests. Even in that case, it was necessary to lower the coal feed rate to 900 lb/hr after about 5 hours of operation. The following describes each of the components or modifications tested and the test results.

Uniform coal feeding at a sufficiently high rate to achieve full rated boiler thermal input has been one of the primary test objectives of this project.

Prior to DP 14 test, a series of coal flow tests on pneumatic injection into the combustor using limestone, instead of coal, showed that by using a dual pneumatic coal feed system a total feed rate of at least 1200 lb/hr could be achieved. In test DP 14, one half of the coal feed was to the flow splitter at a rate of 600 lb/hr, while the balance was to an axial pintle. However, prior tests early in the Clean

Coal project in which only the axial pintle was used showed very poor slag retention and considerable combustion in the exit nozzle and boiler. Therefore, a feed splitter section was fabricated that allowed the coal from the feeder to divide into two pneumatic lines. This method proved to be very successful and it was used for the remainder of this project.

Coal firing began at 1 PM with ramp up to 600 lb/hr into the eductor feeding the flow splitter. The oil flow was then shutdown leaving a heat input of 2 MMBtu/hr from gas and 7.7 MMBtu/hr from coal. The oil burner was then removed and the pintle injector was installed. The feed section was then adjusted to divide the coal flow between the pintle and the 4 point injectors. The coal feed was increased to 1100 lb/hr. There were no blockage problems and the feed remained steady for the entire test period until scheduled shutdown at 6 PM.

As noted this was the first test in which the axial pintle was used for coal feed since 1988. As suspected, the combustion was concentrated in the central core of the combustor and especially in the exit nozzle. This was noted by the higher temperatures in the exit nozzle and by the substantial slag flow from the exit nozzle into the boiler. The hot side combustor wall temperature, which normally was at 2000^{o}F was several 100 degrees lower. Also almost no slag flowed through the slag tap. It was clear that the pintle was not driving the coal toward the combustor wall.

The division of coal between the two eductors was adjusted to force 2/3 of the flow to the 4 point injection system with about 750 lb/hr, with the balance going to the pintle. The shift occurred at about 5 PM. Immediately the combustor wall temperature increased and in about 30 minutes it reached the normal range of 2000^{o}F. Also, the slag flow through the slag tap increased substantially. This result shows the critical importance of off-axis injection for utilization of the entire combustor volume for combustion and for slag retention. It provided further confirmation on the unsuitability of the pintle for this combustor. ***(April 2003:Even more important, it showed the power of air-cooling, in that air cooling could control the slag flow, something that is totally unavailable with water cooling.)***

A second important result was the effectiveness of the pneumatic augmentation in the feed lines in maintaining the two lower coal feed tubes clear at the 750 lb/hr feed rate. This was confirmed after the test when both feed lines were found to be clear.

Therefore for the next test pneumatic augmentation was added to the other 2 inner and 2 outer coal feed lines. The pintle was removed. While the two outer feed lines were used prior to the August 18-20 test, they were connected to the same pneumatic feed line as the 4 point injection tubes. In addition, the design of the two outer injectors was modified to improve the dispersion of coal. This design was tested on 9/23/93 with calcium hydrate without any blockage.

In conclusion, the use of dual pneumatic coal feed lines, combined with pneumatic air augmentation in each flow line allowed **for the first time** the attainment of the desired 1200 lb/hr coal feed rate into the combustor. As designed, the axial pintle were found unsuitable due to the very high carryover of coal into the combustor exit nozzle with little combustion inside the combustion chamber. It is interesting that such a pintle was used by TRW in its water cooled, slagging combustors. For the next tests, the dual feed line system was used with a 6 point injection system in which two of the four injectors near the outer wall were connected to the second feed line, and all 6 injection points used pneumatic augmentation of the feed lines.

Also, the performance of the scrubber with the redesigned stack gas cooling water spray was found in this first test to be far superior to the original water spray in that the gas inlet temperature was reduced to 140-150^{o}F compared to the prior 200-250^{o}F. However, the location of the spray was too far from the scrubber inlet and excessive deposits of sludge formed at the scrubber inlet. This was corrected by moving the atomizer further downstream.

The test achieved several major new and important results. Of all the test objectives, only the slag grit removal system objective was not met in this test.

Coal injection: The dual pneumatic coal feed system functioned as per design. As a result it was now possible to inject sufficient coal into the combustor to achieve full 20 MMBtu/hr thermal input under conditions of uniform coal feed. One key elements in this success were the coal feed splitting device that was installed between the coal feeder and the two pneumatic lines. The second key element was the success of the pneumatic augmentation in conveying coal in all the coal feed lines without blocking of the feed pipes.

Flame Safety: The use of the boiler rear viewport for one of the three flame detectors was apparently successful in that no flameouts were experienced during normal coal fired operation. However, as this procedure was only used to allow use of the oil burner port for the coal pintle injection, this flame safety arrangement will not be required in the future. Instead the oil burner port will be used as in the past for the third flame detector.

Scrubber Operation: The use of an air driven water spray atomizer was found to be very effective in cooling the combustion gases to the proper temperature for effective scrubber operation. The energy balance on the water spray cooling of the stack gases was within 15% in balance, which is satisfactory considering the uncertainties in the various measurement techniques. It was planned to move the atomizer to minimize sludge buildup in the inlet duct

Soot Blowing of the Boiler Convective Tubes: This was the first test in which the effectiveness of soot blowing was measured for this boiler. It was found to be very effective in maintaining the boiler efficiency. After two brief periods of soot blowing, each of less than a minute duration, the stack gas temperature decreased from 620^{o}F to 450^{o}F. The latter temperature is near that obtained in this boiler with No.2 oil or gas. The ease with which the ash on the tubes was removed indicates that the deposits are dry and easily removable.

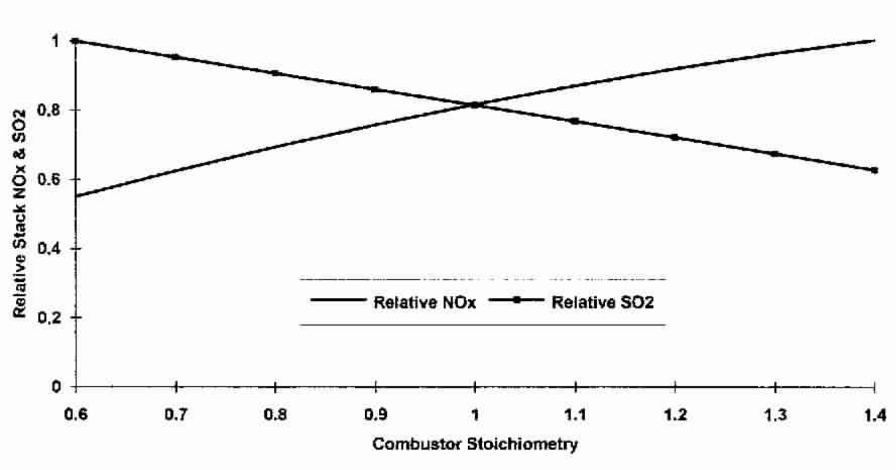
Refractory Exit Nozzle of the Combustor: A higher cooling rate was required to maintain the exit nozzle temperature in the desired range. This was due to the added heat release in the exit nozzle that was caused by axial combustion from the pintle injection. Also, post-test inspection revealed that much of the low temperature ceramic that had been installed on the inner wall of the exit nozzle had been melted during the last two tests. This slightly opened the inner diameter of the exit nozzle to the point where it reached the high temperature fused refractory wall. Since the tests of these 5 months with the air cooled exit nozzle showed that this method was an effective cooling procedure, the next step would be to replace the inner fused refractory material, which had last been replaced in 1990. However, a superior exit nozzle air-cooling design was developed that was used in the task 5 tests.

Added Comments on the Task 1, 2, and 3 Combustion & Environmental Performance

The primary emphasis in the tests to that date had been on combustor durability and coal feed optimization, and automatic computer control. To meet these objectives no attempt was made to achieve operation of the combustor under conditions of optimum combustion efficiency, slag retention, SO_2 and NOx control. Nevertheless, during combustor operation, data on these performance parameters was obtained. However, owing to the accelerated test schedule in order to complete all task 3 testing by mid-December, 1993, little detailed data analysis had been performed.

A total of 11combustor tests (DP-1 to DP-9, and DP-11) had been implemented in the three tasks. Within each tests, periods of different operating conditions were implemented. For a total of 32 different operating conditions. For each condition, the total heat input, combustor stoichiometry, computed flame temperature assuming no dissociation, the Ca/S mol ration, and % SO_2 reduction were tabulated, and reported in the 7th Quarterly Technical Report. . Statistical modeling of the analytical database indicated that simultaneous optimization of NO_x and SO_2 ***inside the combustor*** may not be possible as illustrated in figure 15. NOx is reduced with increasing fuel richness, while SO_2 increases. ***(April 203: This problem was solved after the completion of this project when Coal Tech Corp, using its own funds, developed post combustion controls in the furnace that reduced the remaining SO_2 and NO_x to minimal levels.)***

Figure 15: Stoichiometry Effects on NOx & SO2
Based on Statistical Data Modeling



BOILER GAS PROBE DATA ANALYSIS

A boiler gas-sampling probe was inserted through the rear boiler wall to a location that was within 2 feet of the combustor exit nozzle. Analysis of boiler probe gas sampling data for rich-lean and lean-lean combustor-boiler flame zones indicated that the secondary swirling air mixing was virtually complete about 1 to 2 feet downstream of the tertiary air injectors at the front inner wall of the furnace section of the boiler (see figure 5). In addition, with rich-lean staged combustion both CO burnout and char-sulfur evolution continue in the boiler but sulfur capture by carried over reagent was depressed. This was probably due to dead burning upon passage of the CaO particles through the second stage flame front. Conversely, lean-lean operation lead to quenched CO burnout but continued SO_2 capture in the boiler. In all cases, NO_x appeared to be frozen at its second stage exit value. The following discussion provides more details due to its importance in analyzing combustor performance.

During tests DP8 (5/11/93), DP9) (6/3/93), and DP11 (7/15/93) gas samples were extracted from the boiler firebox by n water cooled probe for on-line analysis O_2, NO_x, CO, and SO_2. The main goals were to assess the degree of mixing of the first and second stage gases and to evaluate the extent of continued gas phase reaction in the boiler by comparison of the boiler and stack gas species measurements.

The sampling probe tip was located about two feet downstream of the combustor exit nozzle, several inches below and to the right (end view) of the exit nozzle center line (see figure 5). This location was also less than one foot downstream of the second stage tertiary air injectors. It was, therefore, well positioned for detecting stratification or other in-homogeneities arising from incomplete first and second stage gas mixing.

Basically, two operating conditions were evaluated: classic fuel rich (FR) fuel-lean (FL) staged combustion in DP9 and DP11, and a FL-FL configuration in DP8.

The combined FR-FL data correspond to a first stage combustor inverse equivalence ratio (SRI) of 0.86 and a second stage SR2 of 2.09, with coal supplying 86% of the total fuel heat input of 12.5 MMBtu/hr. In addition, around 500 lb/hr of steam was injected for combustor temperature control.

The FL-FL data are for SR1=1.18 and SR2 = 1.69 with coal accounting or 80% of the 11.5 MMBtu/hr thermal input. Steam injection averaged 800 lb/hr. The above SR2's arc based on stack oxygen which, along with all other gas species, was measured on a dry basis.

Q_2 MEASUREMENTS

Fig. 16: O2 at Combustor Exit & Boiler Stack-5/11, 6/8, & 7/15/93 Tests

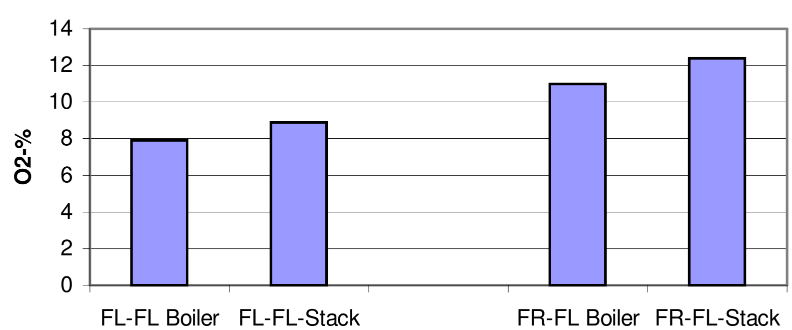


Figure 16 presents the boiler and stack oxygen measurements for both the FL-FL. and FR-FL conditions. In the FL-FL case, the boiler oxygen is only a little lower than that measured in the stack, namely 7.9 vs 8.9%. Similarly, in the FR-Fl case, the boiler and stack oxygen are close except that the boiler oxygen is now somewhat higher than the stack value, namely 12.4 vs 11.0%. With both cases having boiler vs stack oxygen agreeing within about 12%, it is concluded that the first stage off-gas and the second stage air are fairy well mixed at the sampling location, indicating that the directed flow of the tertiary air injectors is effective in providing rapid mixing.

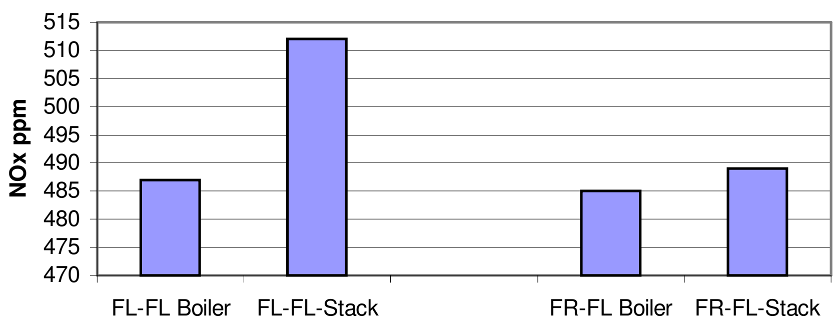
NO_x MEASUJREMENTS

Measurements of boiler vs stack NOx for both the FL-FL and FR-FL cases are shown in figure 17. All NO_x measurements are normalized to 3% 02 or 15% excess combustion air to account for dilution effects. As with oxygen, the boiler and stack NO_x levels are• very similar in each ease. Namely, in the FL-FL case the boiler and stack values are 487 and 512 ppmv, respectively while in the FR-FL cast the corresponding NO_x values are 485 and 489 ppmv.

The negligib1e change between the boiler and stack NO_x in each case, besides supporting the conclusion of a well inked second stage, additionally indicates that NO_x levels are frozen at their final values in the exit nozzle or in the early second stage due to thermal quenching by radiative heat transfer to the boiler tubes and/or by second stage air dilution- In both cases his results in essentially no further NO_x reaction in tile boiler.

Also initially surprising is the fact that the NO_x levels do not vary greatly with and without staging. In the EL-FL case the stack NO_x is 512 ppmv while in the staged FR-FL case it is 489 ppmv. One key element here is that the FR-FL case was only mildly staged at SR1=0.86, while previous testing had shown that SR1 of around 0.7 is required for NO_x control, (e.g. Ref. A-3)

Fig.17: NOx at Combustor Exit & Boiler Stack- 5/11, 6/8, & 7/15/93 Tests

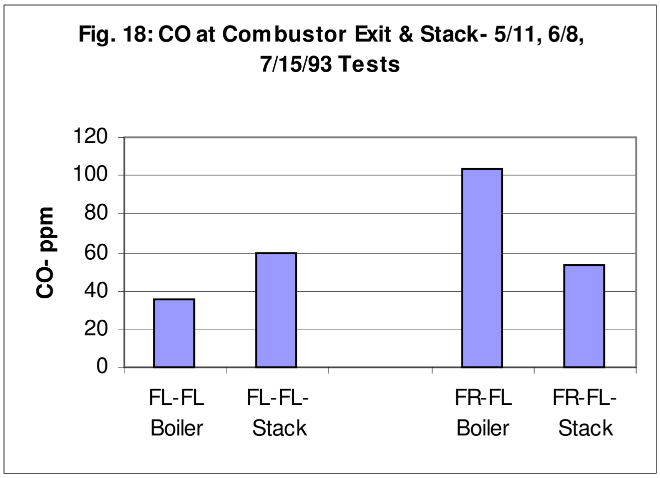


In addition, in the FR-FL case, the first stage (i.e. combustor) gas average temperature was 3170°F. Even with high second stage (i.e. furnace section) air addition which resulted in SR2 = 2.09 and a second stage gas temperature of less than 2100°F, the high first stage exit gas temperature probably gave rise to locally high flame temperatures in the second stage. This, in turn, probably generated thermal-NO_x, which partially offset the reduction in fuel-NO_x that is obtained with staging. This thermal-NO_x formation illustrates the importance of regulating peak flame temperatures in the second stage even with FR-FL staged combustion.

In any case, previous statistica1 modeling of NO_x data had indicated that final NOx values also depend on the amount of coal firing, as a percent of total fuel heat input (PCTPC). A statistical model of the currently available NO_x data vs SRI and PCTPC, for the present project, predicts 564 ppmv NO_x in the FT-FL case and 429 ppmv NOx in the FR-FL case. Since the error in the predictions is (+/-) 81 ppmv, the measured values lie within this deviation.

CO MEASUREMENTS

Figure 18 presents the boiler probe and stack probe CO data. The results were normalized as with NO_x. In the FL-FL case, the measured CO rose from 36 to 60 ppmv as the gas flows from the furnace section of the boiler to the stack. Although the absolute values are small, the increase corresponds to 67%. It would appear was that the higher stack CO in the FL-FL case was due to incomplete combustion of char carried over into the boiler. Although the first stage (i.e. combustor)



gas had an average (computed) temperature of about 2925°F, it was reduced by second stage air injection (i.e. final air injection) into the furnace section of the boiler to about 2400°F. The final combustion gas resulting from the second stage combustion was rapidly cooled by radiative heat transfer to the water tubes lining the furnace wall and the tubes in the convective section to 420°F in the stack.

From the above, it appears reasonable that the gas phase CO-to-CO_2 conversion, which nominally does not occur below around 1500°F, was thermally quenched. However, in light of the low absolute values of CO this mechanism is not significant in the FL-FL case in terms of overall fuel utilization or combustion efficiency.

It should be emphasized that these CO measurements are not a measure on the amount of unburned char, from which the overall combustion efficiency can be determined. The unburned char was estimated from the char in the slag (which generally was negligible) and the char in the scrubber solids. From this the overall combustion efficiency in the FL-FL case was determined to be 87 to 97%.

In the FR-FL case the boiler CO dropped from 103 ppnmv to 53 ppnw in the stack. Unlike the FL-FL case, where the introduction of the second stage air in the boiler resulted only in thermal dilution, fuel rich-fuel lean, staging will result in a second stage having locally high temperatures and a burning flame front extending into the boiler- Under these conditions, somewhat higher levels of CO could be expected just downstream of the second stage, even in a well mixed system.

However, the existence of a second stage flame front will promote CO-to-CO_2 conversion until the temperature falls below the gas kinetic threshold due to radiative cooling in the boiler. As a result the measured CO dropped from the boiler to the stack in the FR-FL case.

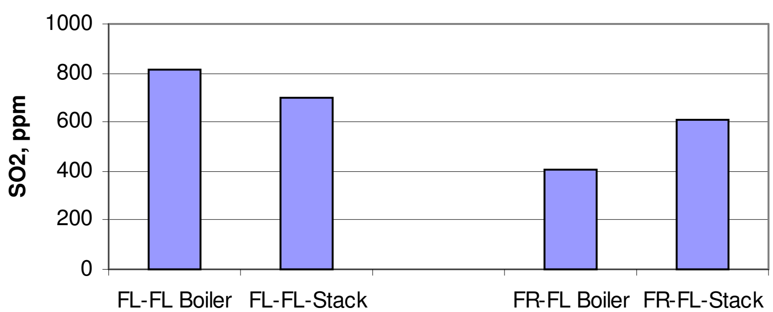
As with the FL-FL case, the absolute CO values in the FR-FL case are relatively low, again indicating that overall CO-to-CO_2 conversion is good.   However, as with the FL-FL case, the issue of unburned char carried over into the boiler is not directly addressed by CO measurements. Based on the same methods used in the FL-Fl. cases to assess the degree of carried over char utilization, the overall combustion efficiency in the FR-FT. case was determined to be 83 to 93%.

It ought to be noted that the relatively low combustion efficiencies obtained in these tests were primarily due to non-uniform coal injection, which lead to high char carryover into the boiler.

SO_2 MEASUREMENTS

Although significant lime (calcium hydrate) sulfur capture occurred in the combustor, the boiler probe data shed light on additional downstream effects. Boiler and stack SO_2 measurements, normalized to 3% O_2, are shown in figure 19. In the FL-FL case the SO_2 dropped from 817 ppmv in the boiler to 703 ppmv in the stack. This trend coupled with previous experimental evidence of significant calcium hydrate carryover out of the combustor, appeared to indicate that the sulfur capture reaction continued in the boiler to some extent, probably until gas temperatures below some reaction kinetic threshold.

Fig. 19: SO2 at Combustor Exit & Stack, 5/11, 6/8, & 7/15/93 Tests



Based on the CO data from the FL-FL. and FR-FL cases, it was believed that carried over char continued to undergo some degree of combustion, forming some CO and SO_2. In the FL-FL case, the carried over CaO captured this newly evolved SO_2, as well as SO_2 released in the first stage, i.e. inside the combustor, so that the net effect was continued SO_2 removal by CaO in the boiler.

In the FR-FL case, the opposite trend occurred, namely, the SO_2 increased from 407 ppmv in the boiler to 611 ppmv in the stack. This result suggests that SO_2 was formed in the boiler after the second stage. However, as already discussed in the NO_x and CO sections, the presence with staging, of a second stage flame zone probably also accounted for the observed behavior in SO_2. Therefore, in the FR-FL case, the carried over CaO must pass through the second stage flame front, which was expected to result in additional dead burning. Thus the overall effect was that the SO_2 released in the second stage (i.e. immediately downstream of the exit nozzle), from carried over char was not captured and its level increased to the final stack value. (***April 2003: The above analysis was performed in 1993.***

Based on subsequent task 5 testing, this dead burning assumption is highly questionable. More probably, the swirling combustion gases drive CaO particles into the colder gas regions immediately outside the hot cylindrical gas flow exiting the combustor. This probably accounted for the lesser reaction in the exhaust region, and not dead burning. This hypothesis is very interesting because it may explain why in SO_2 tests in the task 5 combustor conducted under other projects, the SO_2 level was generally higher in the stack than immediately downstream of the combustor exit, or near the colder regions nearer to the boiler furnace wall.)

As an alternative explanation for increased SO_2 in going from the boiler to the stack in the FR-FL case, the desulfurization in the boiler of carried over sulfated particles was considered. Here, passage through the second stage flame zone may partially desulfurize sulfated-particles. However, since thermal instability of $CaSO_4$ occurs above about 2200 to 2400^{o}F and gas temperatures were under 2100^{o}F at the probe location downstream of the second stage, the probe should have detected a frozen value for SO_2 with no additional desulfurization in the boiler.

A more complex interpretation would be that carried over sulfated particles were partially desulfurized upon passage through the second stage of the FR-FL gas stream, but the SO_2 is then recaptured in the boiler by carried over CaO. However, this mechanism requires the somewhat contradictory assumption that the second stage flame front was hot enough to desulfurize sulfated particles but not hot enough to cause CaO dead burning.

These last two hypotheses are presented to show the thought processes that were used in 1993. At the time it was concluded that the simple explanation for the increase in SO_2 in going from the boiler to the stack in the FR-FL case was due to SO_2 released in the boiler from continued combustion of carried over char. This SO_2 was not captured by carried over CaO particles as in the FL-FL case because it was assumed to have been dead burned by the second stage flame zone, (***or more likely the CaO particles were thrown out of the effective gas temperature reaction zone by the swirling combustion gases***).

The above analysis was in agreement with global correlations of calcium hydrate-sulfur capture with operating conditions in Coal Tech's Clean Coal I and the present project, which showed better sulfur capture with non-staged combustion. However, comparison of the final stack SO_2 values in the present two cases <u>superficially</u> suggests that SO_2 was captured more efficiently in the FR-FL case than in the FL-FL case. This is not correct for two reasons. One is that the coal used in the FR-FL. case had a sulfur content of 1.65% while that used in the Fl-FL case had 2.42% sulfur. Thus the expected SO_2, based on 100% conversion of fuel-sulfur to SO_2 and corrected for the relative coal firing rates was 1271 ppmv (FR-FL) and 674 (FL-FL) ppmv. On this basis, the reductions in stack SO_2 were 52% in the FR-Fl. case and 58% iii the FL-FL case.

A second factor is that the Ca/S ratio in the FR-FL case was 5.47 while in the FL-FL case it was 4.17. It should be noted that Ca/S mol ratio in excess of 3 arose from the need to inject limestone for slag conditioning, along with calcium hydrate for sulfur capture. Based on a unit Ca^1S ratio, the superior performance of un-staged operation is clearly perceived with the FL-FL. reduction being 14% CaO utilization vs 9.5% for the FR-FL case. (*April 2003: The high Ca/S mol ratio is misleading because the limestone particles were mostly captured in the combustor. Also, it was determined the limestone has only 1/3 the effectiveness of lime*.)

GAS TEMPERATURE MEASUREMENTS

During tests DP9 and DP11 the gas sampling probe also served as a suction pyrometer for gas temperature measurement. A W-5% Re/W-26% Re thermocouple was installed inside the probe with the measuring junction at the sampling tip. The junction was surrounded by a single alumina tube shield to minimize conductive and radiative heat losses. However, owing to the relatively small diameter of the gas sampling tip, it was not possible to install the multiple refractory shielding necessary to obtain accurate readings. In addition, the gas sampling pump was ***almost certainly undersized*** resulting in sufficient convective heating of the measuring junction The gas temperatures obtained with this system were 950^{o}F in DP9 and 840^{o}F in DP11. Even taking into account rapid gas cooling in he boiler, these measurements were well below the expected second stage exit gas temperature of about 2100^{o}F. (***April 2003. This pump was a very small fractional horsepower gas sampling pump. Coal Tech used the same probe for suction thermocouple temperature measurement above the traveling grate of a 90 ton/day municipal incinerator, where we found a very large temperature difference between the values recorded when the probe tip was inserted into the luminous flame and when the readings took place above the luminous flame. The probe was also used to measure gas temperatures in a 37 MW, 50 MW,, and 100 MW coal fired utility boilers before and in the superheater sections. In all cases the gas temperature was within the range measured for those locations. However, in all those cases, we used a much larger vacuum pump to provide the sampling gas suction.)***

CONCLUSIONS FROM BOILER GAS SAMPLING

1) The first stage off-gas (i.e. combustor exhaust gas) and the second stage air (introduced into the boiler furnace at the combustor exit) are well mixed just downstream of the final air injectors at the front face of the boiler (figure 5)..

2) With no staging final NO_x levels appear to be quickly frozen in the first stage exit (i.e. combustor exit) due to thermal quenching by second stage air dilution and radiative heat losses in the boiler, resulting in no further gas phase NO_x reaction in the boiler..

3) With staging, NO_x quenching occurs early in the second stage due to cooling by radiation to the boiler tubes, resulting in no further gas phase NO_x reaction in the boiler. However, excessive second stage temperatures may lead to formation of additional thermal-NO_x which partially offsets the reduction in fuel-NO_x obtained by staging.

4) Depending on operating conditions, mass balance data showed that a variable char fraction was carried out of the combustor. This char continued to burn in the boiler for an indefinite period, initially forming CO. In un-staged combustion, further conversion of CO-to-CO_2 is suppressed by thermal quenching of the first stage off-gas by second stage air dilution and radiative heat losses in the boiler. With staging, the existence of a second stage flame front allows CO to be converted to CO_2 until the hot gases are cooled by radiation to the boiler tubes. In either case, the absolute levels of CO were low so that the CO-to-CO_2 conversion had little impact on overall fuel utilization or combustion efficiency.

5) In addition to partial combustion to CO, char carried over into the boiler also releases some

SO_2. Without staging, CaO carried over into the boiler continues to capture some of this "new" SO_2 as well as SO_2 formed in the combustor. With staging, the boiler released SO_2 remains un-reacted with CaO, which was assumed at the time (1993) as being due to carried over CaO that dead burned upon passage through the second stage flame front. This was the reason given for the global correlations that sulfur capture was better with unstaged combustion than with staged combustion. (*April 2003: Based on test work in Philadelphia after the completion of this project, a more likely explanation is that unstaged combustion gases had a higher swirling gas flow velocity. This resulted in a wider conical hot gas zone past the combustor exit. Since some of the lime was injected in the final combustion air pipes (see figure 5) the reaction of this lime, as well as CaO particles leaving the combustor, resulted in better mixing of solids and SO_2 gas molecules, which would account for the better sulfur capture with unstaged combustion.*)

6) Boiler probe data were in agreement with historical data, which showed that stack NO_x is less at lower SR1, while stack SO_2 is lower at higher SR1. This result suggested at the time (1993) that a trade-off to controlling these two pollutants was required in selecting optimum" operating conditions. (***April 2003: This is not a problem today because post combustion processes developed after the completion of this project can eliminate almost all the remaining SO_2 and NO_x.)***

Task 3: The Final 10 Proof of Concept Tests- Fall 1993

The information gathered in the previous Task 3: "Proof of Concept" tests were used to design the final tests in this task. The next step was the Task 5:" Site Demonstration" task in which all the information of the previous 4 tasks, including the task 4 "Commercialization" effort were to be incorporated in a final redesign of the 20 MMBtu/hour combustor and applied to a commercially ready combustor. It was envisioned to actually place the combustor in a commercial configuration that generated about 500 kW of electricity for sale. However, there was no way that this would have been possible at the Williamsport site, if for no other reason that it had been clear long before then that the key personnel could not be located 175 miles from the test site. Also, the operational conflict between the requirements of manufacturing and test operations by the site owner and Coal Tech's project made such an effort essentially impossible to implement within the project resources. It should be noted here that the original proposal for task 5 on this project was about double the amount allocated for the actual entire project. In retrospect this lack of funds, which in light of what was accomplished since then, including subsequent to the end of this project, was really unfortunate. At present (2004) this combustor is an ideal device for implementing a low cost strategy for total reduction of all coal combustion emissions, including CO_2 and mercury.

Fortunately, by an incredible coincidence, just as the task 3 effort was completed, Coal Tech was notified at the end of November 1993 that the entire plant site had been sold, and we would have to vacate within 60 days. The P.I. immediately decided to move the facility to Philadelphia. Had we stayed, we would have most probably implemented task 5 in Williamsport, with only modest changes to the combustor. Also, all the equipment would have been scrapped at the end of the original project completion in 1995. Instead, the facility is still operational, and we installed a superior combustor and test plan that cut costs to such an extent that we doubled the number of tests in task 5. In addition, we continued, at Coal Tech's expense, post-combustion emission control R&D to the point that Coal Tech has developed processes that could eliminate all emissions from coal fired power plants. The task 5 effort is described in Appendix "C".

Ten days of testing were conducted in the 4th quarter of 1993. This completed the key test objectives planned for task 3. To show the development of the technology, these tests as well as key results are described in this section in chronological order.

Test DP 15- October 20, 1993

The first test, coded DP 15, was performed on October 20,1993. The focus of the test was on combustion optimization. This was a brief one-day test in which uniform coal injection was achieved by using 8 injector ports instead of the normal 4 or 6 injection ports used in most prior tests. Previous tests showed that four injection locations limited to the coal to a total of about 750 lb/hr of uniform feed. The other four injection ports were previously used for reagent injection. In previous tests in which over a 1000 lb/hr of coal injection had been achieved, two of these four outer ports were used for coal injection.

For the present test, the coal flow from the coal feeder was divided into two pneumatic flow transport lines. One was used to feed the original four feed tubes, while the other was used to feed the other four feed tubes. Instead of separate injection of the reagent, in this test it was mixed with the coal. This freed the four reagent lines for coal feeding.

Coal firing was limited to several hours, as the purpose of the test was only to verify the suitability of this arrangement. The results confirmed the superiority of this arrangement. 30% of the slag was collected through the slag tap. This was the highest level achieved in the tests in this project. An equal amount of slag was collected after the test at the ---outlet of the exit nozzle inside the boiler.

Fig. 20: Scrubber Particle Retention vs Coal Injection-Test Date (L-R)8/19, 7/15, 8/6, 9/23, 10/20/93

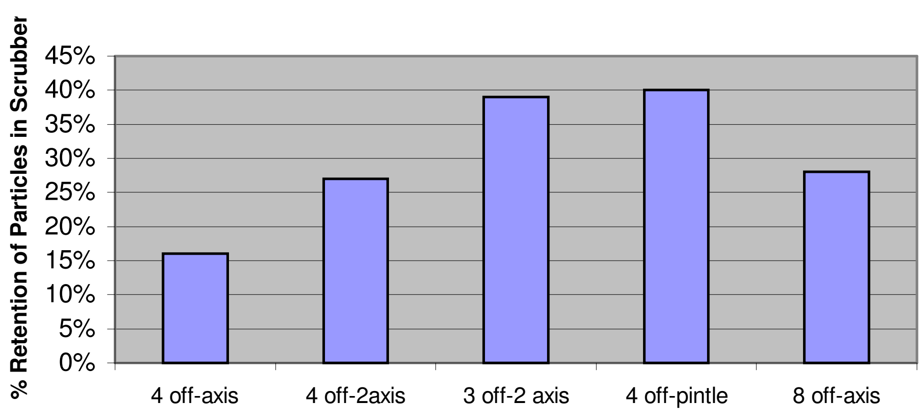
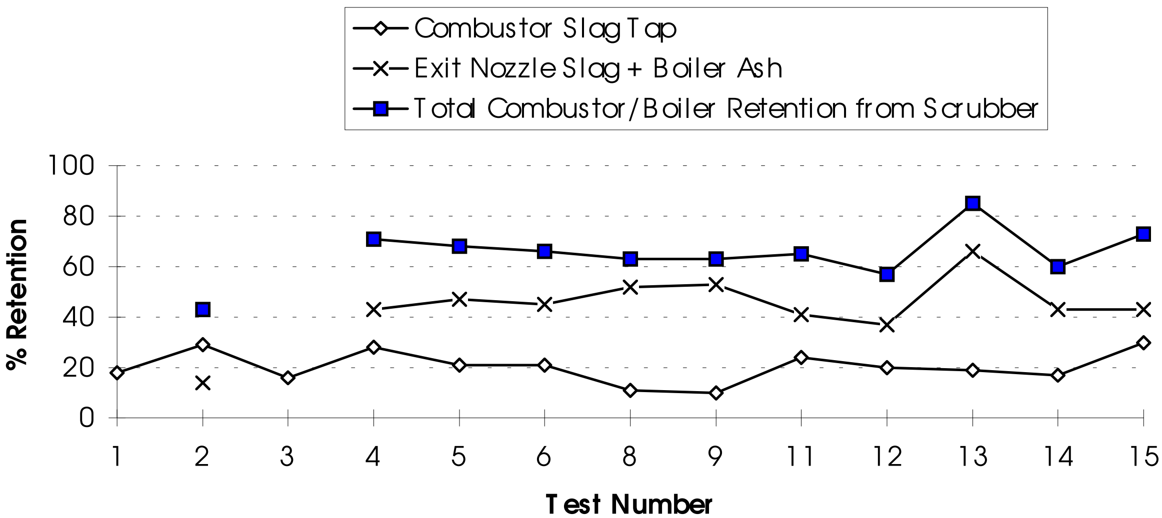


Figure 20 shows the scrubber solids retention for 5 tests with different coal injection locations and methods. With the latest 8 injectors, (10/20/93 test) 25% of the solids reported to the scrubber. This was much lower than the 40% with 4 off axis + axial pintle (9/23/93) and the 39% with 3 off axis+2 axial injectors (7/15/93). It was about the same as the 27% with 4 off axis+2 axial (7/15/93) and higher that the 16% with 4 off axial injectors ((8/19/93). However, these four earlier tests were at substantially lower coal feed rates.

Figure 21 is a mass balance of the slag and ash distribution that was removed from the slag tap, the exit nozzle slag and boiler ash combined, and the ash collected in the scrubber. The slag contained essentially no carbon, while the boiler ash and scrubber ash had unburned carbon. This has been

Figure 21: Total Ash & Slag Retention versus Project Test No. (8/92 to 10/93)



removed from the data shown. The tests took place between August and October 1993. (The 8/92 should be 8/93). The key result is that about two-thirds of the slag/ash was retained in the combustor and boiler proving that the combustor was too short.

In addition, the measured SO_2 reduction in these final tests with improved and higher coal injection was in the 60% range, which was also higher than the values measured in prior tests.

Another significant result was that it was possible to bring the combustor to the full planned thermal input after a flameout using coal for restart, as opposed to No.2 oil. The wall temperatures increased very rapidly to steady state levels. In prior tests, after flameout, the use of coal only to restart and reheat the combustor wall would result in slag and char buildup on the combustor wall followed by slag flow flooding of the slag tap once operating temperatures are achieved.

These results in this test demonstrated the importance of rapid mixing of the coal, reagent and air at the inlet section of the combustion chamber.

Test DP 16- November 2, 1993

This test was the first one to use 8-point coal injection, which was used in the previous test, on a regular basis. This allowed uniform injection at coal feed rates in excess of 900 lb/hr. The first three of the six-hour coal fired period was performed at 1150 lb/hr with a total fuel input of 17 MMBtu/hr. Both fuel rich (SR1=0.8) and fuel lean (SR1=1.1) conditions were maintained in the combustor.

This test was also the first one in which additional transport air controls were added to the pneumatic feed lines in order to balance the feed to all injection points. After 3 hours of operation, the input to the pneumatic feed line began to back up with coal forcing a cutback in coal feed. This was not implemented fast enough and a flameout occurred. On restart, the gypsum injection test was performed in which various levels of $CaSO_4$ ($2H_2O$) were injected to test reagent and slag desulfurization. These results were not analyzed at the time. However, gypsum injection was performed contemporaneously with the task 5 tests under another project (Ref. A-7).

A key result of this test was the finding that several slight modifications were needed to the coal injection system. One was operational in that the proper pneumatic airflow rates were established. It was found that excessive transport air caused erosion of combustor liner refractory near the outer coal injection points. The other was the finding that pintles were not as effective as off-axis injectors in yielding rapid mixing of coal and air. These were minor adjustments compared to the key result that uniform high coal feed rates could be achieved. As reported above, in prior tests uniform continuous feed rates above 900 lb/hr could not be maintained without an axial pintle. However, as shown in figure 20, the use of the axial pintle resulted in excessive ash carryover out of the combustor.

This test maintained the effectiveness of the new computer operated wall temperature control in maintaining a constant combustor wall temperature (within 50°F at 2000°F) even at these higher feed rates of 1100 lb/hr.

<u>Test DP 17, 18, and 19- November 9,10 and 11, 1993</u>

<u>a) DP 17 & 18</u>: These tests were the first in the accelerated test schedule which was necessitated by the decision of the test facility landlord to close the plant at the end of December. The first two days of testing were devoted to a DOE-SBIR project on the control of dioxin emissions from high chlorine content waste fuels. However, a substantial part of the combustor operating data and combustor durability data is directly applicable to the present project, and those relevant results are reported here.

A key requirement of this dioxin test was to maintain the combustor at a steady condition for the entire period of the two test days in order to obtain dioxin stack gas samples meeting EPA test procedures. Accordingly, it was decided to perform all the test conditions at a steady 900 lb/hr of coal feed because insufficient operating time had been accumulated at the higher feed rates to assure reliable continuous operation.

Two flameouts early in the test day were caused by a trip in the high pressure fan controller. This problem recurred several more times during the remaining tests. It was partly resolved by increasing the rating of the heater elements on the motor controller. However, it appears that there is some random defect in this controller, and if it continues to recur in task 5 testing, the controller will be replaced. (*April 2003: This fan was never used again. Instead an improved air-cooling system was designed and a fan rated at one-half the power was used.*) The computer data collected for the next day's test, DP18 was lost during its retrieval at the end of the test day. Only the last hour's test data was saved. However, as all the test conditions until the last hour remained unchanged this data loss is not important.

b) DP19: After the successful completion of the dioxin tests on the 10th, the following day' s test was devoted to continuing the higher coal injection rate tests and coarse coal injection tests.

A study of a 20 MW re-powering project performed as part of task 4 showed that the cost of the coal pulverization system is a very substantial components in the cost of the plant. It was, therefore, of considerable interest to determine the performance of this combustor with coarser ground coals as this would allow the use of much lower cost (*as much as 10 times lower*) coal crushers. Therefore, the first part of this test was devoted to injecting, at a rate of 1000 lb/hr, one ton of coal having a 44% minus 200 mesh size distribution versus the normal 70-80% minus 200 mesh distribution. This was followed by full boiler thermal input operation at 1300 lb/hr of coal and 2.3 MMBtu/hr of gas, for a total of 19 MMBtu/hr heat input. At both flow rates, fuel rich and fuel lean conditions were used in the combustor.

One important observation was that the combustor wall temperature was substantially higher than had been the case in the tests prior to the initiation of the high coal flow rate tests on November 2nd. Once this was recognized, it was nevertheless possible to maintain the combustor air-cooled metal tubes at a safe temperature. However, this was only accomplished by lowering the combustion temperature, which resulting in lower combustion efficiency and slag retention in the combustor. Before this corrective action was taken the average combustor wall heat transfer rate was about 20% higher than the previously measured peak levels. Furthermore, based on the measured refractory liner thickness in the roof section of the combustor after the combustor was disassembled in December, the local heat transfer rate in this roof section was about double the peak average value. That the metal cooling tubes survived this high heat flux is a measure of the effectiveness of the various combustor wall temperature control procedures that were introduced over the years since 1988. In early 1988, the combustor refractory roof section failed completely and the cooling tubes partially melted at fuel firing rates that were lower than those attained in the present tests.

Rather than refurbish the combustor roof section, we decided to implement ash replenishment procedures in the following tests. This will be reported below.

c) Boiler Performance.-*Sticky Deposits* The dioxin control tests, DP 17 & 18 had an effect on the boiler performance that is of some significance in evaluating the impact of this combustor on oil designed boilers. One of the key concerns on the applicability of the present test effort to commercial operation is the relatively short total test time accumulated. Since the test effort on this combustor-boiler system was initiated in 1987, about 1800 hours of total operating time, with about 1/3 on coal, have been accumulated. Therefore, one may question the relevance of this relatively short operating time in evaluating the impact of the combustor on the boiler. The dioxin tests suggest that this is more than sufficient time for the combustor to impact the furnace section of the boiler.

During these tests, a salt, $CaCl_2$, was injected at a rate sufficient to reach chlorine concentrations of 2.4% (by weight) of the coal flow. After the completion of these tests internal inspection of the boiler revealed a 3/8 inch thick deposit of a sticky material that covered the entire downstream half of the furnace section roof, end wall and two side walls, as well as the initial set of water tubes in the convective section of the boiler. It was found that this material could be washed off completely with cold water. This cleaning was implemented in the week after the tests, prior to the next test on November 18th.

It was initially thought that this entire deposit consisted of calcium chlorate dihydrate, which is very soluble in cold water. However, a chemical analysis of the deposit revealed that only about 3% of this material consisted of chlorine. It was, therefore, concluded that the chlorine compound acted as a glue which bonded successive layers of fly ash to the boiler tubes. This result shows that if any low temperature compounds had existed at any time in the past 7 years of coal fired operation, the boiler wall would have long since developed thick deposits on the tubes. The fact that this did not occur shows that normal operation of this combustor will not lead to slag buildup of the boiler tubes.

d) Boiler Performance- *Soot Blowing*: Another measure of the impact of this combustor on the boiler is the effect of sootblowing on boiler performance. All oil designed package boilers have soot blowers in the downstream end of the convective tube bank. In this boiler the sootblowers use steam from the boiler. Due to oversight, the sootblowers were not used in the task 2 tests and in the task 3 tests prior to the September 23rd test. By that time well over 100 hours of coal-fired operation had been accumulated. As the task 3 tests proceeded, it was noted that the gas temperature at the boiler outlet, i.e. the base of the stack, gradually increased from about 500^{o}F to over 600^{o}F. This compares with a 450^{o}F stack temperature with oil. During the 9/23/93 test, a short 10 second burst of sootblowing was implemented at about 15:45 hours. This immediately decreased the stack gas temperature from 620^{o}F to 500^{o}F. A second 10-second burst near the end of the test decreased the temperature to 450^{o}K, the same as with oil. The impact of the sootblowing increased steam flow from about 12,000 lb/hr to 13,000 lb/hr after sootblowing at 15:45 hours.

Subsequent to this test soot blowing was implemented on a regular basis at the end of each test day. The stack gas temperature at the base of the stack was maintained in the 450^{o} to 500^{o}F for all subsequent tests. The significance of this result is that it demonstrates that the deposits on the boiler tubes are basically dry ash and they are readily removable. Therefore, with suitably placed soot blowers it should be simple to maintain steady long term operation in these oil designed boilers.

e) Boiler Performance-*Ash Deposition:*: It has been reported previously that an ash blowing device had been installed inside the boiler furnace section early in the task 3 tests. This device was located on the opposite wall from the convective tube section. It was effective in blowing ash toward the other wall. In the present three-day tests, over 9 tons of coal were consumed, and 1820 lbs of slag and ash were removed from the combustor, boiler, and scrubber during and after the tests. 35% of this mineral matter was dry ash that accumulated on the furnace floor and 7.5% accumulated at the bottom, upstream end of the convective tube section. This relatively high carryover of mineral matter from the combustor was due to a number of factors, the most important of which was combustion efficiency. *(April 2003: Based on the task 5 tests results in the longer combustor, where the ash deposition in the boiler was a very, very small fraction of this, it is concluded that the high deposits in the boiler in Williamsport was due to too much unburned char blown out of the much shorter combustor.)* As noted above, it was necessary to maintain a lower than normal combustion gas temperature to limit the wall heat transfer rate to the combustor wall. This adversely affected the combustion efficiency. (*April 2003: This only made the unburned char blown out worse.)* In any case, there was no means to remove this ash while the combustor was in operation. This ability to remove ash from the boiler floor was included in the design of the task 5 effort, but it was never needed.

f) Boiler Performance--*Boiler Restoration Inspection:* Following the completion of the task 3 tests on December 2nd, the combustor was disassembled and removed from the boiler. Since our contract with the site owner called for restoring the boiler to its prior use, we retained a boiler inspection specialist to carefully examine the boiler internals. This boiler is a Keeler-D Frame unit rated at 250 psig saturated steam and 17,5000 lb/hr. A detailed ultrasonic inspection of all the accessible boiler tubes was made, including all the tubes in the furnace section and the convective tubes. The upstream end of the tubes were accessed from the furnace side while the downstream convective tubes were accessed from the stack side. All tubes were found to have an average wall thickness of 0.11", which is 0.020" higher than the minimum allowed by the manufacturer. There was no evidence of any tube erosion.

In addition, no corrosion was found underneath the refractory floor tiles which are placed on top of the floor boiler tubes. The use of floor tiles was generally discontinued in the late 1970;' s in favor of a web construction. The reason for this was that moisture would accumulate underneath the tiles, which would lead to corrosion of the tubes. Since we operated the boiler intermittently over the past 7 years, there was concern that moisture from condensation would form underneath the tiles. However, inspection revealed no evidence of corrosion. It is hypothesized that the reason for this is that some of the coal particles were carried out of the combustor and deposited on the boiler floor. This coal char would continue to smolder for several days after a test. In addition, slag flowing out exit nozzle provided another heat source to limit condensation. In fact, it took a minimum of 3 days before the boiler cooled off.

The one area that needed replacement is the front plate and part of the refractory of the furnace section of the boiler. This plate was perforated with various holes that were inserted for the combustor exit nozzle and final combustion air.

Rather than refurbish the boiler we purchased it for a sum that was in the range of what we would have had to pay for another equally rated used boiler. The boiler is still in use after the completion of task 5 testing.

In conclusion, the operation of the combustor did not have an adverse effect of the boiler' s fire side components during the past 7 years of operation.

Test DP 20- November 18, 1993

This test had three objectives.

- To perform ash replenishment of the combustor wall at a low thermal input.
- To determine the effect of swirl on the combustor performance.
- To fire with a very coarse coal size distribution, namely 30% minus 100 mesh.

Ash Replenishment: As noted above, during the high coal thermal input test earlier in the month, the combustor wall heat transfer exceeded the previous peak values. This resulted in thinning of the refractory liner, especially on the combustor roof. It was estimated that the roof section was only 1/3 of its thickness at the completion of the refurbishment in the Spring of 1993. Rather than rebuilt the liner, it was decided to use ash replenishment, which had been tested successfully under the prior DOE-SBIR Ash Vitrification Project. 200 lb/hr of a western coal fly ash was injected with the combustor operating at 750 lb/hr of coal.

The hot side ceramic liner thermocouples (i.e. those nearest the liner-gas interface) failed due to overheating during the high coal feed rate tests. While they were replaced, it was not possible to place them at the exact same location in the liner. Therefore, a comparison of the wall temperature before and after liner replenishment with fly ash would not be meaningful. Instead the thermocouples in the rear of the liner near the air-cooled metal tubes were used for test DP19, (Nov.11) before ash replenishment. After steady operation was reached, at about 13:30 hours, the wall temperature was a steady 1400^{o}F during this test. The same thermocouple reading for the present test, DP20 showed that once steady state was achieved at about 13:00 hours, the temperature averaged somewhat less than 1300^{o}F, which is over 100^{o}F lower than in the previous test. This indicates that the slag layer thickness has increased compared to the previous test.

The replenished liner thickness is determined from the slag liquid flowing temperature, which was in the range of 2200-2500^{o}F depending on the slag properties. The thermal conductivity of slag is lower than that of alumina based refractories. It is about 0.75 Btu/hr-ft-F between 1500 and 2500^{o}F. [See Appendix C in Combustion, J.G.Singer, Ed. CE, Windsor,CT,1981]. Therefore, for the 20,000 to 30,000 Btu/hr-ft^2 heat transfer rates at which these tests were implemented, a slag liner thickness of only 0.3 to 0.45 inches is sufficient to provide the necessary temperature drop of about 1000^{o}F between the above measurement and the slag melting temperature.

Several more ash replenishment periods were implemented in the remaining four test days in task 3. After the combustor was disassembled in December, there were two distinct refractory regions on the sidewalls of the combustor. An outer liner consisting of the replenished liner thickness was approximately 0.5 inches thick, and an inner liner of the original refractory had same thickness. A chemical analysis revealed that this layer was enriched in slag in that its silica content was 31% (by weight) while the alumina content (which was the original liner material) was 30%. The alumina in the coal ash was about one-half that of the alumina. Therefore, only about 15% of the original liner material was present in this outer layer.

The chemical analysis of the inner liner was 56% alumina while the silica content was 12%. This shows that this layer consisted mostly of the original liner.

The roof section of the combustor liner was half the thickness of the side walls. A chemical analysis of a sample of this section had an alumina content of 45% and a silica content of 21%. This showed that it was mainly the original liner, but with a higher penetration of coal slag. This analysis indicates that the replenishment was not effective on the roof section. Since the upper section is hotter, the mass flow rate and hence the tube air-side heat transfer coefficient is lower than on the floor section. In addition, due to the effect of gravity, the liquid slag layer thickness is always thinnest on the roof and it gradually increases down the side walls. Therefore, to replenish the roof section, the air flow rate on the top half of the combustor must be increased relative to the lower half. Overall, the result of the ash replenishment tests show that is effective in rebuilding the refractory liner of the combustor.

Effect of Swirl Velocity of Combustion : Since no data was available at low swirl in the combustor, the swirl inlet pressure was lowered by 50% from its normal value. This test was performed for 1 hour at 750 lb/hr of coal and fuel lean conditions, after the completion of the ash replenishment. This was followed by a low swirl 1 hour test at fuel rich conditions and the same feed rate. This data was not been analyzed in detail. However, no significant difference in performance was observed at the lower swirl values.

Coarse Coal Combustion Test: After the completion of the above tests, a 1000 lb of the coarse (35.5%-100 mesh) coal was fed at 750 lb/hr. The first test conditions was fuel lean with calcium hydrate injection.. When it became apparent that the large coal particles were blowing out of the combustor, the hydrate was replaced with fly ash and this improved the retention of larger particles. The data from this test was not analyzed because it was then clear that a longer combustor would be needed. In that longer combustor used in task 5 another coarse coal test was implemented with satisfactory combustion.

During all these tests, a wire basket was used to catch the slag passing through the slag tap. This allowed a determination of the slag flow rate for each test condition. This is not perfect determination because slag from a previous condition can melt and flow out at the next condition. The results were not analyzed in detail. One result was that at most of the test conditions the slag tap passed about one-half of the total slag, with the balance collected at the outlet of the combustor exit nozzle inside the boiler. This provided further confirmation that the combustor should be lengthened to provide better carbon burnout and slag retention in the combustor.

Test DP 21- November 22, 1993

The previous test had been performed with alternating periods of fly ash injection for slag replenishment, followed by injection of calcium hydrate for SO_2 control. In the present test, the primary objective was to inject a 50%-50% mixture of fly ash and calcium hydrate in order to perform both functions simultaneously. Another objective was to operate at full thermal input to the combustor with a coal feed rate of 1300 lb/hr and a total heat input of 19 MMBtu/hr. The initial 4 hour test period was at 1000 lb/hr, followed by 2 hours at 1300 lb/hr.

Scrubber Performance: At the end of the above test time, 17:00 hours, the scrubber fan motor failed when a bolt sheared and shorted the power leads into the motor. In January 1993, one of the three windings in this motor had failed and it was taken by our maintenance sub-contractor to a motor shop to be rewound. After the present failure we sent the motor to a local repair shop. We learned that the previous repair shop used by our sub-contractor at that time had replaced the motor instead of rewinding it. It is interesting to note that the original 30 hp scrubber fan motor as well as the 5 hp primary air fan motor, which failed last year, were both manufactured by a foreign company. We replaced the 5 hp motor with an American brand and it operates to this day, 2003. Both motors failed after only 1000 to 1500 hours of operation.

Another interesting scrubber related result was the observation that after this test the scrubber fan was again out of balance. It had been previously balanced in April and September. The fan bearings were also replaced in April. In addition, the entire fan housing was replaced in April because of severe wall corrosion. At first the vibration problem was attributed to lack of maintenance of the bearings. However, this could not account for this last vibration problem, which occurred with only about 50 hours of operation. The only explanation was that very fine ash particles deposited on the fan blades, which drove them out of balance. This is especially a problem in the present application where the high CaO content of the fly ash yields a cementitious ash. A baghouse stack cleanup system that uses a stack ID fan should be much less susceptible to this problem. For a wet scrubber it is necessary to add a grit removal device before the fan to remove these deposits to keep the fan balanced.

In some of the tests in August 1993 it was observed that the scrubber performance deteriorated under variable and heavy solids loading conditions. On discussing this problem with the manufacturer, they attributed it to too high a gas inlet temperature to the scrubber. As noted in a previous section, the stack temperature was as high as 620^{o}F before we instituted regular soot blowing. The scrubber does not function well with gas inlet temperatures above 250^{o}F. On examining the scrubber water spray system at its inlet, we concluded that the manufacturer' s design for cooling the scrubber inlet gases to this required temperature was ineffective. Accordingly, in September 1993 we designed and installed a spray cooling system that was located further upstream of the manufacturer' s system. This proved to be very effective in cooling the stack gases, and the measured temperatures at the scrubber inlet were in the 130-140^{o}F range. This dramatically improved the scrubber performance even at heavy particle loading conditions. In fact the initial cooling design was too effective in that considerable wet ash deposits formed at the scrubber inlet to the point were after one day' s operation half the inlet cross section was blocked with ash sludge. This blockage was an artifact of the present duct design between the existing boiler stack and the scrubber duct system. Relocating our gas cooling system closer to the scrubber vessel inlet sharply reduced the duct blockage without any measurable increase in the scrubber inlet gas temperature. (*Note added in 2003: Although the scrubber was not used in task 5, it was taken to Philadelphia. The scrubber inlet was of stainless steel, which was stolen by a scrap dealer who regularly entered the Arsenal test site despite security at the gate*.)

The overall conclusions concerning scrubber performance from all the task 3 tests are that duct layout and stack gas-cooling method are key parameters in efficient scrubber performance and blockage free operation. Also, a cleaning device must be added to the scrubber fan to prevent deposit buildup on the fan blade, which can rapidly go out of balance and destroy the fan.

<u>DP21 Test Results</u>: Coal flow was initiated at 10: 45 AM and fired at 1000 lb/hr. At 11:30 a flameout occurred when the primary air fan tripped. As noted above, it is believed that these trips were due to a defect in the motor control circuit. Initially a mixture of 115 lb/hr of fly ash and 115 lb/hr of calcium hydrate was injected with the coal. In addition, 100 lb/hr of limestone was injected separately. These test results have as yet not been analyzed. One major observation noted during the test was the tendency of the ash-hydrate mixture to clump and block the pneumatic feed lines. This was probably due to the absorption of moisture by the hydrate in the mixing process prior to placing the mixture in the feeder. Therefore, beginning at 13:00 hours the mixture feed rate was reduced to 100 lb/hr. At the high ash injection rates to 13:00 hours, the temperature, at the same cooling tube locations as in the tests of 11/11 and 11/18, averaged 1200^{o}F. This was 100^{o}F lower than the previous ash replenishment result. When the ash injection rate was lowered to 50 lb/hr at 13:00 hours, the wall temperature increased to the 1300 to 1400^{o}F range. However, this was still lower than without ash replenishment.

Between 14:26 and 15:00 hours, 300 lb/hr of gypsum was injection instead of the above ash-hydrate mixture. The purpose of this test was to measure the SO_2 concentration at the combustor exit nozzle outlet with a probe inserted through the rear boiler wall. This measurement had been overlooked in the previous gypsum injection test. At 15:00 hours, fly ash injection (without hydrate) at 100 to 120 lb/hr continued for the balance of the test. Note that this mode of injection was not as

effective as the 50-50 ash-hydrate injection in lowering the liner temperature. On the other hand, increasing the coal fee rate by 30% to 1300 lb/hr at 15:00 hours did not increase the wall temperature.

Test DP 22, 23, 24 November 30, December 1, 2, 1993

The objective of the final three tests in task 3 was to verify the repeatability of the combustor's operation, and to complete the minimum total test time planned for task 3. Basically these tests duplicated the performance observed in the previous tests. Again these data were not completely analyzed. However, several interesting observation were noted during the tests.

The flameout at 13:00 hours in DP22 test was due to shutdown of the rented air compressor when it ran out of fuel oil. Another interesting result of this days test was the repeated extensive slag blockage of the exit nozzle, which reached levels as high as 60%. In each case, the blockage was cleared with a ram that was inserted through the rear wall of the boiler while the combustor remained at steady state firing conditions. This blockage occurred when the combustor operated at fuel lean conditions. Blockage generally occurs at this condition due to freezing of the slag as the combustor exhaust gas encounters the air injected into the furnace at the exit nozzle outlet.

The combustor wall temperatures were in the same 1200 to 1350^{o}F range as in the previous tests even without added fly ash injection.

The only interesting event of the second days test, DP23, concerned the coal supply. On all these tests, the 20 ton coal tanker truck was parked outside the boiler house, and the 4 ton coal bin was replenished from the coal in this tanker when it reached the low level indicator. Since this was the last test in task 3, we planned to empty all the coal in the tanker and the 4-ton bin by the end of the three days of testing. Therefore, prior to this test we asked our supplier to weigh the tanker to assure that sufficient coal remained in the tanker. However during the refilling operation on mid-day of the December 1 it was observed that the tanker was empty. After we were assured that an additional 4 tons of coal could be pulverized that evening and delivered the next day, we decided to conserve the remaining coal in the bin in order to at least complete a full day's operation. This was done by cutting the coal feed rate to 400 lb/hr and augmenting the balance of the heat input with No.2 fuel oil. Since there was still not sufficient coal, we used the remaining 800 lbs of the coarse coal (30%-100 mesh) for the final two hours of operation. This provided an additional data point of coarse coal combustion at a low feed rate but high thermal input.

In addition, at 15:00 hours fly ash was injected at the rate of 140 lb/hr to further simulate high solid fuel firing. Here again after 15:00 hours, when the fly ash was injected, the wall temperature decreased to 1200^{o}F.

The coal feed rate was 1000 lb/hr and 1100 lb/hr for the final test day, 12/2/93, Test DP24. The major events of that day, where a general local power failure at 14:40 hours that shut everything down, and a repeat of the combustion air fan trip at 17:30 hours. The test terminated when the coal supply in the 4 ton bin was consumed. There was no ash replenishment on this test day, and as a result the wall temperature was somewhat higher than on the previous day. It was in the 1300-1400^{o}F range, which is still lower than prior to initiating ash replenishment.

Ash/Slag Mass Balance in the Combustor-Boiler-Scrubber

One key objective of the November tests was to obtain a mass balance of the mineral matter, (coal ash, fly ash, sorbents), as a function of operating conditions. This required a partition of the ash and slag between the combustor and exit nozzle, the boiler, and the scrubber. The slag and ash weights inside the boiler cannot be obtained in real time. It takes about 3 to 4 days for the boiler to cool off. Therefore, it was possible only to obtain the weights of slag and ash in the boiler after each week's group of tests. The boiler was cleaned after the November 2nd test, after the three day November 9-11 tests, and after the December 2nd test. In addition, for each test condition, the slag passing the slag tap was collected in a wire basket and weighed. The solids in the scrubber water were sampled every 30 minutes, and these were filtered and weighed. Knowing the scrubber water flow rate, the total solids retained by the scrubber can be obtained. In addition, the carbon in the scrubber provides a key input to the combustion efficiency. The other data needed to compute combustion efficiency is the stack gas analysis. In addition, all the sludge deposited at the inlet of the scrubber was removed after each tests day.

Due to the considerable number of tests performed in the last quarter of 1993, the stack gas analysis for the tests from early August to December were never completed, as is explained at the end of this sub-section. However, the general trends of these results were already clear at the time, and are discussed here. One reason for the incomplete analysis was the resignation of the key test engineer in January 1994 one of whose duties was to analyze the data, which had not been completely done since mid-1993 tests, as well as the relocation of the entire facility to Philadelphia in 1994. Another more important reason is that much of the stack gas data was unique to the 1st generation combustor. Since this combustor was clearly far too short, this date provided little guidance on the performance of a longer combustor. There was no point in expending funds for these data beyond general conclusions.

The slag and ash balance for all the November tests, however, was mostly complete soon after the tests, and the key results are reported later in this Appendix. Certain results were available soon after the tests were completed and they are reported here. Here an initial evaluation of the work is given and it provides a reasonable good overview of the combustor performance. It also provided direction for further analysis of the data to obtain a complete picture of the distribution of mineral matter in the entire system. As noted, the most important **result was further confirmation that the combustor must be lengthened in order to improve slag retention in the combustor**.

The first step in the ash/slag analysis was to separate the carbon content from the ash in the scrubber. In most prior tests before November, the carbon content of the ash was generally in the 40% range. Due to the high cost of laboratory analysis of these samples, we generally sent two to four scrubber samples for each tests day, or one per test condition, to a laboratory for detailed chemical analysis. The other samples, which were collected every 30 minutes during each test, were dried and weighed by Coal Tech. However, when some of the early November scrubber results were reported in December by the analysis laboratory, the carbon content was found to range from a low in the 20% range to a high in the 50% range. Unfortunately, only the dried scrubber samples from the last three days of testing on Nov.30-Dec.2 remained. These two-dozen samples were submitted to the lab for a carbon analysis. The results showed a range from 15% to 51% carbon, with most of the samples in the 40-50% range. Prior to receipt of these latest results, the average of the samples per test day was used to compute the ash composition of the scrubber solids for each test, and the results reported here are based on this latter assumption.

The variable result of carbon concentration in the fly ash shows the importance of frequent sampling of the fly ash. This is simple to implement with scrubber samples, but much more difficult with systems using an ESP or baghouse. In fact, Coal Tech performed tests in 2001 on dioxin/furan control on a municipal incinerator and the stack sampling technician failed to adjust the sampling probe traverse on the stack, upstream of the ESP, to account for the shorter test time than that called for by the EPA protocol. The consequence was that the results were totally skewed and were misinterpreted by the plant operator. Unfortunately, in the task 5 test effort, a baghouse was used and the simple scrubber method of analyzing the fly ash was no longer available. While the fly ash was analyzed, it consisted of samples from the collection barrel, and as such they are averaged results.

To return to the analysis of the data, the next item in the ash/slag analysis was to allocate the slag collected inside the boiler and that flowed out from the exit nozzle to each test day. This slag is part of the combustor slag retention. However, since tests were performed every week in November, it was not possible to enter the boiler between all the tests and remove the ash and slag in the boiler. Therefore, for the three consecutive day tests, the sum of the boiler ash and slag was collected and weighed as a unit. The ash and slag were allocated according to the total coal, reagent, and fly ash injected during the three days of testing.

The preliminary results of the mass balance revealed that about 1/3 of the injected coal ash, CaO, and fly ash was retained in the combustor and exit nozzle as slag, 1/3 was deposited in the boiler as dry ash, and 1/3 was collected by the scrubber. Of the slag retention about 1/2 passed through the slag tap while the other half flowed out of the exit nozzle. These levels of slag retention are lower than historical values. The slag retention is a strong function of combustion efficiency, and since the combustion efficiency analysis was performed (as the test engineer had resigned) the impact of combustion of slag retention cannot be determined. The following are therefore general conclusions. Table 4 shows the averaged slag and ash mass balance for three sets of tests: November 2nd, November 9 to 11, and November 30 to December 2.

TABLE 4:SLAG & ASH IN THE COMBUSTOR, EXIT NOZZLE, BOILER, AND SCRUBBER
(Shown as % of mineral matter injected into combustor)

Test Dates	Slag Tap (%)	Slag Tap+Exit Nozzle (%)	Boiler (%)	Scrubber (%)	Total Collected as % of Total Injected
11/2/93	18	34	26	35	95
11/9-11/93	31	40	22	41	102
11/30-12/2/93-	14	28	23	33	84

Column 3 shows the slag collected at the outlet of the exit nozzle into the boiler added to the slag collected from the slag tap. They are combined because they are the result of combustion in the combustor and exit nozzle. There was no slag in the boiler.

The results in Table 4 are in the same range as those in prior tests, as shown in figure 21 (p. 75 this report), although the slag removed from the slag tap is very low. One possible explanation for the low slag retention is due to operation at high coal firing rates. As noted in previous sub-sections, while ash replenishment was effective in relining the combustor, it was not as effective in the roof section of the combustor liner. As a result, it was necessary to operate at a lower combustion temperature, which adversely affected the combustion efficiency, which in turn lowered the slag retention.

However, this explanation does not account for the generally lower slag retention in this project compared to earlier tests in the Clean Coal Project in 1988-1990. One major difference was in the nature of the injected material. In the Clean Coal tests only limestone, whose size distribution was about the same as for coal, namely 70-80% minus 200 mesh, was used. In the subsequent tests, including the present tests, most of the mineral matter injected consisted calcium hydrate and in some of the tests fly ash, both of whose mean particle size is only 7 microns. The retention of this material in the combustor is very low compared to ash from combustion of the coal particles and from calcination of limestone. Due to the low retention of the calcium hydrate, a small amount of limestone was injected in order to condition the slag to the proper slag melting temperature.

Therefore, an analysis of slag retention in the combustor and the ash/slag mass balance in the entire system must be further partitioned between the mineral content due to coal and that due to the calcium hydrate. This partitioning can be obtained from the concentration of the silicon dioxide, which is due to the coal ash, and the calcium oxide, which is due to the reagent. <u>Using this method, the slag retention in the combustor due to the coal ash increased to above 50%</u>. This is still low. As noted in the previous paragraphs, it can be tentatively attributed to the lower temperatures used in these tests,.

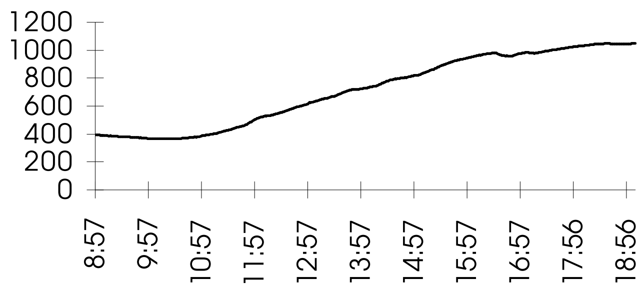
This issue was further clarified after the remaining ash/slag results were analyzed and the combustion analysis was completed in early 1994 (see below). However the results as of the end of 1993 confirmed the key result of the entire task 2 and 3 test effort and our assumption since early in this project **that the combustor had to be lengthened,** as was done for the task 5 tests.

As note above, after the P.I. made the decision to relocate the entire operation to Philadelphia in December 1993, Dr. Fleming who directed the implementation of the tests and performed the combustion analyses left Coal Tech in January 1994 for a teaching position. As a result, due to the press of relocating the facility, designing the new combustor, directing its fabrication, locating a new site, etc. there was no opportunity to perform the detailed combustion performance analysis during the remainder of the project. Also, after the new combustor became operational at the end of 1995, it was immediately confirmed in the task 5 testing that lengthening the combustor cured essentially almost all of the problems listed in this Appendix. For example, almost 100% of the slag was now removed in the slag tap and not the exit nozzle, very little ash deposited in the floor of the boiler, the combustion efficiency improved, as did the overall combustor performance. As a result, the need to analyze the remaining task 3 essentially disappeared because it applied to a deficient combustor design. Therefore, the primary benefit of this entire discussion is to describe the methodology by which the many problems encountered in the test effort on these tasks were resolved. This methodology continued to be used in all subsequent testing.

<u>Thermal Performance Results from the Task 3 Adiabatic & Air- Cooled Exit Nozzle</u>

The exit nozzle air-cooling modification was discussed earlier in this Appendix “A”. The present section provides performance details of tests in task 3. Air cooling pipes were inserted in the refractory wall of the exit nozzle in March 1993 in order to convert the quasi-adiabatic exit nozzle to an actively air-cooled nozzle. The adiabatic exit nozzle consisted of a concentric ring of refractory material, with an inner ring of a high temperature, slag resistant fused refractory, surrounded by an alumina refractory. The problem with this design, as noted above, was that the refractory temperature continued to increase even after 10 hours of operation, which eliminated the possibility of operating this combustor round the clock at full thermal input rating. This can be seen from figure 22 that shows the exit nozzle temperature taken with a thermocouple that was embedded in the ceramic layer in back of the fused refractory inner liner of the nozzle.

Figure 22: Exit Nozzle Temp.-oF-2/9/93 Test



Therefore, to meet the long duration task 3 test objective, the exit nozzle had to be converted to active air-cooling. A heat transfer analysis was performed. Its purpose was to select the radial location for placing the axial cooling tubes and to find the number that would provide uniform cooling around the circumference of these tubes. They were installed along the length of the exit nozzle from the boiler side at a radius that was about double that of the inner radius of the nozzle. However, in late February 1993, prior to the installation of the air-cooling tubes, a series of tests were performed with No.6 oil under contract to the Italian Electric Utility, ENEL, which bears on this problem because the combustion temperature reached such a high value that part of the fused inner refractory liner of the exit nozzle melted to a radial depth of up to 1 inch. Since it was too costly to replace the entire inner fused refractory section, the lost material was replaced with an alumina plastic refractory.

The two-dimensional heat transfer analysis provided the temperature and heat transfer distribution in this air-cooled exit nozzle as a function of the number of cooling tubes placed around the circumference. Based on this analysis, it was decided to install 12 tubes. However, this was reduced to 11 due to concern that the lowest tube, at 6 o' clock would rapidly become covered with slag flowing our of the exit nozzle. This would block the airflow in this tube.

Figure 23 shows the temperature distribution in one-half of an exit nozzle slice, **perpendicular** to the axis of the exit nozzle. The position of the cooling tube is shown on the X axis at a numerical radius value of 18 inches. The combustion gases flow on the left inside corner of the slice. Isothermal temperature profiles are shown. In the analysis for the number of tubes and their axial location was varied. The hottest part is at the combustion gases and the coolest at the air pipes.

The top figure is for a larger number of tubes, while the bottom one is for less tubes. The top figure is the selected design because the isothermals are nearly circular.

Three thermocouples were placed mid-plane between two adjacent cooling tubes, TC1, 2, and 3. at different radii . Also a thermocouple was placed inside an air cooled tube to measure the approximate air temperature, TC4.

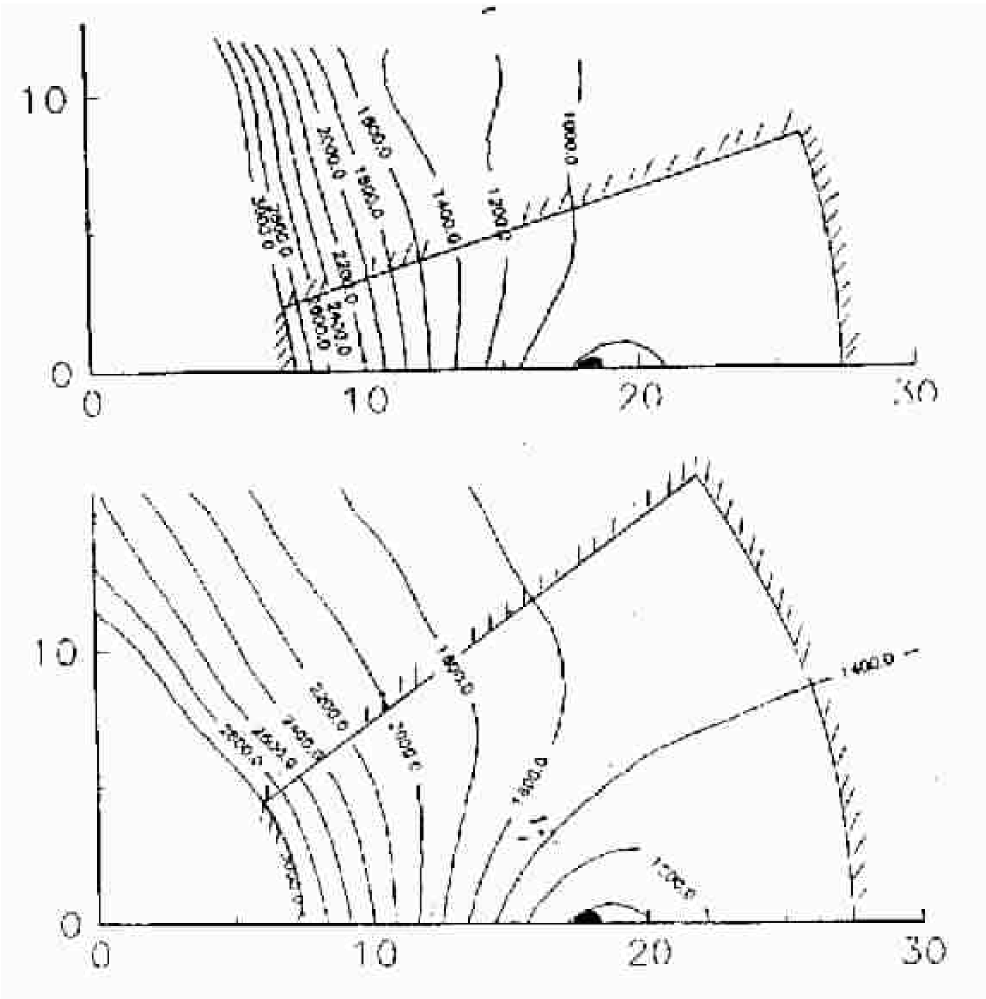


Figure 23: Thermal Analysis of the Air Cooled Exit Nozzle. Narrow Spacing (top) Wide Spacing (Bottom)

The analysis was compared with the experimental results for one of the early tests after the cooling system was installed. The average temperature at a radius equal to that of the air cooling tube location was obtained by two methods. One was to take the average of the air-cooled tube metal temperature and the refractory temperature at this same radius. The other was to compute the temperature at this radius from the heat transfer rates deduced from the inner exit nozzle temperature, the measurements at the other thermocouples, and the heat removed by the cooling air. The two temperatures of 757^{o}F and 760^{o}F are in excellent agreement with each other.

The total heat transfer between the measured and analytical result were in fair agreement. The analysis yielded a value of 80,000 Btu/hr between the nozzle I.D. gas temperature, which was assumed at 3000^{o}F. Based on the slag chemistry used in this test, the slag fluid temperature was 2275^{o}F. It is therefore unlikely that the inner wall temperature was much higher than this value. On that basis the computed heat transfer at the cooling tube radius is 54,000 Btu/hr. By way of comparison with the air-cooled combustor wall, these values are less than 10% of the heat transfer to the combustor wall because the refractory liner is much thicker at the exit nozzle than on the combustor wall. .

Figure 24: Exit Nozzle Wall Temperatures since Installation of Air Cooling in April 1993 (TC 1,2,3 at Three Different Radii -See fig.22)

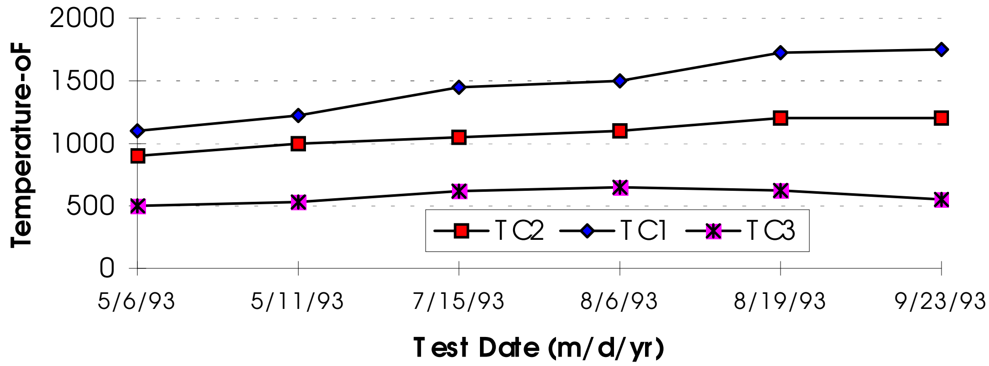


Figure 24 shows the average temperature measurement at the three radial locations corresponding to TC 1, 2 and 3 as a function of the test date after the installation of the cooling tubes. Note that with increasing time the innermost temperature, TC 1 (Top graph) gradually increased from 1100^{o}F to 1800^{o}F. This indicated that the inner wall material was melting due to slag action. This was confirmed by internal measurement between tests and by accurate measurement after disassembly of the combustor. It was determined that the entire alumina section that had been inserted inside the fused refractory liner had dissolved in the slag. The fused refractory remained intact with the exception of the usual radial and longitudinal cracks due to thermal cycling.

This air cooled nozzle operated for over 200 hours during the latter part of the task 2 and all the task 3 tests without any refurbishment. The test results strongly suggest that if the entire inner liner had been replaced with the fused refractory during the installation of the air-cooling tubes it would have survived intact. Even in the present situation, the liner condition remained essentially unchanged from the time when the inner alumina plastic refractory had melted in the August test until the final December 2nd test. Well over 100 hours of additional operation had been accumulated in this final interval.

One final note of interest concerning the exit nozzle concerns the method of installing the air-cooling pipe system. The nozzle cooling pipes were connected to a pipe assembly that was placed on the inner refractory wall of the front boiler wall. This assembly was then routed to a single large pipe that penetrated the front metal wall and was connected to the cooling air supply. The entire pipe assembly in the boiler was covered with a plastic refractory material for thermal insulation that was several inches thick.. However, during installation, no provision was made for differential expansion between this refractory covering and the exit nozzle. As a result in the December tests lateral cracks developed in parts of this tube covering section due to differential thermal expansion. This required patching with cement. This is an installation problem, which could have been avoided by placing expansion cracks in the front wall refractory during installation.

In conclusion, the exit nozzle cooling air assembly was effective in maintaining the nozzle assembly within a safe operating range and this design could have been used for more extended operation.

Air-cooling was used in the 2nd generation combustor design and fabrication, but with a different configuration.

The general conclusion from all the above tests is that the combustor can be repeatedly cycled from a cold start on a daily basis with refurbishment. Wall material loss can be corrected with ash replenishment of the combustor walls and with computer control of wall cooling and combustion temperature.

Analysis of the Combustion Efficiency from the Scrubber Ash in the Latter Task 3 Tests ***(April 2003: This sub-section is extremely important because it corrects prior analysis on combustion performance*)**

A final analysis of the combustor performance in task 3 from test data from mass balance of mineral matter in the combustor, boiler, and scrubber was performed mid-1994, about one-half year after the Williamsport operation had been shutdown. Its objective was to reevaluate the data to obtain a more accurate assessment of slag retention in the combustor. As noted above, due to personnel changes and focus on the task 5 effort, much of the data from the task 3 tests performed after August 1, 1993 had not been fully analyzed. The present reevaluation was performed in preparation for the design of the task 5 stack cleanup system. During this reevaluation it was discovered that important additional information was overlooked in the scrubber data, which would have provided a more accurate description of the combustor's performance. Specifically, it was determined that the combustion efficiency and the **total sulfur capture deduced from the scrubber solids were previously underreported** for the following reasons:

The combustion efficiency can determined from three independent measurements.

a) *The carbon in the slag*. Coal Tech does not use this method because it overestimates the efficiency. The carbon in the slag is generally less than the detectable limit of 0.1%, which would yield over 99.9% efficiency. However, the slag does not account for unburned carbon particles escaping from the combustor, and therefore, it can substantially overestimate the efficiency.

b) *The stack gas composition*: Here also, the loss in efficiency due to unburned carbon is not accounted for. For example, in the four tests of November 9 and 10, 1993, the efficiencies were 102%, 107%, 112%, and 105%.

c) *The unburned carbon in the scrubber water solids*: After filtering and drying the scrubber solid sample, it is oxidized at a temperature of 750^{o}C. The solids weight loss is reported as "loss on ignition" (LOI). In **all** prior analyses, it was assumed that the volatile matter consisted only of carbon from which the carbon balance in the entire system was computed and the combustion efficiency was determined. For the above four tests, this resulted in values of 94%, 90%, 98% and 97%. All previously reported values of overall combustion efficiency were based on this third method of calculation.

In the present slag/ash mass balance reevaluation, it was discovered that calcium oxide that did not react with SO_2 in the gas train would almost certainly react with the scrubber water to form $Ca(OH)_2$. The chemical analysis of the scrubber solids would therefore consist of LOI, Ca and Si concentrations. The latter were reported as CaO and SiO_2. However, the CaO in the solids was actually $Ca(OH)_2$, and this compounds decomposes at 550°C, or 200°C less than the oxidation temperature used to measure loss on ignition. As a result, part of the LOI consists of OH molecules that evolve during oxidation of the solid sample leaving CaO in the scrubber solids. From a reexamination of the measured LOI and CaO in a number of scrubber solids analyses performed during the past several years, it was determined that the contribution of the OH molecule to the LOI can account for about 1/3 of its value. For example, applying this correction to the fourth test condition discussed above, where the combustion efficiency was reported as 97%, yields a corrected value of 99%.

This same procedure was applied to several other tests, and in many cases the effect was more pronounced. For example in a test on 1/24/93, the combustion efficiency was computed as 87.2% assuming all the LOI was carbon, while it was 90.9% when the OH effect is included. It is also possible that other OH, H_2O compounds form with other metals in the ash, which devolatilize in the LOI sample preparation. Therefore, the LOI test must be augmented with one that measures the carbon concentration directly. Unfortunately, as a result of the combustor relocation, all the slag, ash and scrubber samples were disposed. However, the present analysis shows that the combustion efficiencies were in all cases higher than previously reported.

(*April 2003: This should not be as much of a problem in the task 5 tests because a dry particle baghouse was used. However, a water spray was used to cool the stack gases upstream of the baghouse and therefore some $Ca(OH)_2$ would have formed. There is of also the possibility that some of the CaO recombined with the CO_2 in the hot furnace. However, this recombination does not occur as a significant level until 700°C or less so it would not affect the LOI test. In any case due to this uncertainty as to the effect of the water spray on CaO, we did not account for this effect in the task 5 data analysis and therefore those results may be also underestimated.)*

The second item related to scrubber sample analysis concerns the sulfur mass balance in the system. The motivation for this reevaluation was the requirement that SO_2 emissions be no more than 0.5 lb/MMBtu in Philadelphia. For the planned 2% S, PA bituminous coal, this requires 84% SO_2 reduction. The average SO_2 reduction with combustor reagent injection was 70%, as determined from stack gas SO_2 measurements upstream of the scrubber. While additional reagent injection into the boiler could readily achieve the required reduction, this latter procedure would increase the mineral matter loading in the boiler. It was observed during the Clean Coal test effort, that the scrubber produced a modest additional SO_2 reduction. However, since the scrubber's impact on SO_2 reduction was never a project test goal, little attention was placed on this SO_2 reduction effect.

During the present reevaluation, it was noted that in addition to the Ca scrubber solids, a significant amount of Ca dissolve as ions in the scrubber water. The ions can result from the dissociation of $Ca(OH)_2$ or $CaSO_4$. In the latter part of the Clean Coal Tests and fly ash vitrification tests (two other DOE sponsored projects) in 1989 and 1990, the scrubber water was analyzed for Ca^{++} ions and dissolved sulfate. The Ca^{++} test was eliminated at the end of vitrification project, and the sulfate test was replaced with one that measures dissolved sulfur in the water. However, this latter test has a sensitivity limit of 100 mg/l. while many of the final task 3 tests had a total sulfur content in the scrubber solids in the range of about 200 mg/l of scrubber water. Therefore a significant amount of the sulfur was not detected by this test.

In addition, the Ca^{++} x SO_4^- solubility product used in evaluating the 1989/90 data was **2 x 10^{-5}.** More recent published data gives a value of 7.1 x 10^{-5} at 77°F. Therefore, the amount of sulfate in solution until saturation is reached can be substantial.

Since all scrubber samples from the task 2 and 3 tests have been disposed, the only dissolved Ca^{++}, $SO4^-$ data available was from the 1989/1990 test series. This re-evaluation yielded the result that about **50% of the sulfur in the scrubber samples was dissolved**, and that the dissolved $CaSO_4$ ranged from substantially below saturated levels to several times greater that saturated concentrations. It is not known what percentage of the sulfate in the water is due to Ca-sulfur reaction in the scrubber water or solution of $CaSO_4$ captured in the gas stream.

Subsequent to this evaluation the manufacturer of this scrubber was contacted. According to the analytical model of this scrubber's performance, for the pH used in its operation, the SO_2 reduction is predicted to be 33%. When combined with the 70% reduction from reagent injection in the combustor, one obtains a total reduction of 80%, which is near the 84% required by the City.

The final element in this revaluation was to determine the effectiveness of the combustor's and boiler's slag and ash retention by separating the coal ash mass balance from the CaO mass balance. A preliminary result from the scrubber solids data is that in most of the task 3 tests, the coal ash retention in the combustor and boiler was much less than the CaO retention from either the limestone or hydrate. For example, in the November 10,1993 test, the combustor/boiler retention of injected CaO was computed at 81%, while that of the coal ash was only 59%. On the other hand, the slag removed from combustor for this tests shows that only 1/3 of the slag consisted of CaO.

In conclusion, the prior analysis of slag/ash data in the combustor/boiler and the scrubber data was incomplete. Therefore, it was planned to undertake a systematic data reduction of the results of task 3, combined with a reevaluation of the prior combustor data, to clarify the sulfur capture in the entire system and the slag/ash retention in the combustor boiler. However, this could not be done because of the high workload from the task 5 effort, which was implemented with only 3 technical personnel, as opposed to upward of 10, counting technicians, that were used in Williamsport. Consequently this re-evaluation was not performed. In retrospect it would have been scientifically interesting, but not very fruitful. The reason being that it became clear that the 2nd generation combustor was far superior to the first one. Therefore the data from the first one was primarily useful for guiding the design effort of the second one, which it did. Also, since the completion of the present project Coal Tech has, with its own resources, developed processes for removing sulfur and nitrogen oxide emissions in the post-combustion zone. Therefore, the combustor reductions, while still very important in the overall processes, are not the emission control showstopper of previous years.

There are two important lessons to be derived from the above discussion.

One is to retain all test samples from a project at least until all work is completed, and, if possible, to retain at least some samples until several years after the project is completed. This allows further analysis of the samples if additional insights in the data are obtained. Coal Tech's policy is to keep all raw test data on its projects for years after its completion. Slag and scrubber water samples from individual tests were kept for many months after test completion. Due to the high cost of sample analysis, only a limited number of samples were submitted to the test laboratory. However, evaluation of the scrubber samples submitted to the laboratory exhibited considerable scatter in the combustor/boiler slag/ash retention results. Accordingly, beginning in mid-1993, all scrubber samples were dried and weighed by Coal Tech. A substantial number of these samples were then sent to the laboratory for testing of loss on ignition, i.e. carbon content. For the balance, the average LOI was used to determine the residual ash in the scrubber samples. In retrospect, a small number of samples should have been retained for future analysis. While this procedure was implemented for a time until after the task 5 effort was complete, there were no funds to analyze them so they were discarded in 1999.

The second lesson is to perform a second independent analysis of the test data. Unfortunately, to perform this on a regular basis is extremely costly for a small project. Therefore, a critical review of the test data should be implemented at regular intervals. This does not guaranty that the above information would have been uncovered. For example, in all tests for dissolved sulfur it was assumed that all sulfur in the scrubber water was accounted for. It was only when the above analysis was performed and the analytical methods for sample analysis were reviewed that the shortcomings of the dissolved sulfur test were uncovered.

A-4: CONCLUSIONS FROM TASK 1, 2 AND 3

There are important general conclusions to the total effort of the first three tasks that were implemented in Williamsport, PA .

The general conclusions relate to the issue of implementing a complex, multi-year R&D effort, which requires hands-on attention by the senior technical personnel, if the test site is several 100 miles away from the home base of the senior personnel. Not only did this make day-to-day operations difficult, it also substantially increased cost. This despite the fact that Coal Tech was extremely fortunate to have the co-operation of key personnel at the boiler manufacturing site, as well as quite capable technicians that were supplied by outside contractors. This was clearly demonstrated by contrasting the effort on task 5 whose scope was even greater than that of tasks 1 through 3, yet is was implemented at about 50% of the rate of expenditures for the first three tasks and with less than one-half the personnel.

Despite the difficulties that were cited in this report and summarized here**, at the end of the task 3 effort, all the data needed to implement the improved second generation air cooled slagging combustor had been obtained**. In fact the P.I. (and author) of this Final Report, in reviewing the effort during preparation of the Final Report (April 2003), was still surprised how much was accomplished and how many difficulties, some of which were potential "show stoppers", were overcome.

Specifically, the following general conclusions and observations apply:

1) By the end of task 2, and certainly by the middle of task 3, it was very clear that combustor was far too short and the test effort should have been terminated after the planned modifications, especially the actively cooled exit nozzle, had been tested, and work on the 2nd generation combustor

should have been initiated. However, that option was not available as long as the facility was in Williamsport because there simply was no room in the boilerhouse to increase the combustor's length.

2) The major importance of the almost daily participation of key personnel in the project cannot be overemphasized. This should be obvious by comparing the results achieved in task 5 in Philadelphia compared to tasks 1 through 3 in Williamsport. It would have been desirable to relocate the facility after task 2 to Philadelphia because quite a number of operational problems were caused by the inability of the key personnel to live in Williamsport during the entire project period. Not only does this result in better control and direction in between tests, but it also allows operation and implementation with far less personnel. In Williamsport, over 7 people operated the combustor, while in Philadelphia it required only 3, and much more progress was made.

3) Sharing a facility with another organization is not conducive to running a R&D or technically complex development effort. Not only are there interferences, but issues that affect the equipment cannot always be resolved. For example, the roof over the boiler developed severe leaks, which eventually rusted the outer shell of the combustor requiring operation of the boiler under negative draft. This interfered with evaluation of combustor performance due to air dilution into the boiler. Eventually a new roof was installed, for which Coal Tech contributed 50% of the cost. Unfortunately, this roof was installed in September 1993, 3 months before the property was sold and we were evicted and the building was torn down.

4) Developing a new technology, the air-cooled coal combustor in this case, requires extremely careful attention to the quality and reliability of the many auxiliary components, even though said components are "commercial". Examples of defective designed equipment were the fan motors, the boiler feedwater pump, flame safety equipment, speed controls, slag conveyor belt (it cost $5000 and failed the first day in use until Coal Tech, after many design changes developed a reliable unit), the original coal feed auger (clearly the worst piece of equipment), etc.,

In retrospect it was quite fortunate that the entire plant site was sold at the end of task 3 in December 1993, which required the relocation of the entire combustor-boiler facility. The move to Philadelphia saved the project. The progress in the entire air-cooled combustor development and associated coal combustion emission control that was made in the decade since 1994 was far greater than that of the previous 6 years in Williamsport. It would not have been possible had we remained there. In fact it is almost certain that the facility would have been scrapped in 1995, when task 5 was originally scheduled for completion.

The task 3 specific conclusions and major accomplishments were:

- A reliable method of feeding coal and reagent into the combustor and in assuring uniform mixing was been demonstrated.

- The reliability of air-cooling and ash replenishment in maintaining the combustor wall integrity even after the loss of substantial wall refractory was demonstrated. This result is the key to the commercial usefulness of air-cooling for both the combustor and the exit nozzle.

• The operation of the combustor did not adversely affect the combustion side surfaces of the boiler during the entire test effort beginning in 1987 to this date, 2003, which included 1000's of hours of operation. In fact the leaky roof caused the only damage to the outer boiler shell. .

• The heat transfer and combustion performance appeared to be in general agreement with the BYU modeling codes used for analysis. On the other hand the much more costly FLUENT code had a disabling defect, which has now (2003) been identified as most probably due to either a grid size and/or a heterogeneous carbon-oxygen reaction problem.

• Reliable slag tap operation was achieved with an automatic mechanical slag breaker. This is a major accomplishment because slag tap plugging has been a source of considerable difficulty in prior operations.

• Reliable computer control of the combustor' s operation was achieved, especially in controlling air-cooling to maintain constant wall temperatures. This includes the development of a redundant flame safety system. As evidence for this statement, we note that the flameouts in the final intensive November test periods were caused by power failure, motor trips, electric motor failure, or fuel oil loss.

• The design changes needed to achieve continuous and reliable combustor and boiler operation in task 5 were been identified.

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Project: " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE,
COAL FIRED COMBUSTION SYSTEM, PHASE 3"

Contract: DE-AC22-91PC91162

Contract Period of Performance: 9/30/91 to 9/30/99

Final Technical Report

Appendix B

"Economic Evaluation & Commercialization of the Air-Cooled-Slagging Coal Combustor"

Project Task 4

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ABSTRACT :Appendix B

Coal Tech Corp's mission is to develop, license & sell innovative, lowest cost, solid fuel fired power systems & total emission control processes using proprietary technology for domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases. The second phase, "“Economic Evaluation & Commercialization of the Air-Cooled-Slagging Coal Combustor", which is summarized in this Appendix "B", involved the development of coal fired power generating systems suitable for industrial and electric utility applications, and the development of a plan to introduce this combustor technology into the market place. The latter effort involved contacting industrial and electric utility organizations to demonstrate the benefits of this technology and to seek to install such a system at the customer's site. This effort was performed mostly between 1992 and 1994. At the time, the utility industry was embarked on a massive buildup on new natural gas fired power plants, and there was little interest in coal fired power systems. However, with the financial disaster in that industry which was partly caused by the resultant explosion of natural gas prices, Coal Tech's low cost coal combustor and emission control technologies are even more timely today in 2004

The work on this task 4 was divided into two parts. Part one was made necessary by the decision in November 1993 by the owner of Coal Tech's 20 MMBtu/hr combustor-boiler test site in Williamsport, PA to close it at the beginning of 1994. A nearly one year was implemented to find a suitable a site in the Greater Delaware Valley region to implement the present project's task 5 Site Demonstration task. Several such sites were identified, which would have involved the sale of steam or electricity to the site owner. This would have benefited the objectives of the present task 4. However, after evaluating this option, and reflecting on the problems that were encountered in running an R&D effort at the Williamsport site, a stand alone building in Philadelphia was selected, and this proved to be an almost unique choice. The details of this effort are given in Appendix "C" of this report.

The second part of the marketing effort involved finding an electric utility site to install a fully commercial 20 MW electric power plant using the air-cooled slagging combustor. Two 20 MWe power plant designs were developed. One was a steam repowering plant using coalmine waste, and the other was a "Greenfield" combined gas turbine-steam turbine power plant using natural gas for the gas turbine and coalmine waste for the steam plant. Investors were found for both plants, but with the low electricity prices prevailing during the mid-1990s and the competition from "cheap" natural gas power plants, these projects did not materialize. However, this work is still timely at the time of this report in 2004.

A key result from these two power plant studies is the need to develop innovative designs for the balance of power plant in order to achieve capital costs that are competitive with gas fired power plants.

In addition, a number of other site-specific applications where the combustor provided economic advantages were evaluated. The study focused on plants that utilized steam and

electricity for process use, primarily in the paper industry. The projects ranged in size from small firetube boilers rated at 10 MMBtu/hr to large boilers in the several 100 MMBtu/hr range. In all cases, recovery of invested capital ranged from less than 1 year to several years. The two barrier problems Coal Tech faced in implementing these economically attractive projects was the great reluctance of the hosts to be the first to install the air-cooled combustor, and the insistence that third party financing be provided.

The effort also included overseas marketing, especially to India and China. Their primary use of high ash coals is an ideal fit to Coal Tech's the air -cooled, slagging combustor, which converts at least 75% of the ash into inert slag, thereby sharply reducing the particulate emissions that are a problem in the combustion of very high ash coals. This issue is now even more timely due to the rapid growth of the Asian economies, especially China and India. Together they consume 160% more coal than the U.S., and since their ash content is up to 4 times higher than the average U.S. coals, they emit 3 to 6 times more mercury as well as 160% more carbon dioxide than the U.S. Since the Earth's winds blow from Asia toward the U.S. some of that pollution winds up on U.S. shores.

A major effort at Coal Tech, especially in the past 7 years, has been development of total emission control from coal combustion, including SO_2, NO_x, volatile coal ash trace metals, including mercury, carbon recovery and vitrification of fly ash, and dioxins and furans, and the removal and sequestration of carbon dioxide. This has resulted in a series of proprietary combustion and post-combustion processes that meet this goal of total control. The effort of the past 7 years has been totally financed by Coal Tech. DOE has declined to participate in the half dozen proposals that were submitted in this period in response to open solicitations.

Interestingly, Coal Tech's low cost coal combustion and emission control systems are now even more timely in part due to the ongoing financial problems in the electric utility industry, which is partly a result of the total reliance on natural gas for new power plants. This massive draw on natural gas led the sharp increase in the price of gas in the past several years. At the same time pressure increased to further reduce emissions NO_x, SO_2, mercury, and even the greenhouse gas, CO_2. In addition, the sharp shift in manufacturing to Asia, where coal consumption in China and India is 160% of U.S. levels has resulted in increased atmospheric pollution from particulates and mercury from those countries, a situation that is aggravated by their use of very high ash coals. Coal Tech's air -cooled slagging combustor has burned 37% ash Indian coal and 70% ash biomass char waste from gasifiers. This technology is therefore even more timely than when the project was implemented.

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B-1: Executive Summary to Appendix "B"

Coal Tech Corp's mission is to develop, license & sell innovative, <u>lowest cost</u>, solid fuel fired power systems & total emission control processes using proprietary technology to domestic and international markets. The present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 was a key element in achieving this objective. The project consisted of five tasks that were divided into three phases. The second phase, ""Economic Evaluation & Commercialization of the Air-Cooled-Slagging Coal Combustor", which is summarized in this Appendix "B", involved the development of coal fired power generating systems suitable for industrial and electric utility applications, and the development of a plan to introduce this combustor technology into the market place. The latter effort involved contacting industrial and electric utility organizations to demonstrate the benefits of this technology and to seek to install such a system at the customer's site. This effort was performed mostly between 1992 and 1994. At the time, the utility industry was embarked on a massive buildup on new natural gas fired power plants, and there was little interest in coal fired power systems. However, with the financial disaster in that industry which was partly caused by the resultant explosion of natural gas prices, Coal Tech's low cost coal combustor and emission control techn ologies are even more timely today in 2004.

The work on this task 4 was divided into two parts. Part one was made necessary by the decision in November 1993 by the owner of Coal Tech's 20 MMBtu/hr combustor-boiler test site in Williamsport, PA to close it at the beginning of 1994. A nearly one year was implemented to finding a suitable a site in the Greater Delaware Valley region to implement the present project's task 5 Site Demonstration task. Several such sites were identified which would have involved the sale of steam or electricity to the site owner. However, after evaluating the options, and reflecting on the problems of running an R&D effort at the Williamsport site, a stand alone building in Philadelphia was selected, and this proved to be an almost unique choice. The details of this effort are given in Appendix "C" of this report.

The second part of the marketing effort, which is the subject of this Appendix "B", involved responding to a request from a developer of power plants for the cost of a new "Greenfield" power plant rated at 20 MW electric power that used the air -cooled slagging combustor. In responding to this request, Coal Tech retained an engineering firm with experience in developing small power plant projects to assist in the design and cost effort. There existed a potential for the licensing of the combustor technology to this developer because he had a contract to sell 20 MW of electricity capacity to a local utility.

However, we judged the probability as low. Instead we were motivated by the desire to develop a prototype design for a power plant based on Coal Tech's unique, patented, air-cooled, slagging coal combustor. As a result considerable resources were dedicated to this effort. The power plant consisted of a 5 MW commercial gas turbine that was fired with natural gas and used steam injection to achieve the rated power. The turbines exhaust at about 1000^{o}F was used as pre-heated combustion air for the coal-fired, slagging combustor that was attached to a ABB Company D-frame industrial oil design boiler producing superheated steam to drive a nominal

15 MW steam turbine-generator. The power plant efficiency, as computed by Coal Tech and independently by DOE-NETL, was in the low 30% range.

The total plant cost, as developed by the engineering firm and based on quotations from major component manufacturers, was about $1,200/kW. According to this firm, this cost was substantially less than a coal fired fluid bed power plant of equal rating. The developer planned to utilize high ash, coalmine waste to fire the combustor. Based on the results of the 20 MW repowering study, to be summarized next, we judged the 20 MW combined cycle cost obtained by the engineering firm as being far too high. In any case, as we had suspected the developer withdrew his offer to build the plant. Nevertheless, the study proved very worthwhile, as we used the results in the 20 MW repowering study to be summarized next. Furthermore, after the present project ended in 1998, we developed designs for using the combined cycle plant with pyrolysis gas derived either from biomass or coal to fire the gas turbine, and the char to fire the slagging combustor.

The second study for a 20 MW repowering project was an outgrowth of a search for a site to install the combustor for long-term operation. Four potential coal-fired electric utility sites in PA, KY, and KS were evaluated and the PA site provided an ideal fit. The power plant had an unused 20 MW steam turbine in need of extensive refurbishing, all the electric generating and transmission capacity, and most importantly, a very large supply of high ash coal culm. Using the same engineering firm, a design for this plant was developed in which two 150 MMBtu/hour air-cooled slagging combustors would be attached to an ABB Company D Frame boiler. The design developed by the engineering firm was estimated to cost over $900/kW. However, Coal Tech used innovative components and arrangements that lowered the cost to only $520/kW.

With the help of the engineering firm, we found a power plant developer who was interesting in financing the project. However, the power plant owners were considering (in 1994) shutting the entire power plant by the end of the decade, and since the developer estimated that it would take 4 years to obtain the permits and install the plant, the effort was terminated. The plant is still in operation (2004), and ironically, the management decided to install a peaking gas turbine, which went operational just as demand for electricity began to decline with the economic recession. Had our project proceeded, the profits during the power crisis of the late nineties would have been enormous. Furthermore, as the company satisfied its power needs by purchase from another utility, there was no need for 100% reliability for our plant during the initial demonstration period.

A key conclusion from these two power plant studies is that innovative designs for the balance of power plant are as important as the combustor technology in order to achieve capital costs that are competitive with gas fired power plants.

In addition, a number of other site-specific applications where the combustor provided economic advantages were evaluated. They concerned plants that utilized steam and electricity for processes, primarily in the paper industry. The projects ranged in size from small firetube boilers rated at 10 MMBtu/hr to large boilers in the several 100 MMBtu/hr range. In all cases, recovery of invested capital ranged from less than 1 year to several years. The two barrier problems Coal Tech faced in implementing these economically attractive projects was the great reluctance of the hosts to be the first to install the air-cooled combustor, and the insistence that third party financing be provided.

The effort also included overseas marketing, especially to India and China. Their primary use of high ash coals is an ideal fit to Coal Tech's the air -cooled, slagging combustor, which converts at least 75% of the ash into inert slag. This sharply reduces the particulate emissions that are a problem in the combustion of very high ash coals. In addition, Coal Tech's very low cost emission control processes remove the other pollutants. Even more important is the demonstrated ability of this combustor to capture and retain volatile trace metal in coal ash, such as arsenic and lead as inert vitrified slag. The same process is suitable for mercury, and Coal tech submitted two proposals to DOE in 2002 and 2003 to test mercury capture in the slag as well as in the stack exhaust in the 20 MMBtu/hr combustor-boiler facility. They were both rejected. One reason given was that "while it may work in high ash Asian coals, that is not in the DOE mission". Apparently the reviewers were unaware of elevated me rcury levels found in 2000 by a Dr. Hightower in Californians that consumed more than the average quantities of fish. Since the winds blow from Asia toward the U.S., Asian mercury deposits may have contaminated Pacific Ocean fish.

A major effort at Coal Tech, especially in the past 7 years, has been development of total emission control from coal combustion, including SO_2, NO_x, volatile coal ash trace metals, including mercury, carbon recovery and vitrification of fly ash, and dioxins and furans, and the removal and sequestration of carbon dioxide. This has resulted in a series of proprietary combustion and post-combustion processes that meet this goal of total control. The effort of the past 7 years has been totally financed by Coal Tech. DOE has declined to participate in the half dozen solicited proposals that were submitted in this period.

Coal Tech's low cost coal combustion and emission control systems are now very timely in part due to the ongoing financial crisis in the electric utility industry, which resulted in part from the total reliance on natural gas for new power plants. Another timely factor is the recognition that atmospheric pollution from particulates and mercury emitted from the inefficient combustion of high ash coals that are used extensively in some countries contributes to atmospheric warming and mercury transport. It was recently reported that a massive upper atmosphere particulate laden pollution cloud has been found over the Indian Ocean. Atmospheric scientists attribute this "cloud" to inefficient combustion of high ash coals in that region of the World. This combustion also contributes to increasing pulmonary related health problems, which with modern transportation in airplanes can rapidly spread around the globe. The Coal Tech air-cooled slagging combustor has burned 37% ash Indian coals and 70% ash biomass char waste from gasifiers

B-2: INTRODUCTION

B-2a: Foreword:

Coal is by far the most abundant domestic energy source. Yet in the 4th decade of repeated "energ y crises" it continues to be massively underutilized. Instead the U.S. economy has been subjected to repeated international and domestic stresses, including two wars, all of which were caused in part by U.S. reliance on the "clean" fuels, oil and natural gas. During this entire period, the growth in coal use has been relatively modest, and it promises to remain even more modest because ever more stringent environmental constraints are being added, with reduction of carbon dioxide's "greenhouse" emissions being the most recent and potentially the final "showstopper".

To an objective observer the problem with coal has been the failure to develop low cost energy systems that are **totally** environmentally benign and more importantly are economically competitive with the "clean fuel" based systems.

Instead the coal production and coal use industry have engaged in delaying actions against the introduction of the emission controls necessary to enhance coal use on the argument that they are not economically competitive. This argument is indeed justifiable based on the existing and proposed emission control technologies, which are quite costly because the R&D that developed them placed technical sophistication above low cost. As a result, after three decades of coal R&D opportunity still exists to tap this immense domestic energy system provided low cost environmentally benign coal based systems are developed.

This has motivated Coal Tech Corp's two decade long R&D effort to develop such systems, primarily those based on its unique and very low cost air-cooled, slagging coal combustor and associated emission-control processes. The present project was a key element in solving the combustor's technical issues and in solving part of the emission control issues for coal. Following the completion of this project, Coal Tech devoted for the past 7 years its modest internal resources to develop additional emission controls for nitrogen oxide, sulfur dioxide, volatile trace metals, including mercury, and most important for removing and sequestering the "greenhouse gas" carbon dioxide. Consequently in 2004 this technology is even more timely that ever before. This Appendix "B" will address some of this system's applications that were studied in this project.

B-2b. U.S. Energy Policies & Coal R&D Programs

In the mid-1970's, in response to the oil price shocks of that decade, the U.S. government embarked on a massive R&D program to increase coal utilization. The primary focus of the effort in the late 1970's was on conversion of coal to synthetic liquid fuel to replace petroleum. A secondary but still major R&D effort focused on direct coal utilization in advanced coal fired power plants using either direct coal firing, coal gasification, or coal slurry fuels. The synthetic fuels effort terminated and the direct coal utilization R&D effort decreased sharply in the early 1980's as the price of oil collapsed from the artificial levels of the late 1970's.

[Interestingly one "orphan" of that era remains, "the synthe tic fuel "tax credit, which in recent years has degenerated into a multi-billion dollar raid on the U.S. Treasury by claims that "spraying" certain chemicals on coal converts it into a "synthetic" fuel. As with any "benefit" bestowed by the Congress, once given it is almost impossible to remove because a financially benefited constituency lobbies to retain it. This should be a strong caution to the Congress in legislating tax benefits to solve a crisis.]

In response, the focus of U.S. government's coal R&D shifted in the mid-1980's almost totally to direct coal utilization in advanced power and energy systems with primary emphasis on removing the one key barrier to increased coal use, namely, coal's high air emissions of pollutants, primarily SO_2, NO_x, and particulates. The centerpiece of this effort was the Department of Energy's (DOE) Clean Coal Program. A number of advanced coal fired power plant systems at the full scale, electric utility level, were successfully implemented through the decade of the 1990's. Many billions of industry and government funds were expended on these projects.

Yet despite these successes, when the electric utility industry was faced with sharply increased demand in the 1990's, over 90% of new power plant construction wa s natural gas fired. Economic and public policy considerations favored gas fired-combined gas turbine/steam turbine power plants. They were more efficient than the most modern coal fired plants, they were essentially non-polluting, they could be erected in one-half the time of coal power plants, natural gas prices were low, a nationwide pipeline grid was in place, and as an added bonus, natural gas produced much lower "greenhouse gases" than coal. However, in the rush to construct new gas fired power plants, developers appeared to overlook that much of this gas capacity was committed to existing users. As demand increased, gas prices rose sharply and stayed high even as the economy entered recession in around 2000. The result was a financial meltdown of power producers as electricity prices returned to historical norms leaving little or no margin to service debt, much less produce a profit. While the resulting financial meltdown in the power sector in 2001 was almost certainly accelerated by the financial improprieties by certain companies that came to light in 2001, these financial problems would have surfaced eventually. Since industrial users can use gas and oil interchangeably, their prices are coupled. Oil prices increased over the past decade with increasing demand from a shift to larger fuel inefficient cars. Prices were also pressured by political instabilities in key oil producing nations, which included two wars in Iraq. In addition, gas prices would also be pressured by the massive investments in gas exploration and pipeline construction that would be needed to meet the growth in gas use.

These gas supply problems would seem to favor increased coal utilization for electric power as it is in almost limitless supply and offers stable pricing. However, here also, economic, political and public policies have prevented this growth.

Existing coal fired power plants benefit substantially from high prices from gas-fired power because electricity is generally priced at the highest marginal producer. Coal power plants produce by far the lowest cost electricity because they are "grand fathered" and generally exempt from newer and costly emission regulations as long as they make no "substantial" changes to the existing power plants. This has of course resulted in decades long litigation between these producers and the government on the meaning of the word "substantial".

Nevertheless, it has not prevented very low cost emission control technologies, such as "low NO_x" burners" from being widely adopted. However, that has not been the case for the much more costly NO_x, SO_2, volatile trace metals, and very fine particulate emission control technologies. Ironically, it would appear that these costly technologies actually are favored by existing coal power producers because it provides an excuse for maintaining the profitable status quo.

The public's inconsistent position on energy also helps to maintain the status quo. "Clean", but costly, natural gas plants and even more costly taxpayer subsidized- "renewable" energy power plants are favored, while "dirty" coal plants are opposed. Yet the experience of California shows the danger of relying primarily on "clean" hydropower and "clean" natural gas power. In 2000, a booming economy, a drought in the hydropower region and a shortage of natural gas, combined to cause electricity prices to soar. While it was determined in the following year that part of the increase was due to market manipulation, electricity prices would still have risen sharply. In fact, if not for coal-fired electricity from neighboring States, the crisis would have been much worse.

The conclusion from all these factors is that "clean" coal fired electricity is essential for a healthy American economy, **provided it can be supplied at modest added costs to current coal based electricity. While coal R&D has delivered "clean" coal, it is quite costly, and it will become even more costly when new controls on emissions of mercury and carbon dioxide sequestration are added.**

B-2c. Coal Tech's R&D Approach to Coal Based Power

This project's principal investigator (P.I.), the author of this report, was exposed to the overriding importance of a systems approach to evaluating new energy technologies in the mid-1970's. The Energy R&D Administration (ERDA), the predecessor to DOE, commissioned a comparative system study of existing and advanced coal based, electric power generating technologies all of which were to be fired with coal. The key result from that study was that some advanced high efficiency energy conversion technologies lost much of this efficiency and, even worse, they lost their cost advantages when they were evaluated as a total system in a power plant.

This problem was due to the inefficiencies and costs that were introduced as multi-step processes and thermodynamic cycles were added to achieve optimum combinations of the coal fuel with the power cycle. For example:

-Using coal to power a combined gas turbine/steam turbine required a gasifier and a gas cleanup system, each of which suffered from inefficiencies and costly components. Interestingly, the study concluded that this power cycle was one of the most economically attractive, even superior to more efficient advanced power cycle, such as the open cycle magnetohydrodynamic topping/steam bottoming cycle, or a steam cycle with full environmental compliance using stack gas scrubbing for SO_2. However, no comparison was made with a steam cycle without SO_2 or NO_x control as no one envisioned in the mid-1970's that these polluters would still be operating three decades later. As a result, outside of subsidized demonstration projects, few, if any, economically stand-alone coal gasification gas/steam turbine power plants have been erected in the U.S. in the past three decades.

-Using a fluid bed boiler to burn coal and to remove sulfur dioxide emissions required replacing much of the steam boiler with a fluid bed boiler, which rendered the existing stock of coal fired boilers useless. This eliminated this technology for low cost retrofit applications.

-Treating coal to remove sulfur at the mine simple shifted the cost from one location to another

The key lesson this author drew from that and similar studies, and one confirmed for essentially all other new technologies, is that for a new technology to replace an existing one, it must be more less costly. Even the jet plane only replaced the piston driven plane because its higher speed resulted in a lower cost to the traveler.

Low cost is extremely difficult to implement in a capital-intensive system such as a coal fired power plant, where the increased efficiency from alternate power cycles is relatively small, while costly environmental emission control is only a long-term indirect benefit to the public in improved health. Therefore, a critical corollary to the lesson of low cost is that as much as possible of the existing power plant components must remain in use. One successful application of the lesson low cost is the "low NOx" burner.

It is this need for low cost that requires maximum reuse of existing equipment that led to the air-cooled, slagging coal combustor. It meets most of these requirements.

1) It can be directly attached to existing coal-fired boilers.

2) Air-cooling eliminates the need for integration into the existing steam loop of the boiler, or the need for an inefficient separate water-steam cooling loop.

3) A substantial fraction of the NO_x and SO_2 is controlled inside the combustor. This reduces the additional post-combustion reduction needed for complete removal.

4) About three-quarters of the ash is removed in the combustor as slag, which allows its use on oil or gas designed boilers as well as much smaller coal design boilers.

4a) The char combustion capability makes this combustor ideally suited for power cycles in which cleaned pyrolysis gas is used to produce clean gas fuels to gas turbines. Since pyrolysis of volatile matter in coal or biomass occurs at substantially lower temperatures than total gasification the efficiency of gas production is higher due to the absence of air dilution or the need for oxygen. Also, materials requirements are much less stringent.

5) Volatile trace metals in the coal ash, including possibly mercury, are trapped in the chemically inert slag removed from the combustor.

6) Suitable fuels include, low to very high ash coals and coal char, shredded biomass, and shredded municipal solid waste fuels, oil, and gas.

7) Finally, the combustor fabrication and installation cost is very low. Almost all other components are essentially identical to those found in current coal fired power plants.

Therefore, the air-cooled, slagging-combustor meets the requirement for a "clean" coal technology that requires only a modest cost increase above current coal combustion systems

B-3 Results & Discussion for Project Task 4:
Economic Evaluation & Commercialization of the Air-Cooled-Slagging Coal Combustor

B-3.1. Objectives of Tasks 4

The objectives of this task were to evaluate the technical and economic potential of the air-cooled, slagging coal combustor in electric utility power applications and in industrial steam process heat applications. To implement this task under realistic commercial systems the studies in this task were performed as much as possible for users of this technology that were identified in a marketing effort. To implement this task Coal Tech performed a marketing effort to identify users who would benefit from this technology, and once identified, analysis of different degrees of depth were performed to demonstrate to them the economic benefit of using this technology. In other words, the goal of this task was to analyze only those applications where a reasonable chance existed that the result could lead to commercial use of the technology after this project was completed.

B-3.2: Technical Approach to Tasks & Task Description

The work statement for this task was to perform a technical and economics analysis of one or at most two different industrial scale steam based cycles using the Coal Tech air-cooled combustor.

As part of this effort several commercialization plans were developed with partial assistance of a DOE-SBIR sponsored commercialization program. DOE retained a contractor, Dawnbreaker Associates, to assist winners of a Phase 2 SBIR award in preparing a plan for marketing their technology and presenting said plan in person to investors and companies with an interest in energy technologies. As a former winner of several Phase 2 SBIR projects, Coal Tech qualified for this program, participated twice in preparing commercialization plans. On both occasions, which occurred during the term of the present project, Coal Tech presented its Plan to these investors at meetings organized for this purpose. While interest was expressed in our technologies, follow up contacts failed to yield any continued interest. As noted the early 1990's was the decade of natural gas fired power plants.

On the other hand, Coal Tech's marketing effort did yield more serious interest that justified the two main studies in the present task, a 20 MW combined gas turbine/steam turbine, coal fired power plant, and a 20 MW coal fired repowering plant, the results of which are described in this Appendix.

In a parallel effort whose objective was to find a site for the task 5, Site Demonstration effort, potential industrial or electric utility sites were sought out that would be interested in using the combustor system after the completion of this project. While several suitable candidates were identified in the Southeast Pennsylvania region, known as the Delaware valley, prior to the initiation of task 5, it soon became clear that the funds available for such an effort were insufficient to implement a full commercial installation. Furthermore, in light of the difficulties of operating within the boiler manufacturing site in Williamsport, as described in

Appendix "A" of this Final Report, it was decided to implement task 5 in a stand alone site, which eliminated the possibility of leaving the plant at that site for future commercial operation.

Also, an international marketing effort was launched that succeeded in identifying two potential sites in India for industrial process steam use and for electric power generation. However, they required that we supply the financing and we did not proceed.

The marketing effort clearly demonstrated the need for implementing a fully commercial scale project in order to market the combustor system. To this end Coal Tech assembled an industrial team and submitted a proposal for a 20 MW steam power plant to be located at a former large manufacturing site in the Greater Philadelphia Valley in response to the DOE Clean Coal Round 3 solicitation. The estimated cost was in the $20 million range. DOE rejected it. This was most unfortunate because in the years **after** the present project was completed in early 1998, Coal Tech invented and partially developed a series of very low cost processes that could remove all emissions from coal combustion. Had a 20 MW power plant been in operation, the air-cooled combustor system would have been fully commercial by the present time.

B-3.3: **Results & Discussion for Task 4**

1) <u>20 MW Combined Gas/Steam Turbine Power Plant</u>

<u>Note Added in May 2003</u>*: This combined cycle is just a timely today as it was a decade ago when originally analyzed. The difference is that at that time, the gas turbine fuel was natural gas, while now it is either coal or biomass. Beginning in 1997 and continuing through the past year, Coal Tech developed designs for this type of combined power plant with coal and biomass fuel in the size ranged from several 100 kW to 20 MW.* ***The most recent design was for totally coal fired-combined power cycle power plant in the utility size range of 100 MW and up that would greatly increase the output of existing coal fired power plants, by adding a gas turbine cycle that would be fired by a novel coal derived clean gas fuel, and provide 100% emission control with total sequestration of carbon dioxide****. Due to the glut of gas turbines caused by the excess power capacity and extremely high natural gas prices, such a system would be low in capital cost and very timely.*

To return to the project, in early 1992, a representative of a company that had a power purchase agreement to sell 20 MW of electric power to a Western Pennsylvania electric utility contacted Coal Tech to provide a power plant design based on the air cooled combustor. The proposed fuel was either a high ash PA coal or a high ash PA coal washing plant mine waste. The proposed plant was a "Greenfield", i.e. new from the ground up, installation in western PA. High ash mine waste coal is an excellent fuel for the air-cooled combustor, and it was therefore in the interest for the task 4 effort to perform a conceptual design and cost analysis irrespective of the final disposition of this request.

In June 1992, Coal Tech retained the H-R International Engineering Company, Edison, NJ, to perform a layout and costing of a 20 MWe combined steam-gas turbine power cycle. The work was completed in September 1992. The following is a summary of the results from H-R's report:

The cycle consists of an industrial gas turbine whose exhaust would provide combustion air for the air-cooled combustor. The gas turbine output was about 5 MW. To achieve high system reliability, two air-cooled combustors are each attached to a separate industrial boiler, rated at 60,000 lb/hr and 950 psi, 950°F. The steam turbine output was slightly under 15 MW. A major advantage of this system is that all the major components, including the boiler are factory assembled. The results showed that the capital cost was in the range of $1200 to $1400/kW. This compares with a cost of $1400 to $1750/kW for a natural gas fired, steam injected combined cycle, and $2000 to $2300/kW for a similar size, fluid bed boiler power plant. [*Note added in 2003: The prices are 1992 prices.]* The cost of the air-cooled combustor is almost negligible compared to the power plant's total cost. The power plant efficiency was in the low to mid-30% range.

Separately, personnel from DOE-NETL assisted Coal Tech in this cycle performance optimization using the ASPEN systems code.

Additional details are as follows:

The cycle proposed by Coal Tech consisted of a commercially available, small natural gas fired, steam injected gas turbine whose exhaust stream is used to provide combustion air for the coal fired, air cooled combustor. The latter is attached to an industrial boiler, whose superheated steam output is used to drive a steam turbine. A 20 MW nominal output was selected, with the gas turbine providing 25% of the total power. Coal Tech proposed the specific cycle, and performed the initial thermodynamic cycle analysis. H-R used these results to prepare a detailed process flow diagram and plant layout for the combined cycle. Separately, the systems analysis group of DOE/NETL' s Office of Project Management performed several detailed analyses of this cycle using the Aspen computer code. In the course of the work several discrepancies were noted in such areas as fuel input and heating value. Also, assumptions on the method of integration of the gas turbine exhaust were found to be inconsistent with actual gas turbine practice. While the former discrepancies have been resolved, the losses associated with turbine integration were not reflected in the overall analysis. One issue was the matching of the gas turbine's exhaust pressure with the pressure requirements for producing efficient swirling combustion gases in the air-cooled combustor. Since these are final design issues and not "show stoppers" they were not pursued at the time. For this reason, only overall results that show how the cycle is utilized and its economics are presented here.

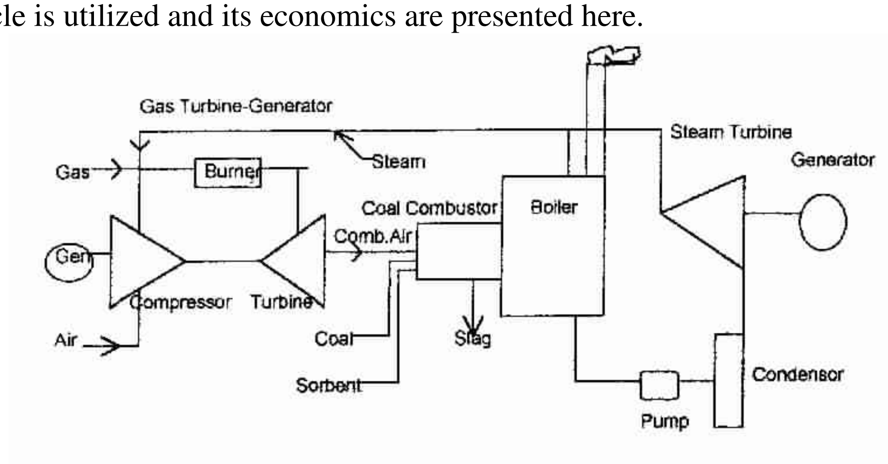


Figure 1: Schematic of the 20 MW Combined Gas/Steam Turbine Cycle

A schematic of the combined cycle is shown in figure 1. The base case assumed a commercial natural gas fired turbine operating at a nominal 1800^{o}F turbine inlet temperature. Its rated output is 5,940 kW with steam injection. The gas turbine exhaust flow provides the combustion air for the coal fired, air cooled combustor. In the 20 MW power plant there are two combustors, each of which is attached to a separate factory assembled industrial boiler. Each of the two boilers produces 63,000 lb/hr-superheated steam at 900F, 950 psi. The steam drives a commercial 13,200 kW turbine-generator. The steam turbine has two extraction points. One extraction point provides the steam for injection into the gas turbine, while the other (not shown in figure 1) is used for feedwater heating. The balance of the steam goes to the condenser.

Benefit of Steam Injection: One question that was addresses is the efficiency gain, if any, of steam injection into the gas turbine. In a conventional combined gas-steam turbine cycle, where over 50% of the power output is provided by the gas turbine, extraction of steam for the gas turbine does not yield any improvement in the efficiency. The reason for this is Dalton' s Law of Partial Gas Pressures in Mixtures. The steam, which represents a small fraction of the combined steam-combustion airflow in the turbine, must be injected above the compressor outlet temperature. On mixing with the compressor outlet air, the steam pressure drops to its mol fraction in the mixture, which is a small fraction of the total mixture pressure. This pressure drop represents a loss, which could have been used to extract power in the steam turbine.

Two sets of calculations were performed. In one set the tradeoff was made between using the steam for injection into the gas turbine. This was compared with using the steam in the steam turbine. In the other set of calculations, the use of steam injection was calculated for the present cycle in which 75% of the power is produced by the steam turbine. The following results show that in the first case no benefit is gained by steam injection, while in the second case about a 50% improvement in steam energy use is obtained. The calculations were performed in the following manner:

A: Without steam injection, the stated power output of the gas turbine is 3,924 kW, and the fuel input is 46.7 MMBtu/hr.

B. With steam injection at 900^{o}F, 260 psia, and 19,800 lb/hr, the power output is 5,940 kW, and the fuel input, 51.4 MMBtu/hr.

C. With steam injection at 400^{o}F, 260 psia, and 19,800 lb/hr, the power output is 5,967 kW, and the fuel input, 56.2 MMBtu/hr.

Calculation Set No. 1

If the steam continued to expand in a steam turbine to 2.5 in Hg, (instead of gas turbine injection), the extra steam power output for case B would be 2,082 kW, and for case C, 1537 kW. Here 78% steam turbine efficiency was used.

The steam flow of 19,800 lb/hr in the gas turbine exhaust is at 960^{o}F. When expanded to the stack temperature of 260^{o}F, it has an energy content of 6.7 MMBtu/hr. This steam flow can be used to raise steam in a heat recovery boiler. For simplicity, assumed that this steam is produced from makeup water at 59^{o}F and 260 psia and it reaches 860^{o}F, i.e. the temperature difference between the gas turbine exhaust temperature and the peak boiler steam temperature is

100^{o}F. Due to pinch point problems only part of this heat is recoverable, estimated at 4445 lb/hr. This yields 467 kW power output at 78% steam turbine efficiency.

The added fuel for case B is 1377 kW thermal. The net added power produced as a result of this added fuel is 2,016+467-2,082=401 kW. This yields a net efficiency for the added fuel of 29%, which is several percentage points lower than a steam only cycle at 950psi, 900^{o}F expanding to 2.5 in Hg.

For case C, the added fuel is 2,783 kW thermal. The net added power is 2.043+467-1,537=973 kW, yielding an efficiency of 35%, or somewhat higher than the steam only plant.

In any case using the steam for gas turbine injection and the gas turbine exhaust for additional steam generation in a heat recovery boiler does not appear to yield any change in the efficiency of the cycle, compared to using the added fuel in a simple steam cycle..

<u>Calculation Set No2</u>

The situation changes for the Coal Tech cycle, where the gas turbine exhaust is used as "pre-heat air" for the combustor. In this case, the basis of comparison is the entire "pre-heat air" i.e. the steam exhaust energy between 960^{o}F and 59^{o}F. The reason for this is that without this energy, the coal combustor would have to provide the pre-heat. In addition, the boiler efficiency over the entire temperature range, i.e. between 2913^{o}F in the boiler and 260^{o}F in the stack should be applied to the present pre-heat energy. The overall boiler efficiency based on the 260^{o}F stack temperature is 93%. This yields 7.96 MMBtu/hr of "pre-heat energy to the boiler' s combustor. Also, there is now no pinch point problem. Finally, the steam has a specific heat of about 0.48 Btu/lb-F. This "pre-heat" allows the generation of an additional 5,723 lb/hr of makeup steam between 59^{o}F feedwater and 950 psi, 900^{o}F. This in turn yielded 731 kW of power. Applying the same calculation as in the first set above, <u>one finds the efficiency of the added gas turbine fuel is 48.3% for the 900^{o}F case B, and 44% for the 400^{o}F case C.</u>

The above arguments are not based on a complete cycle analysis. They suggest that for the present Coal Tech combined cycle, steam injection offers a cycle efficiency advantage. However, in assessing steam injection one must balance the added cost of supplying a higher degree of water purity in the boiler to allow its use for gas turbine steam injection.

<u>20 MW Combined Cycle Analysis:</u> The cycle shown in figure 1 was used by the H-R International to prepare a detailed process flow diagram, shown in figure 2. This process flow diagram contains all the components needed for installing this power plant, which is necessary in order to perform an accurate cost analysis. H-R went to considerable effort to account for all elements of the plant, even to computing the total wiring needed. The final report that they issued was about a three inch thick, on 8.5 x 11 inch paper, loose-leaf binder.

Nevertheless, there were some areas of discrepancy, which were however, not the fault of H-R but the quotations provided by equipment vendors. H-R contacted equipment vendors for quotations on all major components. Coal Tech later determined after the 20 MW repowering project, to be discussed below, that the vendor for the stack gas baghouse for this plant provided a quotation that was twice the cost of the repowering baghouse quotation, this despite the fact the gas flow through the combined cycle plant was only one-half that of the repowering plant. Nevertheless, this work is very useful as it provides a basis for future analysis.

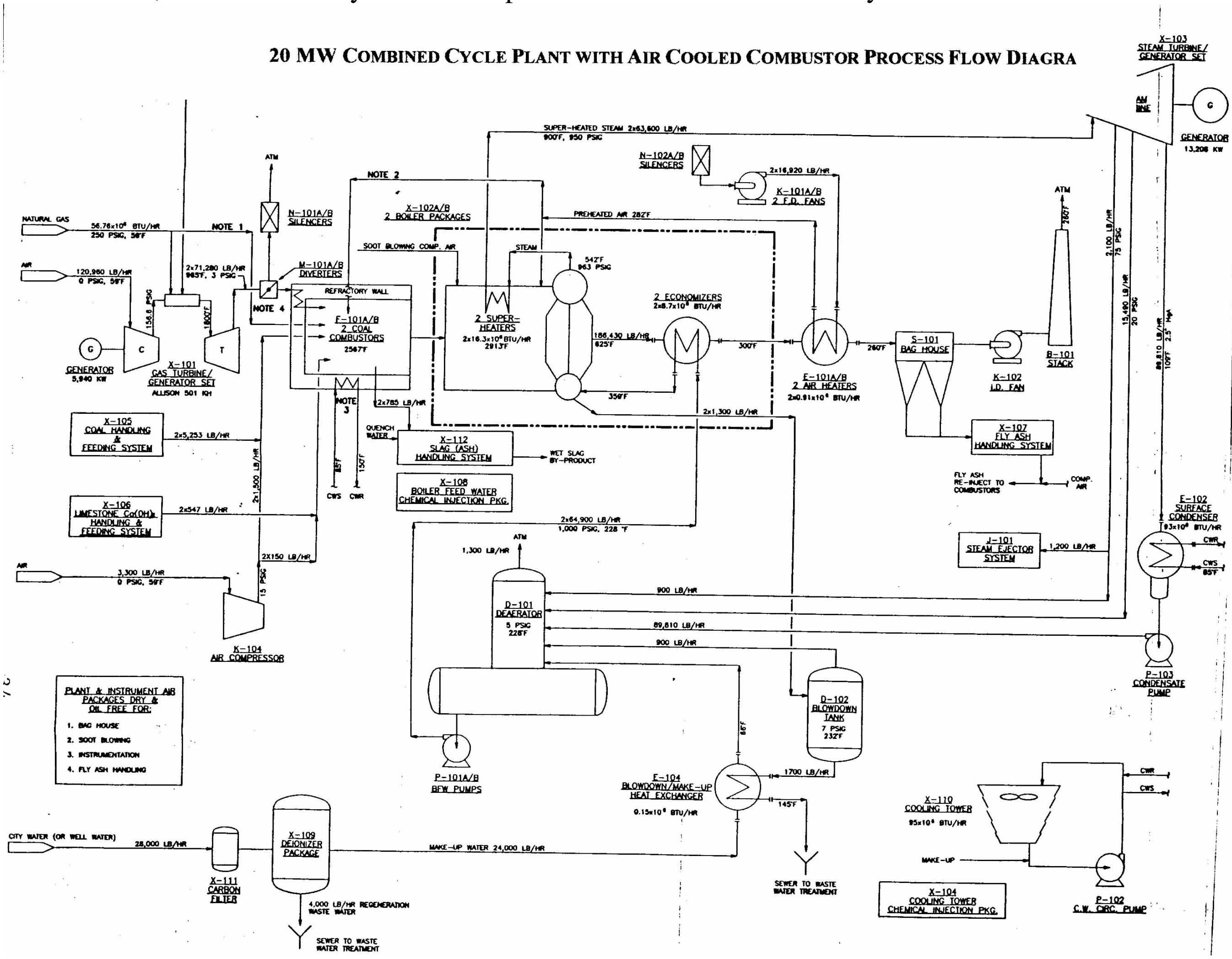


Figure 2: Process Flow Used by H-R Int. for the 20 MW Combined Gas/Steam Turbine Plant

The Systems Analysis Group at DOE's National Energy Technolog y Laboratory (NETL) in Pittsburgh also performed a cycle analysis using the commercial systems code developed by Aspen Corp. The Aspen code process flow diagram used nodes to represent components and sub-systems. Their process flow diagram is shown in figure 3. There are minor differences between the cycles shown figure 2 and 3. For example, the latter has one additional steam extraction point. Also the steam turbine ratings differ slightly.

The present discussion will focus on the latter analysis, as it was more detailed that the analysis used by Coal Tech and the one used by H-R.. Two base cases were considered. In both cases the identical gas turbine with steam injection was used. The turbine inlet temperature was 1800^{o}F. The compressor outlet pressure was 171 psia. The net gas turbine power output was 5374 kW. The gas turbine exhaust at 1080^{o}F was used for combustion air in the air-cooled combustor. The latter was attached to the boiler, which generated steam at 900^{o}F and 950psig.

The stack outlet gas temperature was specified at 260°F. To maintain this stack temperature two approaches were used.

20 MW COMBINED CYCLE PLANT WITH AIR COOLED COMBUSTOR
-PROCESS FLOW DIAGRAM USED WITH ASPEN CODE

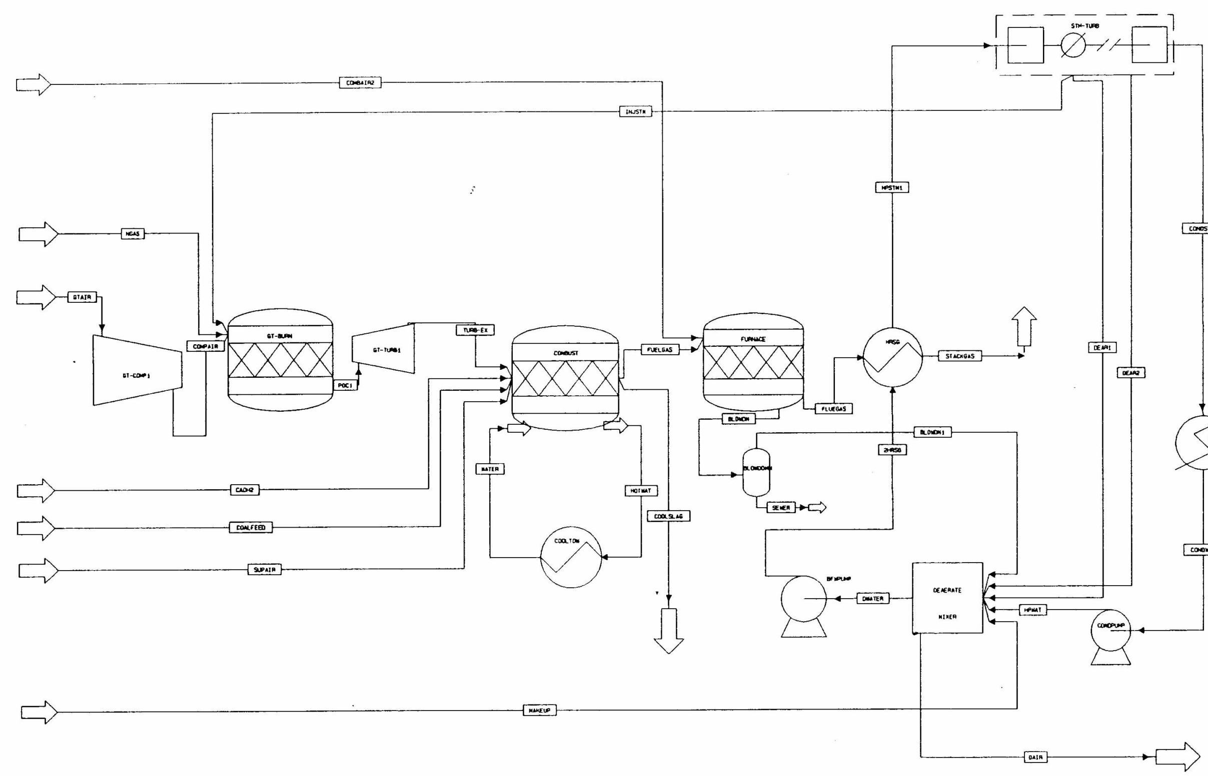


Fig. 3: Process Flow used by DOE/NETL for 20 MW Combined Cycle with Aspen Code

In one case, the coal flow rate was computed at 10,425 lb/hr using a coal with a HHV of 13,200 Btu/lb. This yielded a combined net power output of 19,190 kW, with a cycle efficiency of 32.48%. Note that the computation used the lower heating value efficiencies for the gas turbine and compressor. This slightly lowers the efficiency compared to the HHV efficiencies.

In the second case, the steam flow was increased to maintain the stack temperature at 260°F, and the combined total power was 19,287 with the same efficiency of 32.48%.

In addition, a parametric case in which the turbine inlet temperature was increased to 2300°F, and the cycle efficiency increased to 34.5%.

It would appear that this cycle has a relatively low efficiency. However, its major application is to re-power or retrofit existing industrial and small utility power plants. In that case, the use of the gas turbine is a low cost method of increasing the capacity of the plant. Also, the cycle is designed as a low cost power system using factory assembled major components, namely, the gas turbine-generator, the coal combustor, the steam boiler, and the steam turbine-generator. This results in a relatively low cost plant.

The simplest method of increasing the cycle efficiency is to increase the size of the gas turbine relative to that of the steam turbine. The present cycle assumed fuel rich combustion in the coal fired combustor, with a nominal stoichiometric ratio of 0.75. Operating the coal combustor nearer to stoichiometric conditions would increase the gas turbine size relative to that of the steam turbine. This would also increase the natural gas to coal ratio from the present 25%/75% value, which would increase the total fuel costs. An alternative to increasing the natural gas ratio would be to use a high temperature heat exchanger to pre-heat the gas turbine combustion air with coal firing. As this latter arrangement was under study in another DOE/PETC program. It was not addressed by them for this study.

In conclusion, the present cycle yields acceptable overall cycle efficiencies for industrial or small utility power plant applications involving repowering or retrofit of existing plants.

20 MW Power Plant Arrangement and Economics: As stated above, H-R International performed a plant layout and cost estimation analysis of the 20 MW power plant cycle. The plan view of this 20 MW plant is shown in figure 5 and the elevation view in figure 4.

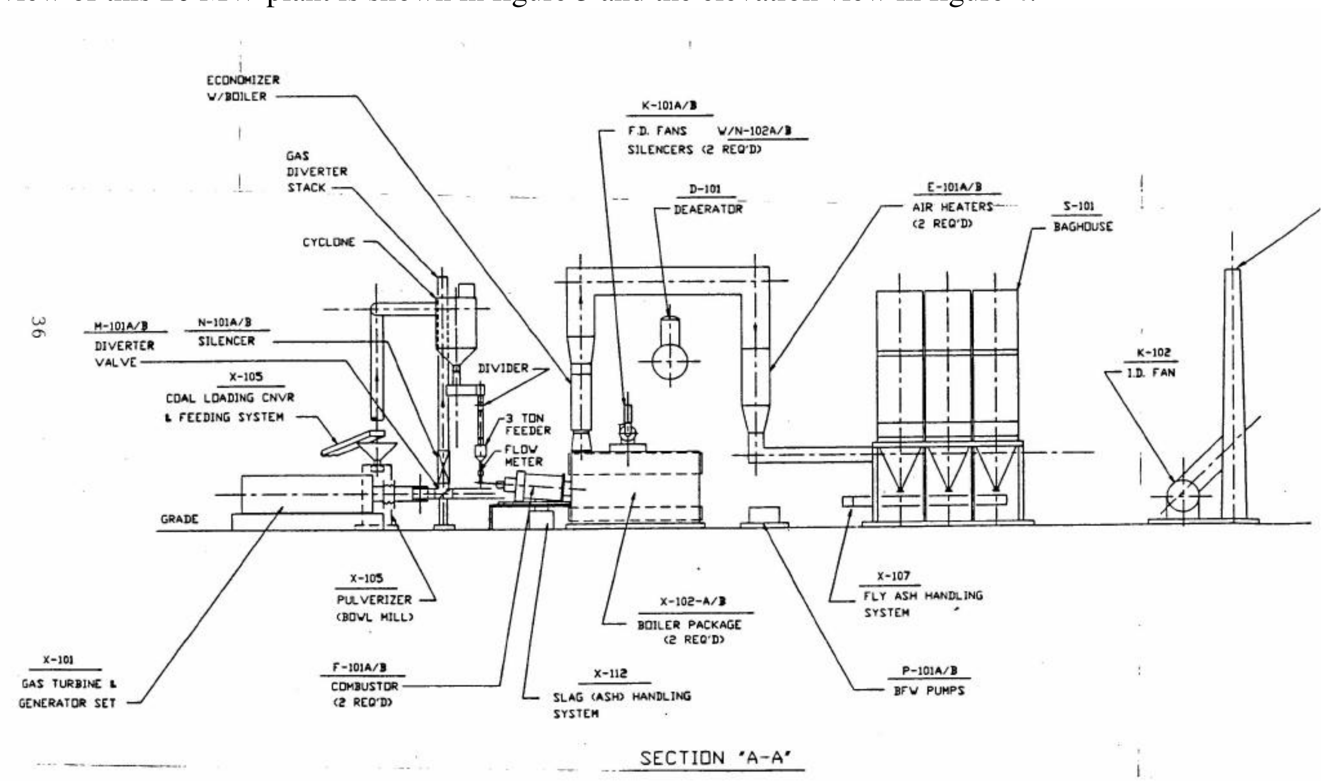


Figure 4: Elevation View of 20 MW Combined Cycle Plant-Showing the Equipment Arrangement

With the exception of the air-cooled coal combustor, all other major components are commercially available. As noted above, H-R obtained budgetary vendor quotations for all major components and sub-systems. These components were arranged according to the layout shown in figures 4 and 5. Costs of the balance of plant elements including site work, concrete, steel, piping, etc., and engineering were developed. A summary of the total cost is shown in Table 1. As noted, the only item missing is the cost of the combustor, which will be discussed below. The total cost of this "Greenfield" plant is **$24 million** for about 19,000 kW, or about **$1265/kW**.

Subsequent to the 20 MW repowering project, Coal Tech re-assessed the results of this 20 MW combined cycle study and concluded that the cost could be reduced, as discussed below.

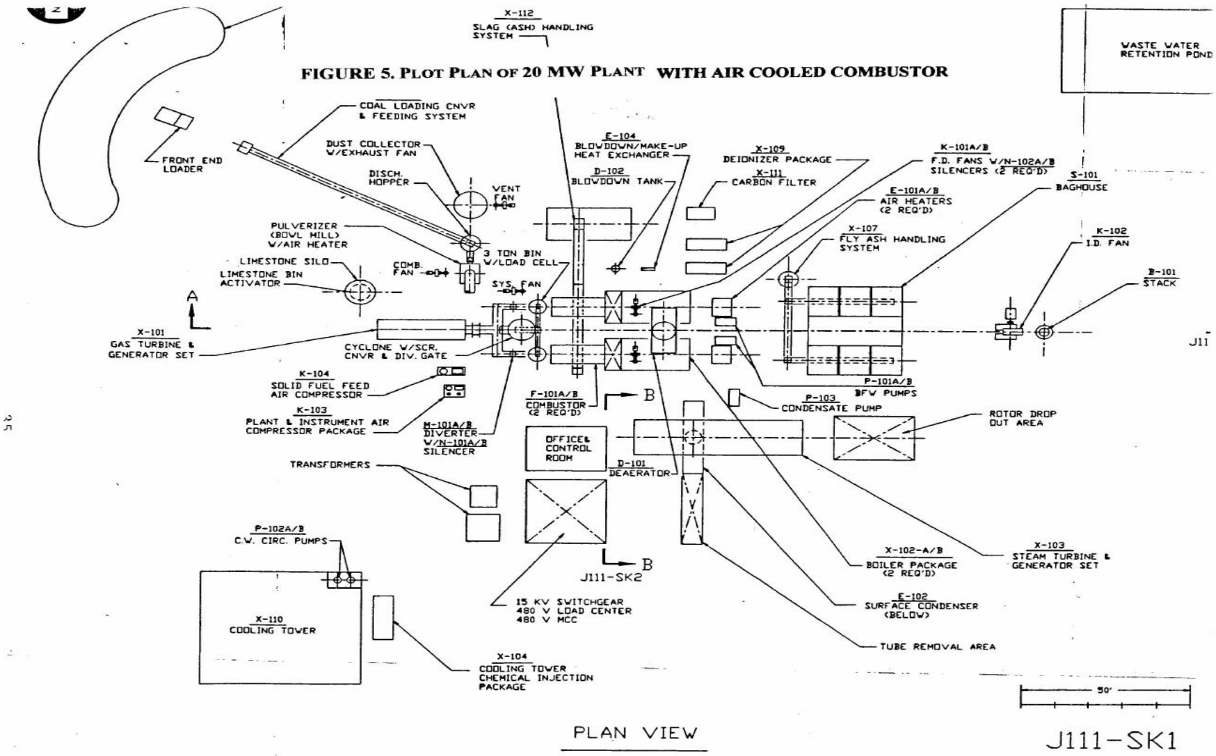


Figure 5 Plot Plan of 20 MW Combined Cycle Power Plant

As noted above, a key element in the design of this power plant is to utilize factory assembled equipment for all major components, including the gas and steam turbine-generators, the coal combustors, the steam boilers, and the solids processing equipment, and the stack particulate control equipment. For this reason, the steam load was divided into two boilers, each with their own combustors. This also increases the plant reliability in that it is less likely that both boilers will require unscheduled maintenance.

The final cost item applies to the combustor fabrication. Coal Tech contacted several machining and fabrication companies in Pennsylvania and New York, which declined to bid. Working through a foreign representative, Coal Tech obtained a budgetary quotation for the fabrication of the combustors in Europe. The price was less than the original fabrication cost of the 20 MMBtu/hr combustor used at the Williamsport, PA test site. Since this cost is negligibly small compared to the total plant cost, it is not included in the total cost given above.

H-R International also compared the cost of the present 20 MW plant with the cost of an equal size plant based on two other commercially available technologies. As noted the present plant cost is **$1265/kW**. **The cost breakdown by major categories is shown in Table 1**. This compares with a cost of $1400 to $1750/kW for a natural gas fired, steam injected combined gas turbine-steam turbine cycle. This latter cycle is similar to the present cycle, except a heat recovery boiler is used without additional firing of this boiler. As such the plant efficiency based on LHV is 39.5% for the plant using the same gas turbine with no additional steam turbine power generation, i.e. the total power output is about 6000 kW. The present cycle was also compared to a similar size, fluid bed boiler power plant whose cost is the $2000 to $2300/kW.

CLIENT: COAL TECH	TABLE 1. COST ESTIMATE FOR 20 MW COMBINED CYCLE PLANT	ESTIMATE/JOB NO.: J111
LOCATION:		ESTIMATED BY:
DESCRIPTION: WASTE TO ENERGY		PREPARED BY:
		DATE: 28-Aug-92

ACCOUNT NUMBER	DESCRIPTION	TOTAL LABOR HOURS	PURCHASED MATERIAL ($)	S/C PURCHASED MATERIAL	TOTAL LABOR COST	OTHER SUBCONTRACTS M&L	TOTAL
1.000	SITEWORK					692,000	$692,000
2.000	CONCRETE					259,000	$259,000
3.000	STRUCTURAL STEEL					501,000	$501,000
4.000	EQUIPMENT	13,626	11,400,000		559,000		$11,959,000
5.000	PIPING	14,323		599,000	587,000		$1,186,000
6.000	ELECTRICAL	3,623		705,000	149,000	450,000	$1,304,000
7.000	INSTRUMENTATION			296,000		1,159,000	$1,455,000
8.000	BUILDINGS					125,000	$125,000
9.000	PAINTING					77,000	$77,000
10.000	INSULATION					547,000	$547,000
	EQUIPMENT RENTAL				194,000		$194,000
	TOTAL DIRECT COSTS	31,572	11,400,000	1,600,000	1,489,000	3,810,000	$18,299,000
	FIELD STAFF PAYROLL AND EXPENSES						1,098,000
	TOTAL FIELD COSTS						$1,098,000
	HOME OFFICE ENGINEERING						2,196,000
	PERMIT, TOPO SURVEY, SOILS TESTS						NOT INCL.
	MECHANICAL CHECKOUT, STARTUP, AND TESTS						NOT INCL.
	SALES AND OR USE TAXES (FED-STATE-LOCAL)						NOT INCL.
							NOT INCL.
	TOTAL OTHER COSTS						$3,294,000

NOTES:	ESCALATION	NOT INCL.
(1) ALL COSTS ARE 3Q92	SUB-TOTAL	$21,593,000
(2) LABOR COST DEVELOPED FROM CLRC AT $41/MANHOUR.	CONTINGENCY	2,568,000
	FEE	NOT INCL.
APPROVED BY PROJECT MANAGER:	GRAND TOTAL	$24,161,000

Table 1 : H-R Int. Cost Estimate for the 20 MW Greenfield Combined Cycle Plant

Note added May 2003 *This 20 MW combined cycle power plant study was performed in 1992/1993. After the results were obtained, Coal Tech presented the results to the representative of the independent power producer. However, he had lost interest in the project. This was not surprising as since by that time there was no possibility of a coal fired power plant competing with natural gas fired simple and combined cycle gas turbine systems.*

It was noted above that DOE/NETL was at that time studying a combined cycle power plant that was totally coal fired, with gasification for the gas turbine. DOE also was sponsoring at the time several large power manufacturers in projects to evaluate combined cycle power plants in which the gas turbine was partially fired by indirect heat exchangers and natural gas. Coal Tech had submitted a proposal DOE for a cycle similar to the present one in response to that solicitation but it was rejected. Several teams were selected by DOE to develop such cycles in a phased competition that would lead to construction of the best prototype plant. To the best of our knowledge that project did not proceed to construction of a demonstration plant. It was supposed to use a water-cooled, slagging combustor, whose water wall cooling losses would have substantially reduced the cycle efficiency. Also, the indirect heat exchanger was supposed to use silicon carbide tubes, which are quite costly. In other words, it was an example of a sophisticated system that was not economically competitive.

The cost estimates provided by H-R for the gas fired power plants were based on actual projects that they had implemented for small 5 MW output gas turbine systems. Coal Tech met with a developer of such systems. However, they were not willing to undertake the financial risk of a first power plant using the air-cooled combustor.

In any case, it was already becoming clear at that time with natural gas priced in the $2 to $3/MMBtu, and with large, 50 MW and up, simple gas turbine power plants being erected at the $600/kW range, that coal fired power plants could not compete. This resulted by the middle to second half of the decade into a veritable stampede among utilities and independent power producers to build almost exclusively natural gas fired power plants. It was driven by electricity de-regulation and accelerated by a stock market bubble that accorded electricity "traders" and power plant developers "glamour stock" status and inflated stock prices.

Overlooked in all this was the fact that capital intensive industries, especially those that depend on commodities in limited supply, such as natural gas, can best be characterized as "roach hotels" in that one can enter, but not leave, except through bankrupt cy. As demand for natural gas increased for power production increased, its price increased. This was no problem as long as demand remained high. However, as the economy entered into recession around 2000, the demand for electricity decreased faster than the price of natural gas. The result was a financial debacle in the electric power sector that began in late 2001 and continues to depress the electricity to this day. According to a recent report in the financial press, 140,000 MW of gas turbine power plant capacity is on the market at 25% of the original installed cost of $600/kW, with no takers. Consequently, banks and other bondholders have agreed to "restructure" the loans in the hope that at least they will eventually recover some of their money.

Interestingly, the basic concept of the coal fired combined cycle remains even more timely today than one decade ago. During and after the completion of this project in 1998, Coal Tech continued to develop this power plant concept. As task 4 continued, the focus shifted to repowering an existing power plants, which sharply reduces the cost of the plant, as is reported below. In addition, natural gas was eliminated and substituted with pyrolysis and gasifier fuel for the gas turbine, and the residual char for the air-cooled combustor driven steam power plant. **The motivation was our recognition that over the long term, the only fuel that made any economic sense in the U.S. was coal. However, coal has and continues to face one major barrier to growth, namely pollution**. **No only must emissions but sharply reduced, they must be eliminated, as DOE has recently recognized. However, the key to zero emissions is low cost, something that most current emission control technologies do not meet**.

Since the latter part of the task 5 on this project to the present, Coal Tech has focused all its efforts on the goal of zero emissions at low cost. Major progress has been made in the past 7 years, exclusively with Coal Tech's extremely modest resources. This was not for lack of trying to find external support. During this time, a series of close to a dozen proposals to advance this work were submitted to various DOE offices, including Sandia, SBIR, and NETL. They were all rejected. Interestingly, the combined power cycle studied in the present task is still the basis for a coal only cycle that has total emission control, including carbon dioxide sequestration. It uses existing coal fired power plants as the foundation for expanded power production.

Commercialization Studies

Another key part of this task 4 was commercialization of the combustor technology. To this end Coal Tech engaged in considerable marketing efforts.

In 1992, Coal Tech retained a consultant to assist in obtaining customer requirements for purchase of the combustor, and to identify potential sites for installation of demonstration and commercial systems based on the 20 MW combustor power plant design.

To identify potential demonstration sites, he performed a survey of small utility boiler plants that could be used for this purpose. To this end, a DOE database of utility plants in the 20 to 50 MW range was used. Contact with the utilities revealed that most of the plants on the list have been torn down. Nevertheless, one -half dozen potential sites were identified in the Middle Atlantic States and in the Midwest. Of these, three were selected for detailed evaluation. The owners of two of these plants agreed to participate in a site-specific evaluation on retrofit with the present power cycle. Some of the results are reported below.

In addition, the consulting firm contacted several companies to determine the commercial acceptance requirements of new technology. They included representatives from the industrial boiler market; from A/E firms; a chemical company, a food company, as well as several others. The results are in the form of responses to about two-dozen questions. Slightly different sets of questions were addressed to each group. The questions and responses from the four boiler manufacturers that were interviewed by telephone are summarized in the following, and they are highlights of these interviews. The responses are composites for those cases where several companies responded to the question. Comments made at the time follow each set of answers. In case where there was a primary response it is shown in **bold type**. Also May 2003 comments to this survey are listed at the end of each question in **bold italics** font.

1. *For retrofit applications, what characteristics are essential for the combustor to work well with the boiler*?

(1) Physical match-up/dimensions
(2) Attachment and fit of components
(3) Comparable or improved performance
(4) Lower emissions
(5) Availability
(6) Confidence in short term delivery (lead time)
(7) Quick installation
(8) **Credibility of the manufacturer**.

Comment: The Coal Tech combustor can meet all the above technical requirements. However, until a number of combustors are sold, installed and operated, credibility cannot be established. Therefore, either full commercial demonstrations and or licensing are preferred routes to commercial acceptance.

Item 8 has and continues to be the "show stopper" for the combustor technology. Numerous business opportunities in the past decade foundered on the refusal of potential

customers to purchase the first combustor. This includes opportunities in Australia, China, India, and Japan

2. *What has been your experience with cyclone combustors*?

(1) The only experience in retrofit has been replacing existing slagging combustors such as the B&W cyclone combustors.

(2) Problems encountered:

- Extremely harsh environment
- All aspects of elimination and removal of slag
- Chemical attack on tubes. (Note-This applies mainly to water cooled cyclones)
- Materials durability
- Slag tap operation
- Supply of low ash fusion temperature coals

Comment: These responses validate the focus of the Coal Tech combustor development effort. They also validate the choice of air-cooling of the combustor walls.

We agree that slag tap operation is the major problem, and much effort was expended on this in the present project. However, this problem also exists in high ash coal fired boilers where slag forms on the boiler walls and large pieces can fall off periodically and damage water tubes. Also, in existing slagging cyclone combustors, the slag drains into a "lake" at the bottom of the very large furnace chamber, where plugging problems can result in severe difficulties. In contrast in the air-cooled combustor, the slag is removed from each combustor separately. Also, overlooked by the respondents is the environmental problems that converting ash into slag eliminates.

3. *In the 20 to 50 MWe range what type of combustors are used*?

Stokers in the bottom end range, pulverized coal and fluid beds in upper range. Cyclones are not used.

Comment: The cyclones referred to use crushed coal.

4. *What degree of SO_2 and NO_x reduction would a power plant require to consider switching combustors*?

(1) Depends of legislation and emission allowances.

(2) Uncontrolled stoker fired boiler emissions are 0.5 lbs of NO_x/MMBtu and 0.5lbs.SO_2/MMBtu. Therefore, 50% reduction of NO_x to 0.2 lbs/MMBtu would be of interest, combined with flue gas injection of limestone or sodium bicarbonate. .

Comment: These emissions are for low sulfur coal. The Coal Tech combustor can meet these goals.

The respondents in 1992 underestimated the ability of the industry to delay implementation of stricter emission control rules. Also, this response is not quite truthful. Coal Tech demonstrated 40% NOx reduction in several utility boilers in 1997 and 2000 with a post-combustion process or negligible capital cost, yet there was no interest in installing the process.

5. *In industrial power plants, at what level are combustor purchase decisions made*?

Director or VP of engineering and responsible level for profit and loss.

6. *What events precipitate a power plants interest in purchasing*?
(1) End of boiler life, components failure (i.e. tubes)
(2) Cost of retrofit
(3) Emission regulations

7. *What is the sell cycle*?
4 months to 18 months, depending on reason for replacement, e.g. failure or end of life.

8. *Are boiler manufacturers asked to recommend combustors*?

(1) Larger manufacturers have their own combustor systems and do not recommend competitor combustors. However, on smaller gas or oil fired units specialty manufacturers are used.

(2) One deterrent to other combustors is contractual liability.

(3) To recommend other combustors need performance data, confidence in company, and acceptable business relationship.

See comments under Question (1)

9. *What characteristic would a power plant owner seek to use a new product*?
(1) Lowest price
(2) Customer support
(3) State-of-the-art technology
(4) Track record and good background
See comments under Question (1)

10. *What specification would you require to sell outside combustors as part of boiler package*?
(1) Combustion efficiency
(2) Low emissions
(3) Appropriate dimensions
(4) Firm price
(5) Performance guaranties
See comments under Question (1)

11. *If you sell combustors, would you consider licensing combustors from others*?

Medium to small boiler manufacturers already license. Large companies would license. But as the combustor is a core technology, no large company has ever licensed.

12. *Do you foresee a substantial industrial market for combustors capable of burning coal and solid waste fuels with environmental control*?

(1) Retrofit Market:
Cyclone don't fit on stoker boilers, and they are too large for 20 -50 MWe boilers.
Coal would only be an auxiliary fuel
(2) New Market
Space is not an issue, economics and performance are key issues.
Market currently favors natural gas fuels due to low cost and low emissions

Coal stack emissions controls are not effective for SO_2 and NO_x at this plant size. Only option here is fluid bed.

Comment: If the low cost projected by the 20 MW plant study are validated, it is possible that Coal Tech would have a unique product for this size market.

All these answers are incorrect. The air-cooled combustor can be retrofitted to boilers as small as fire tube boilers rates at 5 MMBtu/hr. It can be retrofitted to stoker fired boilers. Also, Coal Tech has developed post-combustion NO_x and SO_2 controls that can make coal use attractive even in very small boilers.

14. *If your company is engaged in exports, do you believe there is an export market for this industrial scale technology*?

(1) Most overseas industrial projects are to the Pacific Rim/Third World. For coal, size is 500-600 MWe. Also there is a large combined cycle gas fired market. There is no export market for smaller facilities.

(2) Recommend licensing the technology

Comment: Coal Tech agrees with this approach

The statement that the export market is the Pacific Rim is correct if one adds India. There is indeed a very large market for coal-fired combustion even at small steam and electric power sizes, as Coal Tech Corp determined in subsequent years. The problems have been protection of proprietary rights and financing.

15. *In your opinion, does lower cost offset customer reluctance to accept new technologies*?

(1) Depends on the company. Entrepreneurial companies focus on cost, conservative engineering companies on reliability and track record.

(2) Efficiency alone is not a sales factor.

(3) <u>**Industrial companies do not want to be first.**</u>

How true! That is why the government should act as the bridge in bringing new technologies into the market place. However, the government's procurement practices favor large companies because cost is not a point scored selection criterion. This removes a major advantage of small companies that can bid lower cost and that have historically been the greatest innovators from Morse's telegraph, Bell's telephone, Edison's light bulb, Parson's steam turbine, Whittle's jet engine, De Forrest's talking pictures, and the PC and related software industry, just to name a few.

<u>Conclusions by Coal Tech on the Responses.</u>

There are several interesting results from this survey:

(1) With the low price of natural gas the industrial companies are switching to natural gas. The primary market for coal appears to be special applications such as co-firing for environmental control of industrial air, water, or solid waste emissions.

As noted above, the decision to shift all new construction to natural gas fired power has had disastrous consequences by 2001. High natural gas prices have literally destroyed much of the domestic plastics and chemical to the point where there has been a $17 billion swing from exports to imports in these industries in the last few years.

(2) Reliable commercial scale demonstration is a key requirement for acceptance by the market place.

(3) Smaller manufacturers are more responsive to outside combustor technology than the large integrated companies

(4) Licensing appears to be a preferred route, especially for the overseas market.

(5) Most importantly, if a major economic advantage can be demonstrated, the technology would find acceptance, provided performance and environmental control goals are demonstrated.

Based on the results of this survey, which as noted also included A/E firms and industrial companies, Coal Tech decided in 1993 to focus on special applications where there is an urgent need to control environmental emissions, and where the coal-waste fuel co-firing capability of the combustor offers performance and economic advantages.

This was the path Coal Tech Corp has followed since 1993. However, we were convinced that without total emission controls no coal based energy market would develop in the U.S. Consequently, this has been Coal tech's focus in the past 7 years. Great success has been achieved with processes invented for each major pollutant. For example, Coal Tech's SNCR Nox reduction process reduced said emissions from 0.3 lb/MMBtu to 0.15 lb/MMBtu in tests on a 50 MW coal fired boiler last November. The estimated operating cost was a little over $400/ton of Nox removed. Since all this work was self-financed, progress was slow.,

Independent Power Production/Cogeneration Company Survey.

In November 1992, letters were written to nearly all US companies in the IPP/ cogeneration market. The companies were selected from a published data base. The letter requested information on upcoming projects in the 20 to 50 MWe range that planned the use of solid fuels and that could benefit from the air-cooled combustor technology. It was learned that currently almost all projects were natural gas fired turbines with heat recovery boilers. ***This was not surprising as long as the price of natural gas remained low. Of course the results were disastrous.*** However, several companies that were installing larger (i.e. above 100 MWe) gas fired combined cycle plants, are designing the plants to allow future conversion to integrated gasification. They believe that by the end of the decade, the gas price advantage will disappear. In that case, a market would also open for the air-cooled combustor. ***They were wrong. The glut of new power plants makes conversion to coal gasification totally uneconomical***.

Note that this 1992 survey predicted this trend to install natural gas fired turbine power plants, but even more important the industry's recognition that eventual naturally gas prices would increase from this added demand, although it is very doubtful that they thought prices go to $10 per MMBtu in 2000. Why no one bothered to analyze the natural gas market is a mystery that can only be explained by the mentality of stock market investors who follow the crowd..

B. 3.4. Task 4.2 Commercialization Efforts in 1993

As noted above, task consisted of two sub-tasks. Task 4.1 consisted of the study of various steam and power systems to which the air cooled, slagging combustor offers significant performance and economic benefits. One such cycle, the 20 MW combined gas turbine-steam turbine cycle was discussed above. Another, the 20 MW repowering cycle will be discussed below. Task 4.2 involves the investigation of commercial applications of these systems. In 1992 and 1993 considerable effort was expended on the second sub task, i.e. task 4.2. A number of commercial applications of the combustor were investigated with the dual objectives of determining the suitability of the combustor for these markets and to identify potential sites for initial demonstration of the combustor in a commercial system.

Specifically, three areas of applications are being investigated:

1. Greenfield Industrial Scale (20 MW) Combined Cycle Plants, which was the focus of the task 4.1 effort described above.
2. Repowering Small (20 to 70 MW) Utility Power Plants, which was implemented as the second task 4.1 power plant cycle study for an actual power plant in PA.
3. Greenfield and Retrofit of Industrial Boilers for use with:
   3.1. High ash waste coals
   3.2. Co-firing of coal/oil/gas with paper mill waste products
   3.3. Vitrification of high carbon fly ash in coal fired plants produced in power plants equipped with low NO_X burner. This last effort involved testing of fly ash from a coal fired power plant in Upstate New York, and from a municipal incinerator in Ohio, with the tests conducted under a DOE-SBIR project on the 20 MMBtu/hr combustor. Relevant results are discussed in Appendix "A" of this Final Report.

1. The results of the 20 MW Greenfield plant analysis were described in the previous sub-section.

2. The initial effort at re powering of a small (20- to 70 MW) utility power plant with the air-cooled combustor and a new boiler began in 1992, and initial results were described in the previous sub-section. Five potential sites were identified. One plant in South Carolina was eliminated after the utility determined the high ash coals, which could be used with the air-cooled combustor, was more costly than the low ash coal in current use. (*April 2003-In retrospect, this decision ignored the environmental benefits of converting the potentially leaching fly ash into inert, marketable slag, as well as the other environmental benefits in using the slagging combustor technology*.)

The other four sites were located at three utilities in PA, KA, and KY. Coal Tech and H-R personnel visited two utility power plants in Kansas in February 1993. One of the plants, which had two 40 MW steam turbine generator sets, was found to be unsuitable for retrofit. The boiler part of the plant had been sold to an independent steam producer several years earlier. There was insufficient room on the other boiler for coal storage and for a combustion-boiler system based on Coal Tech' s technology.

The second site was located inside two 800 MW coal fired power systems. The plant had an unused low pressure, 20 MW-steam turbine. Also, three oil fired package boilers were being installed to provide startup steam for the plant. We proposed using one of these boilers for retrofit with the air-cooled combustor. The existing coal delivery system to the large boilers would also be used, as would the low-pressure steam turbine. It was estimated that the entire retrofit could be accomplished for about **$200/kw**. Due to the low steam turbine pressure, the heat rate for the 20 MW turbine would be only about 16,000 Btu/kW-hr. Nevertheless, this plant appeared to have all the characteristics for an economical retrofit. Before proceeding, the utility' s management requested from its analysis group a financial evaluation of the retrofit assuming the 20 MW would be an addition to the utility' s base load power. This analysis, which was completed in March 1993, showed that the project was not economical despite its low cost. The reason was that the utility had excess base load capacity until the year 2000. Therefore, no base load addition is economical for this utility. Also, the utility' s peak power requirements are of such short duration that using the plant for peaking power is also not economical. .

Note Added in April 2003: This experience shows the short-range outlook that we frequently encountered in our marketing studies. At $200/kW the total project cost would have been a drop in the bucket, $4 million. However, had the project proceeded the utility would have learned a great deal about the operation of the slagging combustor as well as our subsequent work on combustion and, more importantly, post-combustion NO_x and SO_2 control. Instead we learned that several years later the company had to switch to low sulfur, sub-bituminous coal from WY and MT to meet lower emission regulations for SO_2. Assuming a hear rate of 10,000 Btu/kW-hr, a HHV of 9,500 Btu/lb for the coal, results in a rate of 842 tons per hour coal use. Assuming a $10/ton extra shipping cost for this high moisture coal, results in about $8420/hour added cost from shipping. Thus in $4 million investment would have been recovered in 475 days, or 16 months.

The <u>third site </u>was plant in PA has an operating power generating system, and a retired medium pressure 20 MW turbine. The boiler for this turbine is of such an old design that its reuse for the project is not economical. It was, therefore, decided to analyze the plant on the basis of re powering the plant with a new oil designed package boiler to which two 150 MMBtu/hr air-cooled combustors are attached. A significant advantage of this plant is access to very low cost high ash waste coal. The second 20 MW power plant analysis required by the task 4 work statement was performed for this project, and the technical and economic results are reported below. Here the marketing issues are presented.

A preliminary economic analysis using the capital costs obtained in the 20 MW combined cycle study indicated that the plant repowering would be in the range of $700 to $800/kw. At this cost, and with the waste fuel cost, power sales from this plant would yield an attractive return using current local utility power purchase prices. This plant would have made an ideal site for a full-scale demonstration of the combustor technology.

For this project, we decided to find an investor to finance the project before proceeding with the analysis. We found one, a developer of independent power plants, with the assistance of H-R International. A series of meetings were held with this developer and the engineering staff at the site proposed for the 20 MW repowering project in PA. The purpose of the meetings was to developed a preliminary plan for third party financing of the project and to develop a schedule for this project. For example, a previously unanticipated task that had to precede the beginning of the project was a 12 to 18 month analysis of the wind and environmental factors at the site. This would require the erection of a weather tower at a height equal to that of the proposed stack. However, as the site already has such a tower, several months could have been reduced from this schedule. In any case, the investor (developer) estimated that if the go ahead on feasibility were given on 1/1/94, the plant would not go on line before 1998. Our original plan had been to sell the power to another utility. However, in the interim, the other utility lowered its power purchase rates by about 20%, which made such sales very marginally attractive.

The site owner on the other hand would require the entire 20 MW output by 1998, and the proposal was re-focused on this option. This, however, created a new problem. The repowering site had at that that time (1993) capacity that was scheduled to be written off in the year 2004. There was also the possibility that the site would be closed at that time. All these factors were discussed at a meeting in early November with the site owner engineering personnel. After several weeks of reflection on this matter, the site manager decided that a decision on which way to proceed would not be possible before mid-1994. In the interim, the investor withdrew as a potential investor. Furthermore, an independent power producer that had arranged to sell power to the utility at a nearby site encountered financial difficulties and its project was terminated. As a result the effort was dropped.

P.S. May 2003: The power plant was not shut down. It remains quite profitable. In fact the plant management decided during the electricity boom of last years of the 1990's to install a 50 MW, gas turbine peaking generator to be fired with natural gas. When the decision was made to install the gas turbine, spot power in PA in the summer reached as much as $1000/MW-hr. As in the battle of Gettysburg, in July 1863 that was the "high water mark" of the utility bubble, and prices subsequently collapsed. The gas turbine generator is now only used infrequently for spot power sales because current (2003) gas prices are about $5/MMBtu.

On the other hand, if our 20 MW repowering project had proceeded with Coal Tech's low cost design (not the one developed by H-R International), the profits would have been enormous because the coal mine waste to be sued as fuel was owned by the utility and was on its books at somewhere in the $0.30 /MMBtu. The project makes even more economic sense today.

The **fourth plant** site was in KY. However, this plant was not investigated because this utility has similar very low power purchase prices as the KA utility. .

Foreign Applications:

A major potential foreign market for the combustor is in countries that have high ash coals, such as India, China, Indonesia, Poland. In 1992, Coal Tech wasin contact with an Indian power equipment company for the demonstration of the combustor with high ash Indian coals. The Indian company had identified a potential industrial site in Central India, whose owners were interested in increasing their steam generation capacity. When using high (35%-50%) ash, Indian coals, the existing boilers at this plant require a substantial derating from the 200,000 lb/hr, 1500 psi, 900F, steam rate required by the plant.

A preliminary conceptual design was prepared for the attachment of two 150 MMBtu/hr air-cooled combustors to a D frame, oil designed boiler capable of producing the required steam generation. Also a cost estimate for the fabrication and installation of the complete 150 MMBtu/hr combustors with all auxiliary equipment was prepared.

Using this information, the Indian company prepared an estimate for the cost of the balance of the plant. **They estimated that the slagging combustor system would cost about <u>65% more</u> than a fluid bed system**. However, on comparing the costs with our cost data for similar sized plants in the US, we noted a major discrepancy between their cost of their plants in that the relative cost of the fluid bed plant was too low compared to our system. It is believed that their higher cost is due to their use of a very complex indirectly fired coal feed system, which greatly increases the total system cost. Coal Tech' s design is based on our direct coal firing. The P.I. has encountered this cost discrepancy on a number of occasions when dealing with A/E firms. We believe that it is due to two factors.

One is that A/E firms accept vendor quotations, and on budgetary requests the vendors give little attention to requests. Our own experience, as reported herein confirms this in that requests are made with little intention of placing an order, even when the vendor expends resources for testing the client's material.

However, a much more important reason is that the A/Ee firms will integrate a new technology component into existing systems without taking advantage of the benefits that the new technology offers to other components in the system. Coal Tech , on the other hand, has used such an approach, which is the key reason why our overall systems are very low in cost. The reader should refer to the task 5 effort to see how we implemented this for that task.

In any case, the Indian company refused to consider our position and the effort ended.

This was unfortunate because this project would have been an ideal vehicle for future joint ventures with this company in India, Southeast Asia, and the Pacific Rim. (***2003 Note***: ***Had it gone into commercial operation at the time the "Brown Cloud" over the Indian that is the size of the continental USA and 2 miles thick, and is almost certainly due to inefficient, high ash coal combustion could have been greatly mitigated with out technology.***) However, as in the case of our experience with another Indian power plant developers, this company insisted that Coal Tech arrange for all the financing, and that was that.

<u>Note added in May 2003:</u>, ***By coincidence in 1997 during the task 5 test effort, we learned that DOE had several tons of a 37% ash pulverized Indian coal in a warehouse in Pittsburgh. We fired this coal and the results were incredible. Not only did it slag well, but we were able to retain 20% of the injected sulfur within the vitrified slag removed from the combustor. This was double the maximum level measured in 100's of previous tests with low ash U.S. coals in this combustor. Therefore, Coal Tech has the technology that would benefit Asian countries that burn extensive high ash coals, including India, China, Indonesia, but we have no financing method to market this technology there.***

<u>Coal Fly Ash Vitrification</u>:

Another potential commercial application that even more valid **today (2003)** is to use the combustor for <u>vitrification of high carbon, fly ash</u>. The high carbon content in fly ash is a result of the poor combustion efficiency in boilers operating under NO_X emissions restrictions. In 1992 we learned of an independent power production company in Upstate New York that had an

80 MW plant that produced about 6 tons/hr of this high carbon fly ash. This ash was landfilled at considerable distance from the plant at very high cost. In January 1993, we visited this company and presented technical and economic data that showed that our vitrification process would allow the company to recover its investment with 1 to 2 years. We also proposed a brief tests on vitrifying the ash in the 20 MMBtu/hr combustor.

A sample of the high carbon fly ash was received by Coal Tech and analyzed. In addition, 200 lbs of this ash was received. On May 6, 1993, it was co-fired with coal in a brief test under a parallel DOE-SBIR fly ash vtrification project. The test showed that the carbon content in the fly ash was reduced from 30% to 4.5%. Although much of the fly ash was converted to slag, a substantial amount escaped the combustor and was captures in the particle scrubber. This means that part of the ash was converted to marketable, vitrified slag, and the balance to marketable low carbon fly ash.

In May 1993, Coal Tech submitted a proposal containing the test results and offering to perform a longer duration and higher feed rate test using 3000 lbs of ash. The proposal included a firm bid to install a fly ash vtrification system at the customer' s plant. The ash processing rate would be 6 tons per hour. This would require the use of one Coal Tech combustor that would be retrofitted to one of the plant' s boilers. Preliminary cost analysis indicated that investment cost recovery would occur **within 2 years**. The company responded that before proceeding with these steps they would test a different coal and hope that this would reduce the carbon content of the fly ash. However, by the beginning of 1994 it became clear that no action would be taken on our proposal. Since this effort took place during a period when NY State utilities were balking at paying the high prices negotiated in the previous decade under the PURPA laws, it is possible that this plant may have been affected by this action

Nevertheless, a conceptual design of a combustor that can vitrify the 6 tons/hour of fly ash produced by this plant was prepared. The total heat input required was 100 million Btu/hr. With an 86% ash vtrification efficiency, the system yields 86 MMBtu/hr for steam production. The energy greater than the carbon energy in the fly ash would be provided by coal from the plant' s coal system. The total system design and cost depends on how much equipment can be used at their plant. It was assumed that the combustor would be attached to a new boiler. Revenue of 3 cent/kW from the added steam power production, 3-year amortization, and an 11% interest loan for the entire conversion was assumed. No additional operator personnel were required. At present the ash is wetted and shipped in open rail cars to a disposal site at least 100 miles away. The result of our analysis showed that <u>the annual net cost of operating this system for each of the first 3 years was about zero, i.e. savings from the plant's current ash disposal costs would be eliminated.</u>

Since this high carbon content in the ash is a result of incomplete combustion from low NOx burners, this ash vitrification process can apply to all boilers equipped with such burners, and at a far lower cost that alternate methods that reduce carbon in the fly ash, some of which are described in the April 2003 issue of Power Engineering, page 22.

<u>Waste Product Combustion</u>:

The final application under study at that time was the co firing of coal/oil/gas with paper mill waste products. Our marketing consultant prepared a special brochure that describes the benefit of using the Coal Tech combustor for co-firing of paper mill sludge and wood chips with coal, gas and/or oil. The advantage of our combustor is that it can be retrofitted to existing boilers at paper mills. Also, by co-firing with coal, the sulfur can be used to bind the chlorine released in the combustion of paper. This removes the key element in the formation of the chlorinated aromatics, which form dioxins. An alternative to this approach is to dry the sludge and pelletize it with coal and wood chips or sawdust. Unless the pellets are pulverized, they must be fired in a stoker boiler. In either case, this alternate procedure should be more costly than our approach of direct co-firing of the sludge with coal, oil, and /or gas.

1) We obtained a response from one paper company, and we prepared a proposal to demonstrate the benefit of co-firing ½ ton/hour of paper mill sludge with coal or gas. A budgetary quote for the retrofit of the air-cooled combustor to an existing boiler rated at 35,000 lb/hr was made. The thermal input due to the sludge was less than 10%, which limited the cost benefit of the retrofit compared to the present landfill disposal. However, this cost proposal was of sufficient interest to the company requested in July 1993 another proposal to use our technology to retrofit an oil design boiler in a plant that produces 400 tons/day of sludge. In that case, the heat content of this waste material represented 40% of the total boiler heat input. Coincidentally, this required an air-cooled combustor in the same 150 MMBtu/hr range as that used in the other projects under study.

Here again when decision time arrived, the company requested that we finance the project, and that was that.

2) Another paper manufacturing company requested a budgetary proposal on converting two 120,000 lb/hr boiler with the air cooled combustor in order to control NO_x emissions from coal firing. The required emission level of 0.45 lb/MMBtu was above the lowest level that has been measured in this combustor, namely 0.26 lb/MMBtu, by that time, namely 1993. (**In 1997 we reduced NOx to 0.07 lb/MMBtu from 1 lb/MMBtu**). Their boilers were coal fired. However, the combustion efficiency was very poor, and the ash has a 50% average carbon content.

We submitted a cost proposal in June 1993. It was based on vendor quotations for the fabrication of four combustors and their installation on the two boilers. The cost was less than $10/lb of steam. This was one-half of the cost of a new gas fired boiler system, and about double the cost of low NO_x burners. As the plant was located in a region that had access to lower grade and lower cost coals, the recovery of the investment less than 3 years. If, in addition, a $10/ton lower cost coal is used, the cost recovery was reduced to less than 2 years.

3) We uncovered a very promising lead to a commercial power plant project for the air-cooled combustor in the Fall of 1994 at a paper mill in Pennsylvania. This mill produced part of its electric power needs on-site and purchased the balance from the local utility. In addition, the balance of the steam was used for processes. We prepared a proposal for Coal Tech's

combustion system for process steam and all power generation at the mill. It would be capable of producing 8.5 MW of power and 125,000 lb/hr of process steam. Our letter proposal offered several options ranging from a waste coal fired combustion system that would be connected to the existing steam-feedwater lines to a totally new power system. The former option would cost about 1/4 that of the latter. It would continue to utilize the existing 3+MW electric power on site. The latter option would require a new 8.5 MW turbine.

After review of the proposal and submission of responses to written questions, the plant manager asked us to submit a proposal in which a third party would finance the project, and sell the steam and power to the mill. However, at that time (1993) the cost of the project was too low (considerably less than $10 million) to justify third party financing. Also, the return on investment would depend on the financial strength of the company, and as a commodity product, it was susceptible to economic conditions.

4) In January 1994, Coal Tech received a request from a major paper company for a combustion system than could process between 400 and 700 tons/day of solid and sludge paper mill waste. The RFQ stated that the company' s preferred option was a fluid bed system that cost $17 million. The scope of supply for this fluid bed system was not specified. Therefore a direct comparison with the approach proposed by Coal Tech is not possible. Coal Tech proposed a system that cost between **$2.8 to 3.5 million** depending on options. Based on the economic data provided by the paper company, we estimated that the entire capital investment with the Coal Tech system would be recovered within 1 year.

We proposed to use the Coal Tech air cooled, slagging, cyclone combustor to incinerate all three waste streams identified in the RFQ plus supplemental natural gas or No.2 oil fuel The combustor was sized to match the total plant' s steam load of 100,000 lb/hr. This required only about 139 MMBtu/hr (assuming 24 hour, 350 day operation) to be supplied as follows:

Paper Sludge: 51 MMBtu/hr; Waste Water-Sludge: 7 MMBtu/hr
Pond Waste- 19 MMBtu/hr Natural Gas or No.2 oil- 62 MMBtu/hr

Total 139 MMBtu/hr

The paper sludge had 50% water content and a dry HHV of 4067 Btu/lb, the pond wastewater had 30% solid content and a dry HHV of 5280 Btu/lb, and the wastewater had a dry HHV value of 6600 Btu/lb. As a result, the dry waste feed rate was 8.59 tons/hr and the wastewater was 11.91 tons/hour.

In order to achieve acceptable combustion, the waste stream would be dried using a combination of stack gas energy, combustor air-cooling energy, and supplemental natural gas fuel.

Two boiler options were considered. One was to use the spare oil fired boiler in the plant. The other option was to retrofit the combustor on a purchased used oil/gas boiler. The latter yields a stand alone waste combustion system.

Therefore, the scope of supply to be provided by Coal Tech would consists of one 140 MMBtu/hr combustor and its auxiliary components, a waste fuel drying and fuel transport system, a baghouse, and as an option, a used oil/gas type industrial boiler. The estimated installed cost of this system was about **$2.8 million** without the purchased boiler and about **$3.5 million** with the purchased boiler. Based on the waste disposal costs at the plant, the average annual saving on waste would be $2.8 million. At $3/MMBtu/hr for gas or oil, the fuel saving would average $1.5 million, for a total saving of **$4.3 million/year.** If the paper mill were to finance the project, the entire investment would be recovered in less than 1 year.

We offered the paper company these financing options:

Option 1: The paper company finances the entire project. This provides the investment return given in the previous paragraph.

Option 2: Coal Tech arranges third party financing to install the entire system with the purchased boiler at an estimated cost of $3.5 million. This system would be installed in parallel with the existing boilers at the plant, with the later available as backup. The third party would sell up to 100,000 lb/hr of steam at a **25% discount** from the sum of the current landfill disposal cost and the 62 MMBtu/hr of gas/oil fuel displaced by the waste fuels. The contract would be for 7 years, at the end of which time the plant would be turned over to the paper company. The total revenue (or savings) consisted of eliminating the landfill costs and eliminating the gas/oil fuel costs. Tax-free financing at 7.5% interest, with a 20% equity-80% debt over a 7-year depreciation and amortization was assumed. **This yielded an extremely high internal annual rate of return of 53%**

The company informed us that it required the bidder to provide financing, a conditions that Coal Tech could not meet.

5) As part of the planning for the task 5 effort, an economic analysis of a small paper waste combustion project was performed to determine the return on investment using a Coal Tech combustor for this purpose. The following is a summary of the analysis.

The Coal Tech combustor would be attached to a small firetube boiler that was matched to the waste-firing rate. The steam production would be a maximum of 6200 lb/hr at an 8.5 ton/day waste feed rate. This waste had a wet HHV of 9460 BTU/lb, and a 33% moisture content.

The following economic conditions applied:

- The current disposal cost were $85/ton for a 5 to 10 ton daily generation rate, including trucking.
- Current gas cost was $3.6/MMBtu. Oil cost was $3.1/MMBtu
- An alternative off site incinerator would accept the waste at a cost of $48/ton for a 10-ton/day generation rate, including trucking.
- Financing for on site combustion would be provided by a third party seeking a 25% annual return of its 100% debt financing.
- Round the clock operation, 350 days annually.
- The estimated installed cost of the system was about $500,000, including design, installation and testing.

• The savings would consist of eliminating the $85/ton disposal method and replacing an equivalent amount of fuel costing $3/MMBtu. The system' s operation and maintenance costs were subtracted from this figure to obtain the **gross annual savings**. All costs contain 3% yearly escalation.

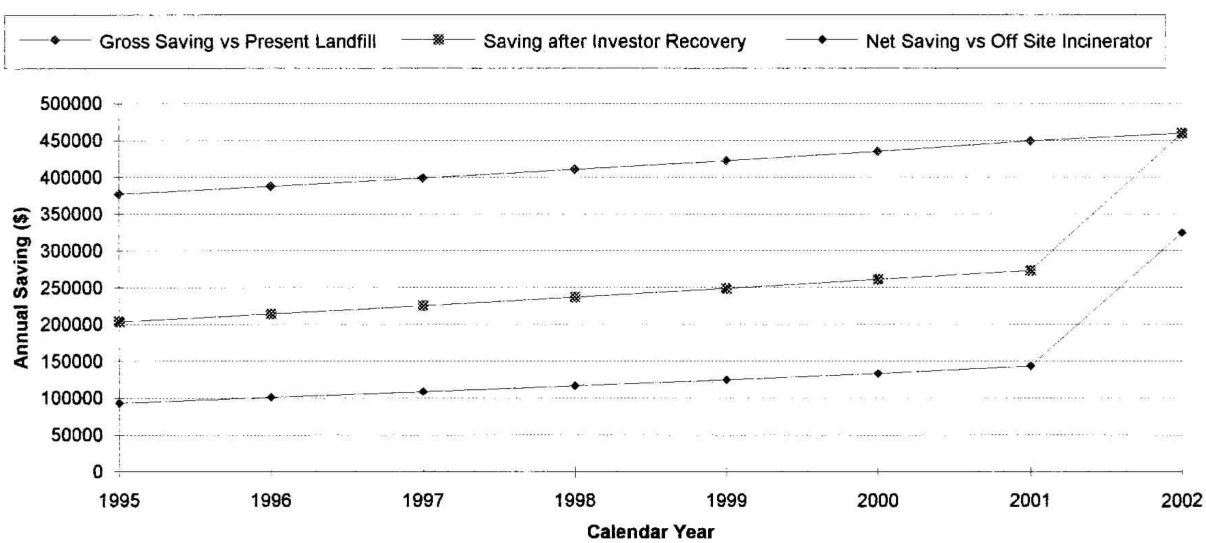
• These savings would be **equally shared** between the site owner and the third party equipment owner **until the entire system cost had been reimbursed**. At that time **the equipment would transfer to the site owner**, who would have the full benefit of all future savings.

• The analysis also compared the savings versus the alternative of off-site incineration using the costs of $48/ton.

The **on-site waste combustion system** would consist of a waste conveyor, a dryer, a shredder, a Coal Tech combustor rated at up to 8 MMBtu/hr, a used firetube boiler rated at up to 6400 lb/hr of steam, and a stack gas baghouse. The entire system would-be automated with computer control, and its steam output would be integrated to operate in parallel with the existing boiler. Therefore, the existing boiler operator at the plant would be able to monitor the operation of the new system because the fuel feed rate would be identical to the waste generation rate.

A representative result is shown in figure 6. The top curve represents the gross savings versus the present landfill method, after deducting O&M costs. The middle figure shows the annual saving after the investor' s cost recovery. The bottom figure shows the saving if compared with the alternative of off-site incineration.

Figure 6: Plant Operator Savings for a Third Party Financed, On Site 8.5 ton/day Waste Combustion Project



As noted, the project provides a 25% return on investment for the third party financier and a 7-year amortization. After that it reverts to the site owner at no cost. The site owner' s savings average **$240,000/year in the first 7 years,** and then increase to over **$450,000/year.** When compared to the alternative of off site incineration, the site owners savings average $125,000 in the first 7 years, and $325,000 thereafter.

In conclusion, these last two analyses show that in regions of high waste disposal and high energy costs even small on site combustion systems are economically attractive.

<u>Design & Cost of the 20 MW Repowering Project:</u>

The marketing part of the proposed 20 MW repowering project on the site of a PA coal fired utility was discussed earlier in this section. Here a brief summary of the analysis and cost estimate for repowering it. H-R International performed the plant layout and the cost estimate.

The boiler was designed to match the existing 20 MW steam turbine that operated at 350 psig, 850^oF and a backpressure of 1.0 inch Hg. It was proposed to replace the original boiler with a new ABB type 'D" package boiler (which is an oil fired design that is factory assembled unit). It would be rated at 184,300 lb/hr at 400 psig and 900^oF

The fuel was a mixture of 80.5% coal waste (0.75% sulfur, 27.5% ash, 10% VM), 16.6% bituminous Pittsburgh seam coal (2.2% S, 9% ash, 41% VM). No.2 oil would be used for start up and auxiliary fuel. The coal would be delivered by truck as the existing coal is delivered.

Two Coal Tech, air-cooled slagging combustors would be attached to the ABB boiler.

The slag drainage system handled 11,131 lb/hr due to the high ash content of the coal

A forced draft fan for the combustor and an induced draft fan to pull the 350^oF stack gas. The baghouse handled 125,000 cfm of flue gas. The stack was 15 foot diameter, 220 foot high steel stack, selected to match the existing stack at the plant.

One area that involved substantial cost was the decision to store a 5 day supply of coal and limestone in bins. The coal waste bin was 30 ft D. X 62 ft high. The coal bin was 22 ft D x 62 ft high. The limestone bin was 21 ft. D x 41 ft. high. These bins are very costly, and in fact at present the coal for the plant is stored on the ground.

Figure 7 shows a plan view of the new repowering components. The 4 circles in the left-center of the figure are the coal and limestone bins. Immediately underneath to the left is the stack and to the right is the baghouse. To the right of the bins is the coal pulverization system. In turn to its right is the boiler with the two Coal Tech combustors.

Figure 8 is an elevation view of the 20 MW repowering plant. The purpose of this figure and figure 7 is to convey the enormous size of the coal, limestone and oil storage bins compared to the boiler, baghouse, and other equipment. Since the power plant at present stores its coal on the ground, and the plant is located in the northern part of PA where winters are very cold, the investment in the bins is almost ludicrous. Unless the bins are heated the coal will freeze in the binds. **The reason an issue is made of this in this report is to show how A/E firms, by following traditional engineering practice can inflate the cost of a project enormously**. **An example was given above in connection with the India power plant concept, where the Indian A/E firm came to the conclusion that a fluid bed boiler would be much cheaper than one fired by the cyclone combustor**. Note in figure 8 the large size of the bins on the left. The coal preparation components and silo is to the immediate right of the storage bins, and to their right are the two combustor attached to boiler on the extreme right.

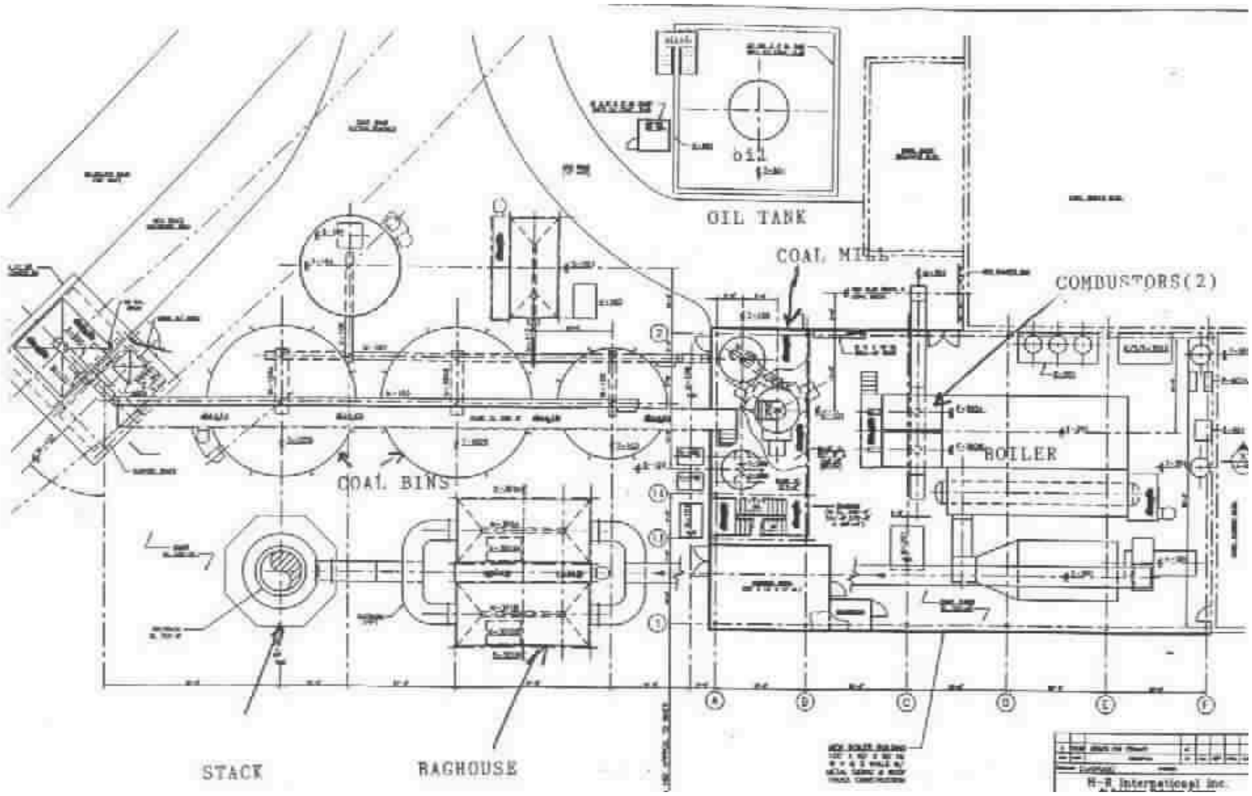


FIGURE 7: Plot Plan of 20 MW Repowering Plant

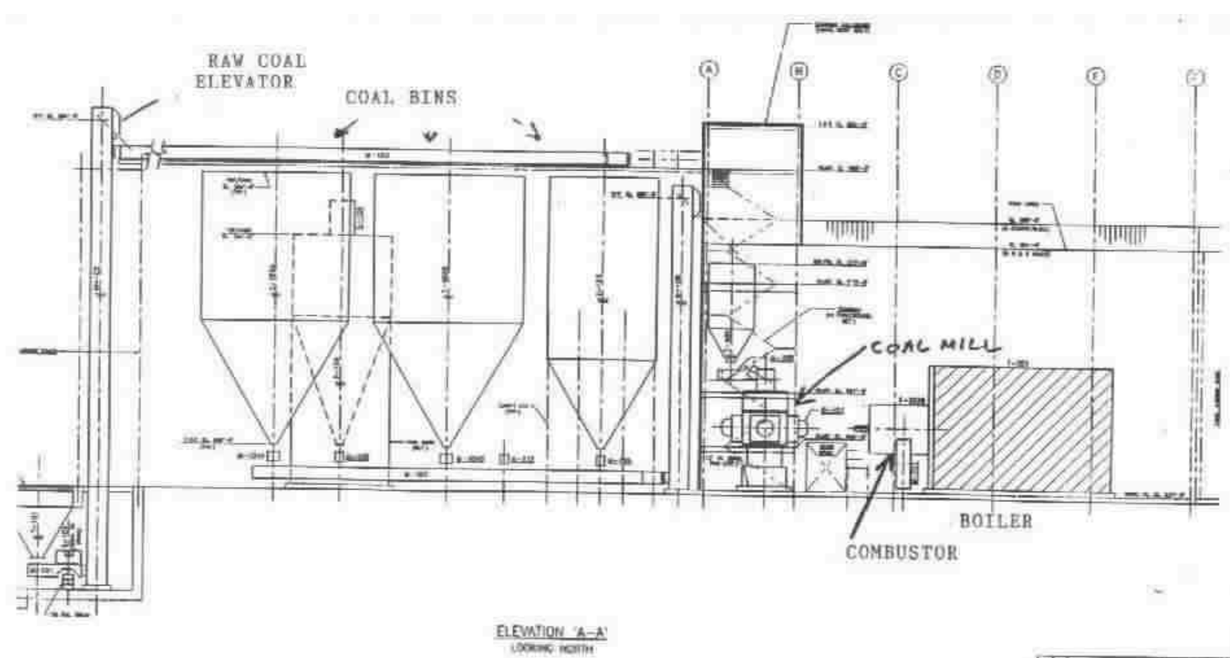


FIGURE 8: Elevation View of the 20 MW Repowering Plant

Table 2 shows H-R's cost estimate on the left side and Coal Tech's adjustment to these costs on the right side for the 20 MW repowering project. It is extremely important to note that the total cost for the balance of plant up to the grand total cost is based on multipliers from the total equipment cost. Therefore, any overestimate of the equipment cost balloons into a higher grand total**. According to the Engineering Firm, H-R the capital cost is $951/kW, while according to Coal Tech is it only $520/kW**. (That was in 1994. In 2003 the cost would be less.)

	Engineering Firm		Coal Tech Adjustemer
EQUIPMENT COST			
COMBUSTORS- (2)	$1,500,000	COMBUSTORS- (2)	$1,500,000
BOILER& AUX	$2,359,100	BOILER & AUX (USED)	$750,000
COAL STORAGE ETC	$824,600	USE EXISTING COAL PILE	$400,000
PULVERIZER	$1,500,000	COAL CRUSHER	$300,000
BAGHOUSE+STACK	$558,300	BAGHOUSE & STACK	$350,000
ASH HANDLING	$120,000	ASH HANDLING	$60,000
COMPRESSOR	$81,600	COMPRESSOR/BLOWER	$40,000
OIL STORAGE	$15,300	OIL STORAGE	$15,300
LIFT STATION	$20,000	LIST STATION	$20,000
COOLING TOWER	$200,000	COOLING TOWER	$150,000
EQUIPMENT COST	$7,168,900	EQUIPMENT COST	$3,585,300
Note: All cost items below use factors of total equipment cost, as provided by eng.firm experience data			
INSTALLATION	$2,333,801	INSTALLATION	$1,168,808
FOUNDATION SITE	$1,338,714	FOUNDATION SITE	$670,451
STEEL+ARCHTECTUAL	$708,731	STEEL+ARCHTECTUAL	$354,945
PIPING	$715,890	PIPING	$358,530
ELECTRICAL	$357,945	ELECTRICAL	$179,265
INSTRUMENTATION	$400,898	INSTRUMENTATION	$200,777
SUB TOT DIR. COST	$13,014,880	SUB TOT DIR. COST	$6,518,076
REFURBISH TURBINE	$1,750,000	REFURBISH TURBINE	$1,750,000
ENG& CONSTRUCTION	$2,147,670	ENG& CONSTRUCTION	$1,075,590
START UP	$307,833	START UP	$154,168
TOTAL INSTALLED COST	$17,220,383	TOTAL INSTALLED COST	$9,497,833
SALES TAX	$501,123	SALES TAX	$250,971
CONTINGENCY	$1,302,920	CONTINGENCY	$652,525
GRAND TOTAL	$19,024,426	GRAND TOTAL	$10,401,329
$/KW	$951	$/KW	$520

TABLE 2: 20 MW Repowering Project Cost: A/E Firm (H-R Int.) Left, Coal Tech-Right

The key differences are :

1) Elimination of the coal storage bins.

2) Replacement of the costly new boiler with a used oil design boiler, which is readily available in the aftermarket

3) Replacement of the expensive pulverizers with coal crushers, which are adequate for the cyclone combustors.

4) The baghouse was clearly overprices on comparison with what Coal Tech paid for its task 5 baghouse and the quotation for the 20 MW combined cycle baghouse.

5) The compressors were over designed. A blower can be used for much of the work.

6) The ash handling was far too expensive.
7) Even Coal Tech's 1994 cost is too high because the combustor cost can be reduced.

To repeat, the importance of this study is to show how the cost of an advanced power plant can be grossly inflated by failure to pay attention to the non-key components, i.e. non-air-cooled combustor, design and cost in the analysis.

<u>In conclusion, this project demonstrates the power of the combustor technology.</u> When combined with the post-combustion emission controls developed by Coal Tech after completion of this project, it offers a unique power system that contains total emission controls for coal fired power generation with a worldwide market.

The overall message from this marketing effort is that existing energy users have one primary concern, namely, to keep the existing energy system on line to produce revenue. While new technologies are desirable, they will not proceed until someone else has tried it first. This probably applies even to new technologies promoted by large organizations, except they are in a financial position to guaranty performance. As proof of this we cite the experience of our host for the first 20 MMBtu/hr combustor test effort. This company was a subsidiary at the time of a major international energy company. As a result, they were able to win a contract to deliver several large fluid bed boilers based on only test experience in a small 10 MMBtu/hr fluid bed boiler system, and many decades of experience in industrial boiler manufacturing. Despite the boiler experience. It is very doubtful that the order would have been placed without the customer's reliance of the financial guaranty of the parent company.

B-4: CONCLUSIONS FROM TASK 4

This commercialization task was certainly almost as important as the other tasks because it showed that there exists a wide market for the air-cooled slagging combustor technology, and it also identified the challenges that must be overcome to bring this technology into the domestic and international energy market.

Conclusions for each different market segment have been incorporated with the specific market section. Some of these conclusions were made at the time of the task 4 effort between 1992 and 1994 because that represented the bulk of the commercialization and marketing effort. Additional marketing activities after that time but before the project ended in 1998 are incorporated in the task. All marketing efforts that were performed by Coal Tech since the end of this project were implemented at Coal Tech's expense. The latter comments are particularly timely in view of the extreme financial difficulties that the electric power industry has experienced in the past few years. In this author's opinion the problems were primarily due to almost sole reliance on "cheap" natural gas and the lure of "low cost" gas turbine power plants. In a sense this "trap" was almost inevitable because modern "clean coal" power plants are more costly.

This leads to the most important conclusion from the entire decade long coal R&D effort at Coal Tech Corp, namely, acceptance of new coal technologies depends primarily on low cost, not only in comparison with other coal technologies, but also in comparison with "clean" natural gas and oil fired energy technologies.

The following are some specific conclusion from the task 4 effort, some of which were already noted in the discussion of results:

The air-cooled slagging combustor's capability to be retrofitted to a wide range of boiler designs and boiler sizes was found to yield economically attractive applications to a wide range of industries. These applications were in almost all cases matched to a specific industrial energy-consuming site. Among those analyzed were:

1) A detailed cycle and cost analysis of a 20 MW combined natural gas fired-turbine with a coal fired- steam turbine power cycle yielded an efficiency in the low 30% range. The cost developed by an A/E sub-contractor was about $1,200/kW. According to the A/E firm this compared favorably with the much higher coat of fluidized bed power plants. However, in Coal Tech's opinion the cost can be drastically reduced to make this combined cycle competitive with natural gas combined cycle plants.

Toward than goal, in the years since the completion of this project, Coal Tech developed system designs for similar combined cycle plants, except that the fuel would be only coal, with either pyrolysis gas firing the gas turbine. Alternatively, biomass pyrolysis gas fires the gas turbine, and biomass char and coal or coal char fires the steam cycle. The latter uses the air-cooled combustor for this purpose. This cycle also incorporates Coal Tech's proprietary combustion and post-combustion emission control processes for NO_x, SO_2, volatile trace metals, including mercury, dioxins/furans, and includes sequestration of carbon dioxide.

2) The second power cycle analyzed in detail was a 20 MW steam repowering cycle that was specialized to an electric utility site that would provide a waste coal to drive the cycle as well as the steam turbine and associating electric generating and power transmission sub-systems. The same A/E firm that performed the combined cycle cost analysis estimated a cost of $921/kW for this project. On the other hand, Coal Tech evaluated the cost analysis and by substituting components that take advantage of the goal of the repowering project as well as the performance capabilities of the combustor, estimated a cost of only $520/kW. Combined with the coal waste costs of under $0.50/MMBtu, this project would have been extremely profitable.

A key result of this study, which also applies to the combined cycle study is that the developer of a critical component to a new technology must integrate it into the entire system. If not, the result will be a much more costly system, as was demonstrated by cost estimates for the repowering cycle.

3) A series of preliminary conceptual designs for process steam boilers, with and without electric power generation, were performed in response to identified applications at various industrial sites, primarily paper mills. The sizes ranged from about 5,000 lb/hr of steam firetube boilers to several 100 MMBtu/hr boilers. The fuels ranged from coal to paper mill sludge. In all cases, the retrofit of the air-cooled combustor produced very attractive cost results.

4) Considerable effort was expended on international applications, especially India because very high ash coals are used the as well as in China and Indonesia. The air-cooled combustor is ideally suited for combustion of very high ash coals, and in fact in the task 5 effort on this project, several tons of a 37% ash Indian coal were successfully tested in Coal Tech's 20 MMBtu/hr slagging combustor.

Although this marketing effort and subsequent test effort was conducted about one decade ago, it is not even more timely because as reported in the Wall Street Journal on May 6, 2003, a an enormous continent size, dark particulate laden cloud exists in the upper atmosphere over the Indian ocean. It is believed by atmospheric scientists that this cloud may very well originate from inefficient combustion of coal on the Indian sub-continents.

After the completion of this project, Coal Tech developed a very low cost version of its air-cooled slagging combustor that would be price competitive in India. This combustor could be easily retrofitted to an extremely wide range of coal, animal waste, and biomass fired boilers to yield not only efficient combustion, but also to remove at least 75% of the fuel ash as inert slag. When combined with Coal Tech's low cos t post-combustion emission processes, these boilers could drastically reduce emissions from coal at very low cost.

5) Another key lesson learned from this marketing effort is that it is almost impossible to sell the first of a kind technology in the energy sector. The energy production system is a core element in revenue production for the customer, be it electricity or an energy dependent product.

Therefore the preferred and possibly only means for developing a new technology is to place it in an income-producing environment, such as selling interruptible electricity or a product that uses electricity or steam energy. Coal Tech attempted this approach by designing the task 5 20 MMBtu/hr combustor test effort to incorporate a 500 kW electricity producing plant. With one of the highest National electricity rates in Philadelphia, such a project would have quite profitable. Unfortunately, the local utility has established punitive rates for use of its power as backup, which made this option not feasible here. The alternative is to produce a product, such as gaseous fuel from coal, and that is one option that Coal Tech is exploring.

6) A very important conclusion is that growth of coal utilization is dependent on achieving total emission control from coal at prices that are competitive with clean natural gas. The work of this project, as well as prior and subsequent R&D, was all aimed toward this goal. To achieve this goal of total emission control, Coal Tech enlisted the support of DOE to continue this effort by submitting about one dozen proposals to DOE in the past 6 years. Unfortunately, the reviewers at DOE did not share this vision and they were all rejected, including one to remove mercury from coal combustion. However, Coal Tech was able to meet most of this goal of total emission control with internal resources and innovation.

Finally, what is almost incredible is that today, 2004, this air-cooled, slagging coal combustor technology is even timelier than when the effort began two decades ago. With worldwide personal communication through air travels, an outbreak of a disease in one place can spread rapidly throughout the world, as has happened with the SRAS pulmonary disease. While its origin may have nothing to do with air pollution, it is certainly not helped by air pollution from high ash coal combustion in its country of origin. Also, the recent discovery of massive particulate laden upper atmospheric pollution near regions of combustion of high ash fuels is another problem that must be addressed. The solution is clear, removal of inefficient combustion and its associated air pollution. Early in the 14th century, King Edward the 1st of England banned coal fired furnaces in London due to air pollution. Sherlock Holmes movies of the 1930's with Basil Rathbone show numerous scenes with pea soup fog, although the cause of coal burning is not mentioned. The air-cooled slagging combustor and associated technology is a very low cost means of solving this problem.

Project: " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL-FIRED COMBUSTION SYSTEM, PHASE 3"

Contract: DE-AC22-91PC91162

Contract Period of Performance: 9/30/91 to 9/30/99

Final Technical Report

Appendix C

"Site Demonstration with the Second Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor"

Project Tasks 5 and 6

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ABSTRACT :Appendix C

This present project " DEVELOPMENT & TESTING OF INDUSTRIAL SCALE, COAL FIRED COMBUSTION SYSTEM, PHASE 3" on DOE Contract DE-AC22-91PC91162 consisted of five tasks that were divided into three phases. The third phase, " Site Demonstration with the Second Generation 20 MMBtu/hr Air-Cooled Slagging Coal Tech Combustor" is summarized in this Appendix "C". It involved the relocation in 1994 of the entire test facility from Williamsport, PA, to the Arsenal Business Center, a former U.S. Army facility in Philadelphia, PA. The plan for task 5 was to design a new second generator combustor that incorporated the lessons learned in the test effort in Williamsport. An additional part of the task 5 plan was to add the other components needed to convert the 20 MMBtu/hr combustor-boiler facility into a continuously operating steam generating plant or electric power generating plant. To implement this would require a steam or electricity host, and beginning in November 1993, a search that took one year was implemented to find an industrial host site that would meet the requirements for installation of the new facility and for utilizing the energy production. After negotiations with several sites stalled, a lengthy negotiations for the Arsenal site was completed in the late Fall of 1994, and modifications for a small electric power generation facility were initiated that winter.

In the first half of 1994, the second generation 20 MMBtu/hr-combustor was designed and after a lengthy search an apparently acceptable fabricator was selected that summer. Unfortunately, the fabricator slipped far behind schedule so that it was not completed until late spring 1995. In addition, while considerable innovation was used in designing and selecting equipment for a 500 kW electric power plant, it became clear that there were insufficient funds to procure and install the power plant, and as a result the facility remained a test site, as opposed to a continuously operating power plant. This was not surprising as the original Coal Tech cost proposal requested twice as much funds for this project as were finally allocated. Nevertheless, by using considerable innovation, we came very close to implementing the entire effort with the reduced allocated funds. The limiting factor was the inability to negotiate a suitable contract for sale of electric power in order to defray the operating costs.

Another very important innovation in this project was the drastic reduction of a factor of 2 to 3 in personnel for installation and operation of the facility, as well as a factor of 2 to 3 reduction in electricity and water consumption as well as a factor of 3 reduction in gas and oil for daily startup and shutdown of the combustor. The plan required 500 hours of testing in 100 hour or more continuous blocks. This was not possible with the personnel resources available. Instead a total of 63 single shift tests were planned. However, due to the cost saving measures in personnel and utility use, a total of 108 test days were implemented from the beginning of 1996 to the first quarter of 1998, when testing on this project ended.

The success of these changes in the design of the second-generation combustor was apparent almost immediately on startup of the task 5 tests. The combustion efficiency even under fuel rich conditions in the combustor was substantially improved. More importantly, slag carryover out of the combustor into the boiler, which had been a major problem in the first generation combustor, was now negligible. Also, ash deposits on the boiler furnace floor, another major problem in the first generation combustor, was minimal.

In view of the immediate success in operating the new combustor, the focus in the task 5 testing shifted toward combustion of high ash coals, and combustion and post-combustion emission control primarily for NO_x and SO_2. After the project was completed this work was extended to combustion of biomass, and a very extensive effort on post-primary combustion emission control processes for NOx, SO2, dioxins/furans, volatile trace metals, such as mercury, and finally to removal and sequestering carbon dioxide.

A major breakthrough was achieved in the combination of staged combustion inside the combustor with post-combustion injection of ammonia based reagent in a process called Selective Non-Catalytic Reduction (SNCR), resulted in an incredible peak 93% NO_x reduction, from 1 lb/MMBtu to 0.07 lb/MMBtu. Similarly, high reductions in SO_2 were achieved.

In addition, tests were performed on 100 MW and 37 MW coal fired electric utility boilers with Coal Tech's Selective Non Catalytic Reduction (SNCR) process that resulted in 40% NO_x reduction in the latter boiler. Further development of the SNCR process resulted in achieving in 2003 nearly 50% NOx reduction to 0.15 lb/MMBtu on a 50 MW coal fired utility boiler. This process is now commercially ready.

A series of proposals to DOE to expand the combustion and post-combustion emission reductions by including biomass combustion and post combustion rebrun, and other reduction processes, such as reduction of trace mercury released during coal combustion, submitted in the period between 1998 and 2002, were all rejected. Consequently, by using great ingenuity, Coal Tech was able to develop almost all its emission control processes on the 20 MMBtu/hr-combustor, and on a utility boiler and municipal incinerator, with its own internal resources. All this emission control work was not part of this project. It was very successful, and a number of patents were either granted or are pending.

In conclusion, the effort expended on this project as well as the subsequent Coal Tech work on emission control from coal combustion has resulted in the development on a solid fuel combustion system that is unique in its capability of achieving total emission control from coal combustion in essentially all types of coal in worldwide use.

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Also, in the first half of 1994, the second-generation, 20 MMBtu/hr-combustor was designed, and after a lengthy search an apparently acceptable fabricator was selected that summer. Unfortunately, the fabricator slipped far behind schedule so that it was not completed until late spring 1995. In addition, while considerable innovation was used in designing and selecting equipment for a 500 kW electric power plant, it became clear that there were insufficient funds to procure and install the power plant. As a result the facility remained a test site to this day, March 2004, as opposed to a continuously operating power plant. This was not surprising as the original Coal Tech cost proposal requested twice as much funds for the entire project as were finally allocated. Nevertheless, by using considerable innovation, we came very close to implementing the entire effort with the reduced allocated funds. The limiting factor was the inability to negotiate a suitable contract for sale of electric power in order to defray the operating costs.

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In view of the immediate success in operating the new combustor, the focus in the task 5 testing shifted toward combustion with high ash coal, and combustion and post-combustion emission control for NO_x and SO_2. While some of the SO_2 and NO_x control work was implemented in task 5, the bulk of this work was implemented solely at Coal Tech expense in the years after the project testing ended. After the project was completed in 1998 this work was extended to combustion of biomass, and a very extensive effort on post-primary combustion emission control processes for NOx, SO2, dioxins/furans, volatile trace metals, such as mercury, and finally to removal and sequestering carbon dioxide.

A <u>major breakthrough</u> was achieved in the combination of staged combustion inside the combustor with post-combustion injection of ammonia-based reagents in a process called Selective Non-Catalytic Reduction (SNCR). It resulted in an incredible peak 93% NO_x reduction, from 1 lb/MMBtu to 0.07 lb/MMBtu. Similarly, high reductions in SO_2 were achieved.

In addition, tests were performed in 1997 on 100 MW and 37 MW coal fired electric utility boilers with Coal Tech's SNCR process that resulted in 40 % NO_x reduction in the latter boiler. Further development of the SNCR process resulted in achieving in 2003 nearly 50% NOx reduction to 0.15 lb/MMBtu on a 50 MW coal fired utility boiler. This process is now commercially ready.

A series of proposals to DOE to expand the combustion and post-combustion emission reductions by including biomass combustion and post combustion reburn, and other reduction processes, such as reduction of trace mercury released during coal combustion, submitted in the period between 1998 and 2002, were all rejected. Consequently, by using great ingenuity, Coal Tech was able to develop almost all its emission control processes on the 20 MMBtu/hr-combustor, and on a utility boiler and municipal incinerator, with its own internal resources. All this emission control work was not part of this project. It was very successful, and a number of patents were either granted or are pending. The most recent of these is a low cost process for the production of hydrogen with the sequestration of the residual carbon. Also, a novel mercury capture process was invented.

A very important benefit of the move to Philadelphia is that it enabled Coal Tech to maintain the 20 MMBtu/hr facility **at its own expense** for the past 5 years by paying for rent and utilities as well as performing emissions control testing. The cost of accomplishing this in Williamsport, had the site not been sold, would have been prohibitive.

One example of the wisdom to continue maintaining this combustor technology was found in a May 2003 Wall Street Journal front-page article. It reported on the discovery of a massive pollution cloud over the Indian Ocean that is 2 miles thick and about 2000 miles across. While the Indian government officials have attributed the cause of this cloud as being due to combustion of dung by India's poor, it is almost certainly a result of inefficient combustion of the high ash Indian coals, whose 1999 consumption outnumbered dung combustion by a factor of 3. Furthermore, as this coal combustion contains high (about 40% on average) ash while dung contains less than 1% ash, it will be easy to verify the source by random particulate sampling in the cloud. Therefore, if any decision is made by appropriate authorities to do something about this "cloud", it will be found that the very lowest cost method of reducing this pollution is by retrofitting Indian coals furnaces and boilers with air-cooled slagging combustors, which can be attached to almost any boiler. As proof, we cite a test conducted in January 1977, as part of task 5 in which several tons of 37% ash, Indian coal was burned with high combustion efficiency and over 75% conversion of the coal ash into slag

In conclusion, the effort expended on this project as well as the subsequent Coal Tech work on emission control from coal combustion has resulted in the development on a solid fuel combustion system that is unique in its capability of achieving total emission control from coal combustion in essentially all types of coal in worldwide use.

C. 2: INTRODUCTION

The effort on the present project that led up to the task 5 work is described in this Appendix "C" is contained in Appendices "A" and "B".

The original objective for task 5 was to incorporate the test results of tasks 1, 2 and 3, as well as results of the commercialization task 4 and demonstrate the durability and hence the commercial readiness of the combustor for its intended industrial application(s). The effort was to consist of two sub-tasks. In the first sub-task any changes required as a result of prior tests were to be made to the combustor. In the second sub-task, a series of tests, each of up to 100 hours of continuous coal fired operation were to be performed, with a total test time of 500 hours.

The results of the testing in the previous tasks clearly indicated that major modifications were needed to the combustor, especially in lengthening the combustor and designing replacing the adiabatic exit nozzle with an air-cooled wall design. This part of the project plan was indeed implemented in task 5 and a new, second-generation design combustor was fabricated and used for task 5 testing.

The original proposal had a much more ambitious objective, namely a commercially operating steam or electric power generating system rated at 20 MMBtu/hr was envisioned. It was proposed to install this system at a host site that would purchase the electricity and or steam, which would enable the system to remain in commercial use after this project was completed. However, the proposed cost for this task was about double the amount that DOE could commit. Consequently, the final negotiated work statement for this project, envisioned, only 500 hours of testing, as noted above. It was envisioned that this testing would be implemented at the Williamsport site where the first-generation combustor was located.

However, in November 1994, the site owner sold the entire facility, which required Coal Tech to vacate within 60 days. In retrospect this was a most fortunate and timely event because there was simply no room in the boilerhouse to lengthen the combustor to any significant extent. Furthermore, as stated in Appendix "A" of this report, operating the combustor 175 miles from Coal Tech's corporate offices and senior personnel resulted in very high operation and maintenance costs. Therefore, had task 5 been implemented in Williamsport, the project would not have met its key goals. The combustor would have been too short to solve the combustion efficiency and slag and ash outflow problems. No resources would have been available for the added environmental control development that were performed as an add-on to the project, and that were subsequently performed at Coal Tech expense. The environmental control processes are certainly the most important output of this project. Since no further funds were made available, despite over one-half dozen proposals submitted by Coal Tech, this project would have ended in 1995 after 500 hours of testing.

Instead, the entire facility was relocated to Philadelphia, a new combustor was fabricated and installed, and we came very close to actually installing a complete 500 kW steam turbine-generator system with sales of the electricity. In the end the inability to negotiate a satisfactory electricity sale contract with the site landlord prevented the power plant installation. In any case, with a number of design innovations and operating cost reductions, both the contractual 500-hour test goal of task 5, as well as the added environmental control process development was implemented.

A very important benefit of the move to Philadelphia is that it enabled Coal Tech to maintain the 20 MMBtu/hr facility **at its own expense to this day, March 2004** by paying for rent and utilities as well as performing emissions control testing. The cost of accomplishing this in Williamsport, had the site not been sold, would have been prohibitive.

This Appendix 'C" describes the effort on task 5 in historical order from 1994 to 1998.

C-3 RESULTS & DISCUSSION FOR PROJECT TASK 5

C-3.1. Objectives of Task 5

The primary objective of the present Phase 3 effort was to perform the final testing at a 20 MMBtu/hr commercial scale of an air-cooled, slagging coal combustor for application to industrial steam boilers and power plants. The focus of the test effort was on combustor durability, automatic control of the combustor's operation, and optimum environmental control of emissions inside the combustor. In connection with the latter, the goal was to achieve 0.4 lb/MMBtu of SO_2 emissions, 0.2 lb/MMBtu of NO_x emissions, and 0.02 lb particulates/MMBtu. Task 5 was the key task in achieving the objectives of this project. For example, meeting the particulate goal required the use of a baghouse or electrostatic precipitator to augment the nominal 80% ash retention in the combustor. The Williamsport installation where tasks 1, 2 and 3 were implemented was equipped only with a wet particle scrubber that could not meet this goal, and there was no room for the other two components. Task 5 would meet and greatly exceed the NO_x emission goal, which required only a modest improvement over reductions achieved in task 3 of 0.26 lb/MMBtu. At the end of task 3, SO_2 levels as low as 0.6 lb/MMBtu, equal to 81% reduction in 2% sulfur coals, had been measured with boiler injection of lime. In task 5 it was planned to reach the 0.2 lb/MMBtu goal by combined injection into the combustor and boiler.

The task 5 project objectives were to be met by a series of tests of increasingly longer duration, and totaling about 500 hours of total testing, comprising 63 days of single shift testing. Actually, 107 days of testing were implemented in this period of which 73 were directly on task 5 and 34 test days were on a parallel project, whose results contributed to the goals of task 5.

C-3.2: Technical Approach to Task 5.

Overview

All the test work on this Phase 3 project was implemented on Coal Tech's patented, 20 MMBtu/hr, air cooled cyclone coal combustor that was installed on an oil designed, package boiler in Williamsport, PA in 1987 and relocated to Philadelphia, PA in 1994 for the task 5 test effort. The primary fuel for all the testing was coal. Other fuels were refuse-derived fuels, rice husks, sawdust, fly ash containing unburned carbon, oil, and gas.

The combustor' s novel features are air-cooling and partial 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 most 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 reagents into the combustor to react with sulfur emitted during combustion. The spent reagent is dissolved in the slag and removed with it, thereby encapsulating the sulfur in slag. NO_x is controlled by staged, fuel rich combustion inside the combustor.

By the end of task 3 excellent progress had been made in the previous several years in meeting the task 5 combustor performance objectives. Ever since the start of this combustor development effort in 1985, one of the most important objectives had been to demonstrate very high SO_2 reduction in the combustor. Prior to the start of the present Phase 3 project, the peak SO_2 reduction achieved with calcium oxide based reagent injection in the combustor has been 56%, (+/-) 5%. Of this amount a maximum of 11% of the total coal sulfur was trapped in the slag. On the other hand, up to 81% SO_2 reduction has been measured with lime injection in the boiler immediately downstream of the combustor. Task 5 focused on optimizing the combined SO_2 reduction. .

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^oF gas temperatures, durability was one of the key challenges in the development process. Here also the use of computer control was the means whereby this problem was being solved. Since introduction of computer control at the beginning of this project, the need for frequent refractory liner patching inside the combustor had been eliminated. The task 3 tests had shown combustor durability by operating the combustor continuously on coal for 8 to 10 hours on successive days. It had been planned for task 5 to achieve continuous round-the-clock coal fired operation for up to 100 hours. 100 hour operation would not add to the durability of the combustor, because start and stop operation is much more severe on the combustor wall than continuous operation. Nevertheless, such continuous tests were planned for task 5. However, due to limitations in funding it was not possible to obtain the needed personnel to implement a 100- hour continuous coal fired operation. Instead durability was demonstrated by operating the combustor for many test days without internal refurbishing of the refractory lines.

For convenience the work planned for each task in the project is summarized here.

<u>Task 1: Design, Fabricate, and Integrate Components</u>

This task consisted of components design, component fabrications, and component integration using the lessons learned in the previous Clean Coal project. The 20 MMBtu/hr-combustor was modified to allow safe and environmentally compliant operation for periods of up to 100 hours.

Task 2: Preliminary Systems Tests

The modified combustor system underwent a series of one-day parametric tests of total duration of 100 hours that validated the design changes introduced in task 1.

Task 3. Proof of Concept Tests

The durability of the combustor was determined in a series of tests of up to 100 hours of continuous operation, with a total test period of 200 hours.

Task 4. Economic Evaluation & Commercialization Plan

The design and economics of a 20 MWe 'Green field" combined gas/steam turbine power plant and a 20 MW steam repowering plant were evaluated. A commercialization plan was developed for marketing the combustor in an industrial environment both in the US and overseas using interactions with power producers and energy companies in the U.S. and abroad.

Task 5. Conduct Site Demonstration

This task, which is covered in this Appendix 'C", had as its objective the demonstration of a second generation combustor, using the lessons learned in previous tasks, that would be integrated into a 500 kW or 17,500 lb/hr steam generating plant. The goal of this effort was to test the durability and commercial readiness of the combustor for industrial applications. The effort was to consist of two sub-tasks. In the first one the changes required as a result of prior tests were made to the combustor design. In the second one, a series of tests coal fired operation were to be performed, with a total test time of 500 hours.

Task 6. Decommissioning Test Facility

The test facility was to be removed from the boiler installation and disposed in accordance with required regulations. In actuality Coal Tech has kept, at its own expense, the Philadelphia facility in operational condition for the past 7 years after the completion of this project in 1998.

C-3.3. RESULTS & DISCUSSION FOR TASK 5

a) The Search for a New Site for the Task 5 Effort.

The details of the site search are presented here in somewhat more than anticipated detail for what appears at first sight to be a minor task. However, as is shown in this discussion numerous technical, business, and human relations issue were confronted, and these are all critical to the marketing of the present advanced solid fuel combustion system.

Even prior to notification by the owner of the Williamsport facility in November 1993 of its closure and sale, it had become obvious that performing the task 5 tests at that site was not possible. One, there was no room to lengthen the combustor. Two, it was not possible convert the 20 MMBtu/hr combustor-boiler into a steam or electricity generation system because the site owner had no need for either steam or electricity that could be produced by this power system. The task 4 marketing effort had shown that a fully operational system and performance warranties were necessary to obtain orders for the combustor system. This required operation of the combustor extending over 1000 hours, which could only be accomplished if the energy produced during operation was sold to the host site to defray part of the operating costs.

To accomplish this goal, it was planned to relocate to a site in the Philadelphia region that could at a minimum utilize the 17,500 lb/hr steam production from the present 20 MMBtu/hr combustor. Subsequently, and preferably, this steam output could be used to generate about 500 kW of power from saturated steam at 200 psi in a condensing turbine. To implement this relocation, a search was initiated in November 1993 for a suitable site, which met these requirements. To minimize the total cost of the relocation, a site within a 40-mile radius of Philadelphia was sought. Sites under consideration were public institutions, large industrial parks, and industrial plants with round the clock operation. A promising University site was eliminated due to objection of the steam plant operators.

Several paperboard-recycling plants fit the requirement for year round steam use. However, inspections of the boiler operations at six plants revealed several major difficulties. In most cases, there was insufficient room in or near the existing boiler house to install the combustor, boiler, fuel and reagent storage, and stack cleanup equipment. A site further removed from the boiler house would have required construction of a new building, which would be beyond the resources of this project. Another problem was the difficulty of obtaining permitting at two of the sites due to proximity to residential areas. Another paper plant had a suitable building, but their steam pressure requirements were 300 psi, which would have required purchasing another used boiler.

<u>Industrial Park at Large Manufacturing Plant, Lester, PA.</u> The primary focus then shifted to an industrial park located on a previous huge manufacturing site. This site was really ideal. It had the infrastructure for 100's of MW of electric power transmission. It even had Delaware River water piped into the massive 500,000 square foot former manufacturing buildings. Also, the landlord could utilize all the steam generated in the winter and the electricity generated in the summer by the 17,500 lb/hr boiler and 500 kW steam turbine of Coal Tech's facility. The 500,000 sq. ft. area, very high ceiling, the building, compared to the 2,500 sq. ft. required by Coal Tech was a major disadvantage because of potential environmental interference with adjacent tenants. For example, one adjacent tenant burned off non-metallic material from scrap metal piping and ducting or unknown composition. This would have required a ceiling high flexible partition on top of the planned 8 foot high cinder block.

However, the real "showstopper" was the landlord's terms, which bordered on the ridiculous. Some of the clauses were:

(1) The site owner's steam purchase offer was about 40% below the wholesale cost for No.2 fuel oil and no credit was given for reduced operating and maintenance costs. This is substantially lower than the usage in the independent power industry where the usual terms are 20% below combined capital, fuel, and O&M costs. Since the site owner already had a steam system, capital costs were not applicable in the present case. In addition, a penalty clause was added which required Coal Tech to pay the landlord 17% more than the landlord' s steam purchase price when our boiler was not in operation. This last clause would make steam generation the primary purpose of our combustor, which would conflict with the R&D objectives of the project.

(2) The environmental clauses were too broad in scope. Only an 8-foot high cinder block wall would separate Coal Tech's leased space from that of other tenants, in a building of about 500,000 sq. ft in area with multiple industrial tenants. Therefore, the environmental clauses had to be restricted to those areas involving Coal Tech's ope ration.

(3) The lease imposed very high insurance requirements, as well as a letter of credit for the cost of removal of all of Coal Tech's the equipment that was 10 times the estimated cost for its removal. The high insurance may have been due in part to the placement of this combustion system in this large building. However, the existing two boilers used for steam heat would have been adjacent to the combustor system. The estimated cost of these two requirements was substantially greater than any anticipated steam sales revenue.

(4) Finally, the landlord was unwilling to commit to terms of power purchase, which could have covered most of the above-added costs.

The lease was returned unsigned to the landlord, and this site was eliminated.

***Note Added –May 2003*: We list these historical events to show how shortsightedness, not-engineering factors, can frustrate the importation of new industries into dying industrial areas. It is almost certain that the investors who purchased this abandoned factory site, which at one time must have employed at least 10,000 people, received tax benefits to convert it to an industrial park. Had our facility been placed there to operate as a low cost, steam and electricity producer, we would have been able to showcase it to industrial clients from the U.S., Europe, and Asia that visited our Arsenal site in Philadelphia. Our site however, never produced any power for sale and as a result we were not able to proceed with any sales of Coal Tech's combustor and power plant system. This could have recouped some of the type of manufacturing jobs that were lost when the previous multi-national owners of the plant shut it down and sold it. However, for that to happen would have required a different type of landlord, one with a technology and entrepreneurial bend, not a real estate investor. This most probably explains why many of these urban "industrial redevelopment" programs wind up replacing high paying manufacturing jobs with low paying retail, entertainment, government, household goods movers, junk dealers, crematoriums, and storage type of jobs. Coal Tech's experience with the poor quality of very few remaining fabrication shops in Eastern PA during the fabrication of the second combustor further validates this hypothesis.**

In this author's opinion the loss to the economic well being of the U.S. by the continued loss of manufacturing jobs, and more importantly, by the know-how that is critical to the

development of new technologies, especially in the vital energy area, is not recognized. One result in the coal R&D area is that complex, sophisticated, but very costly systems are designed that are marvels of technology, but are so expensive that they are not commercialized. Instead there has been a stampede by "investors" into "cheap" technologies such as gas turbines whose basic elements were developed decades ago. Despite the fact that more sophisticated materials have allowed much higher efficiencies, overlooked was the fact that these "cheap" turbines run on "costly" and "limited supply" natural gas. The result has been the financial meltdown in the power industry of the past few years.

A full exposition on this author's opinion on this is beyond the scope of this Final Report.

<u>Paperboard Plant, Philadelphia, PA:</u> The plant uses 22,500 lb/hr of 130-psig steam for 8400 hours annually. In addition, the plant produces between 5 and 10 tons daily of a paper/plastic waste. This waste, after drying could be burned in the combustor. The plant's steam load exceeds the steam output of the 20 MMBtu/hr-combustor-boiler by 5000 lb/hr.

This deficiency can be removed as follows: Since the plan was to operate only one daily shift, while the plant operates round the clock, a means must be provided to keep the primary boiler on instant standby. This can be accomplished by installing a steam coil inside the lower drum of Coal Tech's boiler to keep the feedwater at operating temperature when the plant's boiler is shutdown. The preferred alternative is to keep the primary plant boiler in operation at 5000 lb/hr of steam output. At first this appeared unfeasible because the boiler turndown ratio exceeds the maximum 10 to 1 value generally recommended for boilers. However, the decrease in boiler efficiency is not a controlling factor limiting boiler turndown. <u>The primary factor limiting efficient operation at low heat input is the burner.</u> At 10 to 1 turndown, flame instability develops. This can be corrected by installing a small pilot burner next to the main burner. This addition has the advantage that the primary boiler can be brought on line instantaneously as soon as the 20 MMBtu/hr combustor-boiler shuts down. The feasibility of this last approach was verified with personnel at ABB's industrial boiler group, and it was been proposed to the paper company management.

Another issue that was addressed concerned co-firing coal with plastic/paper residual waste in the 20 MMBtu/hr-combustor. The entire 24 hour waste output of the plant can be burned in a single 8-hour shift at the rate of 1200 to 1600 lb/hr. This would provide 11 to 16 MMBtu/hr thermal input to the combustor, or over one half of its rated capacity. The balance would be provided by coal. However, in the process of reviewing the PA DER permitting requirements, it was learned that this waste is classified as a residual waste. This requires a solid waste permit if burned in excess of 500 lb/hr. Examination of the PA DER requirements for permitting at this site revealed that the setback provisions could not be met at the location of the paper plant. They could be met if the firing rate is below 500 lb/hr.

If combustion is maintained continuously at 500 lb/hr of paper/plastic waste, it would have matched exactly the waste production rate of the plant. Due to the high heating value of this material, namely 9400 Btu/hr as received, and 13,840 Btu/lb dry, this low rate of heat input yields 4.7 MMBtu per hour. Also, the ash content is only 1.3%, while the chlorine content is

0.27%. Therefore, with modest addition of gas or oil, e.g. 1 MMBtu/hr, it would have been possible to combust these material after passing it through a drier to allow pneumatic feeding into the combustor. Due to the chlorine content the dioxin control strategy that was under development in a parallel DOE-SBIR Phase 1 project would have to be used to eliminate dioxin emissions.

NOTE ADDED May 2003: This discussion described the issues faced during the site selection in 1994. The effort at Coal Tech since that time would have resolved the dioxin/furan issue completely. In fact had DOE/SBIR awarded a Phase 2 contract in 1995, which the DOE Technical program Manager had recommended, the dioxin/furan control would have been demonstrated during the task 5 test period. In any case, in 2001 Coal Tech performed several dioxin/furan control tests on a 90 MMBtu/hr municipal solid waste boiler, using two of Coal Tech's control processes. The results showed that with some minor modifications, the emissions could be reduced to less than EPA regulations.

Since the combustor would have to operate round the clock, it was preferable to design a smaller 8 MMBtu/hr combustor instead of using the 20 MMBtu/hr unit. The economics of this approach were discussed in the task 4 effort, and briefly reported in Appendix "B" on that task in the present Final Report.

In any case, the technical staff was averse to taking the risk with a new technology and advised the company President to withdraw his support for the project.

<u>State Hospital, Montgomery County, PA</u>: Another option that was investigated was to locate the project at a local PA State hospital that burns anthracite coal. The intent was to replace the anthracite with anthracite silt. One of the hospitals would have been a good candidate because the 20 MMBtu/hr combustor's steam output matched the non-heating season needs of the site. A small stoker fired boiler was used during this period. However, its performance was very poor with high- unburned carbon loss. This approach was an outgrowth of our study of the 20 MW anthracite repowering project in NE PA. That site used coal silt at a cost of under $0.5 /MMBtu. The hospitals pay in excess of $2/MMBtu. Four anthracite suppliers were contacted for quotations on the anthracite silt and the quoted price for this waste delivered to Philadelphia was in the delivered to Philadelphia was in the range of high quality bituminous coal, or about $1.5/MMBtu. <u>It should be noted that this type of price gouging is frequent among small operators. The silt probably sat there for decades and today (2003) it probably is still there. However, once they became aware that someone was interested it suddenly turned this garbage into gold.</u> In any case, this option was dropped to the adverse effect on PA taxpayer who pay for these anthracite subsidies to a few mine owners.

As a result of these experiences, the site requirements were modified in April 1994. The primary focus became to find a site where the combustor would be located in a separate structure where no intrusions of an operational or environmental nature from adjacent occupants could take place. Also, steam sales were eliminated as a site condition due to difficulty in arranging acceptable conditions. Instead the focus shifted to either internal use of excess power and heat or on producing electric power only for sale.

b) The Site Selected for Task 5:

The Arsenal Business Center- A U.S. Army Munitions Production Site from 1817 to the 1970's in Philadelphia. In April and early May 1994, nine industrial sites in the greater Philadelphia region were evaluated. One factor that drove the selection process was to find a site near a river that would supply cooling water for the condensing steam turbine because at the time the plan was still to erect a steam and electric power generating facility. . Of these, a building at the Arsenal Center was unique. A separate 3000 sq. ft. building with adequate outside space for coal storage and stack cleanup equipment was offered with attractive lease terms in 1994. However, as we soon learned, the lease terms rapidly became more onerous as the years passed. In any case, the site had more than adequate power and water supply. Also it is within *a few 100 feet of an inlet to the Delaware River, which could be used for steam turbine condensing.* The Business Center could have used the excess power that we could generate, but not the steam. A key item that had to be resolved before proceeded was permitting, licensing, and taxes, which was successfully implemented in the summer of 1994 with the various City and State Agencies.

A 3 year lease for the building at this site was executed in July, with an effective date of August 1, 1994. To obtain project revenue, various energy intensive processes were examined for use of the output of the combustor-boiler energy. After examining a variety of processes, it was determined that non-ferrous scrap metal re-melting offered the most cost effective use of the energy production.

As the installation design proceeded, (described in the next, sub-section (c) below), it was discovered that the site requirements could be substantially relaxed. The use of river or well cooling for the steam condenser, which had consumed so much effort in the site search, was replaced by a modified compact cooling tower with over a factor of 10 reduction in water consumption. The use of the local utilities power for daily startup and shutdown of the combustor-boiler system was replaced with a used diesel generator. The wet particle scrubber was replaced with a new low cost baghouse. The water-cooled sections of the combustor and steam condenser were cooled with very compact plate heat exchangers. A used low cost coal pulverizer was selected. The overall objective of these design changes was to produce a very compact, low cost energy system that could be rapidly designed, fabricated, and installed, and that did not have restrictive site requirements related to water and power supply. Also, an old 500 kW Elliot steam turbine-generator was located in a warehouse in NJ for purchase at a reasonable cost. In other words, we came very close to constructing a compact, low cost power plant.

c) The Task 5 Test Site Modifications & Permitting

The task 5 test site is a 3000 square foot building (No. 238) in the Arsenal Business Center, 5301 Tacony Street, Philadelphia, PA 19137. The site is within 100 feet of a tidal stream that drains to the Delaware River about 1000 feet away. It is on the former Frankford Army Munitions Arsenal, which opened in 1816 and was closed by DOD in the late 1970's. The building consists of two rooms, a small room about 20 x 30 feet and a larger room 70 ft. x 30 ft. with a 27 ft. ceiling. The larger room is ideal for the 20 MMBtu/hr combustor-boiler installation that includes the compressors, fans, control panel, computer cabinet, 550 gallon-oil storage tanks, and there is also room for a steam-turbine generator.

Figure 1 shows a plot plan and elevation view of the installation including all the components needed for a 500 kW continuously operating power plant. The components listed in this figure were the ones that were originally planned. As this work progressed substantial modifications were made to accommodate permit requirements, site characteristics, landlord actions, and cost objectives. They are:

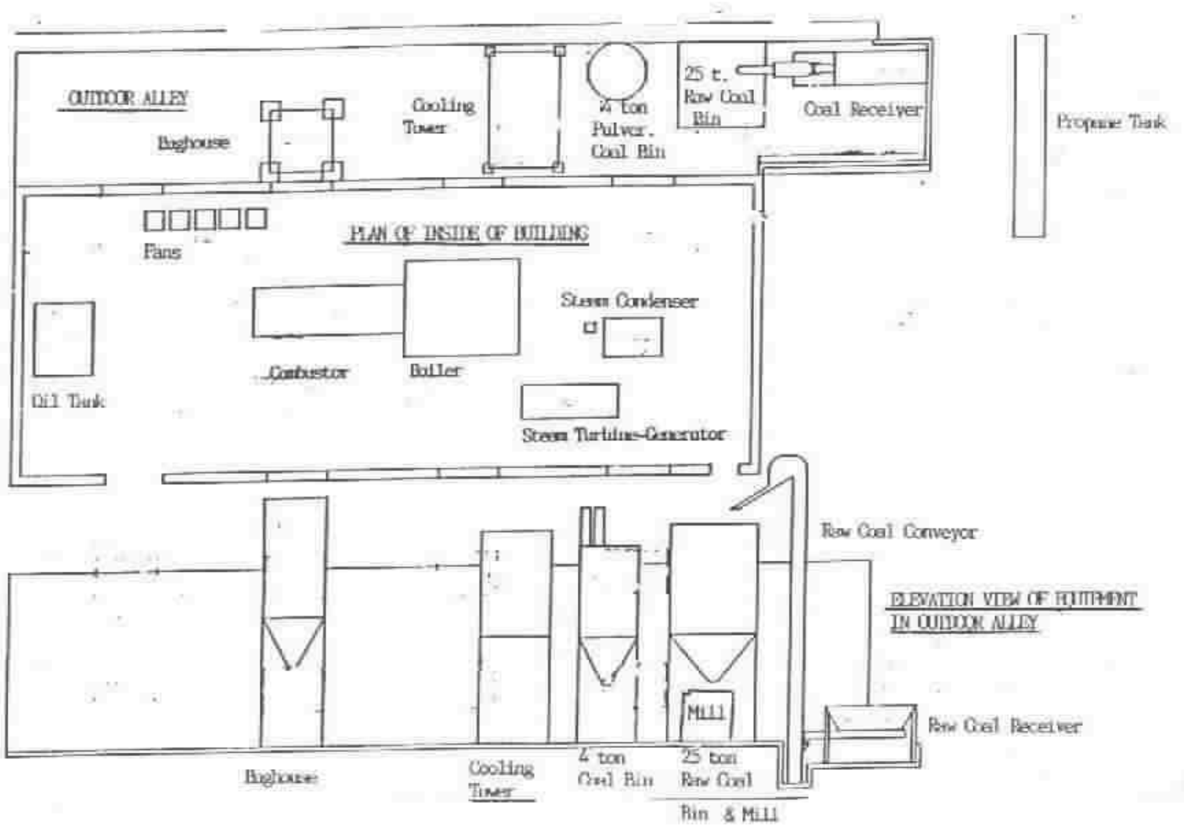


Figure 1: Plan (top) & Elevation (Bottom) Sketch of the Original 500 kW Power Plant for task 5

<u>*Concrete Pad for Outdoor Equipment*</u>: A concrete pavement with a spill containment barrier was designed for the 15 ft. wide, dirt outdoor alley adjacent to the building (see top of figure 1). The alley is design was modified several times to reduce the costs quoted for the original design by 5 different vendors. The original design was for a 4-inch gravel base topped by a plastic vapor barrier and 6 inches of wire mesh reinforced concrete. A 2 foot deep x 3.5 ft wide x 24 ft long concrete pit (top right in figure 1) was to be placed at the open end of the alley for installation of a screw feeder and elevator (shown in figure 1) but then replaced by a conveyor belt (not-shown). A 25 ton load, coal dump truck would back into the driveway and drop the coal onto this conveyor for delivery by means of the conveyor to the top of the 25 ton raw coal bin.

Although the entire coal handling system was to be enclosed, it is not possible to prevent minor spills of a few pounds coal dust on the ground during piping changes. To prevent washing or storm water runoff of this material, the entire pad was sealed at the joints with the three walls, and a 4 inch high concrete barrier was to be placed on the open fourth side to retain the water. The original design called for installation of two drains in the concrete to direct the water to the sanitary sewer that runs under the alley floor. However, this would not solve the problem of draining the coal receiving pit into the sanitary drains. It was therefore decided to direct the entire runoff into the coal receiving pit and install a sump pump therein. During normal operation, this pump would direct the rain and wash into the sanitary drains. During a coal dust spill, the pump outlet would be connected to a filter to remove the coal dust prior to discharge into the sanitary drains. This approach eliminates the need for a storm runoff permit from the PA Dept. of Environmental Resources or the Delaware River Basin Commission. A permit was required from the Philadelphia Water Dept. However, the planned average total daily discharge would be less than 25,000 gallons per day, which does not require any special permit.

Propane Fuel Supply: The building has a propane tank with 1840-gallon (165 MMBtu) capacity. In Williamsport 3 MMBtu/hr was required for pilot gas ignition of the combustor. This was sharply reduced after the new combustor became operational which saved well over $10,000 in propane costs during the project. A series of concrete filled steel poles and a fence was installed to prevent the coal and oil truck from hitting the propane tank.

No. 2 Oil Tank: Initially, a 1000-gallon, aboveground, No.2 oil tank was to be installed adjacent to the propane tank. The oil is used for daily combustor preheat and cool-down. This tank would have a metal dike, which was designed to capture the entire contents of the main tank. It was to be mounted on a 2-foot high steel platform to accommodate the City rule of installation 1.5 feet above the 100-year flood elevation, as this site was in a flood plain. . This was an added precaution because the entire Arsenal site is surrounded by an earth dike whose top is above the 100 year flood level. An oil flow and return pipe from the tank to the building was to be installed above the elevation of the oil tank past the propane tank to the far wall in the alley and cross the alley into the building. This required a total one way pipe run of 100 feet. It was planned to use doubly contained piping for this purpose.

However, Philadelphia licensing regulations require the use of certified tank installers for this purpose. In addition, the City prefers the use of a concrete, sand filled containment chamber for aboveground oil tanks. This approach was totally unsuited for the present project where removal within three years was contemplated. Any oil leakage or seepage into the sand and concrete would require its disposal in a special landfill at very high cost. To obtain a license for our design of a dike tank would have require a two step process, beginning with the Department of Licenses. It could have been approved at this step, but if refused by an appeal to the Safety Board of the Fire Department, where it would have almost certainly be approved. However, regulations require the use of the licensed tank installer for this application process at a cost of $865 per step.

A bid package for installation of the oil tank and a pumped feed line to the building was submitted to three installers licensed in Philadelphia in September 1994. One bid was over 4 times the cost of the oil tank, and another bid that was 7.4 times the cost of the tank were received (about $20,000). This is another example of the problems caused by the complexity of regulations as only a licensed installer are allowed to install an oil tank, which is ludicrous, as

Coal Tech has more experience than the installers in the operation of the facility. After these quotations were received, a further study of City regulations revealed that the installation of a boiler is allowed a 550-gallon tank without the need for this installation permitting process. Accordingly, all the test data from 1992 to 1993 were re-evaluated, and it was determined that this smaller tank would have adequate capacity for heatup and cooldown with <u>one week</u> intervals between refueling.

Therefore, the installation design was changed, and two 175-gallon domestic home heating oil storage tanks were installed (total costs: several $100) inside the building, and placed inside a metal box capable of containing all the oil in the tanks if they leak. The elevation of floor of the building is 1.5 feet above the 100 year flood level. This approach shortened the oil pipe run to the combustor to about 30 feet, and eliminated the need for installation of truck crash poles around the tank, and it <u>sharply reduced the cost of the tank and its installation</u>.

An added benefit of the oil tank installation is that it allowed its use to power a diesel generator, which was originally planned to acquire for backup power and startup and shutdown.

Also, by improving the startup and shutdown procedure, the oil consumption of start up and shutdown was reduced by a factor of more than 3 from that used in Williamsport. After the present project ended, we developed an operating procedure that **reduced the oil required by a factor of 10.**

The above discussion may seem trivial within the context of the goals of the present project. However, this simple step was of major importance, not only for the present project, but also for future commercial use. In India, the use of oil is limited to 1.5% of the total energy consumption, and the original oil consumption in Williamsport was about 5%.

There is an even more important lesson here. Coal fired power plants are very expensive. One could question whether the reason is due to over design and over caution. Or to quote the Republican U.S. Senate leader of the 1950's: "A billion here and a billion there, and pretty soon you are talking real money"

<u>Enlarged Equipment Door</u>: A design for opening the main door in the building from 8 ft x 10 ft to 12 ft x 14 ft was prepared in August and submitted to the landlord on August 30th. It included a steel roll up door to replace the small dilapidated wooden door. This item then became the primary source of delay in the project for 5 months because the landlord insisted on doing the work by his maintenance staff. The landlord failed to follow the requirements in the lease and obtain three independent quotations for this work. After receiving only one bid in September from the landlord's in-house staff to perform this work, Coal Tech contacted three contractors whose bids averaged 30% below the landlord's bid. After landlord's agent agreed in mid-October to allow Coal Tech's contractor to install the new door, he refused to allow the contractor access to the site on October 13th.

The landlord's delaying tactic and failure to respond to communications continued for an additional month. We retained a lawyer and were prepared to break the lease and to sign a lease at another site in upper Montgomery County, 20 miles west of Philadelphia. Finally a last effort meeting was held in November, at which the landlord challenged the structural integrity of Coal Tech's door enlargement design. Also, Coal Tech's design utilized two steel channels to support the new lintel. This exposed channel would clash with the "historical landmark" designation of the building, which according to blueprints at the Arsenal dating from World War II was constructed some time after the War. Note that much of the Arsenal has a historical landmark designation since many buildings date to the 19th Century. According to the landlord, historical designation applies to buildings over 40 years old. It was, therefore, not possible for us to challenge his designation as we have no information on the construction date after the War. However, if this building and its adjacent building are "historical landmarks", then all the run down, eye sore, industrial buildings that dot the East coasts old cities should be preserved, and not torn down with spectacular self-implosions. In fact they are being torn down and converted to shopping malls and "industrial" parks consisting exclusively of office space. Meanwhile manufacturing is leaving the U.S.A. I suggest that anyone interested in America's industrial might, obtain copies of NBC's 1952 10 hour documentary "Victory at Sea", whose theme music by the great composer Richard Rogers alone makes the viewing worthwhile.

These issues were finally resolved at the meeting between the landlord, his agent, and Coal Tech on November 11, 1994. The landlord's architect modified the door design to meet these "historical" objections. We agreed to have the landlord's personnel implement the door enlargement at a price that was in the competitive range with the other bidders. Similarly, the landlord agreed to perform the alley concrete work, install a 2 inch water line to meet the combustor-boiler requirements, and install a 6 inch pipe underneath the road in front of the building to provide for access to the river. All this work was performed at competitive prices. It became clear that the delaying tactics of the landlord was to obtain the maximum revenue from the lease revenue. As proof of this assumption, we cite the case of the "telephone line".

We should also note that one outcome of the November 1994 negotiations with the landlord was that the base rent from August 1 to December 31, 1994 was cancelled, and we only had to pay for maintenance during those 5 months, which included our buildings share of the entire Arsenal maintenance. Also, we did not lose any project schedule because the combustor fabricators slipped their delivery of the combustor from July 1994 to March 1995, as described below.

The Telephone Connection to Coal Tech's Arsenal Building: Immediately after we signed the lease in July, we requested a telephone line. This would have required running an overhead line from an adjacent building about 75 feet away. Here again despite the lease requirement for three competitive bids, the landlord's agent provided us with a single quote for an underground line at the outrageous price of **$3800, which included digging a trench.** The agent claimed that an above ground line was not allowed at the site. However, when Coal Tech found a means of running a line through the existing underground service tunnels that cover the entire site, the Philadelphia Installation Office of Bell of PA suddenly obtaining approval from the landlord to install an overhead phone line between the two buildings. After a month of delay Bell of PA (now Verizon) installed the line and phone in late September at a total cost of about **$240**.

Lessons from Installation Efforts To-date: These events have been included into this technical report because site requirements are a major element in installation of power plants.

The above comments show that clearly defined requirements and problem resolution procedures must be established in negotiations with site owners. During Coal Tech's contacts with independent power developers in the past several years it was found that site permitting is considered a major cost and time element in the installation process. Approval cycles of 2 years and costs in the several million dollars range are not unusual even for plants rated at 10 to 20 MW. For this reason, most of these developers will not consider projects under 50 MW.

As a result of this experience, Coal Tech's new approach to site issues is to identify the potential problem areas and find alternate solutions that will mitigate the complexity of the approval process. In addition, Coal Tech is adopting a design approach in which much of the power plant can be assembled in modules in a factory and moved to a site for rapid installation. In this way installation of the power plant can proceed rapidly as soon as site related issues have been resolved. This approach was to modularize the entire facility, including electrical power, water piping, gas ducting, electrical connections, and auxiliary components, such as fans, pumps, blowers, etc. As a result the entire facility can be disassembled in a few days and moved elsewhere for re-installation by simply re-hooking up all the connection. A power plant contractor installed the Williamsport facility. Its disassembly required breaking all connections in individual pieces. . Modularization is in my opinion the only method by power plants in the 1 to 20 MW range can be installed at attractive costs. Other such areas that impact cost are cooling water and parasitic power.

Additional Parasitic Power: The building has a 200 Amp., 480 , 3 phase installed power. Assuming an 80% power factor due to the large number of motors used, this yields 133 kW of installed capacity. It was originally planned to add an additional 100-kW power capacity from a sub-station 100 feet away to assure adequate power during daily combustor startup and shutdown. This would cover the initial estimate of the parasitic power needs for the combustor-boiler, the coal handling system, the stack gas system, and the boiler-steam turbine system. In addition, it had been planned in the future to install 500 kW of total capacity to the sub-station for future power sales from the steam-turbine generator to the site owner.

This plan was based on the assumption that local utility power (PECO, now Exelon)) costs were $0.14 /kW. However, after analyzing the first electric bill, it was found that there is a very high capacity factor cost for this utility due to its heavy reliance on nuclear power. As a result, the heatup and cooldown time of about 55 hours per month, would be less than 80 hours per month. For that time of use, the power cost **is $0.23/ kW!!!.** Therefore for 150 kW capacity, the monthly charge would be $1900, or $23,000 for one year. This exceeded the 1994 rental costs for the site. As a result, the purchase of a used diesel generator was investigated and it was found that the diesels power production costs, including acquisition cost, would be one-third of the utilities charge. Another consequence of this effort has been to carefully re-evaluate the total parasitic power needs. This analysis showed that about 100 kW would be adequate, compared to the original estimate of between 200 kW and 250 kW that was used in Williamsport. In practice, the power consumption was even less than 100 kW, and as a result, the diesel engine was not purchased.

Combustor Cooling & Steam Condensation:

The original plan was to use cooling water from what was believed to be a well in the adjacent building. In fact it was not a well but underground water seepage and its use was abandoned. Also, when the plan to install the steam turbine generator was also abandoned due to funds limitations, the use of the river water was also abandoned. Instead the potable city water from the 2-inch line was discharged in the sanitary system. However, all the necessary analysis and water testing for using a steam turbine was implemented.

For example if we had proceeded with the steam turbine project we would be required to limit discharge into the Delaware River to 110°F. If the river water inlet temperature reached 80°F in the summer, the cooling system be limited to a 30°F temperature change in order to remain within the 80°F and 110°F limits. This required 1130 gpm flow rate, or 67,800 gph, which requires high pumping power, and large pipes.

It is ironic that after devoting months to locating a site near a river, and finally signing a lease at a river site, the power plant design was modified with the use of a simple cooling tower, which obviated the need for a riverside location. However, prior to this decision, all the necessary work leading to permitting its use was implemented. This water permitting process required by the PA DER for non-contact cooling water required chemical tests of the water. The results clearly showed that the water source was groundwater, whose primary source was leaks into the basement of the building. It did not follow the tidal water level in the river and was therefore not a river source. Neither was it due to leaks from the municipal water supply.

Another option for cooling the steam turbine rejected heat was to discharge to the municipal sanitary system, where the peak limit is 140°F, which would increase the capacity to 5.3 MMBtu/hr, or 32% of the total required. The storm and sanitary water system at this site is very complex. One difficulty is that the storm sewers are superimposed on the sanitary sewers so that heavy rainfalls can impact the sanitary discharge. To assist in resolving the water issue, Coal Tech retained in September 1994 a specialist in water management to assure that an adequate water supply is obtained and that all regulations are met. In addition, by coincidence, the Philadelphia Water Department was in the process tracing these underground pipes at the Arsenal. After reviewing all this data, it was determined that this "well" in the abandoned power plant was actually a sump, and it could not be converted to a primary cooling water source. There exists another substantially larger water source, but it is too far from the building. Another closer source was a manhole opening in an adjacent parking lot that was directly connected to the creek and the river. However, as the river temperature reached an average of 80°F in the summer, the 110°F discharge limit would require 1130 gpm, as noted above.

As a result, the option of using a cooling tower was re-evaluated. This option had been discarded early in the design effort due to misinformation supplied by a cooling tower manufacturer. This supplier proposed the use of three cooling towers, each having a 18 ft diameter and 18 ft height, and at a prohibitive cost. Coal Tech performed a series of cooling tower calculations that was specialized to one atmosphere absolute pressure condensation from the steam turbine. This allowed selection of a low cost, high average water circulation temperature. The cooling tower needed for this was now only 12 ft long, 7 ft wide 11 ft. high.

Combined with the combustor cooling water requirement, the fresh water supply requirement required was now only about 50 gpm. This was about one-half the level used in Williamsport. In addition, since much of the water evaporates in the cooling tower, the discharge load to the sanitary sewer is negligible, namely, between 3 and 15 gpm. This eliminated the permitting need from both the River Authority and the DER, with only a routine permit required from the Philadelphia Water Department. The discharge rate is far less than the lowest level of 24,000 gpd below which no special permit is required.

Another change in the design was to install a 2 inch fresh municipal water line, in place of the originally planned sump water source. The reason for this is that the cooling tower requires a water source with much lower dissolved solids levels than obtainable from the sump. While a 1-1/2 inch line would have been adequate, the high installation cost is such that providing excess water capacity is a good precautionary investment. Inadequate water supply was a major source of difficulty in Williamsport.

Note added in May 2003: The above lengthy exposition has one additional lesson: Never take the word of "experts" at face value without checking. The water use consultant stated that there was not much difference between a 1-1/2 inch and 2 inch water line. He overlooked however a huge difference, namely as the water line is increased the monthly sewer charge increases, and for a 2 inch line that charge is a little over $100/month, or over $1200/yr plus the actual water discharge. However since most of the water used in task 5 was blown off as steam the actual discharge into the sanitary sewer line was minimal. The Water Authority was willing to provide Coal Tech with a credit for this blown off steam. However, since the Water Authority invoice the landlord who has a large, either 10 or 12 inch line, it was necessary for Coal Tech to have the landlord do the correction. However, the Arsenal is so old that water leaks into the ground. The net result was that this "negligible" added 2 inch line wound up costing many $1000's over the life of the project. When Coal Tech continued its internally funded combustion R&D, which was implemented at low thermal input to the combustor, we shut down the 2 inch line and operated from a ½ inch water line that was originally installed for the one washroom.

<u>*Zoning Permit*</u>*:* The first important step in the permitting was the receipt on July 29, 1994 of a zoning permit from the City of Philadelphia. This allowed Coal Tech to use the site for energy development and for the installation and operation of the combustor-boiler system. The importance of this step was that the site is in a flood plain and as such there are a number of restrictions on its use. For example, above ground oil tanks must be installed 1.5 feet above the 100 year flood elevation.

<u>*Boiler Permit*</u>: A permit is required from the PA Bureau of Labor & Industry-Boiler Section for moving and installing a boiler in the state. This permit was obtained for the 17.500 lb/hr boiler in September 1994. PA License &Inspection would have required a final inspection prior to operating the boiler as a pressure vessel. However, when the steam turbine option was eliminated and all the tests were with blown-off steam at low pressure, this permit was not required.

Water Discharge Permits: As reported above, the original plan for river discharge would have required permits from the Delaware River Authority and the PA Dept of Environmental Resources, Water Division. With the decision to eliminate the steam turbine and cooling tower, neither permit was needed. Only a Municipal Permit application was required, which was obtained from the Water Department.

Air Permit: Philadelphia manages its own air emission program, not the State. The emission limits are 0.1 lb/MMBtu for particles, 0.5 lb/MMBtu/hr for SO_2.

A detailed modeling analysis by the manufacturer of the wet scrubber that was used in Williamsport showed that a pressure drop of 50 "w.g. would be required across the scrubber for this particle emission rate. This would have required a 50 hp fan, compared to the 20 hp used in Williamsport. The airflow is about 6000 acfm, and this would require between 45 and 50 gpm, with about a three gpm evaporative loss. Using the sump water supply would eliminate the cost of water for a once through system. By combining this flow with the combustor water-cooling circuit the total discharge to the sanitary drain would not increase. The solids loading in the discharge would be the same as that used in Williamsport. The alternative of operating the scrubber in a closed loop circuit with filtering would be complicated by the problem of disposal of the sludge. It could be dried and re-injected into the combustor, but this would require development work. As noted the scrubber would also contribute to the sulfur reduction needed to meet the SO_2 emission limits.

The main disadvantage of this approach is the high electric power needed by the fan, which is very costly. Also, in a commercial installation a "free" water source would not be available. Also, with the exception of the relatively new scrubber inlet section, the balance of the scrubber wall material is badly worn and would have to be replaced. For these reasons, it was decided to replace the scrubber which a baghouse. This can achieve 0.03 lb/MMBtu emissions. In addition, with stack injection of calcium oxide based reagent, upstream of the baghouse, it was anticipated that a higher percentage of the SO_2 would be removed. Accordingly, two vendor quotations for a baghouse were solicited. Both were in the same price range, with the main difference between them being the projected material lifetime and the recommended bag material.

Due to the high cost of bags operating above 250^{o}F, this temperature was set as the limit. It was originally planned to lower the stack gas temperature, which averaged 450^{o}F with soot blowing, to the lower temperature by installing an economizer in the boiler outlet. The economizer was designed to decrease the stack gas temperature to 360^{o}F, while increasing the feedwater temperature by 30^{o}F. The additional temperature drop was to be achieved by water droplet injection in the boiler exit ducting. Due to the high basic content of the reagent is injection the impact of the SO_3 acid dew point on stack/baghouse metal materials should be neutralized. A convoluted design of the stack duct system was implemented and installed. It would provide sufficient duct length to cool the stack gases to below 250^{o}F. This ducting and the baghouse in the alley are shown in figure 2. A horizontal duct from the boiler to the baghouse exits the building through a window. The duct then rises and turns 180$_o$ before dropping to the baghouse inlet. In practice, the cooling spray regularly filled the duct with wet ash that required frequent cleaning of the duct. Also the economizer was never built. Therefore, this is one area, namely pre-cooling the boiler exhaust gases, that requires some additional optimization.

Note added March 2004. Despite the basic nature of coal combustion operation, extensive testing with No.2 oil has severally corroded the stack ducting.

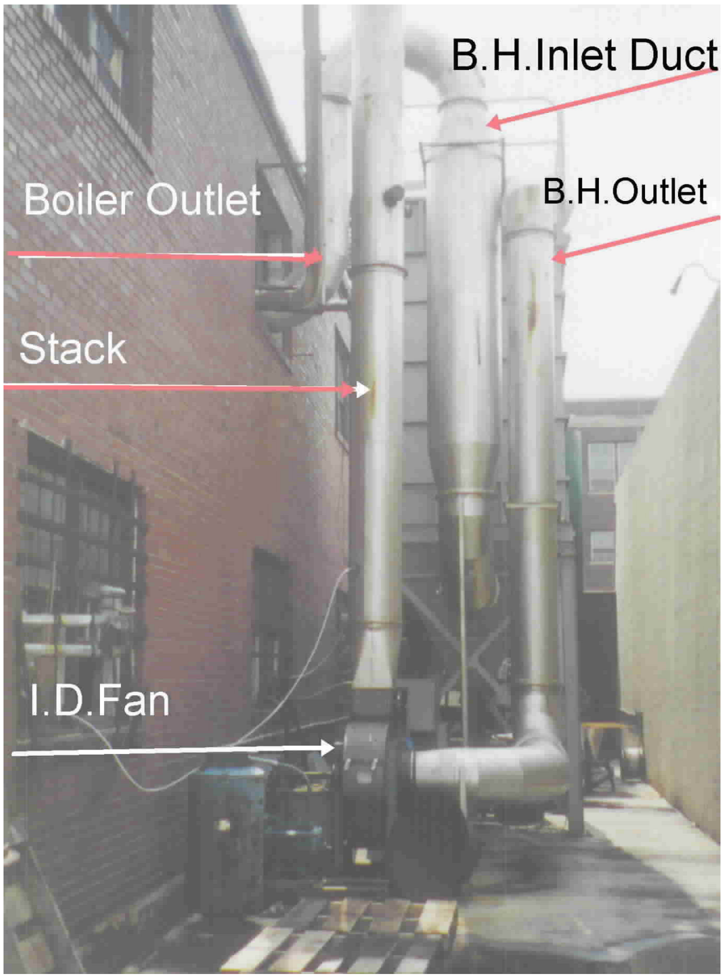


Figure 2: The boiler exhaust ducting, the baghouse, I.D. fan, and stack in the alley of the test building.

One final important element in the air emission permit application is the requirement by the City that the SO_2 emissions at ground level at the boundary of the site be less than 3 ppmv at any time, less than 0.5 ppmv over 15 minutes, and less than 0.1 ppm for an 8 hour period. To determine this level, a screening model was downloaded from EPA's software library. The analysis computes the SO_2 emissions at various elevations for various terrain's as a function distance from the site fenceline, 1050 ft (323 m.) in the case of the Arsenal, as a function of the stack geometry and flow conditions and SO_2 concentrations at the stack exhaust. Several scenarios were calculated for 20 MMBtu/hr thermal input, 13,000 Btu/lb HHV and 2% S coal. The result is a computed ground level SO_2 concentration in μgm/m3 as function of distance from the stack for 85% SO_2 reduction at the stack. The computer analysis showed that the SO_2 would be 104μgm/m3, equal to 0.09 ppmv, at the Arsenal building's fence line. The 8 hour average would be 0.06 ppmv for 8 hour average time. Here it is assumed that 70% reduction is achieved with combustor injection and an additional 60% reduction of the balance is achieved with stack reagent injection. For 70% SO_2 reduction at the stack, the fence line value is 210 μgm/m3, equal to 0.17 ppmv, at the fenceline. The 8 hour average is 0.12 ppmv. Therefore one can conclude that a combination of proven combustor SO_2 reduction with some modest additional stack reduction will meet the City's 0.1 ppmv emissi on requirement at ground level.

d) Second Generation 20 MMBtu/hr Combustor Design & Fabrication

In January 1994, a design effort was initiated to modify the 20 MMBtu/hour-combustor in light of the results of the previous tasks, and to fabricate the modifications. The following summarizes this work:

Combustor Extension and Exit Nozzle: A new design of the air-cooled combustor extension and air cooled exit nozzle was performed and completed in the first quarter of 1994. This design was based on the analyses of prior test results in Williamsport and also on the computer modeling with the BYU code. In view of the severe computer difficulties experienced with the FLUENT code, the BYU code was used in the analysis because its results correlated with the combustor test results. The L/D of the combustor was almost doubled. In addition, an air-cooled design for the exit nozzle was implemented. The slag tap was relocated to the downstream extension section. It was also redesigned to assure much more efficient heat release of the slag tap heaters.

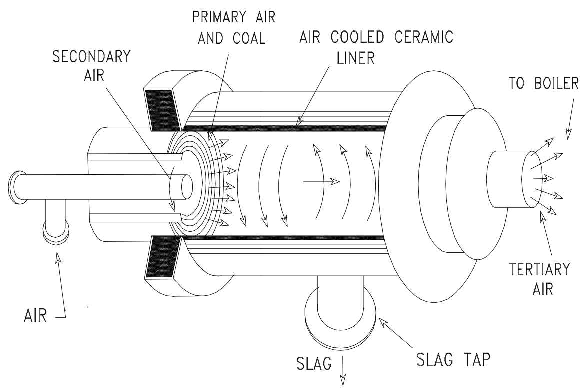
The design was prepared with CAD. Beginning in February 1994, the drawings were submitted to **10** vendors for fabrication quotations. 3 bids and 6 no bids were received by April. The two low bids were within 10% of each other. The two lower bids were consistent with the cost of similar combustor components that we fabricated in the first 20 MMBtu/hr-combustor in 1985. After evaluation of both bids, the order was placed May 1994 with the firm that had the least subcontracting. However, it was necessary to separate the order for the air-cooling assembly from the balance of the combustor. This contributed to a massive slippage in the delivery of the combustor from 4 months to ONE YEAR ! This was due to the need to first fabricate some components at one contractor and ship them to the fabricator of the air-cooling assembly, and then back. In retrospect this has two benefits.

(1) We were able to take a firm stance with the Arsenal Center landlord in achieving reasonable prices for the building modifications. As reported above, this standoff consumed almost the entire second half of 1994.

(2) Much more important, we re-evaluated the combustor design and developed future alternative designs which were based on task 5 test results and subsequent Coal Tech test work that greatly simplified the design and sharply reduced its fabrication cost. This is extremely important because the largest market for this combustor is in Asia, especially India and China, and cost is a major driver in technology selection in those countries.

One interesting lesson from this fabrication is that even with checking, errors do occur. A discrepancy between the assembly and detailed drawings of the air cooling assembly was discovered during the fabrication. As a result, the inner diameter of the exit nozzle would be increased from 50% to 57% of the combustor internal diameter. This was discovered after all the pieces had been cut and it was too costly to procure new pieces. It occurred despite the use of AutoCAD for the drawings and the use of two independent checkers of the drawings. After reviewing the literature of cyclonic flow it was determined that this change was not substantial.

In fact it wound up being beneficial because it simplified the internal maintenance of this combustor. Another difficulty experienced was the need to modify the fabrication of the parts near the slag tap chamber. Again this design differed from the one used in the first combustor. A key lesson for the future is to use three dimensional computer drawings of the tube design to verify dimensional clearances. 3D-CAD was considered initially for the present design but it was rejected as too costly for the perceived benefit. Due to the skill of the fabricator, these problems were satisfactorily resolved. The primary fabricator has machined the balance of the combustor assembly by November and promised completion of the work by mid-December. In actuality, it was not completed until March 1995.



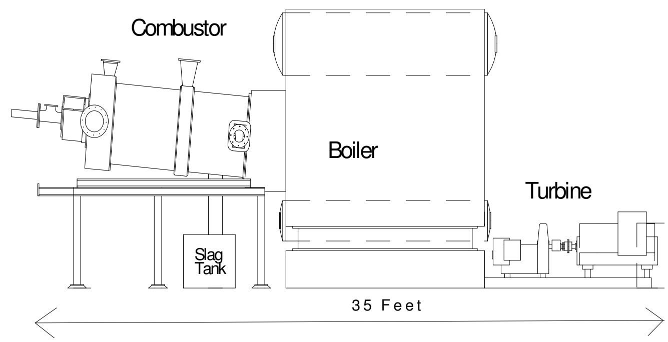


Fig. 3. Air Cooled Slagging Combustor. Fig.4: Combustor-Boiler Steam Turbine. Scaled to 2 MWe

Figure 3 shows a schematic of the 20 MMBtu/hr air-cooled combustor. Figure 4 shows the attachment of this combustor to the 17,5000 steam lb/hr D Frame oil designed package boiler at the Arsenal. Also shown is the steam turbine-generator to scale for up to 2 MW electric output, which was never acquired. Photographs of the equipment will be shown below in the installation section.

e) Auxiliary Equipment Design and Installation

Solid Fuel Preparation: Conceptual designs were implemented on fuel drying and coal and waste shredding and pulverization. Both new and used equipment were considered for paper sludge combustion. Both press drying and thermal drying in either a conveyor or rotary drum were evaluated. Compression drying is suitable only for liquid sludge and not for the 33% paper/plastic waste under consideration. Commercial thermal drying equipment is far too costly, ranging from $100,000 to $200,000 for the present usage rates of about 1 ton/hour. It was, therefore, decided to design and fabricate a rotary dryer using our in-house design of one of our sub-contractors. However, this fabrication was never implemented because we reverted to purchasing pulverized coal from our task 3 supplier in Western PA.

In the area of coal preparation, cage crushing mills, impact mills and ball mills were considered. This would have allowed extension of the previous year' s tests with fine and coarse coal sizes. For our planned utilization rates, a new cage mill would costs about $45,000 but it cannot achieve the maximum fineness of 70%-200 mesh desired. A new ball mill system for the present feed rates costs over $100,000. A used impact mill costs far less, including auxiliaries.

It can achieve 80%-200 mesh as well as coarse coal sizes. The impact mill was the preferred system.

The lead design engineer informed us of a used mill than he had helped develop at his previous employer. It required considerable renovation, for which Coal Tech would have to pay. Inspection showed that the primary value of this mill was as scrap steel. However, as in the case of the anthracite sludge, the minute we expressed an interest in the mill, it suddenly became "valuable" to the own er company. Negotiations were entered into with the owner of coal mill to refurbish it at Coal Tech's expense, as it was a discontinued model. After back and forth negotiations occurred until an agreement was executed on revenue sharing from inventions that we (Coal Tech) might make in improving the performance of the mill. This involved protecting the U.S. government's interest, the manufacturer's interest, the subcontractor in charge of the refurbishment's interest. *Note May 2003: Recalling this today makes me sympathize with the government's effort to move the U.N. to action.* In the meantime, another used mill of identical design had been located and its acquisition and refurbishment cost was evaluated as an alternative option. In the end an agreement was executed with the owner of the first mill, who was the original manufacturer.

We did indeed make the needed modifications and installed and briefly tested the mill, all at considerable cost. However, we never placed it into operation because once the decision was made that insufficient funds were available to implement a complete power plant operation, it was far less costly to procure pulverized coal, as had been done in Williamsport. The mill was removed and the design engineer actually managed to place it into operation with a company that used it to grind some mineral matter.

However, at the time (1994) multiple quotations were obtained for the raw coal screw feed, conveyor belt, mill refurbishment, the coal bin baghouse, and the fabrication of the 25 raw coal ton bin. The overall design of the coal feed system was shown in figures 1

<u>*Stack Cleanup Equipment & Waste Heat Rejection*</u> The Arsenal test site in Philadelphia required a baghouse to meet local particulate emission standards. All the sites investigated, as well as the Arsenal site, were adjacent to major rivers, which could provide a cooling water source for the combustor and steam turbine condenser. However, as noted above, thermal discharge required added permits from both PA DER and the River Commission. To provide an alternative to river cooling, a design of a cooling tower was developed. However, an air-cooled condenser is costly. One rated at the required 16 MMBtu/hr was quoted at about $40,000. The alternative was a water spray cooled condenser, which cost less than one-half that amount.

<u>*Combustion Emission Permitting:*</u> PA-DER requires a new air emission permit when a combustion source is moved. However, as the 20 MMBtu/hr facility is located in Philadelphia, this function is exercised by the City's Department of Health. A problem developed with the application that was filed in December 1994. The regulations concerning the combustion of coal in Philadelphia were written in the early 1970's when economical means for contro lling SO_2 emissions were not available. Consequently, a special permit was required for coal combustion. A meeting was held with the regulatory authorities at which Coal Tech presented status of development of the environmental control technology with the air-cooled combustor. It was also

noted that this is a RD&D project. In January 1995, the air permit was issued on this basis with the requirement that the above emission standards be met, and that continuous emission monitoring be implement, including one test using independent testing organization to be implemented within 90 days of startup. The permit allows up to 2000 hours annual coal fired combustor operation.

<u>*Boiler Acquisition & Modification*</u>: The 17,500 lb/hr boiler used in Williamsport for the past 7 years was purchased from the owner of the Williamsport site for the task 5 effort. It would have been cheaper for us to purchase a used boiler elsewhere. However, out contract with the site owner required us to refurbish the boiler. This would have cost more than the purchase price, which was about $30,000 without the combustion system. Why the site manager insisted on the combustion system remains a mystery, as it was useless, except for spare parts. In fact the other boiler in the building was removed and stored outdoors at the company's other site, and the building was demolished, including the band new roof for which we paid 50% of the cost just 4 months earlier. No wonder that company underwent financial difficulties. In any case, we could have purchased several similar boilers for about $25,000, although we did not inspect them. Other quotations for similar size boilers were in the $60,000 range from dealers in used equipment.

A detailed design was developed for modifying the front of the boiler for attaching the modified air-cooled combustor. The original attachment in Williamsport was clearly deficient, while the new attachment has performed excellently since start-up in late 1995. Fabrication of this modification was completed in October 1994. It consists of an extension section into which the combustor's exit nozzle is inserted. This section allows the removal of any ash or slag that is carried over into the boiler without entering the boiler. Therefore, ash/slag removal can be implemented without combustor shutdown, if needed to clear accumulated slag or ash.

In October 1994 the boiler was removed from the Williamsport boilerhouse and temporarily stored on the outdoor lot of the rigging company right alongside PA Route 15 in South Williamsport, where is stood for almost one year. As noted the Arsenal building door was enlarged to allow it entry into the building, (see figure 1). .

In addition, a steel structure was designed for placement of the boiler at the new site. This design allows the installation of a bottom ash removal section, which can be used while the boiler is in operation. This was not possible in the Williamsport installation, where the boiler sat on the floor. In the event real time ash removal from the boiler floor was never necessary.

The 17,500 lb/hr boiler and all the combustor and auxiliary equipment were moved on three flat bed trucks from Williamsport to the Arsenal in a 24 hour period in January 1995. The boiler was transported on a low bay truck, which required a special road permit to assure the boiler would not hit any highway overpasses. A last minute difficulty in obtaining this permit resulted in the trucks being stuck overnight in a truck stop on Northeast PA. Meanwhile, we had a rented crane waiting at Arsenal to unload the boiler. It required the assistance of our local State Representative's office to 'break" the trailer loose. The boiler was installed in the Arsenal building without difficulty and without the use of complex rigging equipment. The entire move was implemented in two days, January 17 and 18, 1995.

The procedures developed for this installation can be used in future commercial systems using this combustor. Also, the 4 ton pulverized coal bin was reinstalled in the newly paved alley (see figure 1). All this work was completed one week before a severe winter storm followed by extremely cold weather covered the Philadelphia region.

The trials and tribulations are described in this final report show that high tech energy R&D requires major attention to mundane issues. From debriefings on rejected Coal Tech proposals, it appears that some DOE reviewers are not sensitized to this issue in that they give high ratings to large corporations who appear to implement these mundane tasks apparently effortlessly. Overlooked is the fact that these large corporations have large staffs that perform these mundane functions, and those staff cost far more than Coal Tech's very lean organizational structure.

<u>Steam Turbine</u>: An very old Elliot steam turbine, rated at 600 kW and matched to the steam output of the boiler was located in a warehouse in Northern New Jersey and inspected. Analysis of its performance showed that it would produce between 400 and 500 kW with the present boiler system. The output range depends of the steam conditions. The steam input can be between 100 and 220 psig, either saturated or with 100 F superheat. The steam discharge is either 1 psig or 10 in. Hg absolute. One factor in the power output selection was the cost of replacing the nozzles in this single stage turbine versus the required power output. As noted originally it had been planned to sell the power to the site owner. However, this required replacing the governor and adding power synchronization with the utility grid. This is a costly option and the site owner was not interested in purchasing this power at a cost that would be financially attractive to Coal Tech.

As the installation proceeded, it became clear that even with attractive electricity sales, there were insufficient funds in the project to implement a power plant project. It was noted above, that the original proposal for task 5 included the full-scale power plant option at a cost that was double that of the final contract. The fact that we came so close to actually implementing a power plant option demonstrates the power of innovation in reducing costs. Accordingly, the steam turbine option was eliminated, as was the raw coal to pulverized coal conversion.

<u>Internal Use of Energy Generated by the 20 MMBtu/hr Combustor</u>: Prior to abandoning the power generation option, a brief study on the internal use of the combustor's energy output was investigated and reported. The most attractive option was non-ferrous metal scrap re-melting. This option was investigated with Coal Tech internal funds. Preliminary feasibility tests were planned for 1995 in which a small graphite vessel would be utilized to melt several pounds of aluminum continuously into a refractory vessel. All the equipment for this effort was procured. However, when it became clear that there were insufficient funds to complete the power plant option, this melting effort was terminated.

f) Installation of the 20 MMbtu/hr Combustor-Boiler Equipment

<u>Electric Power Usage:</u> As noted above, the power required to operate the combustor facility for task 5, without raw copal preparation, was reduced from the 200 kW used in

Williamsport to below the existing 130 kW in the Arsenal test site building. Including the coal preparation step would have required additional power. It was determined that diesel generator was the lowest cost option, and a permit for this purpose had been obtained from the City. This was of course not used, but it is still available because our proposed approach was to use the discharge from the diesel as combustion air for the combustor. In this way, both particulates and NO_x would have been controlled to the City's stringent standards.

As each step of the installation proceeded, the power requirements were re evaluated. In the final installation design of the air ducting for the combustor cooling and combustion air, a procedure was initially developed in which the large high power fan used in Williamsport would be only turned on after the combustor reached about 3/4 of full combustor output. This would save about 50% of the operating power during the several hours of heatup and cooldown each day. The reason for this procedure was to remain within the capacity of the wiring into the building. On further evaluation of this matter, including a re-examination of all the Williamsport test data related to combustor thermal performance, it was determined that it would be possible to completely eliminate this high pressure fan by modifying the combustor cooling procedure. This lowered the power requirement to about 70 kW without coal processing and about 100 kW with coal pulverization. This is almost a **factor of three- power reduction** from what would have been required if we continued the mode of operation used in Williamsport. This eliminated the need for a diesel generator even with on-site coal pulverization.

Boiler Installation: An outside contractor was retained to bring the boiler into the building and install it on the elevated steel support structure, which had been installed to allow ash removal from the floor of the boiler. Substantial ash deposits had deposited on the floor of the boiler in Williamsport. However, ash removal was not necessary because the ash deposits in the new installation were very low. *(Note added in March 2004: I recall a conversation with a senior engineer at the B&W company in the 1970's in which he stated that ash carryover would rapidly block convective tube passages and also deposit on the boiler floor. As that company had experience with commercial utility scale slagging cyclone combustors since mid-century, that was an area of concern. However, those combustors operate with crushed coal, and their mode of operation is vastly different than the air-cooled combustor. The biggest difference is that they are massive NO_x produces, while we achieved 0.07 lb/MMBtu. Another example of the dangers of extrapolating "expert" opinion.)*

The boiler operated in a steam blowoff mode for the task 5 tests, at a pressure of 15 psig. For this purpose, the two refurbished 6-inch boiler steam blowoff valves, the two refurbished boiler safety valves, and their appropriate piping as well as the water inlet pipe, were installed on the boiler. Also, the boiler blow down valves were refurbished and a homemade blow down steam-water separator was fabricated and installed. The boiler blow down was piped to the sanitary drain. The soot blowers were connected for both steam and high-pressure air blow down. A simple resistance type automatic boiler feedwater refill control was installed.

Water, Oil, Propane, Compressed Air, Combustion and Combustor Cooling Air Systems: Unlike in the Williamsport installation where all these feed streams were piped around the combustor shell, which made rapid removal of the combustor from the boiler impossible, in the new design, each of these streams and their control valves were installed on a separate framework, and connected to the combustor by flexible piping and ducting. This allowed removal of all this equipment in a matter of several hours.

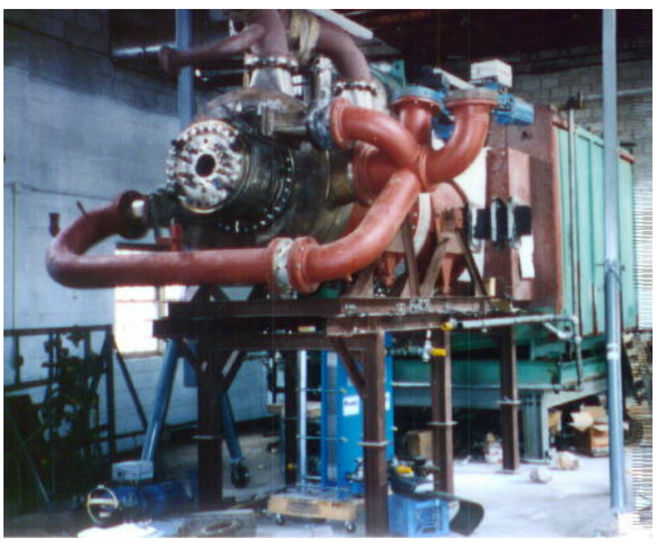
The sections of the combustor that are water-cooled were integrated with the boiler feedwater piping, as was the water circuit for the slag quench tank situated beneath the combustor (see figure 3). One major problem in Williamsport was internal water leaks in one of the water-cooled sections of the combustor. These cracks were caused in part by the high city water pressure. To eliminate this problem, a plate water-water heat exchanger was used to separate the city water from the re-circulating combustor cooling water. An identical heat exchanger was used to isolate the slag tap cooling water from the waste water discharge.

Combustor Refractory Liner Installation: The refractory liner in both the original and extension sections of the combustor was installed at the site. The refractory originally selected for this purpose was not available on a timely basis, and an alternate material with identical thermal chemical, and mechanical properties was selected. The manufacturer assured us that this material similar casting characteristics as the original material.

In preparation for the casting, a series of thermocouples were installed in both combustor sections. Insulating material was installed between the combustor air-cooling section and the outer combustor shell. On removing the outer covering of the liner substantial voids were discovered in the refractory between the tubes. This had not occurred in the previous castings of the refractory liner. On contacting the refractory manufacturer on this matter, their in house staff disclaimed all responsibility for this problem, which was due their recommendation of a poorly flowing refractory that was a result of the coarse size distribution of the filler material. To correct this problem, we removed the insulating material from the rear of the liner in both combustor sections. This also necessitated removing the thermocouples and replacing them. The voids were filled by hand with castable cement. Another example of relying on a suppliers false assurance.

Combustor-Boiler Interface Refractory Installation: A refractory assembly was installed in the boiler front section that interfaces between the combustor and the boiler. This section was a totally new design that was based on years of testing various approaches in Williamsport. The purpose of this design is to allow removal of ash and slag flowing from the combustor outlet to the boiler without shutdown of the combustor and waiting several days for cooling of the boiler. To accomplish this a number of features were incorporated in the design. As part of the installation it was necessary to remove sections of the original boiler refractory brick work. During the installation several design changes were made. The divergence angle of the inner refractory liner was changed. Also, the inlet section of the combustor to the boiler was redesigned in such a manner as to allow rapid, within one day, removal of the combustor from the boiler. In Williamsport, combustor removal required almost complete removal of the combustor-boiler interface ceramic, as well as all the liquid and gas stream piping that enclosed the combustor shell

Combustor Installation: After completion of the installation of the insulating ceramics in the boiler and the liner, the combustor sections were installed on the combustor support stands. Since the combustor is placed on an elevated stand, a preliminary check assembly was conducted on the floor. The check assembly revealed that there was a slight misalignment in the combustor section's bolt circles, which was readily corrected. The combustor sections were then disconnected and each one was hoisted onto the 6-foot high stand and moved into position in front of the boiler. The combustor was then aligned with the boiler. The alignment procedure showed that the originally planned method for connecting the combustor to the boiler wall would not allow ready retraction of the combustor for servicing. A modified method for this attachment was designed which eliminates the connection problem. The combustor was then retracted for installation of the boiler refractory, after which it was bolted to the boiler. The latter effort required less than 1 day. Figure 5 is photograph of the combustor installed on its support stand in front of the boiler. It shows the water-water cooling heat exchangers. In the rear, the boiler support structure underneath the boiler is visible. It was taken in May 1995 right after the combustor was placed on its support stand, and two months after the combustor had been delivered to the site. Figure 6 shows the complete installation. The red pipes are the combustion air-cooling pipes. The combustor water-cooling control structure is in the left foreground under the combustor, while the slag removal belt assembly in the right center. The boiler is the green item in the back.



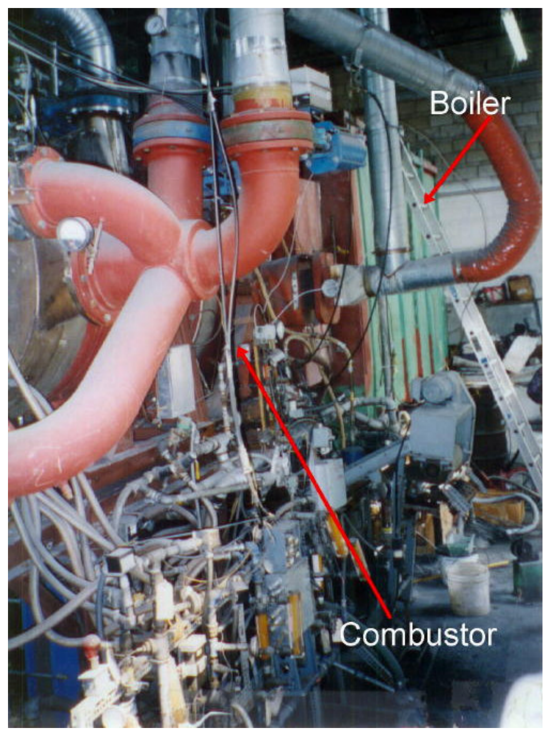


Fig. 5: 20 MMBtu/hr Combustor-Boiler in 1995. **Fig. 6: Combustor-Boiler complete Installation**

<u>Baghouse</u>: The stack gas ducting including the induced draft fan were installed in the alley as shown in figure 2, and connected to the boiler and baghouse. The fan used in Williamsport for the wet particle scrubber was refurbished by replacing the corroded inlet section, and the fan wheel. While the original wheel appeared to be serviceable, it has several corrosion holes at its outer diameter and the wheel was replaced as a safety measure. Since the fan is belt driven, a simple change of the pulley system to the motor allowed modification of the fan for the anticipated conditions of the baghouse operation.

Boiler Startup Permit: Prior to completion of the boiler installation, the Philadelphia Region boiler inspector for the State of PA visited the site to review the compliance status of the boiler. Since it was planned to initially operate in the steam blowoff mode at 15 psig, a State inspection was not required. However, the boiler insurance carrier's inspector was contacted to review the boiler installation. The only issue that noted by the Inspector was the need for a water drain between the two steam valves on top of the drum. This was installed by drilling a small opening in the downstream of the two steam outlet valves. However, while we complied we noted that this was not necessary for operation in the blowoff mode because the condition for which this drain is required, namely to eliminate accumulation of condensate between the valves, cannot occur in blowoff steam mode of operation.

The second boiler installation item is the boiler blow down tank, which was noted above. The State inspector stated that an ASME coded blow down tank was not necessary for operation at low pressure of 15 psig. Quotes for an ASME tank were found to be high. Therefore, a non-ASME certified blow down tank was designed and fabricated by Coal Tech personnel. The cost of the tank was substantially less than a purchased tank. The blow down tank was connected to blow down piping, which was installed at the lower boiler drum. To comply with the City Plumbing and Sanitary Discharge Codes, the boiler blow down water was mixed in the blow down tank with the combustor cooling water to maintain a maximum discharge temperature of 140 F to the sanitary drain. The discharge temperature was always measured with a stem thermometer as well as a thermocouple that continuously recorded this temperature.

Other Installation Items: The Williamsport combustor installation was performed with an outside contractor, and the key Coal Tech personnel only inspected progress at a regular basis. As a result, costs were very high. In addition, there were few opportunities to make improvements in the installation and cost savings. Examples of previous costly practices:

The use of Schedule 40 10 inch pipes for less than 1 psig air. This was totally ludicrous.

The placement of the piping and ducting for air, water, oil, and gas to "encapsulate the combustor.

Consequently, in the Philadelphia installation, Coal Tech's engineers performed the bulk of the work, with assistance from outside contractors, as needed. As a result, very major improvements and large cost savings were implemented during both the installation and operation of the task 5 effort. The improvements listed in this report are only a sampling of the improvements that were made. As a result almost double the planned test work for task 5 was implemented. As stated in this report, we came very close to installing a complete power plant. With only an additional 25% of the total project funds, we could have achieved this goal. This added cost would have been only 25% of the original cost proposal for task 5.

Controls: Most of the combustor operation had been converted to computer control in Williamsport. However, several key components, such as the gas fuel control system, the fan start-shutdown system, the flame safety system, the boiler controls, and several other control elements remained under manual control using relays. The operation of the combustor under those controls was reported in the Task 2 and task 3 test results.

The original plan for task 5 had been to reinstall this system. However, after evaluating all the prior test operations, it became clear that a new approach was needed. During the task 3 testing we acquired a process control program called Genesis. It had features that allowed the programming of a control logic based on operational inputs for operating the combustor. It was used to automate the air-cooling of the combustor and it functioned fairly well. It also allowed the continuous collection of dozens of combustor performance data points from which graphical operational data could be extracted.

The first attempt on improving on this control process was to acquire a newer version of this program, although it was relatively costly. However, here we encountered another example of the: 'If it isn't broke, don't fix it". While our first order was direct to the company, someone at that company decided to 'improve" their sales operation by marketing through d istributors. As a result for some forgotten reason, the new Genesis program did not arrive at Coal Tech until late spring 1995. It also turned out that the entire program logic had been changed so that our software engineer had considerable difficulty in programming it for the modified operating sequence for the new combustor.

As part of the redesign of the control system we had decided to replace the troublesome and unreliable electronic relay system with a programmable control logic (PLC) system. This was a necessity because the key technician who kept the old system operations remained in Williamsport.

Beginning early in the second quarter of 1995, conversion to PLC control was initiated with a part time individual. Unfortunately, this work stopped in early August 1995 due to illness. The backup person who was familiar with the operation of this system in Williamsport was also not available. Therefore, Coal Tech personnel were used to complete this work with input from these individuals. After sending him to a short seminar on PLC, he began the work. The controls for the coal and reagent feed, the fan motors, the flame safety and gas firing, the water the air-flows, pressures, and temperatures were installed on the PLC and the appropriate valves, operators, etc, were installed on the various combustor components.

Here again, two important benefits of using Coal Tech personnel for this purpose were that further improvements were uncovered during the installation, and more importantly, Coal Tech personnel become fully acquainted with all aspects of the control system. This eliminated reliance on outside contractors during the operation of the combustor, which reduced operating costs and reduce down time due to control circuit malfunctions.

Coal Tech personnel connected the control wiring from the various operating modules, namely water, gas, oil, to circuits in the control cabinet. The flame detectors were installed and connected to the control cabinet. An example of savings attained with in house personnel occurred during installation one of the flame detector. A 40 foot long control wire length was specified to connect the detector on the combustor to the control cabinet. The detector supplier charged **18%!** of the original cost of several $1000 of the entire system for this 40 ft wire. The wire supplied with the detector was only 12 ft long and it had been lengthened to 30 feet for use in the Williamsport installation. In the move it had been misplaced, but after a search the wire was found and installed by rerouting from the original routing.

The manual pneumatic controls for the various valves used to control the combustion air were connected for both automatic PLC control and manual control. Pitot tubes were used to measure the pressure and flow in the various combustion air ducts. They were connected to the gauges and pressure transducer used for visual and computer recording and for control.

Note added 2004: The commercial implications of these improvements are noted by the fact that in the since 1998 to March 2004 operation on oil or gas firing requires only one individual could operate the facility. Even with coal firing during task 5 tests only two or three operators were needed. In Williamsport, a total of 7 individuals were used. The cost difference between the two modes of operation is obvious. However, even with 7 operators, on many occasions the relay control system simple failed and only one technician was familiar with its original design and operational idiosyncrasies, and he was not always available during scheduled tests. In contrast in 9 years of operation, the PLC control system has never failed.

By the time the combustor facility was ready for initial testing in the late fall of 1995 the new Genesis program was still not operation due to its complex and new software. Consequently it was never used in the project, and joins Coal Tech's pantheon of overpriced and under-performing software.

g) Shakedown Tests on the new 20 MMBtu/hour Combustor-Boiler Facility

The initial combustor tests began at the end of November 1995 with 6 days of testing.

The first test at the end of November 1995 of the main combustion system was to check the ignition and operation of the propane fuel burner. Ignition of the gas pilot had frequently been a problem in Williamsport. After relocation of one of the two flame detectors repetitive operation of the main gas burners was achieved. The total thermal input was 1.5 MMBtu/hr. Since the combustion air is greatly increased after gas ignition, it was necessary to increase the gas input to 2 MMBtu/hr to prevent flameout. After oil ignition is obtained, the gas heat input is reduced.

The second main combustor test was on December 5, and it focused on the oil burner operation. The newly purchased motor driven, oil pump did not function properly, and after consultation with the supplier, it was determined that the supplier had improperly installed the motor cooling fan so that it scraped against the motor housing. Also, the motor was incorrectly wired resulting in reverse pump rotation. After correcting this, the oil burner was fired at several MMBtu/hr

The next test was on December 7, and various levels of air atomization of the burner were tested to determine from visual flame observation the optimum condition. The test revealed that the low air pressure that was used in Williamsport yielded good atomization. Oil firing continued for five hours with the total heat input ramped up to 6.7 MMBtu/hr using oil and propane. Since the feedwater automatic control was not yet installed, the boiler feedwater was controlled manually. It was noted that positive combustion pressure of several inches water gage in the boiler resulted in water vapor and gas leakage from the combustor and boiler into the room. This was due to the corrosion cracks that had formed along several locations on the outer boiler housing. It was a result of the leaking roof during the final several years of operation in Williamsport. We eliminated the combustion gas leakage by operating the induced draft (ID) stack gas fan to produce a slightly negative pressure in the boiler. This procedure was used in all subsequent tests. This meant that operation was always at high excess air existed in the stack, which made analysis of emission control more complicated.

In view of the need to use the ID stack fan to maintain a negative draft in the boiler, it was necessary to control the stack damper as the thermal input increased. In Williamsport, several attempts to obtain reliable stack damper operation were unsuccessful, and the ID fan was only turned on at high thermal input where the damper was wide open. This procedure was possible since the original, parallel natural draft stack had sufficient capacity to maintain a negative draft in the boiler at part load. This option is not available in the present system, and this means that the ID fan must be used at low thermal input. This in turn requires control of the stack damper. The electro-pneumatic stack damper control was first tested in the December tests. However, the damper rusted stuck after a few months and it could not be removed without removing the stack. This is another example of a poorly designed "commercial" product.

The next combustor test was on December 19. Its main objectives were: to increase the thermal input to 10 MMBtu/hr, to check the automatic boiler feedwater controls, and to check the operation of the stack damper. A combined gas and oil thermal input of over 9 MMBtu/hr was achieved after 3 hours of operation. No problems were noted with the combustion system or the boiler feedwater control. However, the stack damper control tended to stick, which made fine-tuning of the damper impossible. As a result, flameouts occurred as the damper mechanism moved in irregular fashion. It was decided for the next test to perform this function manually by observing the draft in the boiler. As noted, we soon gave up on the damper. *Note March 2004: For our application, a simple slide gate valve would have done the same thing at a very small fraction of the cost of the "fancy" damper".*

Another important result of these tests was in the control of the stack gas temperature. In order to sharply reduce the cost of the stack gas baghouse, low temperature bags were purchased. This required lowering the stack gas temperature upstream of the baghouse. A novel stack gas cooling system was used for this purpose, and it yielded effective control of the stack gas temperature. However, the particular stack gas cooling system was very prone to buildup of ash deposits, which constricted the ducts to the point where frequent cleaning of the duct was necessary. *Note March 2004: By now the duct at that location is totally corroded from operating in the past number of years on No2. oil that has small amounts of sulfur. Therefore the duct will have to be redesigned, a simple procedure, that will correct this problem.*

The final test in this series took place on December 20. This was the first test with coal firing. The thermal input to the combust or was gradually increased over a period of nearly 5 hours to almost 10 MMBtu/hr with gas and oil. One of the bins was loaded with 1/3 ton of pulverized, 0.7% sulfur coal. After cleaning the screw feeder of ice in the discharge tube, coal firing was initiated. The flame detectors shutdown the combustor after a short period,. At the same time, a leak developed in the discharge hose of the combustor cooling water circuit, and it was necessary to stop the test.

This flameout was due to blinding of the flame detectors by injected coal powder. This problem occurred very frequently in Williamsport, and it was corrected by sighting one of the three detectors outside the coal injection area. The present combustor has a redesigned field of view for the detectors, and relocating the detectors generally solved the problem.

The water leak was a result of improper placement of the water pump, which caused excessive tension in a hose. This test also revealed that some modification to the water-cooling circuit was necessary to allow use of a low water cooling flow rate for combustor cooling after shutdown. Due to the high cost of cooling water, a design change is being made to sharply reduce water consumption after shutdown. All these "minor" changes make a su bstantial cost difference due to the very high electricity and water rates in Philadelphia.

In conclusion, six days of testing on the combustion-boiler system have been implemented in a period spanning less than 4 weeks. Five of these tests took place in a two-week period. In addition many brief tests were made of sub-systems such as the slag tap burners, and the boiler feedwater controls. This was accomplished <u>with less than one-half</u> <u>the number of operators</u> used in Williamsport. **Also, in the Williamsport facility, on average only one to two test days were implemented in a one-month period**. The Philadelphia facility and the daily supervision of the combustor installation by Coal Tech personnel greatly simplified the operation of the facility, which allowed much more rapid turnaround between tests.

Additional combustor shakedown tests were implemented on February 12, 13, 14, 16, 19 and 20, 1996. Due to personnel unavailability, no tests were conducted on the 15th, and the 17 & 18th was a weekend. On each day, test operations proceeded for one half day or more. The tests of the 12th through the 14th were with oil and gas, while those of the remaining three days also included coal firing.

One factor in limiting the test duration was the winter weather. A number of hours were required on several days to clear frozen outdoor control lines. On the 16th, the test was shutdown in mid-afternoon due to arrival of a major snowstorm.

In the first few days, difficulties were experienced on gas and oil startup. For example, failure to sustain initial ignition on gas was caused by excessive air fuel ratios during startup resulting from excessive cooling air, pneumatic transport air, or atomizing air. Other factors startup difficulties were due to operating outside the range of automatic shutoff switches. These factors are not inherent operation problems, and they have been eliminated by proper startup procedures.

One major objective in these tests was to develop proper procedures for reducing the stack gas temperature to a level that was compatible with the low temperature bags used in the stack particle baghouse. The results of these tests led to several suggestions, which were implemented and proved successful in the March tests in controlling stack gas temperatures.

In the latter part of the last three test days, coal was injected into the combustor with oil and a small amount of gas. The total heat input was up to 11 MMBtu/hr, or somewhat over 50% of total rated input of the boiler. Due to the larger size of the present combustor compared to the

Williamsport unit, the wall heat transfer rate was substantially lower and no slagging occurred on the combustor walls. However analysis of the ash collected in the baghouse indicated that good combustion efficiency was attained as the unburned carbon was equal to the ash, by weight. The same level of unburned carbon had been consistently attained in Williamsport, with good combustion efficiency. Since the stack gas analysis meters were not connected, no details of the combustion efficiency were obtained. All combustion proceeded with excess air of above 50% above stoichiometric ratio.

Both the water and air-cooling sections in the combustor performed satisfactorily. Only one flameout occurred following oil-fired startup. This occurred as a result of inadequate feedwater flow to the boiler. It was caused by excessive boiler steam pressure, which reduced the water feed rate below that needed to sustain the operating heat input.

The coal feed system performed satisfactorily. Coal fired test duration was limited by fuel supply and by weather.

The key result from this second group of 6 day tests was that they showed that the combustor be brought on line on a daily basis.

Following additional modifications and the purchase of the 25 hp air compressor to replace the costly rented compressor, combustion tests resumed on March 29. Three one-day tests were performed on March 29, April 1 and 2. More extensive coal firing was undertaken. The thermal input rate was increased from the maximum of 10 MMBtu/hr attained in February, to 13 MMBtu/hr. Also the coal feed rate was increased to over 600 lb/hr, or equal to two-thirds of the total heat input. Combustor performance was good. The combustor wall heat transfer rate was substantially below the levels measured in Williamsport for the same thermal input levels.

A very most important result was that excellent slagging was achieved for the first time in the combustor. The entire internal wall of the combustor was covered with a thin layer of slag.

Another important result was that the slag removal system from the combustor operated perfectly. This includes the slag tap burners, the slag tap mechanical breaker, and a newly modified slag conveyor for removing the slag form the slag tank. Each one of these components had previously been a major source of considerable operational difficulties in Williamsport, as reported in Appendix "A". Proper slag removal is one of the key performance requirements of this combustor.

Post-test examination of the furnace section and convective sections of the boiler showed only fine ash deposits on the floor. This contrasted sharply with the substantial coarse ash and char particle deposits observed in Williamsport.

The stack gas sampling and measuring equipment was installed and used in subsequent tests.

Slag samples were removed from the combustor's slag tap and submitted for analysis. Ash from the baghouse was also collected. The operation of the baghouse was excellent and the proper pressure drop across the baghouse was easily maintained.

There were only three flameouts during the three days of coal fired testing. All were due to operator errors. In one case, the flame safety control was turned off by mistake as a result of misreading of the signal from one of the flame detectors. In the second case, the system shut down because the boiler steam pressure rose above the cutoff point during a boiler blow down operation. In the third case, boiler blow down was initiated with the boiler water level near the bottom of its cycle. As a result, the water level dropped below the combustion shutdown cutoff point. These shutdown experiences are positive results in that they show that the boiler and flame safety systems function properly.

These last three coal fired tests showed that the combustor performance was much superior to the best level achieved in the final tests in Williamsport in late 1993, and they confirmed that the redesigned combustor was superior to the one used in Williamsport.

Conclusions from the Shakedown Test Effort: 15 days of combustor tests were been completed between late November 1995 to the beginning of April 1996. These tests were designed to achieve the final goal of coal-fired operation with good slagging in the combustor. The desired slagging condition was first achieved in the April 1 and 2 tests, and the combustor was then ready for regular coal fired operation. An order for 6 tons of pulverized coal was placed for delivery in April 1996 in order to resume coal-fired operation.

The 500 hours of planned tests require 63 days of single shift combustor operation. The 15 days of combustor testing conducted to date thus represent a substantial fraction of the total number of planned tests days. These tests were conducted in a 4-month period. This is double the rate of 24 test days throughout 1993, the last full year in which the facility was operational in Williamsport. The combustor-boiler test facility was fully operational for coal firing. Also, these initial results already indicated that a successful task 5-test effort would be implemented.

Computer Control of the Combustor: As stated above, receipt of the upgraded computer process control system software, Genesis, was delayed due to the company's new method of using a distributor. It was received after coal combustor tests were underway and then it was found that its software logic had changed so much that it took months for our software developer, who had developed the original Genesis program to even begin to adapt it. Accordingly, the original software used in Williamsport was upgraded for the present configuration. It was, however, used only for recording the combustor's operation because the test effort showed that the control logic developed for Williamsport was no longer needed. For example in the critical area of controlling the combustor wall's air-cooling, on which so much effort had been devoted in the Williamsport tests, was replaced with a much simpler procedure that was found to be effective. In addition, the PLC that replaced the Williamsport relay control of the combustor was much simpler and much more reliable. It was, therefore, possible to operate the combustor manually with much less direct operator fine-tuning by computer control, especially the automatic air-cooling system, which was greatly simplified.

Boiler Feedwater Treatment: The boiler was operated in a once-through mode with municipal fresh water at temperatures below 100°F for the entire test program. All the steam produced is blown off. As a result, the boiler is subject to high concentrations of alkalis and oxygen. The former coats the inner boiler tubes and lowers the heat transfer, while the latter corrodes the inner water wall of the boiler. It is, therefore, necessary to inject high concentrations of chemicals to remove and dissolve these compounds. A batch of four chemicals mixtures was used to treat the boiler feedwater. Initially a commercial chemical metering pump and storage system were procured and integrated with the feedwater supply train with the objective of continuously injecting chemicals. Problems were soon encountered because one of the chemicals turned into sludge after several days of storage, which could not be pumped. The sludge was dissolved by adding water and by re-piping the chemical feed to accommodate a added higher feed-rate. Regular boiler blow down and analysis of the boiler water chemistry showed that it was difficult to maintain the water chemistry within desirable limits. After much trial and error work over a period of months, the "commercial" chemical metering pump was removed and a cheap, novel "homemade" system was designed that performed reasonably well.

Pulverized Coal Loading. The initial tests on the new combustor, described above, were implemented with purchased in 50 lb bags that were pneumatically blown from ground level into the top of the 4 ton powdered coal bin (See figure 1). Once the above shakedown tests were complete, a forklift truck was purchased, and the coal was purchased in 1-ton supersacks, which were placed onto the pneumatic filling cone that was piped to the 4-ton bin. The fill rate was 1 to 1.5 tons per hour, which was sufficient to operate the combustor continuously at its rated capacity. The original plan to use a gantry crane to lift the supersacks to the top of the 4-ton bin was abandoned because the forklift involved about the same cost and it has multiple uses. 37 tons of pulverized coal was purchased for use in the initial test series.

Slag Tap Heating System and Mechanical Slag Breaker. Slag tap operation was an area that required considerable attention in the task 5 tests. The slag tap heating system was one area that required an inordinate amount of development time, especially the commercially purchased gas heating control system. The control and the arrangement of the heaters underwent considerable modifications in the course of the task 5 test effort. Fortunately, the much improved combustor design allowed modifications to be implemented in a matter of a few hours, as opposed to multi-days required in Williamsport. One major problem area was maintaining its flame safety system and in preventing slag blockage of the heaters. A whole series of heater arrangements were tested.

Another problem was the poor quality welding of the water-cooled chamber that enclosed the slag tap. This developed water leaks on numerous occasions, each of which required removal of the slag tap chamber, and re-welding. While its removal and replacement was implemented in a matter of hours, sending the chamber to the original fabricator was very time consuming. In contrast, the previous water-cooled section that was fabricated by a professional large shop never developed any leaks in 7 years of operation in Williamsport.

(Note added in 2003: This is one of the "benefits" of exporting manufacturing jobs overseas. The fabricator of the first combustor was shut down by the parent company a large process equipment manufacturer. This and other similar actions over the past two decades

have drastically shrunk the pool of qualified fabrication and machine shops. In the combustor development effort that began in mid-1980's we continuously encountered this problem. Its implications for the U.S. economy is that the small fab shops that are needed to develop new products are hard to find, which of course adversely affects the creation of new blue collar jobs. Now one can of course manufacture prototypes overseas, but that balloons the R&D development time as well as the cost, and very few technologies companies have the commitment or the ability to hang in there over many years until a R&D project matures and comes to market. That may explain why so few coal based energy systems have entered the market place. The ones that were developed were implemented by large companies, which translated in high and non-competitive costs with natural gas and oil power plants.

Note March 2004: Adding to the above is that manufacturing 'bu tsourcing"overseas. Interestingly, despite the avalanche of Democratic Primary campaign rhetoric in 2004, this point of the importance of manufacturing capability in creating new industries and jobs was toi the best of this author's knowledge never mentioned.

And of course the financial fiasco created by relying on scarce and costly natural gas as the fuel for new power plants continues.

After continuous trials with this water cooled chamber including just letting it leak, we finally shifted to a novel air-cooled design which performed satisfactorily for the balance of the project.

h) Results of the First Series of Task 5 Coal Fired Tests – 2nd Quarter of 1996 :

After the first coal-fired shakedown in the first quarter of 1996, 16 coal fired tests were performed in the second quarter. 6 tests days in April, 5 test days in May, including one for the parallel sulfur-slag project, and 5 days in June, including one day for the sulfur-slag project. This brought the total number of test days in task 5 to 28, compared to the maximum planned 63 test days.

April 1996 Tests:

The results of the first two coal fired tests in April were reported above.

The next test on April 18th consisted of coal fired operation for a total of 8 hours, including oil and gas heatup and cooldown. Heat input reached 13.5 MMBtu/hr, of which about 77% was coal, equal to 825lb/hr per hour input. [Note: Calibration of the coal feeder was originally performed for short periods of 1 to 2 minutes. In July, additional calibrations were performed which showed that variations in the feed rate results from changes in the amount of coal in the bin immediately above the coal feeder. As a result the average feed rate is reduced over longer time intervals by 10% to 15% depending on the absolute feed rate. The present data are corrected for this.]

Slagging operation was excellent with over 90% of the slag (equal to 225 lbs) collected through the slag tap, and only 17 lbs flowing out of the exit nozzle into the boiler inlet. Since part of the slag contained combustor liner material, the coal ash and injected limestone retained in the combustor is less than 90%. Nevertheless, this result is excellent when compared with almost a 50-50 distribution of slag flowing through the slag tap and into the boiler in the prior Williamsport tests.

This slag result is one of the important results of task 5 in that it shows that the combustor modifications deduced from the analytical and experimental work of the previous tasks was successful.

Also, note that 16 to 17 MMBtu/hr is at the upper end of the range where most of the Williamsport tests were performed. The combustor briefly reached a thermal input of 16.8 MMBtu/hr on April 18^{th}.

The combustor air-cooling performance was good. This was accomplished with less than 50% of the cooling fan power than had been used in Williamsport. Stack gas temperature control was within the range appropriate for the low temperature baghouse. For the first time, stack gas results for O_2, CO, and NO were obtained. However, since calibration gases were not yet received at the time this data could not be analyzed quantitatively.

Another important result was that coal fired operation with slagging conditions could be achieved at much lower initial oil fired heatup of the combustor. In Williamsport, this had occurred when the oil heat input reached over 60% of rated boiler heat input. In the present combustor, coal firing with slagging was achieved at less than 40% of rated heat input.

The test on the 24th was a repeat of conditions used on the 18th. This test provided proof of a long held assumption, namely that good slag tap operation requires a certain minimum coal, i.e. coal ash throughput in the combustor.

During operation of the water-cooled mechanical slag tap breaker lance, a power failure on the electric circuit used to operate the slag breaker occurred while the breaker was in the combustor. A small piece of steel on the breaker shell broke and the cooling water flooded the combustor, necessitating a shutdown. In three years of operation in Williamsport, the breaker had become stuck inside the combustor on many occasions. However, the outer shell had never before cracked. The steel was submitted to an outside laboratory for chemical and crystal structural analysis. The results showed that the small section that failed, about 1" x 2" in size, had recrystalized into fine elongated crystals. It has also absorbed sulfur and carbon from the coal. However, the latter were statistically no different in concentration from other sound sections of the steel. It was tentatively concluded that a defect developed in the steel from unknown causes, either during our operation or during manufacture.

The next day, the combustor was internally inspected and no water damage was observed. A gradual heatup on propane was conducted for part of the day, and the combustor was dried. This was another more important result in that it showed the combustor floor could survive major water flow during operation without damage to the refractory. In Williamsport, the combustor had been operated for extensive periods of time with a water leak in one of the cooling circuits. However, in that previous situation the water leak was never at the level where it could flood the combustor floor during high temperature operation. This result is also another example of the advantage of air-cooling because in a water cooled unit, a cooling tube failure would require complete refurbishment of the combustor.

On April 29th, another coal fired test was performed, and coal fired operation was conducted at 14 MMBtu/hr, with 75% on coal. In this test, the coal-firing ramp up was introduced much more rapidly than in the previous test, and excellent slagging operation was immediately achieved. This procedure was adopted in order to reduce the frequency of slag breaker operation during conversion from oil to coal firing. Stack gas sampling was performed for O_2, CO, NO_x, and SO_2. As noted, the calibration gases were not yet received.

515 lb. of slag were removed through the slag tap, compared with only 35 lbs through the exit nozzle into the boiler. This continued the excellent slagging and slag retention observed in the previous tests. Retention was at least 75%. Figure 7 is a summary of the slag retention results, and it will be discussed after all the tests are discussed individually.

An extremely important result was that the only ash deposited on the floor of the boiler was very fine, with no evidence of unburned char, as was always present in Williamsport.

<u>May 1996 Tests.</u>

A total of four days of coal fired combustion tests were performed on May 1, 15, 17, and 30. In addition, on May 21, the first test in the concurrent project on sulfur retention in slag was performed. In all tests, excellent combustion and slagging conditions were achieved, and the performance continued to be far superior to that achieved in the prior operation in Williamsport. These tests were the first ones in which stack gas sampling compared to calibrated sample gases were obtained. It was also the first tests in which calcium hydrate, which has superior SO_2 capture capabilities, was injected into the combustor.

In the first coal-fired test on May 1st, after a short period of coal-fired operation, combustion gases began to escape from cracks in 30 year old-boiler. This did not usually occur because the boiler was operated under negative draft. Almost simultaneously, the belt on the slag conveyor broke and the slag tank overheated. The test was therefore terminated.

Post-test observation revealed that fly ash had deposited in an elbow duct inlet to the baghouse, which increased the pressure drop and resulted in positive draft in the boiler. This deposition was caused in part because no provision had been made to remove accumulated fly ash from the bottom of the baghouse. We had not anticipated such excellent combustor performance and had not yet addressed this matter. The baghouse supplier offered two solutions by providing drain valves that can remove ash. However, we designed a simple system that costs about 5% to 10% of the cost of the drain valves, and it was installed.

The problem with the slag tank developed as a result of the excellent slagging of the combustor. The quenched slag heated the slag tank water. Slag was sucked into the hoses leading to the water-water heat exchanger and resulted in their blockage. This result was unexpected because a commercial device for removing solids from water had been in use since the last year of testing in Williamsport. In Williamsport, only once-through cooling was used, and slag tank overheating was not a problem. Various alternate means of operating this slag tank re-circulation system were explored. In the end, the slag grit removal circuit was separated from the slag tank cooling water circuit, and after several trials in subsequent tests, the cooling circuit has performed satisfactorily. A design and operating procedure was also developed for operating the water-grit separation system in order to remove slag grit that deposited outside the conveyor belt. However, due to the press of other activities, this redesigned system was not used. Instead accumulated slag grit was periodically removed from the bottom of the slag tank after several test days. This was not viewed as a high priority item, as a number of solutions can be used to remove this grit. It generally represents only a small fraction of the total slag removed from the slag tank.

Analysis of the slag removed from the combustor and ash removed from the baghouse showed that the combustor refractory liner had been operated at very high temperature, which resulted in some refractory loss, some of which was replaced by slag.

The baghouse ash in this test had less than 1% unburned carbon, which compares to about 50% carbon observed in Williamsport. This shows that the combustion efficiency was over 99%. In the earlier April tests, unburned carbon was up to 50% in the baghouse ash.

One problem with the baghouse use is that real time ash samples are very difficult to obtain. In several of the tests, real time samples were collected. However, this collection interfered with stack gas operation. In Williamsport, a wet particle scrubber was used and real time sampling of the scrubber water was no problem.

Another extremely important result was the observation that by adjusting the stack induced draft essentially all the fine ash accumulated on the floor of the boiler could be removed and blown into the stack baghouse. Also, compressed air was used for soot blowing in the boiler. This is very important in that it eliminated the need for ash removal in the boiler. Provision had been made for removing fly ash from the floor of the boiler in light of the experience with heavy ash and char carryover to the boiler floor. However in the task 5 tests this ash removal was not necessary.

All the May tests were implemented at an average of 825 lb/hr of coal, which equaled 10.4 MMBtu/hr, plus additional oil and gas to reach an average of 14 to 15 MMBtu/hr. The combustor continued to perform well in all the tests. A number of problems were encountered in some of the auxiliary components, some of which required early termination of some of the all-day tests. The following summarizes the major results:

(1) While stack gas sampling had been taken in the April tests, extensive delays in delivery of calibration gases prevented achieving accurate stack gas samples until the May 15 test. This test revealed that the sulfur concentration in the coal was higher than the value supplied by the coal company and obtained in initial coal analysis. The SO_2 level was over 1.5 times the maximum expected on the basis of the coal sulfur. Consequently real time coal samples were taken to analyze its content, and they revealed that the coal sulfur was about 2.75%, not 1.2% as in the first coal delivered.

(2) To condition the slag, all operating conditions were implemented with limestone injection in the combustor. Prior test results in Williamsport showed that there appeared to be little reduction in SO_2 with limestone injection.

(3) Calcium hydrate is a much better sulfur capture reagent. The May 30 test was the first one with hydrate injection into the combustor. The results were inconclusive. Only very short duration operating periods were possible with hydrate because it appeared to adversely affected the slagging properties of the coal. The was due to the very fine particle size of the lime (i.e. calcium hydrate) and most of it blew out of the combustor, and did not report tot the slag. However, very careful observation of the combustor's internal slag coating has revealed that the slagging problem may have been due to poor coal-reagent mixing. With the hydrate injection into the combustor, about 20% reduction in SO_2 was measured at the stack outlet from the boiler, and over 40% reduction as measured at the baghouse outlet. However, these results were obtained under poor slagging conditions.

(4) In the May tests, continued removal of over 95% of the slag though the slag tap inside the combustor was measured, and the slag carryover into the boiler remained negligible. Also, the ash deposits in the boiler were very small and easily removed by the induced draft stack fan. This is a very important result. It was not achieved in the Williamsport installation, and its present achievement augers well for future commercial use of this technology.

(5) Even without computer control, it was possible to stabilize the combustor wall heat transfer, and the wall heat transfer rates were substantially lower than in the earlier combustor.

(6) The PLC control of the combustor proved to be far superior to the previous relay control system. Its major benefit has been the ability to rapidly troubleshoot the system. For example, the coal feed system shut down in one test. Diagnosis of the PLC system showed within seconds that we had inadvertently turned off an air-flow in the oil flow circuit which was tied into the coal control circuit. With the relay system, it would have taken much longer to find this cause.

The May 25th test was on the concurrent sulfur-in-slag project and the results are reported in the Final Report on that project.

June 1996 Tests.

A total of five days of coal fired combustion tests were performed in June, namely June 6th, 11th, 24th, 25th, and 28th. The last test was the second test in the concurrent project on sulfur retention in slag. The focus of these tests was on improving the performance of the combustor, especially in the area of slagging operation and slag removal from the combustor. Continued good combustion and slagging conditions were achieved, and considerable test data on slag properties and stack gas sampling was obtained.

A major thrust of the month's work w as to improve the reliability and ease of operation of the slag tap in the combustor. The slag is removed from the downstream end of the combustor through a tap on the combustor floor (see figure 2 & 3). This tap is maintained open by a combination of localized heating and mechanical action on the opening. A major change was accomplished in the past month by the introduction of a much simpler device for mechanically clearing the slag tap of frozen slag. In addition, work continued on improving the local slag tap heaters. The test results in this month showed that operating conditions were more important in achieving good slag removal than the thermal/mechanical operation of the slag tap. Slag tap blockage by frozen slag occurred almost exclusively during shutdown operation. Consequently, the shut down procedure was modified in order to eliminate this problem. Improvements in slag tap operation continued throughout the test effort.

A second major result was achieved in the last test on the 28th. All tests prior to date were performed with manual operation of the combustor. As a result, variations in wall temperatures occurred during the tests. This in turn resulted in a cumulative loss of some wall liner refractory. This loss was evidenced by measurement of the inner wall diameter after each test, and by chemical analysis of the slag, which showed elevated concentrations of liner materials. In Williamsport, a procedure was developed for injecting fly ash to reline the combustor walls. In the June 28th test, it was possible to accomplish this same result by controlling the rate of reagent injection and wall cooling. Post-test internal measurements showed that a substantial fraction of the wall refractory liner was re-deposited in a matter of hours on the combustor wall. Furthermore, it was possible to maintain fairly constant wall temperatures with a minimum of changes in the air-cooling rate. In connection with this it should be noted, that the present combustor, which is larger than the Williamsport unit, is being cooled <u>with one half the fan horsepower</u> used in Williamsport.

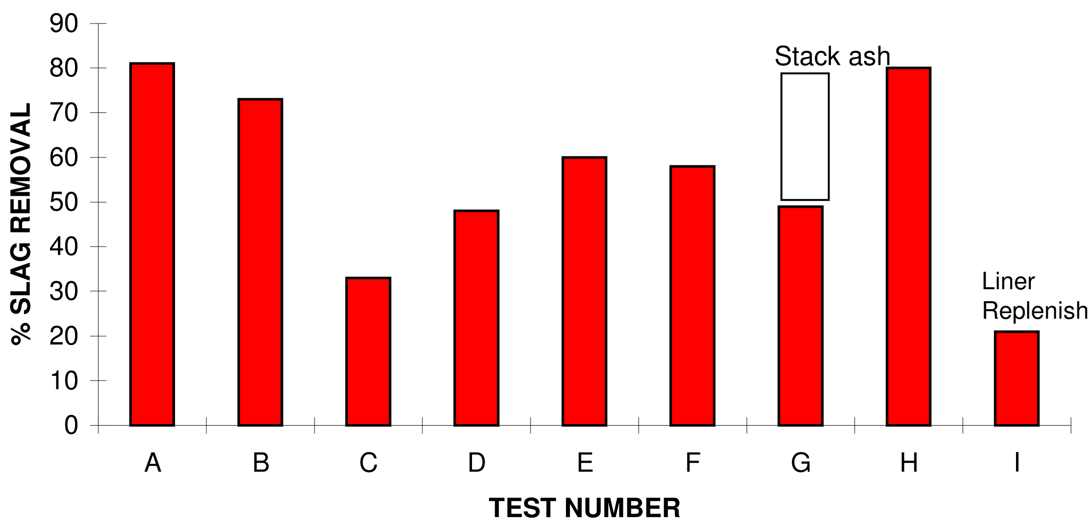
Another very important result in the later tests was that a substantial fraction of the coal sulfur was captured in the slag. In Williamsport, the highest sulfur concentration in the slag from the coal ash was about 10%. In recent tests, concentrations in the high teens to approaching 20% of the coal sulfur were been measured in the slag.

<u>Summary of Slag Retention, SO2, NOx Reduction, and Sulfur in Slag to mid 1996..</u>

The tests in this quarter were the first ones in which slagging operation was implemented in all the tests. Some variation in combustor performance occurred, and as a result only quasi-quantitative overall performance can be given. The following charts show these results in graphical form.

Figure 7 shows the slag removed through the slag tap as a percentage of the coal ash and

Fig. 7: % OF COAL ASH + CaO REMOVED AS SLAG FROM COMBUSTOR TAP
Est.Ave. Retention- 65 to 75%



calcium oxide injected into the combustor. This data applies to 9 of the 16 tests conducted in this period. These slag data also include liner material that was removed from the combustor wall. The liner material in the slag is determined from slag sampling chemical analysis. Note that in some tests the slag removed through the tap is low. However, in these tests much of the missing slag is replenished on the combustor wall, as was determined by post-test measurements of the inner combustor dimensions. In figure 7, test number 'G" shows the amount of fly ash collected in the baghouse in addition to the slag removed. The total is less than 100%. Some of the missing mineral matter is deposited on the liner of the combustor, as fly ash on the boiler floor, and in calibration errors in the amounts injected. For example, it was noted recently that an 8% to 15% overestimate of the coal feed rate was detected in the coal feeder calibration. The data in figure 7 are based on the original coal feed rate calibration. Therefore, the slag retention is actually about 10% higher. [It is not 15% higher because the coal ash is only a majority, not 100% of the injected minerals.] Therefore, the estimated average mineral matter retention in the combustor is between 65% and 75%. Once the combustor operation is fully optimized this number will increase.

The really important result from figure 7 is obtained by comparing it with figure 8. This figure 8 shows the slag retention in this combustor's previous design as used in Williamsport. The latter data was obtained in 1993 when the original combustor had been optimized for this project's task 3 tests.. Note that while slag retention also averaged 65% to 70%, over 50% of this slag flowed into the boiler out of the combustor exit nozzle. Only an average of 20% was removed through the slag tap. This compares with the results in figure 7, and it **is the key result and advantage of the present combustor**.

As noted in all tests, limestone was injected with the coal for slag conditioning. For a number of operational reasons, only limited tests on calcium hydrate injection in the combustor were performed in the in the 2nd quarter of 1996. Limestone injection is not as effective for SO_2 reduction, as has been reported on many occasions during the Williamsport tests. Due to an error by our coal supplier, the bulk of this quarter's tests were performed with 2.75% sulfur coal, instead of the 1.2% sulfur coal used in the very first tests at the beginning of the year.

Figure 8: Slag Retention in Combustor-1993 Tests

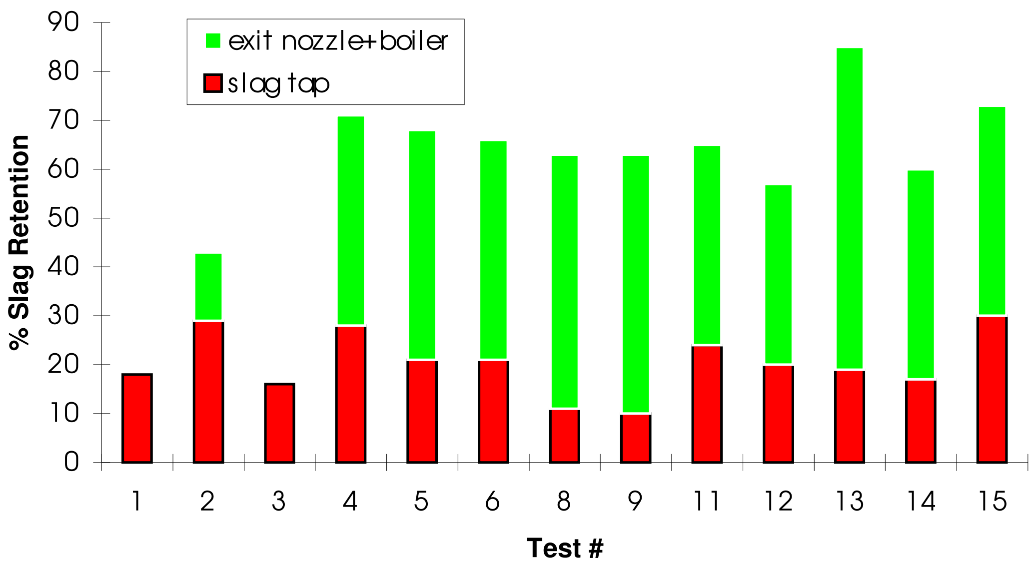


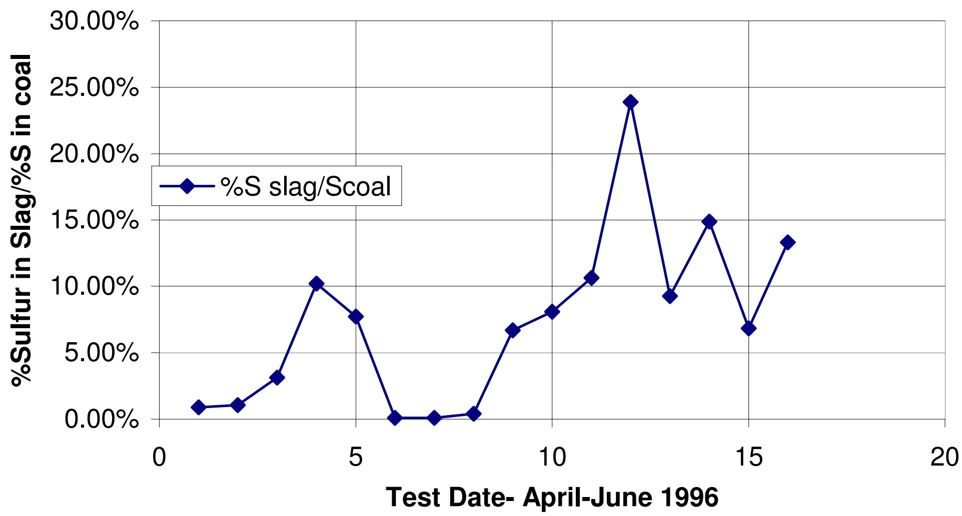
Figure 9 shows the percentage of the sulfur in the slag as a percentage of the total sulfur in the coal. Again these figures should be increased by 8% to 15% due to the correction in the coal feeder rate measured in July 1996. Note that this graph does not show the absolute amount of the total sulfur in the coal that reports to the slag, it only shows the ratio of sulfur in the slag to the ratio of sulfur in the coal. To estimate the ratio of the total sulfur that reports to the slag, these data need to be reduced by at least 25% because only 3/4 on average of the coal ash is retained in the combustor slag. In any case, the data show that as much as 20% of the <u>total</u> coal sulfur is retained in the slag in one of the tests. This is twice as high as the maximum of 10% ever measured in the Williamsport tests, which was also the maximum reported elsewhere to the best of the author's knowledge.

Similarly, figure 10 shows the percentage of sulfur in the baghouse fly ash as a percentage of the total ash in the coal. Here it is assumed that all the ash reports to the stack. In fact only about 1/4 to 1/3 of the coal ash reports to the stack. This indicates that a maximum of 10% of the total coal sulfur reported to the baghouse ash.

Figure 11 shows the percent SO_2 reduction in the combustor for the May/June 1996 tests with limestone injection. Also shown are two tests with lime (calcium hydrate) injection into the **boiler**. Note that these data were taken with a pulsed fluorescence instrument, which according to the manufacturer requires a correction factor which depends on the concentration of O_2, CO_2, CO, and the nature of the calibration gas. In the results reported for the Williamsport combustor tests the correction factor, which generally amounts to 1.35 to 1.38, increased the measured SO_2

data when the calibration gas was 500 ppm SO_2 in nitrogen, as opposed to air. If the calibration gas is air, the correction factor for combustion gases is only 1.15 to somewhat less than 1.2. Since these issues are not clear at this time, the data obtained in the present combustor is reported as measured by the instrument. Recalibration of the instrument with SO_2 in air will be

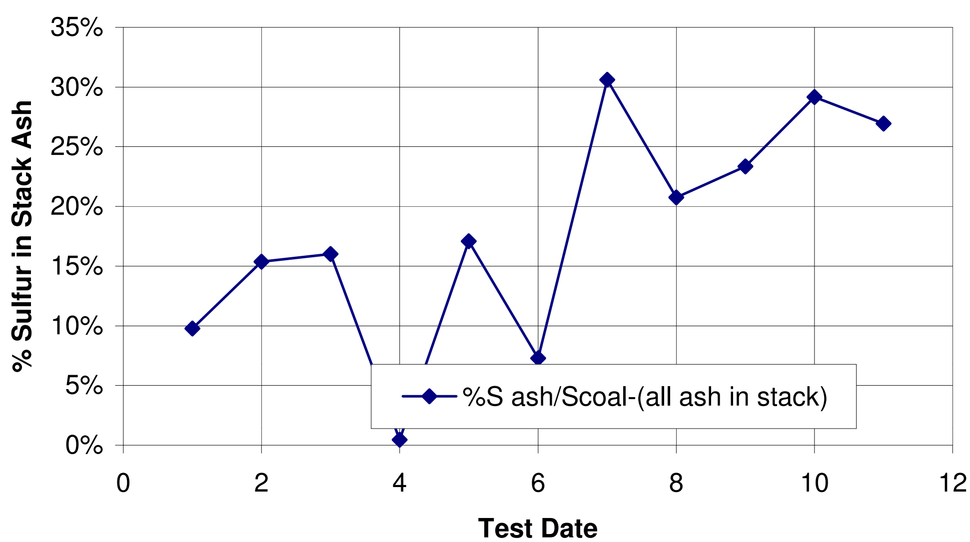
Fig. 9 S in Slag/ S in Coal vs Test Date (w/o Liner Loss)



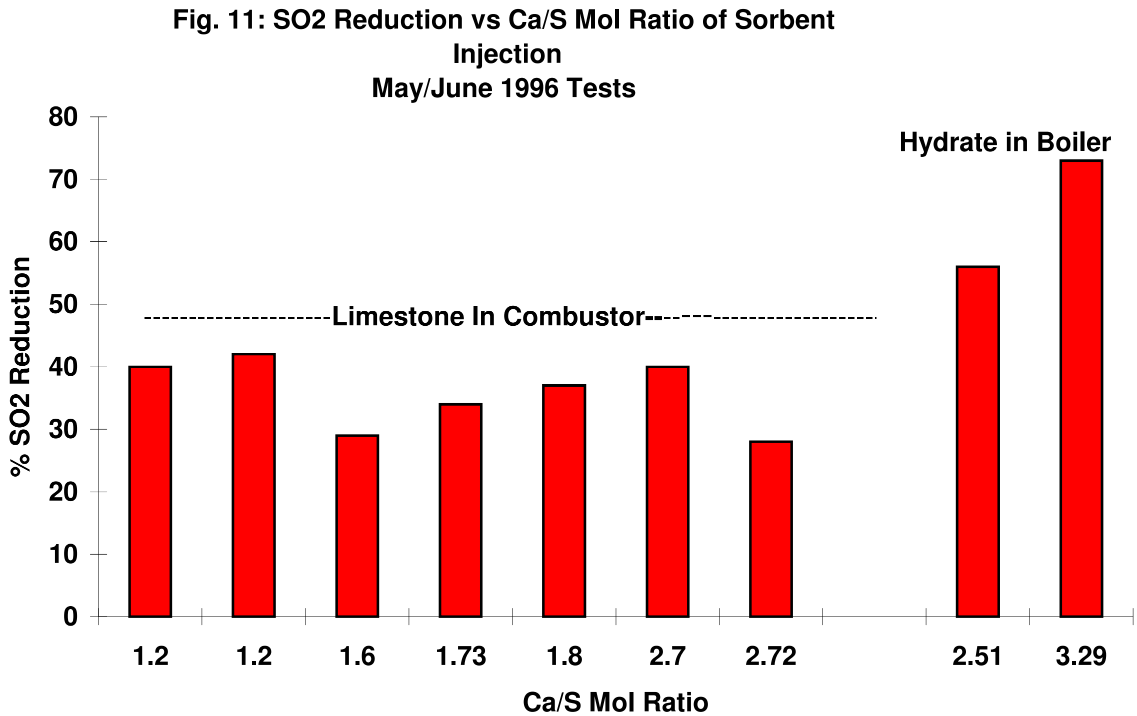
performed to clarify this matter.

In any case, the data in figure 11 shows that substantial SO_2 reductions were obtained with limestone, which based on prior tests in Williamsport, is about 1/3 as effective as calcium hydrate. On the other hand, the calcium hydrate injection in the boiler is very effective. This test was performed to determine if the stringent SO_2 standards for Philadelphia, namely 0.5

Fig. 10: % Sulfur in Stack Ash/% S in Coal vs Test Date



lb/MMBtu could be met with injection into the boiler when using a high sulfur coal. The uncorrected 70% SO_2 reduction in the 2.75% sulfur coal to about 0.6 lb/MMBtu appears to be within the range necessary. However, note that the main objective of these tests was reliable combustor operation. Therefore, no attempt at optimizing emission performance was made, especially since these tests were still classified as shakedown. If the standard could not be met with this coal, then the option remained to return to the 1.2% sulfur coal, where only 72% SO_2 reduction is needed to meet the standard.



The corresponding NO_x emission levels were 0.46 lb/MMBtu. This compares with the very stringent Philadelphia standard of 0.3 lb/MMBtu. Again note that these tests at not optimized with respect to stack emissions

The 28 days of combustor testing conducted to the end of June thus represented a substantial fraction of the total number of 63 planned tests days. They were conducted in a 7-month period. This compares with a total of 24 test days throughout 1993, the last full year in which the facility was operational in Williamsport.

i) Results of the Task 5 Tests in the 3rd Quarter of 1996

The effort in the 3rd quarter of 1996 was devoted to improving the operation of the auxiliary components. In addition major progress was made in using the combustor's operating conditions to maintain the durability of the combustor's inner refractory liner and in improving the reliability of the operation of the slag tap.

A total of 13 days of combustor operation were performed in this quarter, of which three test days were under a parallel project on sulfur control during combustion. The latter results are reported in that project's progress report. This brought the total number of test days by 9/30/1996 to 41, or 65% of the 63 days planned for task 5..

The tests in this quarter resulted in about the same level of slag retention and NO_x reduction as were observed for the tests in the second quarter. The lowest NO_x measured at the stack in the 3rd quarter was 0.41 lb/MMBtu, (reported as NO_2). No correlation of the NO_x data to combustor stoichiometry was made for the results to-date. However, based on the absolute magnitude measured, it appears to be similar to previously reported results in the Williamsport installation.

Slag retention was in the same range as observed in the previous quarter, namely, about 2/3 of the mineral matter was retained as slag in the combustor. Of this amount about 95% was retained in the combustor as slag wall replenishment or drained through the slag tap. A minor amount ranging from 0% to about 5% flows out of the exit nozzle to a combustor-boiler interface section from which it can be readily removed during combustor operation.

Ash deposits in the boiler continued to be modest and did not require real time removal from the boiler floor. The bulk of the mineral matter was collected as fly ash in the baghouse.

SO_2 Reduction in the Combustor: Figure 11 (above) shows the SO_2 reduction measured at the boiler outlet as a function of Ca/S for reagent injection into the combustor or furnace section of the boiler. This figure shows the actual instrument reading without any correction factor. It was noted above that there we subsequently clarified the proper correction factor to be used for the pulsed fluorescence SO_2 instrument. According to the manufacturer, if a calibration gas containing SO_2 (500 ppm in our case) in a nitrogen atmosphere is used, the actual instrument reading must be increased by a factor of 1.35 to 1.38. Late in the present quarter, using dry air in place of nitrogen it was determined that the calibration factor for nitrogen was 1.25 not the values given above. **Thus the SO_2 reduction data in figure 11 must be reduced by 20%.** This does not change the general conclusion regarding the effectiveness of different reduction reagents or methods.

The best method for determining SO_2 reduction is to compare operation with and without reagent injection. However, as some of the reagent is used for slag conditioning, there is always some SO_2 reduction at very low reagent injection rates. Therefore, in the 3rd quarter, the emphasis was placed on determining the general relationship between reagent injection location and SO_2 reduction. Specifically, several different locations of reagent injection were tested. The major differences between tests were injection location and quantity and type of reagent. As reported many times previously, **calcium hydrate is about three times more effective than limestone in sulfur capture**, and the former was used exclusively for SO_2 control. Specifically, three injection locations were used. One was to mix the reagent with the coal, the other was to inject the reagent independently near the coal injection location, and the third one was direct injection into the furnace section of the boiler.

The furnace injection yielded the best reduction in the tests of this period. Injection of calcium hydrate into the boiler at a Ca/S mol ratio of 3.7 yielded a 72% reduction in high, 3.6% sulfur coal as measured at the stack downstream of the baghouse. At a Ca/S ratio of 4.85, the reduction was 64% at the boiler outlet to the stack and 75% downstream of the baghouse. This reduction is in the same range as was measured with boiler injection of calcium hydrate in the Williamsport facility, where 81% reduction was measured at the boiler outlet with a Ca/S of about 4.

This result shows some modest improvement in the sulfur capture is obtained due to humidification upstream of the baghouse. However, this is almost insignificant compared to the reduction achieved in the combustor and/or boiler. Note that the high Ca/S ratio is not indicative of the calcium utilization because injection was only at one point to the side of the combustion gas inlet to the furnace. A post-test inspection revealed that a substantial quantity of the hydrate was deposited on the floor of the furnace section of the boiler. It is probable that much of this hydrate did not react with the combustion gases. In view of this high deposition rate in the boiler, it was decided defer further work on this approach and focus on combustor injection of the reagent. This latter approach has the added benefit that the reacted reagent can be dissolved in the slag.

A series of tests were performed with injection of calcium hydrate into the combustor. Here the injector's internal diameters restricted the quantity of reagent that could be injected. Consequently a series of modifications were made to allow greater rates of injection. This was especially the case when the reagent was mixed with the coal and pneumatically injected. Here the quantity of reagent was limited to a Ca/S mol ratio of less than 3 in the high sulfur coal. Subsequent work corrected this problem and higher levels of lime were injected with improved sulfur capture. This work is reported in the 4th quarter 1996 sub-section. The tests in the present reporting period (3rd Q 1996) with combustor injection yielded SO_2 reductions at the boiler outlet of up to 50% at Ca/S mol ratios of less than 3.

<u>*Conclusions*</u>: The results of the test effort in the third quarter of 1996 confirmed the conclusion from the initial tests in the previous two quarters, that this second generation combustor's performance was very much superior to the previous first g eneration 20 MMBtu/hr combustor that was tested in Williamsport. This second-generation combustor-boiler system has all the key features that would be incorporated in a commercial system. The test effort also resulted in substantial progress on the auxiliary components and sub-systems of this technology. A most encouraging result was that the combustor-boiler system could be rapidly started and shut down in single shift operation with no need for any internal maintenance between tests. The only factor limiting continuous operation were funds for hiring the added personnel and resources for the needed additional consumable storage. There was no evidence that the combustor could not be operated continuously.

j) Results of the Task 5 Tests in the 4th Quarter of 1996

The bulk of the effort in the 4th quarter of 1996 on focused on a parallel DOE project on sulfur capture and retention in the slag of the combustor. A total of 15 days of combustor operation were performed in this quarter, of which 10 test days were under the parallel sulfur project, and the results are reported in that project's Final Report. This brought the total number of test days to 57 by 12/31/1996, counting the tests on the other project because they also contributed to the evaluation of the combustor performance. In the end, it made no difference because the total number of tests implemented were double the number of 63 planned for task 5.

The 10 tests on the other project focused on high slag flow conditions, which are necessary for substantial sulfur retention in slag. The results contributed to the present project because high slag flow occurs in high ash coals of which extensive domestic supplies are almost exclusively used in a number of other countries, such as India, China, Indonesia, and Pakistan.

Note March 2004: As is discussed later in this Appendix in connection with the high ash Indian coal tests, the tests with high ash coal and high ash injection may very well be the biggest contribution of this combustor to clean coal combustion. The combustor is almost certainly the lowest cost method of eliminating a huge 2000+ mile wide, 2 mile thick pollution cloud over the Indian Ocean that is most likely due to inefficient combustion of high ash coal in nearby Asian countries. Also, high ash coal firing in the air-cooled combustor can encapsulate volatile trace metals, including mercury, emitted during coal combustion at costs that are at least 100 times lower than any other process under current development.

The 5 tests conducted in the 4th quarter on the present project focused on several areas. One was to further improve the reliability of the slag tap, a major effort in these tests. The other objective was to determine the processes by which slag deposits in the exit nozzle of the combustor could be removed. Another was to operate the combustor under identical conditions in consecutive tests in order to evaluate the durability of the combustor internals. Finally, attention was directed toward further reducing the SO_2 and NO_x emissions in the combustor.

<u>Slag Tap and Combustor Exit Nozzle Performance:</u> Maintaining an open slag tap inside the combustor is obviously critical to its operation, and this was one of the development items in this project. The tests on the parallel project involved injection of calcium hydrate, limestone, and an "artificial" ash consisting of a mixture of alumina and silica powder mixed with either calcium sulfate or calcium hydrate powder. Considerably difficulties were experienced during the injection of these minerals in satisfying the conflicting requirements of high slag temperatures for draining the slag from the combustor and preventing frozen slag from blocking the exit nozzle versus the need to keep the combustor's refractory liner cool enough to prevent significant refractory loss. Details are reported in the other project's Final Report.

To improve the slag tap operation, the thermal heat input to the slag tap was increased and this greatly improved the reliability of the slag tap operation in all the tests in this quarter.

To address the exit nozzle blockage, which was a result of high ash injection, the test on November 15th involved metal oxide powder injection into the combustor to simulate high slag flow rates. The injection of this material exacerbated the problem of exit nozzle blockage with frozen slag deposits. The latter blocked most of the nozzle to the point that combustion gases escaped from the combustor into the slag tank. A mechanical breaker, developed and used in the Williamsport combustor, was used to clear the exit nozzle during combustor operation during this test. It was assumed that the coal used had a high ash melting point. However, subsequent analysis of the ash revealed that the ash composition did not differ substantially from the other coals used in the test effort.

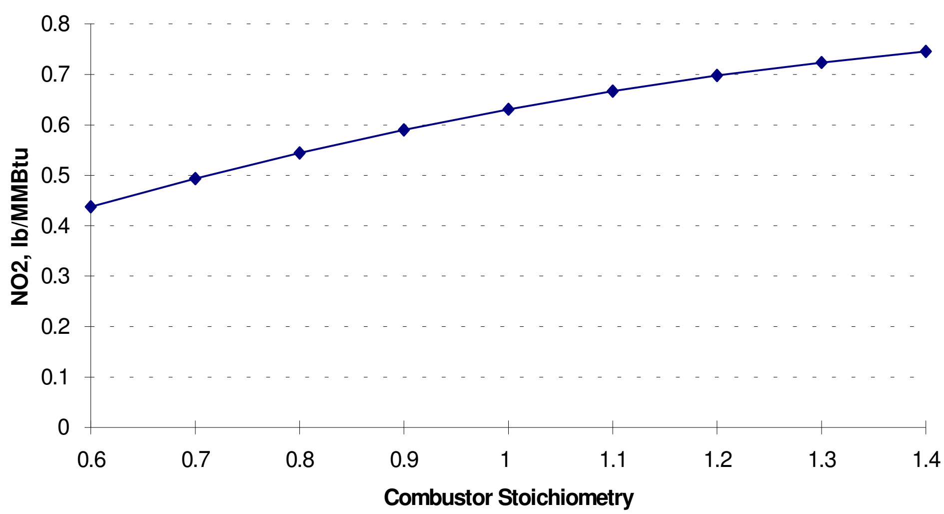
To further explore the exit nozzle blockage three tests were performed on December 10th, 12th, and 17th. The results indicated that the exit nozzle blockage was partly a function of the thermal input to the combustor, and by increasing the thermal input it was possible to re-melt frozen slag in the exit nozzle.

The operational aspects of the tests are cited to emphasize the importance of developing the "software" of the combustor , namely its operating performance, which is more important than the "hardware", the combustor design. This report only highlights this "software", which took years of testing on the 20 MMBtu/hr-combustor to develop.

Another objective of these tests was to operate the combustor regularly at one set of conditions. This would provide a database on repeatability of the combustor's performance characteristics. Accordingly, the tests in this quarter were performed with only coal injection and limestone injection into the combustor. Calcium hydrate was injected only for brief periods. The combustor's performance was excellent in all three tests, and no emergency shutdowns were required.

NO_x Emission Control: The objective of the fourth December test on the 19th was additional NOx emission control beyond that obtainable with fuel rich combustion in the combustor. Figure 13 shows the average NO_x levels measured at the stack in the 20 MMBtu/hr combustor tests in Williamsport.

Figure 12: Stack NOx vs Combustor Stoichiometry-
20 MMBtu/hr Williamsport Air Cooled Slagging Combustor



Note that to achieve 0.45 lb/MMBtu required a combustor stoichiometric ratio {SR1) of 0.65. At this conditions carbon conversion was very poor, being in the range of 80%. In the present 2nd generation combustor, the comparable NO_x emissions levels were higher due to higher combustion efficiencies. For example, in the test on December 19th, under slightly fuel lea n conditions, the stack NO_x was in the range of 1 lb/MMBtu versus about 0.7 lb/MMBtu in the Williamsport combustor. Even under slightly fuel rich conditions, NOx ranged from 0.7 to 1.1 lb/MM versus 0.55 to 0.7 lb/MMBtu previously. Further details on NO_x emissions are given in connection with the tests performed in 1997.

In the test of the 19th, reagent injection in the post-combustion zones downstream of the air-cooled combustor exit was used to reduce the NO_x levels below the values attainable with fuel rich-fuel lean combustion. In that test the NO_x level was reduced by 50% or greater, to as low as 0.32 lb/MMBtu. This was within striking distance of the level of 0.2 lb/MMBtu that is one of the goals of this project. (Note: As described below, in tests in January 1997, further reductions in the NO_x level to as low as 0.07 lb/MMBtu were measured.) This result was a very major advance in this project because NO_x reduction has been one of the difficult goals to achieve in all the tests prior to that time. This result was achieved three times during the test of the 19th in that the NO_x level decreased sharply each time with reagent injection in the post-combustion zone and it returned to its original level when it was turned off.

Based on the SO_2 measurements in the boiler, the SO_2 emission levels were as low as 0.2 lb/MMBtu in several test conditions. This result was achieved in coal having sulfur content between 1.3% and 2%.

k) Results of the Task 5 Tests in the 1st Quarter of 1997

<u>The effort in the 1st quarter of 1997 was the most productive in the Task 5 test effort.</u> A total of 17 days of testing was completed in a two-month period. This included a one-day test in a parallel project on sulfur capture and retention in the slag of the combustor. This brought the total number of test days to 74 by 3/31/1997 versus the 63 days planned. These tests showed the need for additional tests to clarify the two major advances made in this quarter, namely greatly improved NO_x control and successful combustion of a very high ash (37%) Indian coal. We were able to implement additional tests through much of 1997 due to major cost savings that were made possible by sharply reducing the number of personnel to operate the combustor facility and by innovations in the operating procedures and in the equipment utilized to operate the facility.

The 16 tests in this quarter focused on optimizing the post-combustion NO_x control process that was discovered at the end of the previous quarter, and on further improvements in the combustors operation. This patented post-combustion NOx control process is a variation the Selective Non-Catalytic Reduction (SNCR) process that is used commercially in coal-fired industrial and utility boilers. The advantages of Coal Tech's process are extremely low equipment cost, low reagent cost, and low ammonia slip. An outside company stack testing company was retained to sample stack gases for particulates and combustion gases.

As a result of the success with the high ash Indian coal, this coal was used in the parallel project to test sulfur retention. As predicted, due to the high ash content of the coal, 20% of the sulfur injected as gypsum remained in the slag. This sulfur content was double the generally highest level previously measured, and it is due to the very high slag mass flow rate.

The following are highlights the results of the test results in this quarter.

January 1997 Combustor Tests: The tests in the present quarter were performed in January and February and the results are reported for each month separately. Ten test days were performed in January, on the 6th, 7th, 8th, 10th, 15th, 16th, 21st, 23rd, 28th, and 30th. This brought the total number of test days on this combustor to 67 days, and it completed the required test days for task 5. However, in view of the excellent progress made in these tests, additional testing were performed in the quarter and the next quarter.

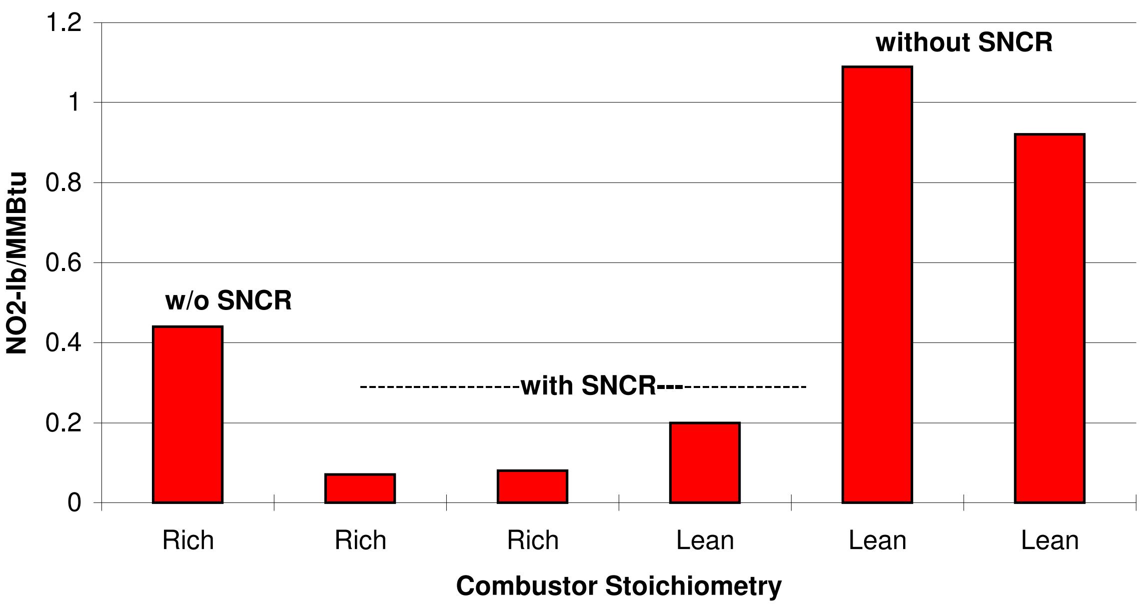
In addition to the high ash Indian coal tests and the NO_x control tests, important incremental improvements were made on components of the system. A simpler and much more thermally efficient slag tap assembly was tested, and a more efficient means of feeding powders into the combustor was installed and tested. Also, as components wore, important information on reliability and equipment quality was accumulated. For example, high-pressure fans are obviously a core component in an "air coo led" combustor. To date, reliability problems have been encountered in the fans supplied by three different manufacturers, some of which were manufacturing defects. For example, the bearings on the high-pressure fan in current use have been noisy since its purchase and the noise has recently increased. On replacement of the bearings in January, it was determined that the fan shaft had not been properly secured during assembly at the factory. This accounted for the degradation of the bearings.

Note added May 2003: In this report we keep emphasizing the reliability and quality problems that we encountered with "commercially" sold equipment in this project. One reason for this emphasis is that in our marketing of the combustor technology the oft-repeated comment was that we have no "commercial" installations sold. Overlooked is the fact that many of our operational problems were caused by equipment that was purchased "commercially". Since these purchased components and sub -systems are generally used in power systems, other users will experience the same problems irrespective of the application. That being the case, a purchaser of Coal Tech combustor should only focus on its cost-benefit ratio, not the cost benefit ratio of a power plant that uses this combustor. In the worst possible case, the purchaser can simply replace the combustor with a "commercial" burner, of which there are many, and continue operating without the specter of bankruptcy. On the other hand, to reject the air-cooled combustor because "no one else is using it" and instead invest in a coal combustion technology that cost orders of 10 to 100 times more does not appear to be a sound business decision.

Even worse has been the decision in the early 1990's by almost all developers of new power plants to use the "commercially" proven and "low cost" natural fired turbines. They are extremely reliable, the only problem has been the high price of natural gas that was driven in part by all these new power plants, as well as the glut in new power plants that drove these developers to the brink or into bankruptcy. Had any of these taken a chance of this new low cost coal combustion technology in the mid-1990's they would have made a fortune in the late 1990's and they would still be quite profitable today in 2004.

NOx Control Tests: The tests on January 6th, 7th, 8th, and 10th focused on NO_x reduction with SNCR reagent injection into the combustion gas flow train. Operation under both fuel rich and fuel lean conditions was performed. Various methods of injection were tested resulting in different degrees of NOx reduction. Figure 13 shows the results obtained in the tests of January 7th. The greatest percentage reduction was obtained under fuel lean conditions in the combustor, with over 80% reduction to 0.2 lb/MMBtu. **<u>Under fuel rich conditions, a value of NO_x as low as 0.07 lb/MMBtu was been measured</u>**. In all the tests, when the injection ceased,

Figure 13: NOx Emissions from 20 MMBtu/hr Combustor-Boiler w./w.o. Staged Combustion & w./w.o./ SNCR- January 7, 1997 Test



the NO_x level returned to the prior non-injection value. Various methods of injection were tested in order to optimize this process. A considerable amount of information on this NO_x control process has been accumulated in these tests and in subsequent tests in February. Some of these data were reported at the DOE NOx Control Conference in Pittsburgh on May 15, 1997.

The results in figure 13 are typical of the results obtained in numerous test conditions with SNCR injection under fuel rich and fuel lean conditions in the combustor. In general during each test day multiple SNCR post-combustion injection tests were performed with recovery to no injection. "Fuel rich" means staged combustion in which the combustor was operated at various levels below a stoichiometric ratio of 1, which is called "staged combustion", while "fuel lean" means excess air operation in the combustor. The "fuel rich" results in figure 13 shows that the NO_x reduction level achieved by staged combustion in the combustor is augmented by SNCR injection to approximately the same degree as SNCR without staged combustion..

Since the description on these data may not always align with the graph, the following elaboration is given. The first and last two of the six columns represent the fuel rich and fuel lean NO_x emissions, reported as NO_2, as measured without SNCR injection downstream of the combustor. The middle three columns show the result for rich and lean combustor conditions with SNCR injection downstream. Note that the reductions are proportional to the initial NO_x levels. Therefore, to achieve the lowest NO_x levels, 0.07 lb/MMBtu in this case, fuel rich staged combustion is advantageous. However, this condition may result in increased unburned carbon in the fly ash as well as potential increased corrosion of boiler tubes due to sulfur compounds in the gases. Therefore, quite a number of tests were performed with only limited fuel rich conditions, namely SR1 of about 0.9, compared to the very fuel rich operation of SR1 of 0.65 that was practiced before this SNCR process was used, as shown in figure 13.

The NO_x reduction achieved with this process varied according to the quantity of reagent and the method of injection. Numerous graphs similar to the one in figure 13 were obtained from the NO_x control tests in January and February.

The significance of the new NOx results is that the second of the three emission goals of this project were now achieved. The first one, SO_2 emissions below 0.4 lb/MMBtu was achieved earlier in the project. SO_2 levels as low as 0.2 lb/MMBtu were measured at the stack in coal with 1.3 to 1.7 % sulfur. The NOx emission goal of 0.2 lb/MMBtu was achieved in the 1st quarter of 1997. The particulate goal was 0.02 lb/MMBtu. However, due to limited funds only one set of tests were performed on particulates by contracting with an outside stack testing company. Unfortunately, there was a problem with the attachment of the bags to the baghouse support structure and some modest gas blowby around the bag supports resulted in high particulate readings, as discussed with the February 1997 tests. However, this is at worst a manufacturing defect in the construction of that bag support plate. It is not a deficiency in baghouse operation. Also, it is essential to stress that by removing about ¾ of the coal ash in the combustor, the particle loading on the baghouse is sharply reduced.

The next two tests on January 15th and 16th involved injection of a mixture of metal oxides that simulated an artificial coal "ash". The objective of the tests was to evaluate ash replenishment on the combustor wall using oxide particles that are large enough to be retained in the cyclonic flow in the combustor. One of the metal oxides agglomerated and plugged the pneumatic feed line. This problem could have been corrected if the pneumatic capacity of the mixture feed line had been greater. On several previous occasions, a diesel compressor had been rented for this purpose. However, this proved to be an unsatisfactory solution, and in order to solve this problem once and for all, the decision was made to acquire a second high-pressure blower. It was installed for the later tests in January.

A second objective of these two tests was to investigate the effectiveness of liquid lime injection into the boiler and the stack as a means of reducing SO_2 emissions. Several injection methods were tested, none of which proved satisfactory. Both the injection methods proved to be unreliable and the measured SO_2 reduction was relatively small. It was not known at the time whether these results are due to the injection method, the condition of the lime, an improper temperature range, or inadequate residence time.

***Note added May 2003: After the end of this project, Coal Tech, at its own expense developed the lime injection process and achieved 80% SO2 reductions in the post-combustion zone*. *March 2004: This process is now patented by Coal Tech*.**

To assure that these results were not due to instrument errors, replacement O_2, NO, and CO sensors were purchased. The results were the same. Furthermore, on February 20th the stack-testing company measured the stack gases with sophisticated EPA approved instruments and the results were in reasonable agreement with the in-house instruments.

The primary purpose of the test of the January 21st was to burn all the remaining coal in the pulverized coal bin. This was done to allow testing of the high ash Indian coal, to be described below. Again the opportunity was used to further test SNCR injection for NO_x control under different operating conditions. Again substantial NO_x reductions were measured. Since the overall results were similar to the January 7 tests, with differences due to injection method, injection locations, injector design, they will not be presented here.

The Indian Coal Tests. As early as 1989, Coal Tech performed tests in the Williamsport 20 MMBtu/hr combustor in which coal fly ash was injected into the combustor with coal to achieve over 50% ash content in the mixture. However, due to the small ash particle size, (<10 microns), much of the ash was blown out of the combustor. The highest ash content in coal that was tested had about 15% ash. Last fall, a substantial number of tests were performed in which the artificial ash was injected into the combustor. These tests were performed for the parallel sulfur in slag project, and in the present project, as reported above. But these tests had specific objectives and they may not represent actual conditions of combustion of high ash coal. The high ash coals are widely used in certain European and in much of Asia.

At the DOE Clean Coal Conference on January 9th, the PI learned from DOE-FETC personnel that several tons on 37% ash, 0.4% sulfur, 8100 Btu/lb Indian pulverized coal were stored at a DOE warehouse in Pittsburgh. It was shipped to Philadelphia, and on January 23rd and 28th tests on this coal were performed. The results were excellent, far exceeding expectations. Excellent slagging was achieved and the ash deposits on the combustor wall substantially reduced the wall heat transfer.

In view of the excellent results with this coal, the second test on the 28th was performed under the parallel sulfur in slag project. Gypsum was injected to determine the suitability of high ash flow rates on retention of sulfur in the slag. As observed previously, the calcium sulfate greatly increased the slag viscosity. As a result, slag removal from the slag tank nearly ceased late in the test. After draining the slag tank at the end of the test, slag was found to have filled the slag removal duct beneath the combustor. It was very easy to break it apart and remove it.

The following two graphs show the SO_2 and NO_x emissions obtained during the two Indian coal tests:

Figure 14 shows the SO_2 results measured with a probe inside the boiler and at the stack outlet from the boiler. The former probe always yields a much lower reading that the latter in almost all other tests on this and the sulfur-in-slag project. The Final Report on the latter project contains an extensive discussion on his issue, without reaching a final conclusion. It was speculated that the differences could have been due to gas blowby from the slag tap to the boiler exhaust duct, which bypassed the entire boiler. However, no conclusive explanation has been found. These results were obtained under high excess air conditions where SO_2 emissions are highest. No special reagent injection to control SO_2 emissions was used. The average 0.5

lb/MMBtu emission was below New Source Performance Standards of 0.7 lb/MMBtu, and it was near the 0.4 lb/MMBtu standard for this project.

Note added May 2003: This result is obsolete because Coal Tech's subsequent internally developed post-combustion SO_2 control process can sharply reduce SO2 emissions even with fuel lean combustion.

Fig. 14: SO2 Emissions with Indian Coal vs SR1. -1/23/97 Test

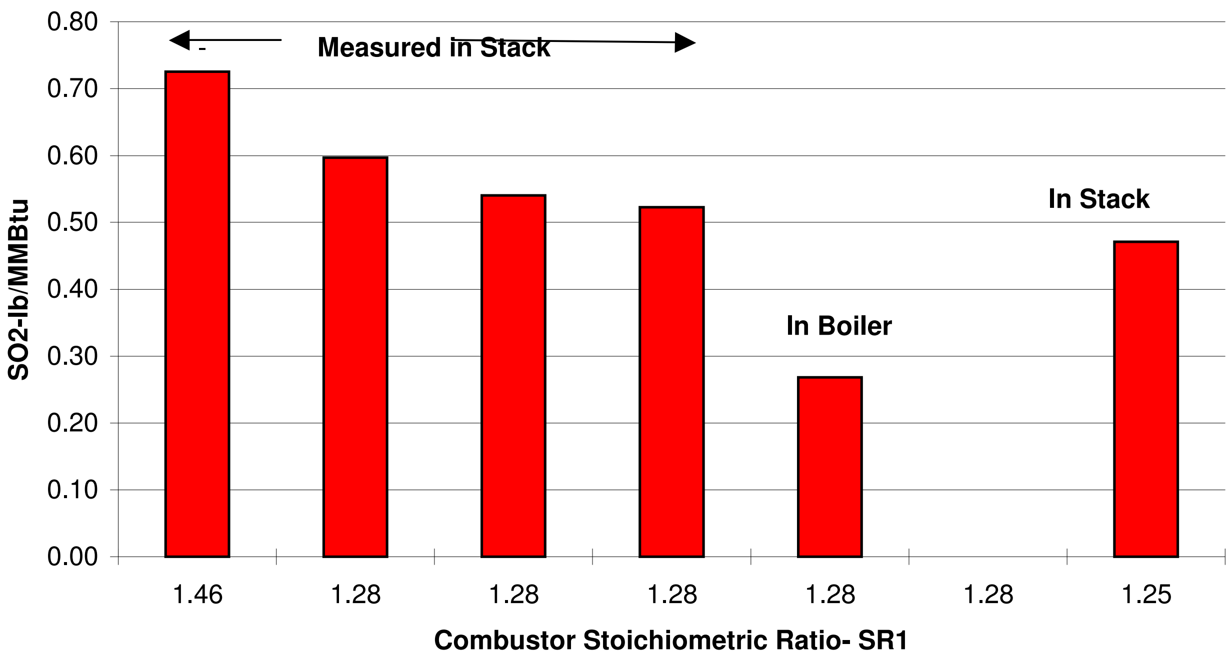


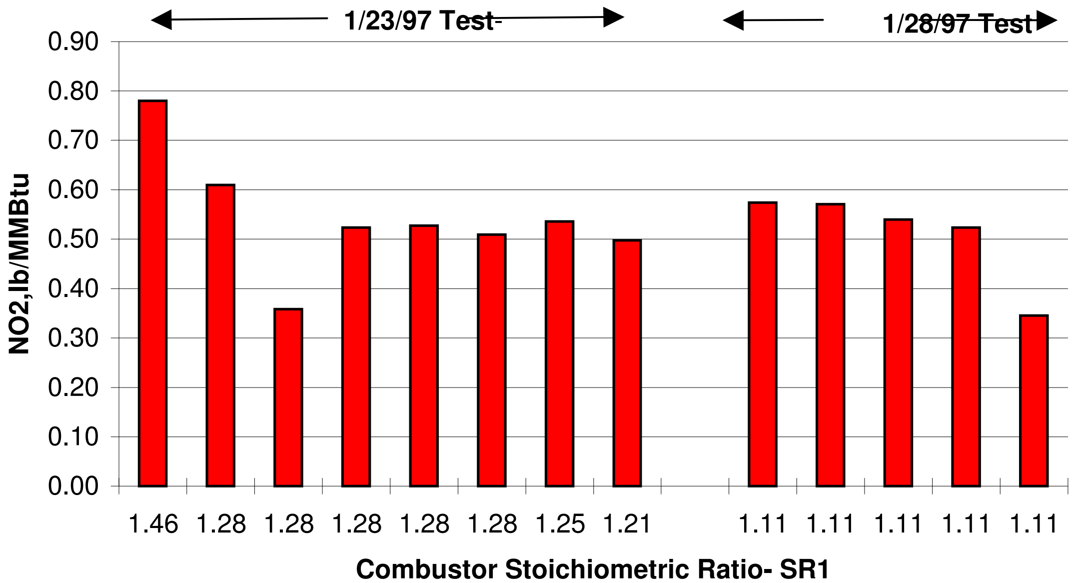
Figure 14 shows the SO_2 measured at different times during the test. As stated above, the average SO_2 measurement was 0.5 lb/MMBtu measured in the stack, while the measurement with a probe inserted in the furnace section of the boiler gave a reading of 0.26 lb/MMBtu. In view of the extensive air leaks into the boiler, it is possible that the Boiler reading may be more accurate.

Figure 15 shows the NO_x emissions measured for the Indian coal tests. These tests were conducted under high excess air conditions and one notes that the NO_x emissions average only 0.5 lb/MMBtu, which is excellent considering to no effort was made to reduce the NO_x level by staged combustion or SNCR injection in the boiler.

Note added in May 2003: As noted above, with SNCR reduction by at least 50% and with added reburn, another internally developed Coal Tech NO_x control process, the combined reduction of 75% is readily possible. This would result in a NOx emission level of 0.13 lb/MMBtu.

Note: March 2004: NOx Emissions of 0.15 lb/MMBtu was achieved with Coal Tech's SNCR process on a 50 MW coal fired utility boiler in November 2003.

Figure 15: NOx for Indian Coals, 1/23 & 28/97 Test



Based on these limited results it is concluded that firing Indian coals in the air-cooled combustor yields excellent slagging performance, and acceptable SO_2 and NO_x emissions without any post-combustion controls.

In the final test in January the low ash, high HHV bituminous coal used in the previous tests was used. In this test much of the slag deposited on the combustor walls during the previous Indian coal test was released. Also in this test, the new blower was used to inject calcium hydrate into the combustor and into the boiler. The SO_2 reduction in the combustor was about 50% at a Ca/S for hydrate of 2. This compares with a reduction of about 33% at a Ca/S mol ratio of 1.8 for limestone injection only. The SO_2 reduction from boiler injection of dry pulverized lime was about the same due to limitation in the injection rate from the small pneumatic feed line.

February 1997 Combustor Tests Seven days of combustor tests were performed on this project during this month, on the 6th, 10th, 13th 17th, 18th, 20th, and 27th. The focus of the tests in this month were on optimization of SO_2 and NO_x control by injection of reagents into the post-combustion gas flow train downstream of the combustor, on modified operation of the slag tap, and on stack gas testing using an outside stack gas sampling company.

NOx Results: In all the tests of this month, part of the focus was on NO_x reduction with SNCR injection into the combustion gas flow train. Operation under some fuel rich and mostly fuel lean conditions were performed. Various methods of injection were tested resulting in different degrees of NO_x reduction. As in the previous month, the number and nature of the reagent injectors were changed from test to test. A number of unusual results were observed. Some of these are reported below. In general, NO_x reductions ranged from over 50% to as much as 80%, with levels as low as 0.1 lb/MMBtu measured.

SO_2 Reduction: Various methods of injecting reagents into the hot post-combustion gas stream, downstream of the combustor were tested. Furnace injection had been attempted earlier in this project. However, the Ca/S mol ratio in those tests was relatively high. In the present tests, the objective was to minimize the Ca/S mol ratio to below 3. SO_2 reductions ranging from 50% upstream of the baghouse to 90% downstream of the baghouse were measured. In the latter case, the SO_2 measured was as low as 0.2 to 0.3 lb/MMBtu. These tests were performed with low sulfur coal, S< 2%. Later in the month, higher sulfur (S>2%) coal was received. However, due to a number of operational problems, the number of tests with hot gas stream reagent injection was limited and further tests were performed in the next quarter. Some of these results on SO_2 reduction are reported below. The results to date showed superior calcium utilization compared to the boiler furnace lime injection tests earlier in this project and in the previous 20 MMBtu/hr project in Williamsport, PA. The reason is that with the new injectors it was possible to focus the reagent injection on the hot gas stream as opposed in the earlier powder injection method where much of the lime dropped to the floor of the furnace section of the boiler without reacting with the hot gas stream.

Combustion Efficiency: A technique that had been developed in Williamsport, but not used here, was tested to determine the impact of the coal feed uniformity on combustion efficiency. It was found that with uniform feeding the carbon monoxide level in the stack gas was reduced from the range of several 100 ppm to under 100 ppm. This occurred with fuel lean conditions in the combustor.

In almost all prior tests, the combustor was operated at stoichiometric ratios of unity or fuel rich conditions in order to minimize NO_x emissions. However, with the success of the SNCR injection method for NOx control, most of the test conditions in the combustor were from then on fuel lean. With the more effective uniform coal feed rate tests this month, the fuel lean conditions resulted in consistent CO levels below 100 ppm.

Stack Gas Sampling Test: On February 20, 1997, an outside stack gas sampling company was retained to measure the stack gases, O_2, CO_2, CO, NO_x, SO_2, NH_3, and stack particulates by EPA method 5. The primary purpose of the stack gas measurements was to determine the accuracy of Coal Tech's stack instruments. The O_2, CO, CO_2, and SO_2 were in general agreement within 10% to 15% of the values obtained with Coal Tech's instruments

The stack particulate tests were designed to verify the performance of the baghouse. Surprisingly, the results showed particulate emissions in the range of 0.3 lb/MMBtu, or almost a factor of ten higher than guaranteed by the manufacturer. There was no evidence from visual stack gas observations that the baghouse had failed. Internal inspection of the baghouse walls on the clean (downstream) side of the bags and on the stack duct walls revealed a thin crust of material that most probably was rust. This rust could flake off and impact the particulate measurements. The cause of the rust is almost certainly due condensation from the numerous startup and shutdowns as well as from the water spray injection cooling of the combustion gases upstream of the baghouse inlet. There is no indication that the result was due to bag failure.

Note added May 2003: Since 1997 a considerable portion of the stack ducting has experienced extensive rusting to the point where the steel inlet ducts to the baghouse are totally *corroded. It is therefore probable that rust flakes were partly responsible for the high particle reading. In addition, as briefly noted above, there were problems with the flatness of the perforated steel plate, which held the several 100 bags. It is thus possible that some gas blowby occurred there. To fully resolve this issue would have required a number of costly tests by the outside stack gas sampling company and no funds were available for this purpose. .*

Coarse Coal Test: A brief test was performed on February 16 in which a coarse coal, 30% passing 100 mesh, was fired in order to compared it to the normal 70% passing 200 mesh used regularly. The volumetric coal feeder had not been calibrated for this test and it was determined that the actual feed rate was about 1/3 higher than normal. This was due to the greater density of this coarse coal. Consequently, the actual feed rate was over 1600 lb/hr, or over 21.5 MMBtu/hr, compared to the anticipated value of 1080 lb/hr, or 15 MMBtu/hr. Some unburned carbon passed out of the combustor since the combustor stoichiometry was only 0.84, or fuel rich. The test did not last long enough to determine overall combustion efficiency. However, it appeared from the brief run that this coarse coal could be burned efficiently if fuel lean conditions prevailed in the combustor.

l) Task 5 Combustion Tests on the 20 MMBtu/hr Facility in the 2nd Quarter 1997

A total of 9 days of testing was completed in the 2nd Quarter of 1997. This included 3 days of tests in a parallel DOE project on sulfur capture and retention in the slag of the combustor. This brought the total number of test days to 83, versus the 63 days planned. The following highlights the results of the tests in the present reporting period.

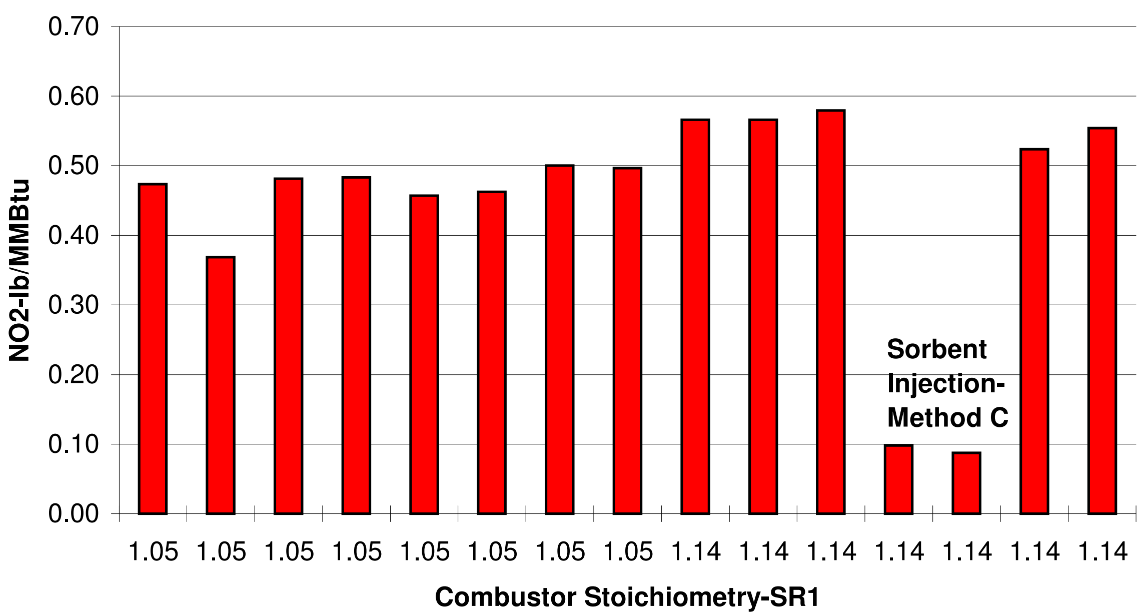
Post Combustion NOx Control: Four tests in this quarter focused on further optimization of Coal Tech's post combustion NO_x control process.

The objective of the first two tests, performed in April, was to determine if the Coal Tech post combustion SNCR injection process for NO_x control would be applicable on oil fuels. In the first test, the oil-firing rate was 5.6 MMBtu/hr. Only 25% NO_x reduction was measured. In the next test, the oil flow rate was almost doubled to 9.8 MMBtu/hr in order to increase the downstream combustion gas temperatures. However, there the NO_x reduction remained at 25%. On shifting to coal firing, the NO_x reduction was about two-thirds, in the same range as the previous coal fired tests. However, the absolute level of NO_x was much higher with coal than with oil. The relative concentrations of reagent to NO_x was maintained the same in both oil and coal firing conditions. Three-dimensional computer modeling of the combustion gas flow in the post combustion zone was performed for coal firing conditions in this boiler. The computer results showed a wide variation in the temperature distribution in the post combustion zone. Limited temperature measurements with a thermocouple with coal firing were inconclusive because a complete temperature profile could not be obtained due to the limited access ports in the boiler. With oil firing, especially at the lower total heat input, this temperature non-uniformity will be much more pronounced. Although originally designed for oil firing, this boiler has been modified for coal firing. Therefore, the temperature distribution in the post combustion zone is substantially different from that with oil firing.

Note added May 2003: The explanation for the difference between the oil and coal firing is as follows: 1) The base NO_x level is lower with oil because there is no fuel bound nitrogen in oil. 2) The SNCR had no impact with oil because the flame pattern entering the boiler was narrower than with coal. As a result the SNCR spray pattern with oil did not interact with the gases in the proper gas temperature range, which explains the absence of NO_x reduction.

An additional pair of daylong NO_x control tests was performed in June. The objective was to determine the impact of different injection locations on the magnitude of NOx reduction by post combustion SNCR injection. The results showed that injection location is critical to NOx reduction. In the tests, the NOx reduction remained constant as long as the injection was at the appropriate temperature. However, at one injection point the NOx reduction decreased by about one half. Post-test internal boiler inspection revealed that the injector had not been placed at the appropriate temperature location. Thermocouple temperature measured showed wide variations in the post combustion gas zone in the boiler. This was also confirmed by three-dimensional modeling of the combustion gas flow from the combustor through the boiler. Figure 16 shows the impact of injection location on the NO_x reduction with SNCR. The measurements were taken upstream and downstream of the baghouse. Injection location C into the furnace section of the boiler yielded greater reductions than the other location.

Figure 16: NOx Emissions in Inner & Outer Stacks & w & w/o Sorbents-2/6/97Test



The average level of 0.5 lb/MMBtu is with excess air in the combustor and no SNCR.

Figure 17: NOx Emission-2/10/97 Test

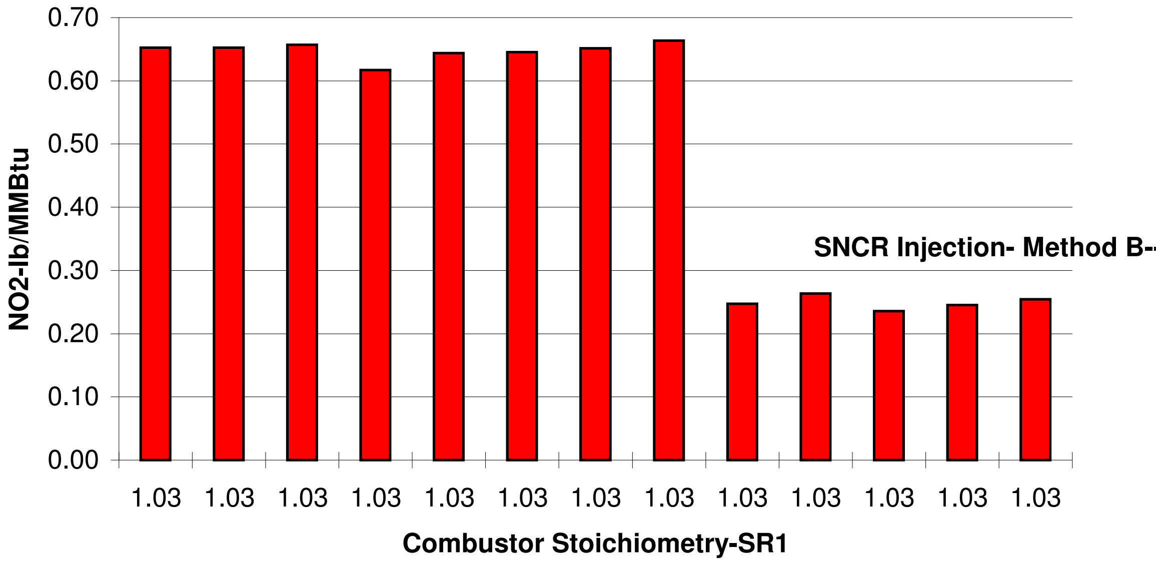


Figure 17 shows another SNCR test with a different injection method and location and in this case the NOx reduction is substantially less that in the test shown for figure 16. Due to the simplicity of the injection method developed by Coal Tech it was simple to perform numerous test conditions in order to optimize the SNCR NOx reduction. Figure 16 and 17 are examples on this optimization process.

The Indian Coal Tests.

As reported above, in January 1997 two tests with the Indian coal were performed. Excellent slagging was achieved and the ash deposits on the combustor wall substantially reduced the wall heat transfer. However, the slag accumulated in large blocks in the slag tap. To determine if this was due to the short test time or if it was an inherent feature of burning high ash coal, two additional tests were performed with this coal in May 1997. The primary purpose of these tests was to validate the earlier results, which showed that high slag mass flow rates are effective in retaining sulfur in the slag. The results of these two tests are reported in the Final Report of the sulfur in slag project. For present purposes, the relevant aspect of the two May tests was the substantial improvement in slag flow with the Indian coal. In place of very large, almost cubic foot volume slag blocks that dropped out of the combustor's slag chute at irregular intervals in the January test; in the May test, continuous slag flow in golf ball size globules was observed throughout the test. These slag globules were much greater than the fine nominal ¼ inch slag grit that was obtained in typical US bituminous coal having maximum ash concentrations in the 10% range.

This result is of considerable significance in view of the recent discovery of extensive air pollution in Asian regions that utilize primarily very high ash coals.

Post Combustion SO_2 Reduction Tests

In May 1997 two tests were performed whose objective was to extend the previous effort on the effectiveness of lime injection downstream of the combustor for SO2 control. A medium (2.5%S) sulfur coal was used. However, unlike the low sulfur coal test results, there was no substantial additional percentage reduction of SO_2 with furnace injection above the percentage reduction obtained with reagent injection into the combustor. Also, the SO_2 reduction measured at the boiler stack outlet was only about 30% due to reagent injection in the combustor only, and it increased to 42% with additional injection downstream of the combustor. Unlike earlier tests, the SO_2 measured downstream of the baghouse was now only slightly lower. However, the Ca/S mol ratio injected in the combustor was only 0.96, while the additional furnace injection added a Ca/S of 1.5 and 1.9. This was about one half the Ca/S mol ratios used in the low sulfur coal. Higher reagent injection rates could not be achieved due to feeding equipment limitations. This suggests that a longer injection period may be required to properly coat the baghouse surfaces with higher sulfur coals.

Note Added May 2003: On reflection on these test in the years after the completion of this effort and after considerable success was achieved in Coal Tech's internally funded post-combustion SO_2 and NO_x control processes, it is almost certain that the erratic results in the 1997 tests were due to incomplete coverage of the injected reagent in the proper gas combustion zone.

m) Coal Tech's SNCR NOx Control in a 100 MW Electric Utility Boiler 2nd Q 1997:

The most significant new result obtained in this quarter was the initial successful application of Coal Tech's SNCR injection process for NO_x control to a 100 MW utility boiler. Coal Tech SNCR process is readily adaptable to large boiler. A search was initiated late in the previous quarter for a suitable test boiler, and one was found in March. An inspection trip to this boiler was made in April to find suitable locations for reagent injection, based on the results on the 20 MMBtu/hr combustor-boiler. In June 1997, a NO_x control test on the 100 MW boiler with only 1 injector was performed. The initial injection point, which was selected on the basis of results on the small boiler, produced no NO_x reduction. A subsequent test at the second pre-selected injection area, using the one-injectors, yielded a 25% NO_x reduction. *This was a significant milestone in this project since a factor of 100 scaleup of the NO_x control process was successfully implemented*. Further tests on this boiler and a 37 MW boiler at the same plant were implemented in August 1997, and are reported below.

n) **Combustion Tests on the 20 MMBtu/hr Combustor-Boiler in the 3rd Quarter 1997**

The effort in the 3rd quarter, ending 9/30/97, focused on two areas: Further optimization tests of Coal Tech's post combustion NO_x and SO_2 control processes in the 20 MMBtu/hr combustor-boiler facility in Philadelphia, and tests of Coal Tech's SNCR NO_x control process on a 37 MW and a 100 MW utility boiler, reported in the next sub-section. . Excellent progress in each of these areas was made in this quarter.

A total of 10 days of testing for task 5 of this project was completed on the 20 MMBtu/hr facility in the present reporting period. This brought the total number of test days to 93, versus the 63 days planned. This total of 93 includes 19 days of tests in the parallel DOE project on sulfur capture and retention in the slag of the combustor. These latter tests are included in the total because they were implemented on the 20 MMBtu/hr combustor and they add to the total operating experience on this unit. The following are the highlights of the tests in the 3rd quarter, ending 9/30/97.

o) Computer Modeling of the Temperature Distribution in the Boiler's Furnace Section:
Additional three dimensional computer modeling of the combustion gas flow in the post combustion zone in the furnace section of the boiler was performed. The results that were performed in the previous quarter were found to have errors. The initial solution was insensitive to the quantity of ash particles entrained in the combustion gas. This is of course impossible since radiation should increase sharply with adding particle loading in the gas. After checking the computer code, the source of the error was found and corrected. The previous calculations were repeated, and several additional calculations of the temperature distribution in the furnace section of the boiler were made. All these results showed that a narrow, cylindrical, high temperature zone emanated from the combustor exit to the far end wall of the boiler's furnace. Outside this zone the gas temperature dropped sharply toward the furnace wall. Changing the combustor operating parameters, such as the inlet combustion air swirl, changed the diameter of the hot gas zone to a limited extent. Limited temperature measurements with a thermocouple were inconclusive because a complete temperature profile could not be obtained due to limited access ports in the boiler. However, the marked difference between the SNCR tests with oil and coal are consistent with this narrow cylindrical flame pattern model. They showed limited impact of SNCR injection with oil because the flame cylinder diameter would be substantially smaller with oil due to the absence of strongly radiating carbon and ash particles.

(***Note added May 2003: The graphical results of this computer modeling are not shown because the size of this appendix "C" already exceeds 2 megabytes with only 18 figures and problems have been encountered with the "save" feature of this Microsoft Word 2000 word processing program, which locked the "save" feature when the last pair of Excel graphs from pre-2000 versions were inserted in Word. On discussing this matter with software specialists it appears that this is a Word problem in that the program replicated presumably the background data from the inserted chart, or some other unknown function. It is obvious that Microsoft does not know the cause or the cure because the same problem was encountered in 1997 when earlier versions of Word and Excel were used. Since DOE insists that these reports be submitted in Word (now PDF) the simple solution of submitting the graphs in Excel or some other format is not available. We suggest that DOE explore this issue and issue appropriate solution to reduce the bit size of reports with much graphical content, such as allowing submitted of graphs as Excel files***.

A second point, which has been mentioned several times in this Appendix and in the other parts of this Final Report, is the importance of not taking elaborate computer program modeling at face value. In the present case, the recognition that the ash/carbon radiation had been omitted from the gas temperature distribution in the boiler's furnace was made by the

P.I. by inspection of the results, not by digging into the software code, which was far too complex.

p) Post Combustion NO_x Control Tests: Six of the 10 tests performed in the 3rd quarter of 1997 were devoted to the further study and optimization of Coal Tech's post combustion NO_x control process. The objective of these tests was to determine the impact of changing the location of the SNCR injectors, changing the number of injectors, changing the flow rate of reagent, and changing the combustor's operating conditions on NO_x control.

Some of the test conditions had been used previously, and they were repeated to determine reproducibility of the data. Most of the test conditions were at slightly excess air in the combustor, with stoichiometric ratios, SR1, between 1.01 and 1.16. With final combustion air into the boiler, the overall stoichiometric ratio, SR2, in the boiler furnace section was between 1.49 and 1.6. Several tests were performed with fuel rich conditions in the combustor, with SR1 between 0.69 and 0.94. SR2 was between 1.25 and 1.44.

From this database, a pattern emerged on the parameters that govern the NO_x control process. Specifically, the effect of the number of injectors, their location in the furnace, and the reagent flow rate on the degree of NO_x reduction was determined from these and the prior tests. Some of this information was correlated and incorporated in a patent that has since been granted to Coal Tech. Due to the Word software problem no detail graphical results can be given her.. Only overall observations are summarized as follows:

(1) With fuel rich combustion in the generator, the stack NO_x emissions were between 0.4 and 0.5 lb/MMBtu without SNCR post combustion injection. The addition of the SNCR further reduced NO_x emissions by and additional 43% to 53%. Therefore, **the final NO_x emissions were between 0.19 and 0.26 lb/MMBtu**.

(2) With fuel lean conditions in the combustor, NO_x emissions ranged from 0.42 to 0.6 without SNCR injection. The lower values were measured at SR1 near unity. It is, therefore, quite possible that this NO_x data at SR near 1 was actually at slightly fuel rich combustor operation. With post combustion SNCR injection about the same percentage NO_x reduction as in the fuel rich cases was measured. This yielded **a final NO_x emission ranging from 0.23 to 0.36,** depending on the injector location, reagent flow rate, and stoichiometry in the combustor. The reagent utilization rate ranged from 17% to 63%, again depending on the previous three parameters. Many of the data points were at reagent utilization rates well above 40%, which is excellent when compared to the average one-third utilization rates reported by other commercial and advanced post combustion NO_x control processes.

The tests in this reporting period concluded the planned effort in the post combustion NOx control process for task 5. Well over 100 different test conditions were investigated, and at this time a good understanding of this process has been obtained. **Economic analysis of the cost of this process indicates that both its capital and operating costs are very much lower than any other post combustion NOx control processes now on the market, all of which were developed with far more resources than Coal Tech's process.**

Also, it should be noted that this entire post combustion NO_x control effort was not in the original project plan for this contract. It was made possible by the effort of Coal Tech to effect major cost savings in the implementation of this project.

q) Post Combustion SO2 Reduction Tests: Various methods of injecting sorbents into the hot gas stream, downstream of the combustor have been tested in the decade of development of the 20 MMBtu/hr combustor. Furnace injection had been attempted as early as the late 1980's in the previous Clean Coal Project. However, the Ca/S mol ratio in all those tests was relatively high, typically 4 about for 80% reduction. Early in 1997, test results were reported whose objective was to minimize the Ca/S mol ratio to below 3. SO_2 reductions ranging from 50% upstream of the baghouse to 90% downstream of the baghouse were measured. In the latter case, it was hypothesized that calcined CaO deposited on the bags, thereby aiding in SO_2 reduction. The SO_2 measured was as low as 0.2 to 0.3 lb/MMBtu. These tests were performed with low sulfur coal, S< 2%.

In May 1997, tests were performed whose objective was to extend the previous effort to higher (2.5%S) sulfur coal. They were reported in the previous sub-section. These higher sulfur coal result differed from those obtained with the low sulfur coal in that lower reductions were measured, part of which was due to the lower Ca/S mol ratio of 0.96 from the reagent injected in the combustor and the additional furnace injection which increased the Ca/S mol ratio by another 1.5 and 1.9. This was about one half the Ca/S mol ratios used in the low sulfur coal. Higher injection rates could not be achieved due to feeding equipment limitations. Also, the CaO coating on the baghouse had little effect. These May 1997 results suggested that a longer post combustion injection period should be tried to increase the coating layer thickness on the baghouse surfaces.

In the 3rd quarter, ending on 9/30/97, four tests with post combustion reagent injection for SO_2 control were performed in late August and September. Their purpose was to implement the two objectives listed in the previous paragraph, namely longer continuous reagent injection and higher injection feed rates. However, in one of the prior tests in mid-July, slight smoke emanated from the stack. Inspection of the baghouse revealed that several bags had torn, most probably from metal chips that had fallen off the inner roof of the baghouse. (***Note of May 2003: This strongly confirmed that the high 0.3 lb/MMBtu particulate emissions measured in the stack be the outside testing company was contaminated by rust particles***.) Since the total operating time of these bags was under 1000 hours in 2 years, this rusting of the walls was due to poor fabrication in not providing rust proof surfaces. 121 replacement bags were ordered from another supplier who promised a one week delivery versus over one month from the original manufacturer. Removal of the old bags was extremely time consuming as they had adhered to the wire cages. This was due in part to operation of the bags above the design temperature.

Operation of the new bags showed that the gas pressure drop across the bags was one-third of the value measured with the prior bags. Also to save on compressor power consumption, the bag pulsing sequence was modified. These two factors reduced the deposition of ash and calcium oxide on the bags to the point that the effect of CaO coating on the bags on the SO_2 reduction could not be measured in the next four tests. In fact subsequently an additional 12 combustor test were been implemented, the pressure drop across the bags was still about 1/3 less than that with the old bags. Consequently, no conclusive correlation on the impact on SO_2 reduction due to CaO deposited on the bags has been obtained. The SO_2 data at the baghouse outlet ranged from no difference to about 10-percentage points difference. (***Note added May 2003: here is another example where equipment changes can impact test results, a factor that is generally not reported in the literature where emphasis is usually placed on test results***.)

The second objective of increasing the reagent flow rate for post combustion injection with 2.5% sulfur coal, was not be implemented due to boiler access limitations and cost considerations. A higher capacity pneumatic feed train for the reagent requires a rented compressor and the purchase of pneumatic feed equipment. In its place, a new injection location in the furnace section of the boiler was selected for the tests. Based on the abovementioned computer modeling of the gas temperature in the furnace section of the boiler, it was deduced that this injection location would yield increased SO_2 reduction. The Ca/O ratio from the limestone injected into the combustor ranged from 1.39 to 1.6. This resulted in SO_2 reduction ranging from 7% to 19% measured at the boiler outlet to the stack. This increased from 20% to 30% at the baghouse outlet. The addition of reagent injection into the boiler increased the SO_2 reduction at the boiler outlet from 32% to 44%. There was no significant increased SO_2 reduction downstream of the baghouse.

These results were somewhat disappointing because the injection location was judged to be ideal for high SO_2 capture. However, the specific access port selected had been originally installed for another purpose, and its current use required a convoluted pneumatic feed line from the reagent feeder to this port. In addition, the two reagent injection nozzles used may not have yielded very extensive gas-calcium oxide mix. A new access port could be installed at this location by drilling through the boiler wall, which would simplify the feed. Also different injection nozzle could have been designed to assure better mixing of the gas and reagent. While these changes could be readily implemented at relatively modest cost, we judged that the remaining resources had to be conserved for the final report and possible disassembly of the facility under task 6 of this project.

(Note added May 2003: Coal Tech implemented a totally new approach for post-combustion SO_2 reduction, with its own resources, after this project ended. It included far superior mixing of reagent and gas. We succeeded in achieving up to 80% SO_2reductions.
March 2004: A patent has been granted on this process which also combined NOx reduction)

r) SNCR Post Combustion NO_x Control in a 37 MW & 100 MW Electric Utility Boiler:

As reported in sub-section (m) above, Coal Tech's SNCR post combustion process is readily adaptable to large boilers. In June, a brief one-day NO_x control test on the 100 MW-boiler was performed. With only one injector, a 25% NO_x reduction was measured.

This test revealed that the process was effective, but that the injectors would have to be modified somewhat. Coal Tech process is so low in cost and so simple to implement that the entire test on one boiler, including driving to the plant, installing the injection equipment, performing the test, removing the equipment and driving home can be done in one day. Coal Tech was responsible for the entire cost of the test, including installation of the test equipment. Working inside the closed off boilerhouse during the heat of August and hauling equipment and 50 lb reagent up to the top of the boiler was extremely exhausting, especially since the elevator did no stop on the elevation of the test location. Labor agreements with the operating work force prevented us from receiving any manpower help from the utility. The utility provided the boiler and the regular operating personnel as well as an environmental supervisory engineer who arranged for the test. Due to Coal Tech resource limitations this precluded extended test periods and the installation of sufficient injectors to duplicate the high NO_x reduction measured in the 20 MMBtu/hr-combustor.

To maximize the results within these resource limitations, a second test was planned for early August. Since the plant had a smaller 37 MW boiler, it was decided to include this boiler in the test effort, and add a second test day. Its smaller size allowed a greater impact on NO_x reduction with fewer injectors. From our decades long experience with test operations, we were certain that there would be problems that would limit the planned test objectives. Accordingly, we had hoped to implement a third series test on these boilers. However, two substantial unexpected expenses prevented this.

First at the insistence of the regulatory authorities we were required to measure trace pollutants, especially ammonia slip, during the injection process. Since these were short duration tests, we would have preferred to defer ammonia slip tests until more test data had been gathered. This testing required retaining an outside stack gas-testing firm for this purpose at considerable expense, which added substantially to the cost of the test.

Note added March 2004: This requirement made absolutely no sense because the 37 MW boiler emitted 1 lb/MMBtu of NO_x continuously, which was far worse than the few milligrams of ammonia slip during the several hours of testing. As a result of this "decision" and the refusal of the utility to pay for any part of the tests, we could not afford any more tests. As a result we shifted to another utility, which has a 50 MW boiler, and performed a series of tests in 1999, 2000 and late 2003, again at our expense but with the help of the power plant staff. These tests resulted in a major breakthrough in that late last year Coal Tech SNCR process reduced NO_x by nearly 50% to 0.15 lb/MMBtu, the EPA 2003 limit. Furthermore, the process operating cost is under $500/ton of NO_x removed, and the capital cost is a few dollars per kilowatt. Had either the utility invested the few 1000 dollars for ammonia slip tests, or DOE selected our solicited NO_x proposals, this technology would have been fully commercial before 2000 and could have reduced by now several additional million tons of NO_x annually. The moral is the elementary school rhyme: "For want of a nail, the horse was lost, for want of a horse, the war was lost".

Secondly, one of the boilers had a common stack with a second identically rated boiler. We suggested that one could simply deduct the NO_x reduction achieved by the injection process, and attribute it all to the test boiler. This was unacceptable to the utility personnel. We agreed to bring Coal Tech's portable NO_x instrument to measure the NO_x on the test boiler outlet. However, two days before the scheduled test, the instrument broke down and there was not time to repair it. Since all the test arrangements had been made, the only option was to purchase another instrument from the suppliers stock for almost $5000. The utility had promised to pay for half the cost of the instrument, but as this had only been a verbal promise, it was not kept. The expense incurred for these two items equaled our budget for one series of tests, and it precluded a third series of tests.

In addition, without the help of the plant operators, we hired 3 technicians from our old Williamsport contractor to assist in the tests. This was in addition, to four Coal Tech personnel. The reason for all these people was the need to mix the reagent with water in 55-gallon drums, which required mixing a new batch about every 10 minutes at each of the two-injector locations. In the event, this method of mixing was totally unsatisfactory and poor results were obtained.

The first day of testing on August 6, 1997 was on the 100 MW boiler. This boiler is equipped with low NO_x burners and overfire air. In the June test, the baseline NO_x emission was about 0.3 lb/MMBtu. On the day of the August test, the NO_x level was 0.44 lb/MMBtu. The ash deposits on the furnace wall and boiler tubes were relatively high and it was necessary to perform soot blowing before and during the test. One injector was placed at the same location as in the previous test and another one was placed on the opposite boiler wall. As anticipated, problems developed immediately. The 115 Volt outlets that were used to power the small pumps blew the circuit breakers, and no one could find the circuit breakers. Consequently, a search was made for working 115 V. outlets. After a brief period, these circuit breakers also blew. As a result of all the delays incurred, the test periods were greatly reduced. Meanwhile our costly stack test crew had to restart sampling after every breakdown. Three test conditions were implemented and the maximum reduction measured was 24% at one of the test conditions. This was about the same as had been achieved in the previous test with one injector. The injectors were then moved to a different location in the boiler for the final condition. Here the NO_x reduction was substantially lower.

These results were very puzzling. However, two factors were highly suspect.
One was the rapid pace of the tests and the high heat meant that the mixing of the reagent with the water in the 55 gallon was hurried and incomplete. This meant that the reagent injection was non-uniform

The other factor was the observation of severe distortion in the compressed air pipe in the injector assembly. This meant that the injection mechanism was overheating which means that the reagent dispersal was deficient.

Both these factors were corrected in subsequent tests. The first one that of proper mixing was partially corrected on the next day. The second one of proper cooling of the injectors was corrected in subsequent tests performed on a 50 MW coal fired utility boiler several years after the present project ended. In that later test 40% NOx reduction was obtained. However, in one test on the 50 MW boiler where the injector cooling circuit was blocked, the NO_x reduction was minimal, which proved injector cooling is critical to proper injector functioning.

Nevertheless, the 37 MW and 100 MW tests results provided information on the required number of injectors that are needed to cover the combustion gas flow path. Due to the interruptions listed above, the measurements of trace gas ammonia slip in the stack showed wide variations. They, therefore, provided only qualitative guidance on the magnitude of trace pollutant emissions of ammonia slip, and the expense incurred for this measurement was wasted.

On the second day, the tests were performed on the 37 MW boiler. It used a very high ash coalmine waste and had no NO_x control. The uncontrolled NO_x emission levels were 1 lb/MMBtu. A brown pollution plume was visible from the stack of this plant as a result of the high NO_x. Here again due to boiler operational issues on the parallel 37 MW boiler, the test duration was less than planned originally. The stack gases were sampled at the outlet of the stack particulate control equipment at a point where the gas ducting enters the common stack to both 37 MW boilers. On comparing the NO_x results measured with the Coal Tech instrument at the duct leading from the test boiler to the common stack with the utility's NO_x instruments at the top of the stack, it was found that the NO_x values were nearly identical. It was concluded that the exhaust gases from both boilers, which entered the stack on opposite sides, mixed completely at the base of the stack so that the measurement at the base was not necessary. In hindsight, it was not necessary for Coal Tech to waste nearly $5000 and purchase the replacement NO_x instrument.

The best NOx reduction obtained at one of the test conditions in the 37 MW boiler was 40%. Of greater importance, the utilization of the reagent was 75% for that test condition. Furthermore, the ammonia slip in the stack was below 10 ppm. This was a very significant result in that the cost of operating Coal Tech's NO_x control process is far less than other post combustion SNCR NO_x control processes that achieve almost the same nominal one-third reduction and that are now on the market.

The utility's staff refused to participate in any further tests for which they would have had to incur the expense of the test, which would have been minimal. In early 1998, Coal Tech offered to install the SNCR system on the highly polluting 37 MW boiler at a cost that was less than one-half of the lowest cost alternative SNCR on the market. The offer was rejected on the grounds that we could not implement it at that low cost. Instead the power plant continued to pollute the atmosphere. Interestingly, at one of its largest power plants, this utility installed a SCR NOx controls system that conservatively costs at least a factor of 10 more than Coal Tech's process.

As noted above, Coal Tech did successfully demonstrate this process at its own expense on a 50 MW coal fired boiler in 1999, 2000 and 2003. As noted in the March 2004 note above, the tests in 2003 resulted in nearly 50% NO_x reduction to 0.15 lb/MMBtu, which is EPA's 2003 emission limit.

Note March 2004: A summary of the results of these NOx tests as well as Coal Tech's SO2, dioxin/furan, volatile trace metal emission control processes can be found in the "Proceedings of the 19th International Conference of Solid Waste Technology", Philadelphia, PA March 21-23, 2004, published in the Journal of Solid Waste Technology & Management"

Over the next several years, Coal Tech submitted about one-half dozen proposals to DOE for demonstrating its post-combustion processes on utility boilers, including the SNCR and reburn processes for NO_x control, and its combined NO_x/SO_2 process. All were rejected in favor of other projects that cost 5 to 20 times more than Coal Tech's proposals.

Table 1 is a summary of the test results on the 37 MW and 100 MW boilers.

Table 1:
Results from Coal Tech's SNCR Test on a 37 MW Coal Fired Electric Utility Boiler

Test Day	# Injectors	NOx, lb/MMBtu	% NOx Reduction	NH3 Slip, ppm
8/7/97	0.	1.07	0	0
8/7/97	1	0.6	40	8.7
8/7/97	1	0.6	40	7.6

t) Final Tests on the 20 MMBtu/he Combustor-Boiler: 4th Quarter 1997 to 2003

The above tests were the last ones on the present project. A total of 73 test days had been performed compared to the 63 days originally planned for task 5.

Testing on the parallel sulfur-to-slag project continued for another 6-month period until March 31, 1998, by which time a total of 34 tests days had been implemented on coal firing. This brought the total number of test days to 108.

In the following 5 years over 100 days of testing was implemented on this combustor, which led to the development of Coal Tech proprietary, patented and patent pending, NO_x and SO_2 post combustion emission control processes. They include SNCR and "Reburn" NO_x control as well as SO_2 control, and combined SO_2 and NO_x control, all of which are patented.. All these tests were implemented with oil and/or biomass firing with the injection of compounds that duplicated the NO_x and SO_2 emissions released during coal combustion. Since these tests were performed mostly with oil, the slag, which had replaced much of the refractory liner of the combustor, melted. It will be necessary to reline the combustor with refractory to return to coal firing. This can be readily implemented without removal of the combustor from the boiler.

In addition, processes were invented for the total removal of volatile trace metal, such as mercury, that are released during coal combustion. Also, more recently, a process has been invented for converting removing the carbon dioxide from the combustion gas stream and sequestering it in the earth. Coal Tech has financed all this work of the past 7 years. As noted above, the NO_x and SO_2 processes have been tested on a 50 MMBtu/hr coal fired utility boiler.

Only the mercury capture and the carbon dioxide sequestration processes remain to be tested. With these final steps, the air-cooled slagging, cyclone combustor is capable of coal combustion with the total removal of all gas, liquid, and solid pollutants that result from coal combustion.

w) Response to DOE Reviewer Questions on the 22nd Technical Quarterly Progress Report on Task 5: 2nd Quarter 1997.

Before summarizing the conclusions from task 5, Coal Tech's responses to the 22nd Quarterly Technical Progress report will be presented. These responses were originally presented in the 24th Technical Project Report for the 4th Quarter of 1997. They are included here because they clarify what was accomplished in task 5. The DOE reviewer's questions and comments related primarily to the general and specific objectives of this project, and clarification of the procedures and results. Since these items were raised at the conclusion of the work on this project, they are an overview of the project, and represent the details of the conclusions, as stated in the next Section..

(A) Compare the Technical Accomplishment in the Project with the Goals Stated in the Original Project Contract:

The work statement to this project contained the following list of performance goals for the 20 MMBtu/hr coal fired, slagging combustor: After each goal, the status at the end of the task 5 effort is given.

1. **Primary Fuel:** "
   GOAL: Boiler-grind (i.e.70%-200 mesh) pulverized coal, coal water slurry, dry, ultra-fine coal.

   FINAL STATUS: 70% to 80% -200 mesh pulverized coal, ground off site, and delivered in 1 ton supersacks to Philadelphia has been used in all the tests. Also, brief tests were successfully implemented with 50%-100 mesh coarse ground coal. 10 tons of coal-water slurry had been successfully fired in the first-generation 20 MMBtu/hr combustor in Williamsport, PA, in 1987. This fuel is not economical. There is no need for ultra-fine coal in the slagging combustor.

2. **Secondary Fuel Capability:**
   GOAL: Fuel not specified

   FINAL STATUS: Gas and No.2 oil are used to preheat the combustor, and No.2 oil up to 10 MMBtu/hr has been co-fired with coal. Also, several days of single shift tests with No.6 oil were performed in the Williamsport combustor. (*Note added May 2003: After completion of this project, wood biomass, rice husk biomass, and 70% ash- 30% carbon, rice husk gasifier waste has been fired in the combustor.*
   .
3. **Turndown Ratio:**
   GOAL: At least 3 to 1

   FINAL STATUS: The 20 MMBtu/hr combustor has been fired with coal at rates from 8.5 to 16 MMBtu/hr. With gas only, firing rates start regularly at 1 MMBtu/hr. Most operations were in the 15 to 17 MMBtu/hr heat input ranges. Higher inputs are at present limited by boiler safety and coal feed capacity limitations. The 17,500 lb/hr, 20 MMBtu/hr, saturated steam boiler is 33 years old, and it was designed for oil/gas.

4. **Emissions:**
GOALS: SO_2< 1.2 lb/MMBtu, NO_x<0.6 lb/MMBtu, Particulates <0.03 lb/MMBtu. These goals were set on the basis of the technology in 1990.
For ultimate commercial acceptance, DOE suggested goals equal to fuel oil fired units, viz,: SO_2< 0.4 lb/MMBtu, NO_x<0.2 lb/MMBtu, Particulates <0.02

FINAL STATUS
Status of SO_2:
Task 5 tests were conducted with coals ranging from 0.42% S Indian coal to 1.5% and 2.5% S, US Bituminous coal. The results depended on many factors, only some of which are given here. The measurement results shown here were taken **downstream of the baghouse.**

-With the 37% ash, Indian coal, SO_2 emissions were reduced by 50% to **0.5 lb/MMBtu** with calcium oxide injection into the combustor.
-With 1.5% S coal, coarse calcium oxide (limestone) injection into the combustor at a Ca/S= 2, and fine calcium oxide (lime) injection into the combustor at a Ca/S=2.44, SO_2 reduction was 57% to **0.9 lb/MMBtu**
-With 1.5% S coal, and coarse calcium oxide (limestone) injection into the combustor at a Ca/S= 1.81, and fine calcium oxide (lime) injection into the boiler at Ca/S=2.7, SO_2 reduction was 90% to **0.2 lb/MMBtu** . This is one-half of the DOE's suggested goal.
-Subsequent tests with higher sulfur coal, 2.5% S, yielded lesser reductions. This result is discussed in the sub-section above for the 3rd quarter ending 9/30/97.
-After the completion of both DOE projects, Coal Tech developed an effective calcium oxide dispersal method into the post combustion zone, which resulted in SO_2 reductions of up to 80% in a simulated combustion gases having sulfur levels typical of coal.

Status of NOx:
-With staged combustion at a fuel rich stoichiometric ratio, SR1, of 85% in the combustor, the NO_x emission at the stack was measured **at 0.44 lb/MMBtu.**
-With the addition of Coal Tech's patented post combustion SNCR injection, the NO_x emission at the stack was reduced to **0.07 lb/MMBtu.** This value is less than one-half of the DOE suggested goal.
-With fuel lean combustion in the combustor, SR of 1.07, the NO_x emission at the stack was **1.09 lb/MMBtu.**
-With the addition of Coal Tech's post combustion SNCR process, the NO_x at the stack was reduced to **0.2 lb/MMBtu**.

These results were obtained by intermittent sampling at a fixed combustion gas condition. This condition was maintained at a steady condition for a sufficiently long period to allow multiple readings. A wide range of operating conditions was tested, and variations in test results were obtained. The above results are representative of the best results obtained.

-After completion of the two DOE projects, the SNCR process was further perfected. In addition extensive development testing was implemented on "reburn" with oil or biomass as the reburn fuel. NO_x reductions of about 50% were measured. This process is additive to the SNCR process. Therefore, NO_x reductions of over 90% can be obtained by combining all three processes. This process is also patented.

FINAL STATUS *of Particulates*:
The baghouse in the gas outlet of the 20 MMBtu/hr combustor was guaranteed to yield less than 0.03 lb/MMBtu by the manufacturer. In February 1997, a stack gas sampling company performed one test with EPA Method 5 stack gas sampling. The result yielded substantially higher particulates. An internal inspection of the baghouse and stack ducting showed extensive internal rusting of the wall and loose metal chips. Since the stack plume was totally clear, the higher particulate results were most probably due to these metal chips. Since the combustor removes about two-thirds to three-quarters of the coal ash as slag, dust loading on the stack is less than conventional pulverized coal fired boilers. Therefore, the goal of particulate control to at least 0.02 lb/MMBtu is achievable in a properly fabricated baghouse.

5. **Economics:**

GOAL: Allow cost recovery of the retrofit of a slagging combustor in less than 4 years, when the oil-coal price differential is $4/MMBtu or less. Retrofit means that the original boiler, and other downstream components, such as turbo-generator units are already on site at the power plant.

FINAL STATUS: At the time of preparing these comments (January 1998), $4/MMBtu oil/gas-coal cost differentials had not existed in over a decade. Instead, the differential between bituminous coal at the mine, which is about $20/ton ($0.8/MMBtu), and natural gas ($2/MMBtu) was a little over $1/MMBtu. Consequently, Coal Tech's goal for the Demonstration Task 5 had been to design the 20 MMBtu/hr combustor-boiler so as to make it **economical at a $1/MMBtu oil/gas to coal differential.** To achieve this goal, various alternate component designs were developed that reduced cost. Some were incorporated in the design of two 20 MW prototype electric power plants, and some of them were fabricated and tested in the Philadelphia facility. The status of this effort as of January 1998 was as follows:

Details:

In task 4 of this project, two 20 MW power plants were designed. One was a combined cycle with a natural gas fired turbine cycle and a coal-fired steam turbine cycle. Its capital cost was estimated at $1,200. While this was substantially lower that comparable coal fired systems, it was not a retrofit application, and it would not meet the rapid payback goal for this project. The second application was a retrofit. A 20 MW steam turbine generator system with all required power components at an existing power plant that had extensive supplies of coalmine waste was retrofitted with a slagging combustor firing into a new oil design boiler that is at most

50% of the cost of a new coal fired boiler. The retrofit included fuel storage and feed, slagging combustors, a boiler, and stack cleanup equipment. The original cost estimate was $850/kw, which was subsequently reduced to about $480/kw by removing the costly storage silos, correcting an inconsistency in the baghouse cost, etc. (Details are in Appendix "B"). However, even this lower cost requires 10 years and a $2/MMbtu coalmine waste-oil/gas differential to obtain an acceptable rate of return of 20%.

These results, which were obtained prior to the start of task 5 in 1994, were used to design the present second generation 20 MMBtu/hr combustion system. The focus was on sharply reducing the cost of the entire combustion system including the combustor-boiler and all auxiliary components. Considerable progress has been made in reducing the capital and operating costs. This in turn has lead to new approaches to marketing this technology, with a focus on overseas markets.

Note Added May 2003: *The improvements made in the task 5 effort has led to additional design changes that further lower the total system cost. For example a design was developed for very high ash coals, as are used widely in Asia, which sharply reduces the fabrication cost of the air-cooled combustor.*

Furthermore, since 1994, the oil-coal price differential has again skyrocketed to currently (March 2004) about $5/MMBtu, due mostly to the shortsightedness of "merchant" power plant developers and utilities and the ignorance of investors, who financed the construction of power plants that can run only on natural gas.

Also, increasing worldwide pressure on emission controls, as evidenced by the May 2003 debate of the Indian Ocean continent wide "Brown Cloud" which is almost certainly caused by inefficient combustion of high ash Asian coals, plus the new focus on mercury control and greenhouse gas controls, has totally changed the fuel economics. The only question is when this changeover will become effective. It is highly unlikely that Asia will shift to natural gas for electricity production. Consequently, a premium will be placed on coal fired power systems that can burn all types of coal with total control of emissions. Coal Tech's work in this project and primarily in the half-dozen years since this project was completed, has developed such a uniquely very low cost combustion system. Therefore, it will almost certainly offer the lowest total cost solution to electricity production compared to other coal fired systems or natural gas fired systems.

6: Goal of the Task 5 Testing:

The purpose of task 5 was utilize the results of the previous four tasks to design a second generation, slagging combustor system, and to perform endurance testing on this system. Endurance was defined as 500 hours of operation to validate the durability of the combustor. Environmental performance was a secondary objective.

The original project plan was based on task 5 being implemented at the same Williamsport Site as the task 1, 2 and 3 tests. Had that been the case, the 500 hours Task 5 tests would have been implemented in five or more tests with up to 100 round the clock tests with the first generation combustor for two reasons:

1) There was no room at the Williamsport site to install the longer combustor that was used in Philadelphia.
2) The cost of operating in Williamsport was much higher than in Philadelphia. Consequently, the goal of 500 hours would have been met, but the results would have been useless because the task 5 tests showed the clear need for, and the superiority of the longer combustor.

On the other hand, the project resources consumed in the move and installation of an essentially new facility precluded round the clock operation. Consequently, the 500-hour period was divided into single shift days of operation for a total of 63 days. Since every time the combustor is operated its durability is tested, operating time on other projects that use the 20 MMBtu/hr contribute to its durability. For this reason, time on the parallel DOE project is counted in the total operating time, while its number of days of testing is also reported separately.
Bottom line: A total of 107 days of operation were implemented of which 73 days were on the task 5 effort.
In addition, well over 100 additional tests days were implemented in the years after the present project ended during which major advances were made in developing post combustion emission control processes and in extending the combustor's capabilities to near total control of coal fired emissions. **All this added work was performed with Coal Tech's resources.** Had the combustor remained in Williamsport, it would have been scrapped in 1995 when the task 5 effort would have ended, the equipment would have been scrapped because Coal Tech was in no position to finance the costly operation there.

8. Objective of the 37 MW and 100 MW SNCR NO_x Control Tests:

The objective of the 100 MW utility boiler test was to determine if the post combustion NO_x control process tested in the 20 MMBtu/hr-combustor-boiler could be scaled up by a factor of 100 to a utility boiler. The results showed that Coal Tech's SNCR process did scale by a factor of 100 and it yielded comparable NO_x reduction with that obtained in other commercial non-catalytic NOx reduction processes, except that Coal Tech process is much less costly. The latter generally report about 1/3 NO_x reductions with a large number of injectors. In comparison, Coal Tech's June 1997 test, achieved a reduction 25% in the 100 MWe with only one injector. In the August test, repeated power failures in a un-locatable 115 Volts circuit breakers, combined with the distraction that it produced, resulted in poor mixing of the reagent with water, which produced erratic results. However, the next day with no operating problems, 40% reduction was achieved in the 37 MW-boiler. This reduction was subsequently reproduced on another 50 MW boiler in 1999 and exceeded to nearly 50% in 2003. The effectiveness of Coal Tech Corp's patented, extremely low cost SNCR NO_x process has been proven..

9. How is the coal loaded at the Philadelphia site?

DOE questioned the means by which off-site pulverized coal was loaded into the 4 ton pulverized coal bin. In Williamsport, the coal was delivered in a 20+ton tanker and blown into the 4 tons coal bin. For multi-day tests, the tanker remained at the test site. This was economical because the supplier of the pulverized coal was located about 15 miles from the test site. However, it was not economical when the suppliers were either 175 miles or 300 miles from Philadelphia.

Instead the coal was delivered in 1 ton supersacks, in 20 sack lots. Initially it was considered to lift the sacks to the top of the 24 feet high 4 ton bin with a permanently installed crane and dropping the coal though the bottom outlet of the supersack into the coal storage bin. However, the cost of constructing a gantry crane and moving the supersacks by forklift truck to the crane, the increased labor required, and most importantly concern over the safety of a 1 ton pulverized coal bag hoisted nearly 30 feet far outweigh the simplicity and low cost of the pneumatic system developed by Coal Tech. The supersacks were lifted by a forklift and placed over a funnel from which a blower pneumatically blew the coal into the 4 ton bin. This method was used throughout task 5.

10. Impact of ash injection on combustor performance.

The final question from DOE was on the impact of ash injection on the combustion system. Coal fly ash injection obtained from a utility power plant had been injected into the first-generation 20 MMBtu/hr combustor in Williamsport in the early 1990's. However, the small particle size of the fly ash resulted in a substantial amount blowing out of the combustor into the boiler. In the task 5 effort, the "ash" consisted of over coarse particle metal oxides with the objective of coating the combustor wall with slag. The results were inconclusive due to the difficulty of melting the particles. As reported above, the 37% ash Indian coal resulted in excellent slagging and re-coating of the combustor wall. Also, after the project ended, a 70% ash-30% carbon biomass char was burned in the combustor. This latter fuel can be used to study retention of volatile trace metals, such as mercury, in low ash coals in that the biomass can supply the high slag mass flow rates needed to capture and retain the mercury without contributing to the concentration of these volatile metals.

C-4: CONCLUSIONS TO THE TASK 5 TEST EFFORT

The previous sub-section summarizes the key technical results of task 5. This section presents some general insights that the author gained in preparing of this Final Project Report in May 2003, as well as further insights and comments gained in the editorial review of this report in March 2004..

(a) Status of the Air-Cooled Slagging Combustor at the End of Task 5

At the end of the task 5 testing in 1998, the work statement for this project had been completed and in some key areas, such as emission control, substantially exceeded. Most all the key technical issues on the operation of the combustor and its internal emission controls for SO_2 and NO_x had been resolved. **Two key issues remained**.

a.1)-*Long duration (1000's of hours), continuous operation of the combustor*. This required the installation of a complete electric power generation system, with power sales to a user, for which a design and equipment specification had been developed. While Coal Tech had proposed this task in the original proposal in 1990, no funds were available for this purpose. And it was beyond available project resources.

a.II)-*Near zero emissions from coal combustion,* including NO_x, SO_2, dioxin/furans, volatile trace metals in ash, and sequestration of carbon dioxide. This was not in the project work statement. From assessment of the coal utilization market, Coal Tech's P.I. reached the conclusion that without zero emissions, coal use would not increase significantly, and it might very well decrease. As there was no follow-contract for this project, and when Coal Tech's over one-half dozen proposals to DOE were all declined, internal resources were used in the following years to accomplish this task. At present (March 2004), only Coal Tech's inventions of a mercury emission control process and a carbon dioxide removal sequestration process remain to be experimentally demonstrated. All of these processes have either been patented or have patents pending.

Even without the last two tasks of mercury control and carbon dioxide emission control, the air-cooled cyclone combustor is today (March 2004) the lowest cost, totally environmentally friendly, coal combustion system, ready for the domestic and international energy market.

(b) ***General Observations:*** This final report is based in large part of the technical reports that were written contemporaneously with the effort on this project, which in the case of the present Appendix 'C" that deals with Task 5 , covers the 5 years from the end of 1993 through early 1998. The 5-year interval before the preparation of this Report has enabled the author to approach this work with a new and hopefully more objective point of view. One unexpected aspect of the current review was how much was accomplished during this project. It is now very clear that within the constraints of the modest resources that were available, the task 5 effort was very successful. Key results were:

- The second-generation design of the combustor solved the major problem of slag retention in the combustor, with essentially no outflow of slag into the boiler.
-Concurrently this greatly improved the combustion efficiency in that the extensive unburned carbon laden ash deposits on the boiler's furnace floor essentially disappeared.
-Almost all the steps necessary to complete the development of the air-cooled combustor for commercial use were implemented. The one item that was missing was long period operation, namely in the 2000 hour per year range and up. For that additional funds were needed and a users of steam and or electricity.
-In retrospect the most surprising result was how close we came to building a complete electric generation power plant, considering that we implemented task 5 within the budget that we had originally proposed for only the first four tasks. Our original proposal for task 5 was for a sum equal to the value of the final total contract. As it was, we could have implemented the power plant with additional funds of about one-half more than the funds that in the proposal for implementing tasks 1 through 4.

(c) ***Electric Power Generation as a Marketing Tool:*** One intriguing idea that occurred to this author in reviewing task 5 is that we should have focused on the power generation part of the plant instead of the coal part of the plant. This would have entailed purchasing the very old 600 kW Elliot steam turbine-electric generator, a very low cost new atmospheric plate condenser, and a water spray-cooling tower. Instead we focusing more on the raw coal storage and pulverization part of the plant and when its costs began to balloon out of proportion to the benefit we simply abandoned the power plant option.

Even without an outside revenue-producing customer for the electricity, we could have used up to 40% of the power for more flexible operation of the combustor. We could have purchased an electric furnace to melt scrap metals, instead of trying to develop a novel new furnace.

What motivated this idea was Coal Tech's experience in marketing the combustor. A considerable number of potential customers visited the site or contacted Coal Tech to this day, 2004. In all cases the barrier was the lack of any commercial sales, and no one wanted to be the first. With the addition of the electric generator, revenue from electricity would have been obtained and this would have assured customers of the commercial potential.

(d) ***Moving Task 5 to Philadelphia:*** The totally unanticipated event in this project was the closing of the Williamsport test site, which necessitated the move to Philadelphia. More than any other aspect of this project, it prevented the air-cooled combustor technology from premature termination. Had task 5 been implemented in Williamsport, it is almost certain that it would have been implemented with minor changes to the first generation combustor. As such we would have focused on continuous round-the-clock operation in increments of 100 hours. It was written into the work statement and it was an issue desired by potential customers. However, the first-generation combustor had severe design deficiencies, as is amply documented in this Final Report. Therefore, on a technical basis the work would have been a dead-end.

It would have also been a dead-end from a policy standpoint. As there was no follow-on to this project, all the equipment would have been scrapped, as indeed was contained in task 6 of this project. Coal Tech was in no position to finance continued work on this technology with its internal resources. On the other hand the move to Philadelphia enabled Coal Tech Corp to keep the facility operational to this day (March 2004) because the internal resources required were far lower, mainly rent. More importantly, it enabled us to develop new or improved, very low cost emission control processes for post-combustion SNCR and reburn for NOx, post-combustion SO_2, dioxins and furans for municipal waste, mercury control, and more recently carbon dioxide sequestration. Most importantly, it has made the air-cooled combustor technology available for markets in Asia and the U.S. that are now coming into focus.

(e) ***Slagging Combustor Market***: As is evident from this report, the preferred markets for the slagging combustor are users of high ash coals, which are located in Asia, primarily India, China, and Indonesia, among others. The reason for this is that extraction costs are low while revenue from exporting low ash coals is high, leaving the high ash coals for domestic use.

Conventional pulverized coal fired boiler are very inefficient when burning high ash coals. While the B&W slagging combustor can burn such coals efficiently, as a wall-burning device this can only be accomplished under high excess air, which results in very high NO_x production. An even more important disadvantage of the B&W slagging combustor is that it is water cooled, and as such it must be constructed as an integral part of the water-steam loop of the boiler. This eliminates its use in all existing boilers. A major R&D effort has been expended by another firm in the past several decades on developing a slagging combustor whose water-cooling circuit is separate from the boiler water-steam loop. However, this involves efficiency losses because the cooling water is low grade heat.

Coal Tech has recognized the major advantage of the air-cooled combustor for the high ash coal market because it can be retrofitted to almost any boiler or furnace. This was the motivation for burning the 37% ash Indian coal in task 5. Throughout the decade of the 1990's, Coal Tech had attempted to market this combustor to Indian companies, and to a lesser extent to Chinese companies. However, there was no financial incentive for these companies to switch to this technology as long as existing methods were profitable, even under inefficient combustion conditions. Similarly, there was little regulatory pressure to sharply reduce the air pollution resulting from this type of combustion, especially from foreign governments.

However, the air-cooled combustor market may change in the near future.

On May 2003, the Wall Street Journal carried a front-page story about a massive "Brown Cloud" over the Indian Ocean that is 2 miles thick with an area equal to that of the continental U.S.A. Indian environmental officials prevailed on the U.N. to cut off funding for further study of the "cloud" on grounds that it was caused by India's poor burning animal dung for cooking and stopping that would result in starvation. However, the 'cloud' is almost certainly due to inefficient combustion of the high ash (40%) Indian coals. Coal is used primarily for electricity production whose high cost places it out of reach of India's poor. According to India's Tata Energy Research Institute (TERI), New Delhi, India, the fuel consumption of animal dung in 1999 was **106.9** million metric tons (MMT) compared to over **300** MMT of coal**.**

The source of the 'cloud' can be readily verified. Biomass, including dung, firewood, and crop residue, with the exception of rice, have at most several percent ash. If biomass were the primary source of the Indian Ocean cloud, particles sampled inside the cloud would consist exclusively of black unburned carbon particles. On the other hand, if inefficient combustion of high ash Indian coal were the source, then gray ash particles would substantially exceed the black carbon in the samples.

The 1983 annual report of the World Health Organization (WHO) stated that **respiratory diseases were the main cause of death in developing countries**. Since that time, India's coal consumption has grown by about 300%, while dung consumption has increased by only 50% (TERI). China's coal consumption has also grown dramatically during this period. China also has an air pollution problem. Interestingly, whatever the origin of the SARS virus, it is a respiratory disease. Also, the results of a study by a California physician, Dr. Hightower, that was released last year found elevated levels of mercury in Californians that consumed more than the average number of fish. Mercury in coal ash is emitted during combustion, and the world winds blow from the East in Asia to the West in America.

As proven by the results of the 37% ash Indian coal test, Coal Tech's air-cooled combustor offers a low cost solution to this emission problem. Replacing all the coal burners on power plant boilers and other furnaces with this combustor would remove over 75% of the ash as chemically inert slag, which would also trap part of the mercury. In the process, all the carbon would be burned. We estimate that the cost saving from the recovered carbon energy exceeds the cost of these combustors.